August 31, 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 Rate Application, EB-2012-0161
Interrogatory Responses

On July 25, 2012, the Board issued an Issues List Decision and Procedural Order No. 2 in the above-captioned proceeding which set out a timetable for interrogatories. Accordingly, PowerStream is submitting responses to the interrogatories that were received from Board Staff and intervenors.

These interrogatory responses have been filed on RESS and two paper copies have been forwarded to the Board Secretary. Included (in a separate sealed envelope) with the material sent to the Board Secretary is a document that is being filed pursuant to the Board's Practice Direction on Confidential Filings.

This document is part of the response to School Energy Coalition IR #28 and it outlines the process for selecting a consultant based the competitive bids that were received by PowerStream. The document contains pricing information and comments on the capabilities of the consultants and its release would prejudice the competitive position of the bidders.

We trust this is satisfactory, but if there any outstanding matters, please contact the undersigned.

Yours truly,

Original signed by

Colin Macdonald,
Vice President, Rates & Regulatory Affairs

cc. All Parties

PowerStream Inc.
161 Cityview Boulevard, Vaughan, ON L4H 0A9 Tel: 905-417-6900 Fax: 905-532-4505 www.powerstream.ca

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

BOARD STAFF INTERROGATORY #1:

Reference(s): **Ref: Appendix 1 Support Schedules Schedule 11**

It is stated that the current version of PowerStream's Conditions of Service is available on PowerStream's website. With respect to this document:

a) Please identify any rates and charges that are included in the applicant's conditions of service and if there are any such rates and charges, provide an explanation for the nature of the costs being recovered.
b) If there are any such rates and charges, please provide a schedule outlining the revenues recovered from these rates and charges from 2008 to 2011 and the revenue forecasted for the 2012 bridge and 2013 test years.
c) If there are any such rates and charges, please explain whether in the applicant's view, these rates and charges should be included on the applicant's tariff sheet.

RESPONSE:

a) PowerStream Conditions of Service Section 5 Appendices and References (accessible through Conditions of Service web page) contain links to OEB approved rates and charges along with documents, forms and sample agreements identified in the Conditions of Service.

Section 1 through Section 4, of the Conditions of Service, contain clauses outlining the circumstances where PowerStream will charge customers. This are based on actual cost and relate to damages to PowerStream's equipment and capital contributions in accordance with the Distribution System Code.

b) and c) Not applicable – see response to a) above.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

BOARD STAFF INTERROGATORY #2:

Reference(s): **Updated Revenue Requirement Work Form**

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

RESPONSE:

The revised Revenue Requirement work form is attached as Table Board Staff #2-1. The proposed adjustments are listed in Table Board Staff #2-2 below:

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

Table Board Staff#2-2: Summary of Changes and Corrections

Area	Description	Reference
Cost of Capital	The EDFIN debt is refinanced on Aug.15, 2012 at a lower rate, reducing overall cost of long-term debt to 4.75%	Update to the Ex E1 T.1, S.1
OM&A	OMERS Contribution rate increase in 2013; estimated OM&A increase of $340,000	See (1) below
PP&E	The contributed capital paid for Midhurst TS to Hydro One and the corresponding amortization included	See (2) below
PP&E	Correction for amount of Fair Market Value adjustments for Aurora Assets in the PP&E transitional amount	See (3) below, Appendix 2-EA
Taxes	Change in Ontario Tax rates (rate decrease cancelled), tax rates were updated in the tax model by Board Staff	Staff #5, EP#33
Taxes	Estimated tax credits for 2013 increased by $83,000	Staff #5, EP #34
PP&E	Correction to calculation of full year depreciation on 2013 additions, increase in depreciation expense of $357,000.	See (4) below

The proposed adjustments result in a revenue requirement of $169.9 million, an increase of $0.4 million from the originally submitted revenue requirement of $169.5 million. The resulting revenue deficiency is $7.8 million.

As a result of these interrogatories and the passage of time, there is additional information available where PowerStream feels it is appropriate to update its application. These changes are summarized in Table Board Staff#2-2 above with reference to relevant interrogatories which contain additional details. Some of the changes, as noted, are discussed below.

(1) OMERS contribution rates are increasing in 2013 as per the information below from the OMERS website. PowerStream employees are in the normal retirement age 65 group and PowerStream is required to match employees' contributions.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

2012 Plan Changes: 2013 Contribution Rates

What are the contribution rates for 2013?

The contribution rates for 2013 are shown in the table below. In 2010, OMERS announced a three-year plan to increase contribution rates. The contribution rate increases set for 2013 are the third increase.

Table Board Staff#2-2: Summary of Changes and Corrections

		2012	2013
Normal retirement age 65 members	On earnings up to CPP earnings limit*	8.3%	9.0%
	On earnings over CPP earnings limit*	12.8%	14.6%
Normal retirement age 60 members	On earnings up to CPP earnings limit*	9.4%	9.3%
	On earnings over CPP earnings limit*	13.9%	15.9%

** The CPP earnings limit in 2012 is $50,100; the limit in 2013 will be higher. Contributions are tax deductible which lessens the net impact on Plan members.*

(2) In 2012, PowerStream was required to pay another $4.4 million in contributions for the Midhurst Transformer Station under the true up condition in the cost sharing agreement based on actual load.

(3) PowerStream found that the account 1575 IFRS-CGAAP Transitional PP&E amount had not been adjusted for the fair market value increase recorded on Aurora assets when Aurora Hydro was purchased November 1, 2005. These amounts had been removed from rate base

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

and depreciation expense in the calculation of revenue requirement but the depreciation amounts for the calculation of the PP&E amount had not been adjusted. This has now been corrected.

(4) In preparing responses to the interrogatories, it was discovered that some errors were made in the calculation of the additional half year depreciation on 2013 additions to bring this to a full year. These errors have been corrected in this update.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

BOARD STAFF INTERROGATORY #3:

Reference(s): <u>Updated Appendix 2-W, Bill Impacts</u>

Upon completing all interrogatories from Board staff and intervenors, please provide an updated Appendix 2-W with any corrections or adjustments that the applicant wishes to make incorporated for all classes at the typical consumption / demand levels (i.e. 800 kWh for residential, 2,000 kWh for GS<50).

RESPONSE:

The updated bill impacts are attached as Appendix E. Note that due to rate harmonization there are separate rate impacts for each of the former rate zones, South and Barrie.

As a result of the proposed updates, the revenue requirement increased by 0.18%, with minimal impacts on the monthly bills. The table below shows the summary of the total bill impacts.

Table Board Staff #3-1: Summary of Total Bill Impacts

Customer Class	*Billing Determinant*	*Consumption per customer*	*Load per customer*	Total Monthly Bill Impact			
				PowerStream South		PowerStream Barrie	
		kwh	*kW*	$	%	$	%
Residential	*kWh*	*800*	-	$ 2.83	2.6%	$ (5.09)	(4.4%)
GS<50 kW	*kWh*	*2,000*	-	$ 1.95	0.7%	$ (5.93)	(2.1%)
GS>50 kW	*kW*	*80,000*	*250*	$ 175.54	1.6%	$ (77.60)	(0.7%)
Large Use	*kW*	*2,800,000*	*7,350*	$ 14,707.62	4.2%	$ (8,200.53)	(2.2%)
USL	*kWh*	*150*	-	$ (5.76)	(16.5%)	$ (0.55)	(1.9%)
Sentinel Lights	*kW*	*180*	*1*	$ 0.65	1.9%		
Street Lighting	*kW*	*280*	*1*	$ 1.42	3.7%	$ (9.39)	(19.0%)

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

BOARD STAFF INTERROGATORY #4:

Reference(s): Updated Revenue Requirement

Upon completion of responses to all interrogatories, please identify any adjustments to the proposed service revenue requirement that the applicant wishes to make relative to the original application.

RESPONSE:

Please refer to the response to Board Staff IR #2 above, for the list of all proposed adjustments to the service revenue requirement.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

BOARD STAFF INTERROGATORY #5:

Reference(s): <u>Filing Requirements Update</u>

The Board in a letter dated January 26, 2012, identified those electricity distributors, which included PowerStream, which it expected to file a cost of service application for 2013 rates. In this regard the Board indicated that applicants that wished to request cost of service rates effective January 1, 2013 should file their applications sooner, and no later than April 27, 2012. The Board also expected that distributors filing applications in advance of any revisions to the Filing Requirements for Transmission and Distribution Applications would update their applications in due course to address any material changes that may be reflected in the revised Filing Requirements.

The Board on June 28, 2012 issued the filing requirements for 2013.

Please make any necessary updates to bring PowerStream's application into conformity with the 2013 filing requirements (including the revised Chapter 2 Appendices issued on July 12, 2012) and state what these adjustments are. For all relevant years, please file the following Appendices:

Appendix 2–B Fixed Asset Continuity Schedule,
Appendix 2–CA CGAAP Depreciation Expense 2011
Appendix 2-CB MIFRS Depreciation Expense 2011
Appendix 2-CC MIFRS Depreciation Expense 2012
Appendix 2-CD MIFRS Depreciation Expense 2013
Appendix 2-D Overhead
Appendix 2-U IFRS Transition Costs

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

Please update the PILs proxy calculations using the PILs model Income Tax/PILs Work Form_Version 2.0 as posted on the Board's website on June 28, 2012. Please ensure that the PILs filings are updated in accordance with section 2.7.8 of the Filing Requirements.

If PowerStream does not make any of these updates, please provide an explanation

RESPONSE:

PowerStream has made the following updates to its application to comply with the updated 2013 filing requirements issued June 28, 2012:

- Filing of updated Chapter 2 Appendices as detailed below
- Updated PILs model Income Tax/PILs Work Form
- Filing of 2011 tax return and other tax information as discussed below

These documents are attached to this response with the attachment reference noted in parenthesis.

PowerStream has attached the updated Chapter 2 Appendices requested:

- Appendix 2–B Fixed Asset Continuity Schedule (Attachment Board Staff 5-1)
- Appendix 2–CA CGAAP Depreciation Expense 2011(Attachment Board Staff 5-2)
- Appendix 2-CB MIFRS Depreciation Expense 2011 (Attachment Board Staff 5-2)
- Appendix 2-CC MIFRS Depreciation Expense 2012 (Attachment Board Staff 5-2)
- Appendix 2-CD MIFRS Depreciation Expense 2013 (Attachment Board Staff 5-2)
- Appendix 2-D Overhead (Attachment Board Staff 5-4)
- Appendix 2-U IFRS Transition Costs (Attachment Board Staff 5-5)

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

PowerStream has also attached the following new or updated chapter 2 appendices:

- Appendix 2–EA IFRS-CGAAP Transitional PP&E Amounts (Attachment Board Staff 5-6)
- Appendix 2–M Regulatory Costs (Attachment Board Staff 5-7)

- Board Staff has updated the OEB PILs model submitted by PowerStream to reflect the tax changes in the PILs model Income Tax/PILs Work Form Version 2.0. PowerStream has attached the updated model (Attachment Board Staff 5-8). The updated model includes the following changes resulting from the responses to these interrogatories:
    - Updating the historical test year to reflect the final 2011 tax return as filed,
    - Revised tax credit estimates based on the final 2011 return,
    - Changes in revenue requirement arising from the changes noted in the response to Board Staff IRs 2 and 4.

The 2011 tax return, filed in June 2012, is attached (Attachment Board Staff 5-9).

As per the updated Filing Requirements, section 2.7.8, PowerStream has also attached all Notices of Assessment and Notices of Re-Assessment for the three immediately prior tax years, namely 2008, 2009 and 2010 tax years (Attachment Board Staff 5-10).

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

BOARD STAFF INTERROGATORY #6:

Reference(s): <u>CDM Update</u>

The Board's Conservation and Demand Management ("CDM") Guidelines for Electricity Distributors (EB-2012-0003) at page 3 notes that: "At a minimum, distributors must apply for disposition of the balance in the LRAMVA at the time of their Cost of Service rate applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their Incentive Regulation Mechanism rate application, if the balance is deemed significant by the applicant." Board staff acknowledges that the final results for PowerStream's 2011 OPA-Contracted Province-Wide CDM programs are not currently available.

a) Does PowerStream plan to update its evidence to identify and/or seek disposition of variances between the final results of its 2011 CDM programs and the CDM savings reflected in PowerStream's 2011 rates in this proceeding after it has received the final results from the OPA?
b) What is PowerStream's plan for disposing of its LRAMVA in future applications?

RESPONSE:

a) No, PowerStream does not plan to update its evidence with respect to the final results of 2011 CDM programs based on final reports from the OPA.

b) PowerStream plans to submit requests for the disposition of the LRAMVA account on an annual basis, as part of its IRM applications, if the balance is determined to be significant.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

SEC INTERROGATORY #1:

Reference(s): [A1/2/1, p. 2]

Please provide a mathematical demonstration that the Board's use of the half year rule in setting rates on rebasing provides insufficient funding for depreciation during the initial IRM period. Please ensure that the calculations show the dollar impact of the Board's current practice taking all material variables into account.

RESPONSE:

Please see the response to Board Staff IR# 33, filed at Exhibit J1, Tab 4, Schedule 4.2.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

SEC INTERROGATORY #2:

Reference(s): [A2/1/1, p. 1]

Please provide a full list of all ways in which the Application varies from the OEB Filing Requirements, and the dollar impact, if any, of each.

RESPONSE:

PowerStream is aware of only one area where it has varied from the OEB Filing requirements and that is in respect of the inclusion of a full year's depreciation on the 2013 test year capital additions. Table SEC#2-1 below calculates the impact on revenue requirement of the additional depreciation of $1,569,000 on 2013 additions included in the application.

Table SEC#2-1: Impact of Full Year Depreciation on Revenue Requirement ($000)

Rate Base Impacts		
Reduced NBV	$	(1,569)
Less averaging effect	$	785
net impact on rate base	**$**	**(785)**
Revenue Requirement (RR) Impacts		
Rate base impact on RR	$	(51)
Depreciation increase	$	1,569
PILs grossed up (26.5%)	$	(10)
Total RR impact	**$**	**1,508**

Note: Based on weighted cost of capital of 6.51%, Debt Equity ratio of 60%-40% and tax rate of 26.5%.

There is one other area where PowerStream is in compliance with the OEB filing guidelines but wishes to take this opportunity to clarify this. The updated 2012 filing requirements re HST Deferral Account states that:

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

The applicant must provide an analysis that supports the applicant's conformity with December 2010 APH FAQS, in particular the example shown in FAQ#4.

PowerStream has complied in that it has clearly indicated its degree of conformity with *December 2010 APH FAQS, FAQ#4.* This is discussed in Exhibit I, Tab 1, Schedule 12. PowerStream has not calculated any HST savings on depreciation and explains why. PowerStream does not believe that there is any merit to the calculation shown in Table 1 – PST Savings on Capital Purchases and there is no supporting rationale in the FAQ. Accordingly PowerStream has made no attempt to quantify this.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

SEC INTERROGATORY #3:

Reference(s): [A2/1/1, p. 4]

Please file all documents, including in particular documents filed in confidence, previously filed in the EB-2008-0335 proceeding that refer directly or indirectly to the forecast savings, efficiencies, or productivity from the merger.

RESPONSE:

The request to provide all documents related directly or indirectly to the forecast savings, efficiencies or productivity from the merger cannot be provided with reasonable effort. PowerStream has attached the following documents it believes will be helpful:

- Appendix A – Summary of Merger Savings by Department
- Appendix B – June 2011 Merger Synergy Report
- Appendix C – Merger Final Report April 27, 2011 Report to Board of Directors
- Appendix D – Merger Final Report – April 30, 2010 Report to Board of Directors

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

SEC INTERROGATORY #4:

Reference(s): [A3/1/1, p. 1 and 4]

Please provide

a) the full current corporate strategy (i.e. not only the strategy map);
b) the most recent Two Year Budget;
c) the most recent Five Year Budget outlook; and
d) all presentations to executive management and the Board of Directors supporting approval of those documents.

RESPONSE:

a) The strategy map on page 3 of Exhibit A3, Tab 1, Schedule 1 is the document that guides PowerStream's current corporate strategy. PowerStream last prepared a full corporate strategy report in 2010 which addresses business planning matters including information beyond the Test Year. PowerStream declines to file this document as it is not relevant to this proceeding.

b) Please see the attachment to the response to The Consumers Council of Canada Question 1b). The attachment details PowerStream's five year budget outlook (including the two year budget) presented to PowerStream's Board of Directors on December 14, 2011.

c) Please see the attachment in response to The Consumers Council of Canada Question 1b). The attachment details PowerStream's five year budget outlook (including the two year budget) presented to PowerStream's Board of Directors on December 14, 2011.

d) Please see the attachment referred to in b) and c) above for the presentation to the Board of Directors for the approval of the two and five year budgets. Please see the attachment to the

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

response to The Consumers Council of Canada Question 2b) for the presentations to the Executive Management Team for the 2012/2013 budget.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

SEC INTERROGATORY #5:

Reference(s): [A3/1/1, p. 1 and 3]

Please provide an explanation of where keeping rates as low as reasonably possible is included in the “four perspectives” and the “strategy map”.

RESPONSE:

Although keeping rates as low as reasonably possible is not explicitly stated in the four perspectives of the balanced scorecard and in the strategy map, it is an outcome of PowerStream’s approach.

The “foundation” area focuses on managing costs for our customers by having skilled employees, ensuring a healthy workplace and making effective use of technology. These initiatives will all lead to lower costs.

The “process” area addresses our core business processes and ensuring that process improvements are made to help manage costs. It also has the aspect of proactive and positive advocacy whereby PowerStream is able to influence the regulatory process with customers in mind.

The “customers” perspective directly deals with improving service levels and reliability which must be done while managing costs.

Implicit in the “financial” perspective is the need to provide the allowed rate of return which means that both revenue and costs must be managed according to our budget.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

In totality PowerStream is very focused on efficiency improvements which will lead to lower costs and keeping rates as low as reasonably possible.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

SEC INTERROGATORY #6:

Reference(s): [A3/1/1, p. 5]

Please advise what components of the corporate budgeting process require, promote or deal with reduction to headcount.

RESPONSE:

PowerStream looks for opportunities to reduce costs by analysing any vacancies, retirement or otherwise, in order to determine if there is a possibility to reduce staff.

The search for opportunities to reduce the overall count of staff is of course counterbalanced by operational pressures to, for example, increase staff to meet PowerStream's growing customer base, growing regulatory requirements and an aging workforce.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

SEC INTERROGATORY #7:

Reference(s): [A3/1/6, p. 4]

Please provide a description of how projects of this type were managed differently prior to the introduction of the PMO. Please provide the internal business case for the establishment of the PMO.

RESPONSE:

Please see response to IR CCC # 55.

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Choose Your Utility:	File Number:	Rate Year:
Peterborough Distribution Incorporated PowerStream Inc.	EB-2012-0161	2013

Application Contact Information

Name:	Tom Barrett
Title:	Manager, Rates & Applications
Phone Number:	(905) 532-4640
Email Address:	tom.barrett@powersrteam.ca

Copyright

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Table of Contents

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)	$3,599,305	$ 805,987,960		$805,987,960	
	Accumulated Depreciation (average)	($86,568,565)	(5)	($74,323)	($86,642,888)		($86,642,888)	
	Allowance for Working Capital:							
	Controllable Expenses	$85,701,101		$340,000	$ 86,041,101		$86,041,101	
	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		$0	$162,044,558			
	Distribution Revenue at Proposed Rates	$169,487,804		$382,847	$169,870,651			
	Other Revenue:							
	Specific Service Charges	$3,385,000		$0	$3,385,000			
	Late Payment Charges	$2,500,000		$0	$2,500,000			
	Other Distribution Revenue	$2,032,000		$0	$2,032,000			
	Other Income and Deductions	$1,145,000		$0	$1,145,000			
	Total Revenue Offsets	$9,062,000	(7)	$0	$9,062,000			
	Operating Expenses:							
	OM+A Expenses	$83,906,062		$340,000	$ 84,246,062		$84,246,062	
	Depreciation/Amortization	$35,844,204	(9)	$763,218	$ 36,607,422		$36,607,422	
	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)		($21,082,904)			
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$1,832,511			$1,818,117			
	Income taxes (grossed up)	$2,449,645			$2,461,463			
	Federal tax (%)	15.00%			15.00%			
	Provincial tax (%)	10.19%			11.14%			
	Income Tax Credits	($627,700)			($710,000)			
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			
	Short-term debt Capitalization Ratio (%)	4.0%	(2)		4.0%	(2)		(2)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			
	Prefered Shares Capitalization Ratio (%)							
		100.0%			100.0%			
	Cost of Capital							
	Long-term debt Cost Rate (%)	4.96%			4.75%			
	Short-term debt Cost Rate (%)	2.08%			2.08%			
	Common Equity Cost Rate (%)	9.12%			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	$3,599,305	$805,987,960	$ -	$805,987,960
2	Accumulated Depreciation (average)	(3)	($86,568,565)	($74,323)	($86,642,888)	$ -	($86,642,888)
3	Net Fixed Assets (average)	(3)	$715,820,090	$3,524,982	$719,345,072	$ -	$719,345,072
4	Allowance for Working Capital	(1)	$122,652,505	$44,200	$122,696,705	$ -	$122,696,705
5	**Total Rate Base**		$838,472,595	$3,569,182	$842,041,777	$ -	$842,041,777

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$85,701,101	$340,000	$86,041,101	$ -	$86,041,101
7	Cost of Power		$857,779,706	$ -	$857,779,706	$ -	$857,779,706
8	Working Capital Base		$943,480,807	$340,000	$943,820,807	$ -	$943,820,807
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$122,652,505	$44,200	$122,696,705	$ -	$122,696,705

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

Version 2.20

PowerStream Inc.
Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$169,487,804	$382,847	$169,870,651	$ -	$169,870,651
2	Other Revenue	(1)	$9,062,000	$ -	$9,062,000	$ -	$9,062,000
3	Total Operating Revenues		$178,549,804	$382,847	$178,932,651	$ -	$178,932,651
	Operating Expenses:						
4	OM+A Expenses		$83,906,062	$340,000	$84,246,062	$ -	$84,246,062
5	Depreciation/Amortization		$35,844,204	$763,218	$36,607,422	$ -	$36,607,422
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	$1,103,218	$122,648,523	$ -	$122,648,523
10	Deemed Interest Expense		$23,967,373	($862,391)	$23,104,982	$964,415	$24,069,396
11	Total Expenses (lines 9 to 10)		$145,512,678	$240,827	$145,753,505	$964,415	$146,717,919
12	**Utility income before income taxes**		$33,037,126	$142,020	$33,179,146	($964,415)	$32,214,732
13	Income taxes (grossed-up)		$2,449,645	$11,818	$2,461,463	$ -	$2,461,463
14	**Utility net income**		$30,587,481	$130,202	$30,717,683	($964,415)	$29,753,269

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	$3,385,000	$ -	$3,385,000		$3,385,000
	Late Payment Charges	$2,500,000	$ -	$2,500,000		$2,500,000
	Other Distribution Revenue	$2,032,000	$ -	$2,032,000		$2,032,000
	Other Income and Deductions	$1,145,000	$ -	$1,145,000		$1,145,000
	Total Revenue Offsets	$9,062,000	$ -	$9,062,000	$ -	$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	$30,717,684	$30,717,684
2	Adjustments required to arrive at taxable utility income	($20,821,865)	($21,082,904)	($20,821,865)
3	Taxable income	$9,765,615	$9,634,780	$9,895,819
	Calculation of Utility income Taxes			
4	Income taxes	$1,832,511	$1,818,117	$1,818,117
6	Total taxes	$1,832,511	$1,818,117	$1,818,117
7	Gross-up of Income Taxes	$617,134	$643,346	$643,346
8	Grossed-up Income Taxes	$2,449,645	$2,461,463	$2,461,463
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$2,449,645	$2,461,463	$2,461,463
10	Other tax Credits	($627,700)	($710,000)	($710,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	10.19%	11.14%	11.14%
13	Total tax rate (%)	25.19%	26.14%	26.14%

Notes

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.
Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Initial Application				
		(%)	($)	(%)	($)
	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%	$54,554,853
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$471,543,395	4.75%	$22,404,403
2	Short-term Debt	4.00%	$33,681,671	2.08%	$700,579
3	**Total Debt**	60.00%	$505,225,066	4.57%	$23,104,982
	Equity				
4	Common Equity	40.00%	$336,816,711	9.12%	$30,717,684
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$336,816,711	9.12%	$30,717,684
7	**Total**	100.00%	$842,041,777	6.39%	$53,822,666
	Per Board Decision				
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$471,543,395	4.96%	$23,368,818
9	Short-term Debt	4.00%	$33,681,671	2.08%	$700,579
10	**Total Debt**	60.00%	$505,225,066	4.76%	$24,069,396
	Equity				
11	Common Equity	40.00%	$336,816,711	9.12%	$30,717,684
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$336,816,711	9.12%	$30,717,684
14	**Total**	100.00%	$842,041,777	6.51%	$54,787,080

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		$7,812,690		$8,777,105
2	Distribution Revenue	$162,044,558	$162,044,531	$162,044,558	$162,057,961	$162,044,558	$161,093,547
3	Other Operating Revenue Offsets - net	$9,062,000	$9,062,000	$9,062,000	$9,062,000	$9,062,000	$9,062,000
4	**Total Revenue**	$171,106,558	$178,549,804	$171,106,558	$178,932,651	$171,106,558	$178,932,651
5	Operating Expenses	$121,545,305	$121,545,305	$122,648,523	$122,648,523	$122,648,523	$122,648,523
6	Deemed Interest Expense	$23,967,373	$23,967,373	$23,104,982	$23,104,982	$24,069,396	$24,069,396
	Total Cost and Expenses	$145,512,678	$145,512,678	$145,753,505	$145,753,505	$146,717,919	$146,717,919
7	**Utility Income Before Income Taxes**	$25,593,880	$33,037,126	$25,353,053	$33,179,146	$24,388,639	$32,214,732
8	Tax Adjustments to Accounting Income per 2009 PILs	($20,821,865)	($20,821,865)	($21,082,904)	($21,082,904)	($21,082,904)	($21,082,904)
9	**Taxable Income**	$4,772,015	$12,215,261	$4,270,149	$12,096,242	$3,305,735	$11,131,828
10	Income Tax Rate	25.19%	25.19%	26.14%	26.14%	26.14%	26.14%
11	**Income Tax on Taxable Income**	$1,202,204	$3,077,366	$1,116,078	$3,161,563	$864,011	$2,909,496
12	**Income Tax Credits**	($627,700)	($627,700)	($710,000)	($710,000)	($710,000)	($710,000)
13	**Utility Net Income**	$25,019,376	$30,587,481	$24,946,976	$30,717,683	$24,234,628	$29,753,269
14	**Utility Rate Base**	$838,472,595	$838,472,595	$842,041,777	$842,041,777	$842,041,777	$842,041,777
	Deemed Equity Portion of Rate Base	$335,389,038	$335,389,038	$336,816,711	$336,816,711	$336,816,711	$336,816,711
15	Income/(Equity Portion of Rate Base)	7.46%	9.12%	7.41%	9.12%	7.20%	8.83%
16	Target Return - Equity on Rate Base	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%
17	Deficiency/Sufficiency in Return on Equity	-1.66%	0.00%	-1.71%	0.00%	-1.92%	-0.29%
18	Indicated Rate of Return	5.84%	6.51%	5.71%	6.39%	5.74%	6.39%
19	Requested Rate of Return on Rate Base	6.51%	6.51%	6.39%	6.39%	6.51%	6.51%
20	Deficiency/Sufficiency in Rate of Return	-0.66%	0.00%	-0.69%	0.00%	-0.77%	-0.11%
21	Target Return on Equity	$30,587,480	$30,587,480	$30,717,684	$30,717,684	$30,717,684	$30,717,684
22	Revenue Deficiency/(Sufficiency)	$5,568,104	$1	$5,770,708	($1)	$6,483,056	($964,415)
23	**Gross Revenue Deficiency/(Sufficiency)**	$7,443,273 **(1)**		$7,812,690 **(1)**		$8,777,105 **(1)**	

Notes:

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

PowerStream calculates Revenue Deficiency as difference between Revenue at current Rates and Proposed revenue (line 4).
The resulting revenue defficiency is $7,826,093 , which is by $13,403 higher than revenue deficiency calculated on line 23.

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		$84,246,062		$84,246,062	
2	Amortization/Depreciation	$35,844,204		$36,607,422		$36,607,422	
3	Property Taxes	$1,795,039		$1,795,039		$1,795,039	
5	Income Taxes (Grossed up)	$2,449,645		$2,461,463		$2,461,463	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$23,967,373		$23,104,982		$24,069,396	
	Return on Deemed Equity	$30,587,480		$30,717,684		$30,717,684	
8	**Service Revenue Requirement (before Revenues)**	$178,549,803		$178,932,652		$179,897,066	
9	Revenue Offsets	$9,062,000		$9,062,000		$ -	
10	**Base Revenue Requirement**	$169,487,803		$169,870,652		$179,897,066	
11	Distribution revenue	$169,487,804		$169,870,651		$169,870,651	
12	Other revenue	$9,062,000		$9,062,000		$9,062,000	
13	**Total revenue**	$178,549,804		$178,932,651		$178,932,651	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$1	(1)	($1)	(1)	($964,415)	(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

			Current Board-Approved			Proposed			Impact	
		Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
1	Monthly Service Charge	monthly	$ 11.9900	1	$ 11.99	$ 13.6000	1	$ 13.60	$ 1.61	13.43%
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**			**$ 26.12**	**$ 2.15**	**8.97%**
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**			**$ 34.64**	**$ 2.44**	**7.56%**
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**			**$ 108.74**	**$ 2.74**	**2.58%**
29	HST		13%		$ 13.78	13%		$ 14.14	$ 0.36	2.58%
30	**Total Bill (including Sub-total B)**				**$ 119.78**			**$ 122.88**	**$ 3.10**	**2.59%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 11.98**	-10%		**-$ 12.29**	**-$ 0.31**	**2.59%**
32	**Total Bill (including OCEB)**				**$ 107.80**			**$ 110.59**	**$ 2.79**	**2.59%**
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

#		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	$ 15.3400	1	$ 15.34	$ 13.6000	1	$ 13.60	-$ 1.74	-11.34%
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**			**$ 26.60**	**-$ 1.48**	**-5.27%**
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**			**$ 35.12**	**-$ 3.35**	**-8.71%**
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**			**$ 108.84**	**-$ 4.79**	**-4.22%**
29	HST		13%		$ 14.77	13%		$ 14.15	-$ 0.62	-4.22%
30	**Total Bill (including Sub-total B)**				**$ 128.40**			**$ 122.98**	**-$ 5.42**	**-4.22%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 12.84**	-10%		**-$ 12.30**	**$ 0.54**	**-4.21%**
32	**Total Bill (including OCEB)**				**$ 115.56**			**$ 110.68**	**-$ 4.88**	**-4.22%**
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

#		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	$ 28.6400	1	$ 28.64	$ 27.9700	1	$ 27.97	-$ 0.67	-2.34%
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	$ 0.0149	2000	$ 29.80	$ 6.60	28.45%
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**			**$ 56.17**	**$ 0.35**	**0.63%**
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**			**$ 75.41**	**$ 1.05**	**1.42%**
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**			**$ 274.96**	**$ 1.88**	**0.69%**
29	HST		13%		$ 35.50	13%		$ 35.74	$ 0.24	0.69%
30	**Total Bill (including Sub-total B)**				**$ 308.58**			**$ 310.71**	**$ 2.13**	**0.69%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 30.86**	-10%		**-$ 31.07**	**-$ 0.21**	**0.68%**
32	**Total Bill (including OCEB)**				**$ 277.72**			**$ 279.64**	**$ 1.92**	**0.69%**
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

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
1	Monthly Service Charge	monthly	$ 16.1100	1	$ 16.11	$ 27.9700	1	$ 27.97	$ 11.86	73.62%
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	$ 0.0149	2000	$ 29.80	-$ 3.00	-9.15%
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**			**$ 57.37**	**$ 2.53**	**4.61%**
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**			**$ 76.61**	**-$ 1.68**	**-2.15%**
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**			**$ 276.42**	**-$ 5.63**	**-2.00%**
29	HST		13%		$ 36.67	13%		$ 35.93	-$ 0.73	-2.00%
30	**Total Bill (including Sub-total B)**				**$ 318.71**			**$ 312.35**	**-$ 6.36**	**-2.00%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 31.87**	-10%		**-$ 31.24**	**$ 0.63**	**-1.98%**
32	**Total Bill (including OCEB)**				**$ 286.84**			**$ 281.11**	**-$ 5.73**	**-2.00%**
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

Appendix 2-B
Fixed Asset Continuity Schedule [CGAAP]
Year 2009

CCA Class	PS GL Account	GL account to map	Detail Asset Class	Depreciation Rate	Notes	COST (000's) Opening Balance	COST (000's) Additions	COST (000's) Disposals/ Adjustments	COST (000's) Closing Balance	ACCUMULATIVE DEPRECIATION (000's) Opening Balance	ACCUMULATIVE DEPRECIATION (000's) Additions	ACCUMULATIVE DEPRECIATION (000's) Disposals/ Adjustments	ACCUMULATIVE DEPRECIATION (000's) 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

CCA Class			Detail Asset Class
10			Transportation
8			Stores Equipment
8			Tools, Shop & Garage

Less: *Fully Allocated Depreciation*

Transportation	$	2,207
Stores Equipment	$	11
Tools, Shop & Garage	$	347
Net Depreciation	$	41,855

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 life. Depreciation rate shown is based on the average useful life

Appendix 2-B
Fixed Asset Continuity Schedule [CGAAP]
Year 2010

CCA Class	PS GL Account	GL account to map	Detail Asset Class	Depreciation Rate	Notes	COST (000's) Opening Balance	COST Additions	COST Disposals/ Adjustments (3)	COST Closing Balance	ACCUMULATIVE DEPRECIATION (000's) Opening Balance	ACC. DEP. Additions	ACC. DEP. Disposals/ Adjustments (3)	ACC. DEP. Closing Balance	Net Book Value (000's
on														
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

10			Transportation
8			Stores Equipment
8			Tools, Shop & Garage

Less: *Fully Allocated Depreciation*		
Transportation	$	2,424
Stores Equipment	$	4
Tools, Shop & Garage	$	363
Net Depreciation	$	45,971

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 life. Depreciation rate shown is based on the average useful life

Appendix 2-B
Fixed Asset Continuity Schedule [CGAAP]
Year **2011**

CCA Class	PS GL Account	GL account to map	Detail Asset Class	Depreciation Rate	Notes	COST (000's) Opening Balance	COST Additions	COST Disposals/ Adjustments	COST Closing Balance	ACCUMULATIVE DEPRECIATION (000's) Opening Balance	ACC. DEP. Additions	ACC. DEP. Disposals/ Adjustments	ACC. DEP. 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

CCA Class			Detail Asset Class
10			Transportation
8			Stores Equipment
8			Tools, Shop & Garage

Less: *Fully Allocated Depreciation*

Transportation	$	2,531
Stores Equipment	-$	0
Tools, Shop & Garage	$	356
Net Depreciation	$	45,756

NOTES:

1) More then one asset type in the class with different useful life. Depreciation rate shown is based on an average useful life

Adjusted Appendix 2-B
Fixed Asset Continuity Schedule [MIFRS]
Year 2011

CCA Class	GL account	Detail Asset Class	Depreciation Rate	Notes	COST (000's) Opening Balance (3)	Additions	Disposals/ Adjustments	Closing Balance	ACCUMULATIVE DEPRECIATION (000's) Opening Balance (3)	Additions	Disposals/ Adjustments	Closing Balance	Net Book Value (000's)
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	5.88%		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	2,791	(171)	2,621	91,668
47	1840	U/G Conduit	1.67%		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	4,996	218	5,215	180,071
47	1850	Line Transformers	2.92%	1	121,621	12,598	(1,172)	133,047	0	5,779	27	5,806	127,242
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	33,554	54	33,607	807,862
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	1,273	(74)	1,199	8,391
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	8,590	(33)	8,557	70,662
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	42,875	21	42,895	895,343
47	1995	Contributed Capital	varies		(220,641)	(23,754)	516	(243,879)	0	(7,281)	(1,056)	(8,338)	(235,542)
		NET DISTRIBUTION ASSETS	n/a		613,158	82,951	(1,749)	694,360	0	35,593	(1,036)	34,557	659,803

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*		
Transportation	$	1,273
Stores Equipment	-$	0
Tools, Shop & Garage	$	371
Net Depreciation	$	33,949

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 2 subclass 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).

Adjusted Appendix 2-B
Fixed Asset Continuity Schedule [MIFRS]
Year 2012

CCA Class	GL account	Detail Asset Class	Depreciation Rate	Notes	COST (000's) Opening Balance	Additions	Disposals/ Adjustments	Closing Balance	ACCUMULATIVE DEPRECIATION (000's) Opening Balance	Additions	Disposals/ Adjustments	Closing Balance	Net Book Value (000's)
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	5.88%		609	4,363	0	4,972	29	289	0	318	4,654
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	(26)	112,066	2,331	2,637	0	4,969	107,097
47	1835	O/H Cond & Devices	2.50%		94,289	11,888	(155)	106,022	2,621	3,078	(51)	5,648	100,374
47	1840	U/G Conduit	1.67%		63,374	4,271	0	67,645	1,081	1,254	0	2,334	65,311
47	1845	U/G Cond & Devices	2.22%		185,286	24,556	(700)	209,142	5,215	5,522	(198)	10,539	198,603
47	1850	Line Transformers	2.92%	1	133,047	13,542	(1,805)	144,784	5,806	6,262	(577)	11,491	133,293
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	79,269	(2,771)	917,967	33,607	32,510	(826)	65,292	852,676
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	1,199	1,409	(21)	2,586	8,899
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	0	8,679	1,482	963	0	2,445	6,235
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	(63)	89,642	8,557	8,925	(21)	17,461	72,181
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	89,754	(2,834)	1,025,159	42,895	42,168	(847)	84,217	940,942
47	1995	Contributed Capital	varies		(243,879)	(15,098)	525	(258,452)	(8,338)	(7,902)	66	(16,174)	(242,278)
		NET DISTRIBUTION ASSETS	n/a		694,360	74,656	(2,309)	766,706	34,557	34,266	(781)	68,043	698,664

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*		
Transportation	$	1,409
Stores Equipment	-$	0
Tools, Shop & Garage	$	422
Net Depreciation	$	32,436

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 2 subclass of assets within the asset group

Adjusted Appendix 2-B
Fixed Asset Continuity Schedule [MIFRS]
Year 2013

CCA Class	GL account	Detail Asset Class	Depreciation Rate	Notes	COST (000's) Opening Balance	Additions	Disposals/ Adjustments	Closing Balance	ACCUMULATIVE DEPRECIATION (000's) Opening Balance	Additions (3)	Disposals/ Adjustments	Closing Balance	Net Book Value (000's
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	5.88%		4,972	0	0	4,972	318	289	0	606	4,366
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	4,129	0	13,379	83,793
47	1820	Distribution Stations	3.33%	1	21,825	4,021	0	25,846	3,245	1,277	0	4,522	21,324
47	1830	Poles, Towers & Fixtures	2.50%		112,066	9,861	0	121,927	4,969	3,012	0	7,980	113,946
47	1835	O/H Cond & Devices	2.50%		106,022	17,940	(26)	123,936	5,648	3,673	(51)	9,269	114,667
47	1840	U/G Conduit	1.67%		67,645	2,957	(155)	70,447	2,334	1,321	0	3,655	66,792
47	1845	U/G Cond & Devices	2.22%		209,142	37,290	(700)	245,732	10,539	6,508	(198)	16,849	228,883
47	1850	Line Transformers	2.92%	1	144,784	11,683	(1,805)	154,662	11,491	6,762	(577)	17,676	136,985
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	1,441	0	3,701	21,901
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		917,967	91,584	(2,686)	1,006,866	65,292	35,428	(826)	99,894	906,972
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	2,117	0	5,364	5,508
12	1925	Computer Software	25.00%		9,993	4,405	0	14,398	4,779	3,288	0	8,067	6,331
10	1930	Transportation	8.33%	1	11,485	2,893	(131)	14,247	2,586	1,803	(17)	4,372	9,875
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%		8,679	624	0	9,303	2,445	975	0	3,420	5,883
47	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		89,642	10,852	(131)	100,363	17,461	10,544	(17)	27,988	72,375
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		1,025,159	102,436	(2,817)	1,124,778	84,217	46,703	(843)	130,077	994,701
47	1995	Contributed Capital	varies		(258,452)	(17,734)	525	(275,662)	(16,174)	(8,670)	10	(24,834)	(250,828)
		NET DISTRIBUTION ASSETS	n/a		766,706	84,702	(2,292)	849,116	68,043	38,034	(833)	105,243	743,872

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*		
Transportation	$	1,803
Stores Equipment	$	1
Tools, Shop & Garage	$	472
Net Depreciation	$	35,758

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 2 subclass of assets within the asset group
(3) The additions for 2013 includes a full year depreciation on 2013 additions

Appendix 2-C: Depreciation and Amortization Expense Summary ($000)

Schedule	Year	Basis	Calculated Depreciation	Actual Depreciation	Variance	Adjustments	Net Variance	Notes
2-CA	2011	CGAAP	$ 47,364	$ 48,643	$ (1,279)	$ 1,495	$ 216	1
2-CB	2011	MIFRS	$ 31,513	$ 35,593	$ (4,081)	$ 4,713	$ 632	2
2-CC	2012	MIFRS	$ 34,226	$ 34,266	$ (40)		$ (40)	3
2-CD	2013	MIFRS	$ 36,600	$ 38,034	$ (1,433)	$ 1,883	$ 450	4

Notes:		Adjustments	Net Variance
1a.	**2011 CGAAP Adjustments:**		
	Upon approval of the smart meter filing in 2011, depreciation was recorded for prior year's additions, both for previous years and a full year in 2011. The Calculated Depreciation treats these as current year additions and takes only a half year deprecation for 2011, thereby understating the depreciation to be recorded.	$ 1,495	
1b.	**2011 CGAAP Net Variance**		
	Difference between the actual in-service date compared to the assumed half year depreciation for 2011 additions in the Calculated Depreciation		$ 844
	Simplification of the Calculated Depreciation methodology*		$ (628)
	Total		**$ 216**
2a.	**2011 MIFRS Adjustments:**		
	Assets with shorter useful lives that became fully amortized on January 1, 2011 under IFRS required write-off of the remaining net book value into depreciation.	$ 3,218	
	Upon approval of the smart meter filing in 2011, depreciation was recorded for prior year's additions, both for previous years and a full year in 2011. The Calculated Depreciation treats these as current year additions and takes only a half year deprecation for 2011, thereby understating the depreciation to be recorded.	$ 1,495	
	Total	**$ 4,713**	
2b.	**2011 Net Variance:**		
	Difference between the actual in-service date compared to the assumed half year depreciation for 2011 additions in the Calculated Depreciation		$ 512
	Simplification of the Calculated Depreciation methodology*		$ 120
3.	**2012 Net Variance:**		
	Simplification of the Calculated Depreciation methodology*		$ (40)
4a.	**2013 Adjustment:**		
	The 2013 additions included a full year of depreciation as stated in the cost of service filing. This compares to the half year depreciation calculated by the model.	$ 1,883	
4b.	**2013 Net Variance:**		
	Simplification of the Calculated Depreciation methodology*		$ 450

* This variance is due to the simplification of the Calculated Depreciation methodology which does not take into account the actual remaining live on individual assets but uses the average remaining live of the pool. Also the Calculated Depreciation is based on averages for asset groups that contain components. As a result the Calculated Depreciation is less accurate than the Actual Depreciation. The Actual Depreciation is calculated in the fixed asset subledger which takes all these factors into account.

File Number:	EB-2012-0161
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-CA
Depreciation and Amortization Expense
Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

Year 2011 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 [3]	Less Fully Depreciated [4]	Net for Depreciation	Additions	Disposal Adjustments	Total for Depreciation	Years	Depreciation Rate	Calculated Depreciation Expense	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K	Variance [2]
		(a)	(b)	(c)	(d)	(j)	(e) = (c) + ½ x (d) + ½ x (j) [1]	(f)	(g) = 1 / (f)	(h) = (e) / (f)	(l)	(m) = (h) - (l)
1609	Barrie - Cont. Capital - Ont. Hydro		$ -	$ -	$ 609,442		$ 304,721	19	5.19%	$ 15,830	$ 28,970	$ (13,140)
1611	Computer Software (formerly Account 1925)	$ 18,544,816	$ 11,462,648	$ 7,082,168	$ 4,201,921		$ 9,183,128	3	33.33%	$ 3,061,043	$ 3,055,570	$ 5,473
1612	Land Rights (Formerly Account 1906)	$ 730,285		$ 730,285	$ 29,950		$ 745,260	0	0.00%	$ -		$ -
1805	Land	$ 10,386,334		$ 10,386,334	$ 492,972		$ 10,632,820	0	0.00%	$ -		$ -
1808	Buildings	$ 7,170,856	$ 103,323	$ 7,067,533	$ 154,346		$ 7,144,706	50	2.00%	$ 142,894	$ 142,894	$ 0
1810	Leasehold Improvements			$ -			$ -	0	0.00%	$ -		$ -
1811	Major Spare Parts (1811 is PS account)	$ 8,404,300		$ 8,404,300	$ 779,589		$ 8,794,094	0	0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 121,677,029	$ 1,123,742	$ 120,553,287	$ 4,917,684		$ 123,012,129	40	2.50%	$ 3,075,303	$ 3,070,586	$ 4,717
1820	Distribution Station Equipment <50 kV	$ 34,115,942	$ 2,756,854	$ 31,359,088	$ 2,648,450		$ 32,683,313	30	3.33%	$ 1,089,444	$ 1,094,159	$ (4,715)
1825	Storage Battery Equipment			$ -	$ -		$ -	0	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 140,109,148	$ 12,631,864	$ 127,477,284	$ 13,556,641		$ 134,255,604	25	4.00%	$ 5,370,224	$ 5,370,224	$ 0
1835	Overhead Conductors & Devices	$ 170,577,445	$ 22,838,499	$ 147,738,946	$ 7,383,703		$ 151,430,798	25	4.00%	$ 6,057,232	$ 6,057,232	$ (0)
1840	Underground Conduit	$ 112,414,030	$ 15,845,840	$ 96,568,190	$ 13,281,592		$ 103,208,986	25	4.00%	$ 4,128,359	$ 4,128,359	$ 0
1845	Underground Conductors & Devices	$ 335,710,139	$ 41,023,002	$ 294,687,137	$ 14,624,945		$ 301,999,610	25	4.00%	$ 12,079,984	$ 12,079,985	$ (0)
1850	Overhead Transformers	$ 53,644,466	$ 13,629,451	$ 40,015,015	$ 1,553,952		$ 40,791,991	25	4.00%	$ 1,631,680	$ 1,631,680	$ (0)
1850	Underground Transformers	$ 209,127,529	$ 23,802,534	$ 185,324,995	$ 11,123,226		$ 190,886,608	25	4.00%	$ 7,635,464	$ 7,635,464	$ (0)
1855	Overhead Services	$ 13,685,003	$ 1,087,655	$ 12,597,349	$ 1,435,990		$ 13,315,344	25	4.00%	$ 532,614	$ 532,614	$ (0)
1855	Underground Services	$ 91,583,493	$ 10,358,274	$ 81,225,220	$ 3,504,686		$ 82,977,563	25	4.00%	$ 3,319,103	$ 3,319,103	$ (0)
1860	Meters	$ 8,050,424	$ (1,754,605)	$ 9,805,029	$ 1,420,053	$ (2,111,358)	$ 9,459,377	25	4.00%	$ 378,375	$ 420,602	$ (42,227)
1860	Interval Meters	$ 8,375,920	$ 186,866	$ 8,189,054	$ 2,749,732	$ (281,043)	$ 9,423,398	25	4.00%	$ 376,936	$ 382,557	$ (5,621)
1860	Meters (Smart Meters)	$ 28,061,495		$ 28,061,495	$ 22,969,679		$ 39,546,334	15	6.67%	$ 2,636,422	$ 3,753,683	$ (1,117,261)
1870	Leased Properties	$ 575,421	$ 575,421	$ -	$ -		$ -	0	0.00%	$ -	$ -	$ -
1905	Land			$ -			$ -	0	0.00%	$ -		$ -
1908	Buildings & Fixtures	$ 46,053,909	$ 36,850	$ 46,017,059	$ 151,202		$ 46,092,660	50	2.00%	$ 921,853	$ 921,853	$ 0
1910	Leasehold Improvements	$ -		$ -	$ -		$ -	15	6.67%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 5,712,480	$ 995,403	$ 4,717,077	$ 100,089		$ 4,767,122	10	10.00%	$ 476,712	$ 476,712	$ 0
1915	Office Furniture & Equipment (5 years)			$ -			$ -	0	0.00%	$ -		$ -
1920	Computer Equipment - Hardware	$ 18,154,189	$ 11,171,157	$ 6,983,032	$ 1,229,491		$ 7,597,778	5	20.00%	$ 1,519,556	$ 1,519,556	$ (0)
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -			$ -	0	0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -			$ -	0	0.00%	$ -		$ -
1930	Transportation Equipment	$ 22,794,685	$ 6,946,150	$ 15,848,535	$ 1,145,265	$ (1,766,929)	$ 15,537,703	7	15.38%	$ 2,390,416	$ 2,531,334	$ (140,918)
1935	Stores Equipment	$ 187,317	$ 190,895	$ (3,578)	$ -		$ (3,578)	10	10.00%	$ (358)	$ (358)	$ 0
1940	Tools, Shop & Garage Equipment	$ 6,342,144	$ 3,061,412	$ 3,280,732	$ 558,802		$ 3,560,133	10	10.00%	$ 356,013	$ 356,013	$ 0
1945	Measurement & Testing Equipment			$ -			$ -	0	0.00%	$ -		$ -
1950	Power Operated Equipment			$ -			$ -	0	0.00%	$ -		$ -
1955	Communications Equipment	$ 2,046,516	$ 301,040	$ 1,745,477	$ 264,045		$ 1,877,499	10	10.00%	$ 187,750	$ 187,750	$ (0)
1955	Communication Equipment (Smart Meters)	$ 82,269	$ 15,608	$ 66,661	$ 14,923		$ 74,122	3	33.33%	$ 24,707	$ 24,707	$ 0
1960	Miscellaneous Equipment			$ -	$ -		$ -	0	0.00%	$ -	$ -	$ -
1961	Process Re-Engineering	$ 1,792,927	$ 1,830,514	$ (37,588)	$ 122,798		$ 23,811	3	33.33%	$ 7,937	$ 7,937	$ 0
1975	Load Management Controls Utility Premises			$ -			$ -	0	0.00%	$ -		$ -
1980	System Supervisor Equipment	$ 18,993,192	$ 3,886,687	$ 15,106,505	$ 449,936		$ 15,331,473	15	6.67%	$ 1,022,098	$ 1,022,098	$ 0
1985	Miscellaneous Fixed Assets (Sentinel Lights)			$ -	$ -		$ -	25	4.00%	$ -		$ -
1995	Contributions & Grants	$ (283,353,296)		$ (283,353,296)	$ (23,544,871)		$ (295,125,732)	25	4.00%	$ (11,805,029)	$ (11,839,437)	$ 34,407
2005	Leased Property - 80 Addiscott	$ 18,280,294		$ 18,280,294			$ 18,280,294	25	4.00%	$ 731,212	$ 731,212	$ (0)
	Total	$ 1,230,030,699	$ 184,107,083	$ 1,045,923,616	$ 87,930,235	$ (4,159,330)	$ 1,087,809,069			$ 47,363,774	$ 48,643,059	$ (1,279,285)

Notes:

1 Applicable for the standard Board policy of the "half-year" rule, that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
2 Differences are explained per exhibit D1 tab 4 schedule 1
3 Opening balance has been adjusted to reflect the Aurora fair market value adjustments as a result of the sale of Aurora Hydro to Powerstream in 2005.
4 This adjusts for assets still on the books but which have been fully amortized or depreciated.

Appendix 2-CB
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

Year **2011** **MIFRS**

Account	Description	Opening NBV as at Jan 1, 2011 [5] (a)	One Time Fully Depreciated in 2011 [7] (a1)	Adjusted NBV at Jan 1, 2011 (b) = (a) - (a1)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (b) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2011 Depreciation Expense (k) = (j) + (h)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Remove first year Fully Depreciated and SM [8] (m1)	NET VARIANCE (m2) = (m) + (m1)	Depreciation Expense on 2011 Full Year Additions (n) = (d)/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2011 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	4,246,710	-	4,246,710	4,486,806	3	4	25%	1,477,344	560,851	2,038,194	2,136,699	-98,505	358,605	260,100	1,121,702	130,623	2,468,422
1612	Land Rights (Formally known as Account 1806)	730,559	-	730,559	35,467	-	-	0%	-	-	-	-	-	-	-	-	-	-
1805	Land	10,386,334	-	10,386,334	581,498	-	-	0%	-	-	-	-	-	-	-	-	-	-
1808	Buildings	5,933,089	-	5,933,089	186,983	31	40	3%	193,658	2,337	195,995	190,634	5,361	-	5,361	4,675	-	198,332
1810	Leasehold Improvements	8,404,300	-	8,404,300	779,589	-	-	0%	-	-	-	-	-	-	-	-	-	-
1815	Transformer Station Equipment >50 kV	90,076,266	333,409	89,742,857	4,924,650	20	40	3%	4,574,341	61,558	4,635,899	4,969,781	-333,883	333,409	-474	123,116	480,666	4,216,790
1820	Distribution Station Equipment <50 kV	18,859,841	961,524	17,898,317	2,667,068	17	30	3%	1,071,379	44,451	1,115,831	2,079,067	-963,236	961,524	-1,713	88,902	16,077	1,144,204
1825	Storage Battery Equipment		-	-		-	-	0%	-	-	-		-	-	-	-	-	-
1830	Poles, Towers & Fixtures	88,422,783	-	88,422,783	12,489,807	39	45	2%	2,243,537	138,776	2,382,313	2,331,259	51,054	-	51,054	277,551	-	2,521,088
1835	Overhead Conductors & Devices	87,705,902	-	87,705,902	6,754,029	32	40	3%	2,777,488	84,425	2,861,913	2,791,433	70,480	-	70,480	168,851	-	2,946,339
1840	Underground Conduit	52,827,258	-	52,827,258	10,546,673	51	60	2%	1,029,827	87,889	1,117,716	1,080,517	37,199	-	37,199	175,778	-	1,205,605
1845	Underground Conductors & Devices	170,122,845	-	170,122,845	14,944,755	35	45	2%	4,873,184	166,053	5,039,237	4,996,348	42,888	-	42,888	332,106	-	5,205,289
1850	Line Transformers	121,620,573	-	121,620,573	11,399,873	21	32	3%	5,687,430	180,950	5,868,381	5,778,880	89,501	-	89,501	361,901	13,296	6,036,035
1855	Services (Overhead & Underground)	49,926,056	1,345,710	48,580,346	4,007,045	16	38	3%	3,066,941	53,427	3,120,368	4,468,670	-1,348,302	1,345,710	-2,592	106,855	11,916	3,161,880
1860	Meters	17,306,257	-	17,306,257	2,631,201	16	25	4%	1,113,131	52,624	1,165,755	1,102,747	63,008	-	63,008	105,248	3,145	1,215,235
1862	Meters (Smart Meters)	23,315,991	-	23,315,991	23,219,931	13	15	7%	1,851,997	773,998	2,625,994	3,735,397	-1,109,403	1,136,267	26,864	1,547,995	-	3,399,992
1905	Land		-	-		-	-	0%	-	-	-		-	-	-	-	-	-
1908	Buildings & Fixtures	39,602,555	-	39,602,555	281,899	43	50	2%	916,474	2,819	919,293	918,952	342	-	342	5,638	-	922,112
1910	Leasehold Improvements	0	-	0	-	-	10	10%	-	-	-	-	-	-	-	-	-	-
1915	Office Furniture & Equipment (10 years)	3,537,583	-	3,537,583	127,064	7	10	10%	486,004	6,353	492,358	472,593	19,764	-	19,764	12,706	7,846	490,865
1915	Office Furniture & Equipment (5 years)		-	-				0%	-	-	-		-	-	-	-		-
1920	Computer Equipment - Hardware	3,872,612	80,987	3,791,625	1,227,215	3	5	20%	1,435,737	122,722	1,558,458	1,567,918	-9,460	80,987	71,527	245,443	365,130	1,316,050
1920	Computer Equip.-Hardware(Post Mar. 22/04)			-				0%	-	-	-		-	-	-	-		-
1920	Computer Equip.-Hardware(Post Mar. 19/07)			-				0%	-	-	-		-	-	-	-		-
1930	Transportation Equipment	8,482,917	-	8,482,917	1,181,473	7	10	11%	1,196,409	62,183	1,258,592	1,273,094	-14,503	-	-14,503	124,366	522	1,320,252
1935	Stores Equipment	-2,151	-	-2,151	-569	6	10	10%	-391	-28	-419	-358	-62	-	-62	-57	-	-448
1940	Tools, Shop & Garage Equipment	1,930,578	-	1,930,578	590,928	6	10	10%	348,403	29,546	377,950	371,410	6,540	-	6,540	59,093	22,157	385,340
1945	Measurement & Testing Equipment		-	-		-	-	0%	-	-	-		-	-	-	-	-	-
1950	Power Operated Equipment		-	-		-	-	0%	-	-	-		-	-	-	-	-	-
1955	Communications Equipment	1,340,191	50,034	1,290,157	278,071	4	6	17%	331,204	23,173	354,377	398,389	-44,013	50,034	6,021	46,345	15,046	362,503
1955	Communication Equipment (Smart Meters)			-				0%	-	-	-		-	-	-	-		-
1960	Miscellaneous Equipment	0	-	0	-	-	-	0%	-	-	-	-	-	-	-	-	-	-
1975	Load Management Controls Utility Premises		-	-		-	-	0%	-	-	-		-	-	-	-	-	-
1980	System Supervisor Equipment	7,600,892	446,420	7,154,472	468,054	7	15	7%	990,963	15,602	1,006,565	1,451,653	-445,088	446,420	1,332	31,204	77,827	944,339
1985	Miscellaneous Fixed Assets		-	-		-	10	10%	-	-	-		-	-	-	-	-	-
1995	Contributions & Grants	-220,641,417	-	-220,641,417	-22,181,686	31	43	2%	-7,110,346	-260,961	-7,371,307	-7,281,282	-90,025	-	-90,025	-521,922		-7,632,268
2005	Prop. Under Capital Lease-Addiscott	17,549,082	-	17,549,082	-	24	25	4%	731,212	-	731,212	730,711	500	-	500	-	-	731,212
1609	Barrie-Cont. Capital-Ont. Hydro				609,442		17	6%	-	17,925	17,925	28,970	-11,046	-	-11,046	35,850		35,850
	Total	$ 613,157,606	$ 3,218,084	$ 609,939,523	$ 82,237,268				$ 29,285,925	$ 2,226,672	$ 31,512,597	$ 35,593,484	-$ 4,080,886	$ 4,712,956	$ 632,069	$ 4,453,344	$ 1,144,252	$ 32,595,017

Notes:

1. Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
2. The applicant must provide an explanation of material variances in evidence
3. The applicant should ensure that the years for new additions of assets are the asset useful lives determined by management in accordance with IFRS.
4. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding 2011 additions) under IFRS. For example, Asset A had a useful life of 20 years under CGAAP. On January 1, 2011, the date of transiti
5. NBV must exclude assets still on the books but which have been fully amortized or depreciated.
6. This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next works
7. Assets with shorter useful lives under IFRS that became fully depreciated on January 1, 2011 were removed from the depreciation calculation as the NBV was written-off in entirety during fiscal 2011.
8. Adjustments were made for the fully depreciated assets that were written-off during the year (see note 7) and for the impact of the full year depreciation on prior year additions of software and smart meter assets transferred from the smart meter deferral account.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes**

Appendix 2-CC
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

2012 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2012 Depreciation Expense [1] (h)=2011 Full Year Deprecation + ((d)*0.5)/(f)	2012 Depreciation Expense per Apppendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2012 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [3] (o) = 2011 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 1,243,000	4	25%	$ 2,623,797	$ 2,626,000	-$ 2,203	$ 310,750	$ 381,085	$ 2,398,087
1612	Land Rights (Formally known as Account 1906)	$ 39,000	0	0%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ -	0	0%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 6,000	40	3%	$ 198,407	$ 196,000	$ 2,407	$ 150	$ -	$ 198,482
1810	Leasehold Improvements	$ -	0	0%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 2,115,033	40	3%	$ 4,243,228	$ 4,298,534	-$ 55,306	$ 52,876	$ 203,868	$ 4,065,798
1820	Distribution Station Equipment <50 kV	$ 297,750	30	3%	$ 1,149,167	$ 1,165,446	-$ 16,279	$ 9,925	$ 15,160	$ 1,138,970
1825	Storage Battery Equipment		0	0%	$ -		$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 11,153,052	45	2%	$ 2,645,011	$ 2,637,276	$ 7,736	$ 247,846	$ -	$ 2,768,934
1835	Overhead Conductors & Devices	$ 11,783,767	40	3%	$ 3,093,636	$ 3,077,828	$ 15,807	$ 294,594	$ -	$ 3,240,933
1840	Underground Conduit	$ 4,271,108	60	2%	$ 1,241,197	$ 1,253,568	-$ 12,370	$ 71,185	$ -	$ 1,276,790
1845	Underground Conductors & Devices	$ 24,054,004	45	2%	$ 5,472,556	$ 5,521,929	-$ 49,373	$ 534,533	$ -	$ 5,739,823
1850	Line Transformers	$ 12,313,904	31.5	3%	$ 6,231,494	$ 6,262,167	-$ 30,673	$ 390,918	$ 36,901	$ 6,390,051
1855	Services (Overhead & Underground)	$ 3,697,000	37.5	3%	$ 3,211,173	$ 3,233,000	-$ 21,827	$ 98,587	$ 22,193	$ 3,238,274
1860	Meters	$ 2,471,345	25	4%	$ 1,264,661	$ 1,158,821	$ 105,841	$ 98,854	$ 3,145	$ 1,310,944
1862	Meters (Smart Meters)	$ 759,000	15	7%	$ 3,425,292	$ 3,417,000	$ 8,292	$ 50,600	$ -	$ 3,450,592
1905	Land		0	0%	$ -		$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 1,513,000	50	2%	$ 937,242	$ 939,000	-$ 1,758	$ 30,260	$ -	$ 952,372
1910	Leasehold Improvements	$ -	10	10%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 378,000	10	10%	$ 509,765	$ 494,400	$ 15,365	$ 37,800	$ 5,272	$ 523,393
1915	Office Furniture & Equipment (5 years)			0%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 3,758,400	5	20%	$ 1,691,890	$ 1,679,140	$ 12,750	$ 751,680	$ 353,440	$ 1,714,290
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0%	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ 1,916,000	9.5	11%	$ 1,421,094	$ 1,408,603	$ 12,491	$ 201,684	$ 24,748	$ 1,497,188
1935	Stores Equipment	$ 7,000	10	10%	-$ 98	-$ 358	$ 260	$ 700	$ -	$ 252
1940	Tools, Shop & Garage Equipment	$ 712,000	10	10%	$ 420,940	$ 421,564	-$ 625	$ 71,200	$ 37,336	$ 419,204
1945	Measurement & Testing Equipment		0	0%	$ -		$ -	$ -	$ -	$ -
1950	Power Operated Equipment		0	0%	$ -		$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 336,000	6	17%	$ 390,503	$ 394,000	-$ 3,497	$ 56,000	$ 9,800	$ 408,703
1955	Communication Equipment (Smart Meters)			0%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	0	0%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises		0	0%	$ -		$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 580,000	15	7%	$ 963,672	$ 962,617	$ 1,055	$ 38,667	$ 46,286	$ 936,720
1985	Miscellaneous Fixed Assets		10	10%	$ -		$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 14,639,000	42.5	2%	-$ 7,804,492	-$ 7,902,361	$ 97,870	-$ 344,447	$ -	-$ 7,976,715
2005	Prop. Under Capital Lease-Addiscott	$ -	25	4%	$ 731,212	$ 733,000	-$ 1,788	$ -	$ -	$ 731,212
1609	Barrie-Cont. Capital-Ont. Hydro	$ 4,362,575	17	6%	$ 164,161	$ 288,622	-$ 124,461	$ 256,622		$ 292,472
	Total	$ 73,127,939			$ 34,225,509	$ 34,265,796	-$ 40,287	$ 3,260,983	$ 1,139,233	$ 34,716,768

Notes:

1. Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
2. The applicant must provide an explanation of material variances in evidence
3. This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next works

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes o**

Appendix 2-CD
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	Additional 1/2 depreciation on 2013 additions [3] (m1)	Net Variance (m2) = (m) + (m1)
1611	Computer Software (Formally known as Account 1925)	$ 4,405,000	4	25%	$ 2,948,712	$ 3,287,625	-$ 338,913	$ 550,625	$ 211,712
1612	Land Rights (Formally known as Account 1906)	$ 41,000	0	0%	$ -	$ -	$ -		$ -
1805	Land	$ -	0	0%	$ -	$ -	$ -		$ -
1808	Buildings	$ 15,000	40	3%	$ 198,670	$ 196,188	$ 2,482	$ 188	$ 2,670
1810	Leasehold Improvements	$ -	0	0%	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 74,909	40	3%	$ 4,066,734	$ 4,129,369	-$ 62,635	$ 936	-$ 61,699
1820	Distribution Station Equipment <50 kV	$ 4,021,380	30	3%	$ 1,205,993	$ 1,277,229	-$ 71,237	$ 67,023	-$ 4,214
1825	Storage Battery Equipment		0	0%	$ -		$ -		$ -
1830	Poles, Towers & Fixtures	$ 9,860,995	45	2%	$ 2,878,501	$ 3,011,875	-$ 133,374	$ 109,567	-$ 23,808
1835	Overhead Conductors & Devices	$ 17,965,484	40	3%	$ 3,465,501	$ 3,672,618	-$ 207,117	$ 224,569	$ 17,452
1840	Underground Conduit	$ 2,802,382	60	2%	$ 1,300,143	$ 1,321,090	-$ 20,947	$ 23,353	$ 2,407
1845	Underground Conductors & Devices	$ 36,788,092	45	2%	$ 6,148,579	$ 6,508,187	-$ 359,607	$ 408,757	$ 49,149
1850	Line Transformers	$ 10,454,500	31.5	3%	$ 6,555,996	$ 6,762,431	-$ 206,435	$ 165,944	-$ 40,491
1855	Services (Overhead & Underground)	$ 3,789,000	37.5	3%	$ 3,288,794	$ 3,339,125	-$ 50,331	$ 50,520	$ 189
1860	Meters	$ 3,194,655	25	4%	$ 1,374,837	$ 1,440,846	-$ 66,010	$ 63,893	-$ 2,116
1862	Meters (Smart Meters)	$ 717,000	15	7%	$ 3,474,492	$ 3,480,900	-$ 6,408	$ 23,900	$ 17,492
1905	Land		0	0%	$ -		$ -		$ -
1908	Buildings & Fixtures	$ 284,000	50	2%	$ 955,212	$ 957,840	-$ 2,628	$ 2,840	$ 212
1910	Leasehold Improvements	$ -	0	0%	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 29,000	10	10%	$ 524,843	$ 509,850	$ 14,993	$ 1,450	$ 16,443
1915	Office Furniture & Equipment (5 years)			0%	$ -		$ -		$ -
1920	Computer Equipment - Hardware	$ 2,013,600	5	20%	$ 1,915,650	$ 2,117,220	-$ 201,570	$ 201,360	-$ 210
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0%	$ -		$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0%	$ -		$ -		$ -
1930	Transportation Equipment	$ 2,779,000	9.5	11%	$ 1,643,451	$ 1,802,514	-$ 159,063	$ 146,263	-$ 12,799
1935	Stores Equipment	$ -	10	10%	$ 252	$ 642	-$ 390	$ -	-$ 390
1940	Tools, Shop & Garage Equipment	$ 538,000	10	10%	$ 446,104	$ 472,464	-$ 26,360	$ 26,900	$ 540
1945	Measurement & Testing Equipment		0	0%	$ -		$ -		$ -
1950	Power Operated Equipment		0	0%	$ -		$ -		$ -
1955	Communications Equipment	$ 65,000	6	17%	$ 414,120	$ 420,417	-$ 6,297	$ 5,417	-$ 880
1955	Communication Equipment (Smart Meters)			0%	$ -		$ -		$ -
1960	Miscellaneous Equipment	$ -	0	0%	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises		0	0%	$ -		$ -		$ -
1980	System Supervisor Equipment	$ 624,000	25	4%	$ 949,200	$ 975,417	-$ 26,217	$ 12,480	-$ 13,737
1985	Miscellaneous Fixed Assets			0%	$ -		$ -		$ -
1995	Contributions & Grants	-$ 17,219,494	42.5	2%	-$ 8,179,297	-$ 8,669,819	$ 490,521	-$ 202,582	$ 287,939
2005	Prop. Under Capital Lease-Addiscott	$ -	25	4%	$ 731,212	$ 731,000	$ 212	$ -	$ 212
1609	Barrie-Cont. Capital-Ont. Hydro	$ -	17	6%	$ 292,472	$ 288,622	$ 3,850	$ -	$ 3,850
	Total	83,242,503			36,600,170	38,033,650	- 1,433,481	1,883,402	449,921

Less fully allocated depreciation:	
Transportation Equipment	$ (1,802,514)
Stores Equipment	$ (642)
Tools, Shop & Garage Equipment	$ (472,464)
Subtotal	$ 35,758,030
Depreciation expense adjustment resulting from amortization of Account 1575	$ (596,714)
Total Depreciation expense to be included in the test year revenue requirement	$ 35,161,316

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

3 As stated in the cost of service filing, the 2013 additions included a full year of depreciation expense. Since the model calculated depreciation using a half year, an incremental half year of depreciation has been added.

General: Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes o

Appendix 2-D
Overhead Expense

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that are currently capitalized on self-constructed assets under MIFRS or

Nature of the Overhead Costs		(A) [1] Dollar Impact on PP&E Historic Year	(B) Dollar Impact on PP&E Bridge Year	(C) Dollar Impact on PP&E Test Year	(D) Dollar Impact - PP&E Variance est versus Bridg	(E) [1] Dollar Impact - PP&E Variance est versus Histor	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits					$ -	$ -		No additional payroll benefit related costs are currently being capitalized under MIFRS in comparision to CGAAP
costs of site preparation					$ -	$ -		No additional costs of site preparation are currently being capitalized under MIFRS in comparision to CGAAP
initial delivery and handling costs					$ -	$ -		No additional initial delivery and handling costs are currently being capitalized under MIFRS in comparision to CGAAP
costs of testing whether the asset is functioning properly					$ -	$ -		No additional costs of testing whether the asset is functioning properly are currently being capitalized under MIFRS in comparision to CGAAP
professional fees					$ -	$ -		No additional professional fees are currently being capitalized under MIFRS in comparision to CGAAP
					$ -	$ -		
costs of opening a new facility					$ -	$ -		These types of costs are expensed under both CGAAP and MIFRS and do not form part of self-constructed assets.
costs of introducing a new product or service (including costs of advertising and promotional activities)					$ -	$ -		These types of costs are expensed under both CGAAP and MIFRS and do not form part of self-constructed assets.
costs of conducting business in a new location or with a new class of customer (including costs of staff training)					$ -	$ -		These types of costs are expensed under both CGAAP and MIFRS and do not form part of self-constructed assets.
administration and other general overhead costs					$ -	$ -		No additional Administration and general overhead costs are currently being capitalized under MIFRS in comparision to CGAAP (See below for Administration and General Overhead costs that are no longer capitalized under MIFRS in comparison to CGAAP).
					$ -	$ -		
					$ -	$ -		
					$ -	$ -		
Insert description of additional item(s) and new rows if needed.					$ -	$ -		
Total		$ -	$ -	$ -	$ -	$ -		

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that were capitalized on self-constructed assets under CGAAP but are no l

Nature of the Overhead Costs ($000)	(A) [1] Dollar Impact on OM&A Historic Year	(B) Dollar Impact on OM&A Bridge Year	(C) Dollar Impact on OM&A Test Year	(D) Dollar Impact - OM&A Variance est versus Bridg	(E) [1] Dollar Impact - OM&A Variance est versus Histor	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are not allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits				$ -	$ -		
costs of site preparation				$ -	$ -		
initial delivery and handling costs				$ -	$ -		
costs of testing whether the asset is functioning properly				$ -	$ -		
professional fees				$ -	$ -		
costs of opening a new facility				$ -	$ -		
costs of introducing a new product or service (including costs of advertising				$ -	$ -		
costs of conducting business in a new location or with a new class of				$ -	$ -		
administration and other general overhead costs (Engineering Burden)	8,491	8,491	8,491	$ -	$ -	N	These costs include the labour costs, related benefits and other administrative costs that can not be attributed directly to a specific capital project and therefore are no longer allowed being apitalized under MIFRS.
administration and other general overhead costs (Payroll Burden)	2,472	2,472	2,472	$ -	$ -	N	These costs include labour costs for meetings, training and unproductive time (i.e. weather related downtime) and related benefits, temporary help and memberships. These costs are not directly attributable to a specific capital project and therefore are no longer allowed being capitalized under MIFRS.
administration and other general overhead costs (Vehicle Burden)	328	328	328	$ -	$ -	N	These costs include building allocation costs and the costs of leased vehicles as well as training, memberships and temporary help. These costs are not directly attributable to a specific capital project and therefore are no longer allowed being capitalized under MIFRS.
administration and other general overhead costs (Stores Burden)	208	208	208	$ -	$ -	N	These costs include building allocation costs, training costs, memberships, temporary help and management above the level of Manager. These costs are not directly attributable to a specific capital project and therefore are no longer allowed being capitalized under MIFRS.
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	11,500	11,500	11,500	$ -	$ -		

Notes:

1 If the applicant chooses to adopt IFRS or an alternate accounting standard for financial reporting purposes in 2013, the applicant does not need to complete Columns A, E. If the applicant adopts IFRS or an alternate accounting standard for financial reporting purposes in 2012, the applicant must complete all columns.

Appendix 2-U
One-Time Incremental IFRS Transition Costs

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include one-time incremental IFRS transition costs that are currently included in Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2009 [4]	Audited Actual Costs Incurred 2010	Audited Actual Costs Incurred 2011	Audited Carrying Charges to Dec 31, 2011	Total Audited Actual Costs to Dec 31, 2011	RRR 2.1.7 Balance 31-Dec-11	Variance [2]	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
professional accounting fees	$ 950,435	$ 373,686	$ 192,785	$ 41,944	$ 1,558,850			IFRS consulting and external audit work related to changeover to IFRS.
professional legal fees	$ -	$ -	$ -	$ -	$ -			
salaries, wages and benefits of staff added to support the transition to IFRS	$ 10,204	$ 25,817	$ 94,812	$ 2,418	$ 133,251			Temporary contract staff working exclusively on IFRS or back-filling for regular staff engaged in IFRS work
associated staff training and development costs	$ 1,196	$ 10,063	$ 2,889	$ 316	$ 14,464			Training for staff on IFRS, implementation and new processes.
costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion	$ 22,890	$ 73,640	$ 158,980	$ 4,938	$ 260,448			JD Edwards software consultant provided assistance in determining how to use the existing accounting system to implement IFRS, setting up the new ledgers and reports, assisting with testing and determining changes to processing.
					$ -			
Approved Funding in Rates [3]	-$ 372,500	-$ 869,164	-$ 744,996	-$ 42,397	-$ 2,029,057			
					$ -			
					$ -			
					$ -			
					$ -			
					$ -			
Insert description of additional item(s) and new rows if needed.					$ -			
Total	$ 612,225	-$ 385,958	-$ 295,530	$ 7,219	-$ 62,044	-$ 62,044	-$ 0	

Note:

1 The Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account are exclusively for necessary, incremental transition costs and shall not include ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS costs shall not include capital assets or expenditures.

2 Applicants are to provide an explanation of material variances in evidence. This amount was included in account 1508 that was filed for 2011 Q4 RRR.

3 OEB approved funding for IFRS transition per 2009 Cost of service application

4 Includes 2008 consulting /accounting expenditures of 401,285

Appendix 2-EA
IFRS-CGAAP Transitional PP&E Amounts
2012 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2012 for financial reporting purposes

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2012.

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$				
PP&E Values under CGAAP								
Opening net PP&E - Note 1			643,487,859	687,078,767				
Additions			92,477,737	92,770,195				
Depreciation (amounts should be negative)			(48,886,829)	(49,101,931)				
Closing net PP&E (1)			687,078,767	730,747,031				
PP&E Values under MIFRS (Starts from 2011, the transition year)								
Opening net PP&E - Note 1			643,487,859	687,999,146				
Additions			81,344,596	81,020,195				
Depreciation (amounts should be negative)			(36,833,309)	(35,696,725)				
Closing net PP&E (2)			687,999,146	733,322,616				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)			(920,379)	(2,575,585)				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance			-	(920,379)	(2,575,585)	(1,931,689)	(1,287,793)	(643,896)
Amounts added in the year			(920,379)	(1,655,206)				
Sub-total			(920,379)	(2,575,585)	(2,575,585)	(1,931,689)	(1,287,793)	(643,896)
Amount of amortization, included in depreciation expense - Note 2					643,896	643,896	643,896	643,896
Closing balance in deferral account			(920,379)	(2,575,585)	(1,931,689)	(1,287,793)	(643,896)	-
FMV Bump Adjustment[5]			**2011**	**2012**				
CGAAP - remove depreciation on FMV bump			244,728	244,728				
MIFRS - remove depreciation on FMV bump			150,363	150,363				
Annual Difference			94,365	94,365				
PPE Closing balance Difference			94,365	188,730				
Adjusted Closing balance in deferral account			(826,014)	(2,386,855)				

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	(596,714)	**WACC**	
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	-	**Disposition Period - Note 4**	**4**
Amount included in Revenue Requirement on rebasing	(596,714)		

Notes:

1 For an applicant that adopts IFRS on January 1, 2012, the PP&E values as of January 1, 2011 under both CGAAP and MIFRS should be the same.

2 Amortization of the deferred balance in Account 1575 will start from the rebasing year.
Assume the utility requests for a certain disposition period, the amortization that should be included in the depreciation expense is calculated as:
the opening balance of Account 1575 / the approved disposition period

3 Return on rate base associated with deferred balance is calculated as:
the deferred account opening balance as of 2013 rebasing year x WACC
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

4 Consistent with the 4 year normal rate cycle, the model is using a 4 year amortization period as a default selection to "clear" the PP&E deferral account through a one-time adjustment to rate base to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS.

5. The accounting numbers include depreciation on the fair market value (FMV bump) increase recorded on the Aurora assets at the time of the purchase of Aurora Hydro in 2005.
The FMV bump is not allowed for rate purposes, it is excluded from rate base and the depreciation on this amount is also excluded in determining revenue requirement.

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2009 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E) ***Note 1***	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655.4565		On-Going	$ 992,906	$ 1,010,494	$ 1,102,500	9.11%	$ 1,157,625	5.00%
2	OEB Section 30 Costs (Applicant-originated)	5665-1265		On-Time	$ 7,499	$ 5,115	$ 170,000	3223.56%	$ 110,000	-35.29%
3	OEB Section 30 Costs (OEB-initiated)	**5655**-1265		On-Going	$ 50,303		$ -		$ -	
4	Expert Witness costs for regulatory matters			On-Time	$ -					
5	Legal costs for regulatory matters	5630-1262		On-Time	$ 722,072	$ 59,420	$ 610,000	926.59%	$ 110,000	-81.97%
6	Consultants' costs for regulatory matters	5630-1261		On-Time	$ 125,346	$ 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	$ 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	9083		On-Going	$ 104,282	$ 136,989	$ 139,000	1.47%	$ 141,000	1.44%
10	Any other costs for regulatory matters (please define)									
11	Intervenor costs	**5655**-1265		On-Time	$ 196,426	$ 45,713	$ 80,000	75.00%	$ 50,000	-37.50%
12	Sub-total - Ongoing Costs [3]		$ -		$ 1,756,229	$ 1,829,144	$ 1,930,057	5.52%	$ 2,068,002	7.15%
13	Sub-total - One-time Costs [4]		$ -		$ 1,051,343	$ 196,651	$ 1,010,000	413.60%	$ 320,000	-68.32%
14	Total		$ -		$ 2,807,572	$ 2,025,795	$ 2,940,057	45.13%	$ 2,388,002	-18.78%

1 Please identify the resources involved.
2 Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown between one-time and ongoing costs.
3 Sum of all ongoing costs identified in rows 1 to 11 inclusive.
4 Sum of all one-time costs identified in rows 1 to 11 inclusive.

Please fill out the following table for all one-time costs related to this cost of service application

		Historical Year(s)	2012 Bridge Year	2013 Test Year	
4	Expert Witness costs for regulatory matters	$ -	$ -	$ -	
5	Legal costs for regulatory matters (***Note 3***)	$ -	$ 560,000	$ 60,000	
6	Consultants' costs for regulatory matters	$ 68,345	$ 150,000	$ 50,000	
7	Operating expenses associated with staff resources allocated to regulatory matters (***Note 2***)	$ -	$ -	$ -	
8	Operating expenses associated with other resources allocated to regulatory matters [1]	$ -	$ -	$ -	
11	Intervenor costs		$ 80,000	$ 50,000	
	Total	**$ 68,345**	**$ 790,000**	**$ 160,000**	**$ 1,018,345**

Notes:
1. The amounts in column E represent Actual 2009 regulatory expenses. This information is not available for 2009 Board Approved regulatory expenses.
2. The operating expenses associated with staff resources are on-going; there is no incremental one-time spending in this category.
3. Only the legal costs associated with 2013 EDR application are included

V1.2

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Choose Your Utility:

PowerStream Inc. - South
PUC Distribution Inc.
Renfrew Hydro Inc.
Rideau St. Lawrence Distribution Inc.

Application Contact Information

Name: Tom Barrett

Title: Manager, Rates & Applications

Phone Number: 905-532-4640

Email Address: tom.barrett@powerstream.ca

Copyright

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

Table of Contents

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Data Input Sheet - Applicant's Rate Base

Rate Base			**$ 842,041,777**	

Return on Rate Base

Deemed ShortTerm Debt %	4.00%	T	$ 33,681,671	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$ 471,543,395	*X = S * U*
Deemed Equity %	40.00%	V	$ 336,816,711	*Y = S * V*
Short Term Interest Rate	2.08%	Z	$ 700,579	*AC = W * Z*
Long Term Interest	4.75%	AA	$ 22,404,403	*AD = X * AA*
Return on Equity (Regulatory Income)	9.12%	AB	**$ 30,717,684**	*AE = Y * AB*
Return on Rate Base			**$ 53,822,666**	*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%
Ontario income tax	11.75%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%
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%

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	426,135,939		426,135,939
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			0
2	Distribution System - pre 1988	57,651,853		57,651,853
8	General Office/Stores Equip	53,476,965	3,026	53,473,939
10	Computer Hardware/ Vehicles	6,454,618		6,454,618
10.1	Certain Automobiles			0
12	Computer Software	1,901,386	4,005	1,897,381
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	1,051,144		1,051,144
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	469,386		469,386
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment	4,266,141	4,266,141	0
45	Computers & Systems Software acq'd post Mar 22/04	218,219		218,219
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	226,137,176		226,137,176
50	Data Network Infrastructure Equipment - post Mar 2007	1,009,282		1,009,282
52	Computer Hardware and system software			0
95	CWIP	30,601,600	87,527	30,514,073
				0
				0
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	**810,114,568**	**4,360,699**	**805,753,869**

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 =**	22,463	
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	
			22,463	**22,463**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**7,140,445**
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				**7,140,445**
Current Year Deduction		**7,140,445**	**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	307,333		307,333
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
Provision for regulatory assets/liabilities	792,000		792,000
			0
Total	**18,436,542**	**0**	**18,436,542**

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	550,089		550,089
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	18,436,542		18,436,542
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		100,039		100,039
Apprentice tax credit		111,672		111,672
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
SR&ED expenditures deducted per financial statements		352,794		352,794
				0
				0
Total Additions		**74,502,159**	**87,554**	**74,414,605**

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	59,658,035	1,426,388	58,231,647
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	2,290,771	788,951	1,501,820
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)		30,908	30,908	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		**89,176,731**	**2,249,631**	**86,927,100**
Net Income for Tax Purposes		**20,851,386**	**-4,758,907**	**25,610,293**
Charitable donations from Schedule 2	311	550,089		550,089
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		**20,301,297**	**-4,758,907**	**25,060,204**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

Wires Only

Regulatory Taxable Income						$ 25,060,204	A
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.75%	B	$ 2,944,574	C = A * B		
Small business credit	Ontario Small Business Threshold	$ 500,000	D				
	Rate reduction (negative)	-7.25%	E	-$ 36,240	F = D * E		
Ontario Income tax						$ 2,908,334	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.61%	K = J / A		
	Federal tax rate			16.50%	L		
	Combined tax rate					28.11%	M = L + L
Total Income Taxes						**$ 7,043,268**	N = A * M
Investment Tax Credits						$ 601,332	O
Miscellaneous Tax Credits						$ 227,277	P
Total Tax Credits						**$ 828,609**	Q = O + P
Corporate PILs/Income Tax Provision for Bridge Year						**$ 6,214,659**	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	$ 426,135,939	$ 1,519,000		$ 427,654,939	$ 759,500	$ 426,895,439	4%	$ 17,075,818	$ 410,579,121
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 57,651,853			$ 57,651,853	$ -	$ 57,651,853	6%	$ 3,459,111	$ 54,192,742
8	General Office/Stores Equip	$ 53,473,939	$ 2,772,000		$ 56,245,939	$ 1,386,000	$ 54,859,939	20%	$ 10,971,988	$ 45,273,951
10	Computer Hardware/ Vehicles	$ 6,454,618	$ 1,958,000		$ 8,412,618	$ 979,000	$ 7,433,618	30%	$ 2,230,085	$ 6,182,533
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 1,897,381	$ 1,243,000		$ 3,140,381	$ 621,500	$ 2,518,881	100%	$ 2,518,881	$ 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	$ 1,051,144			$ 1,051,144	$ -	$ 1,051,144	0.0	$ 36,882	$ 1,014,262
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 469,386			$ 469,386	$ -	$ 469,386	8%	$ 37,551	$ 431,835
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	$ 218,219			$ 218,219	$ -	$ 218,219	45%	$ 98,199	$ 120,020
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 226,137,176	$ 62,131,975	-$ 700,000	$ 287,569,151	$ 30,715,988	$ 256,853,164	8%	$ 20,548,253	$ 267,020,898
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	$ 30,514,073			$ 30,514,073	$ -	$ 30,514,073		$ -	$ 30,514,073
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 805,753,869	$ 73,381,975	-$ 700,000	$ 878,435,844	$ 36,340,988	$ 842,094,857		$ 58,720,492	$ 819,715,352

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	307,333		307,333	291,000	307,333	291,000	-16,333	
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	
Provision for regulatory assets/liabilities	792,000		792,000			792,000	0	
	0		0			0	0	
Total	**18,436,542**	**0**	**18,436,542**	**20,320,000**	**17,644,542**	**21,112,000**	**2,675,458**	**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	29,049,863

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	21,112,000
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		486,671
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		**61,416,421**

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	58,720,492
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	18,436,542
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		904,600
Total Deductions		**80,288,524**
Net Income for Tax Purposes		**10,177,760**
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		**9,544,010**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

PILs Tax Provision - Bridge Year

Wires Only

Regulatory Taxable Income						$ 9,544,010	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 1,097,561	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction	-7.00%	**E**	-$ 35,000	**F = D * E**		
Ontario Income tax						$ 1,062,561	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.13%	**K = J / A**		
	Federal tax rate			15.00%	**L**		
	Combined tax rate					26.13%	**M = L + L**
Total Income Taxes						**$ 2,494,163**	**N = A * M**
Investment Tax Credits						$ 473,100	**O**
Miscellaneous Tax Credits						$ 227,000	**P**
Total Tax Credits						**$ 700,100**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year						**$ 1,794,063**	**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	$ 410,579,121	299,000		$ 410,878,121	$ 149,500	$ 410,728,621	4%	$ 16,429,145	$ 394,448,977
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 54,192,742			$ 54,192,742	$ -	$ 54,192,742	6%	$ 3,251,565	$ 50,941,177
8	General Office/Stores Equip	$ 45,273,951	1,973,000		$ 47,246,951	$ 986,500	$ 46,260,451	20%	$ 9,252,090	$ 37,994,861
10	Computer Hardware/ Vehicles	$ 6,182,533	2,893,000		$ 9,075,533	$ 1,446,500	$ 7,629,033	30%	$ 2,288,710	$ 6,786,823
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	$ 1,014,262			$ 1,014,262	$ -	$ 1,014,262	0.0	$ 36,882	$ 977,380
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bld	$ 431,835			$ 431,835	$ -	$ 431,835	8%	$ 34,547	$ 397,288
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	$ 267,020,898	70,855,400	-700,000	$ 337,176,298	$ 35,077,700	$ 302,098,598	8%	$ 24,167,888	$ 313,008,410
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	$ 30,514,073			$ 30,514,073	$ -	$ 30,514,073	0%	$ -	$ 30,514,073
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 819,715,352	$ 82,439,400	-$ 700,000	$ 901,454,752	$ 40,869,700	$ 860,585,052		$ 60,708,643	$ 840,746,109

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	
	792,000		792,000			792,000	0	
	0		0			0	0	
Total	**21,112,000**	**0**	**21,112,000**	**22,084,000**	**20,320,000**	**22,876,000**	**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		30,717,684
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	22,876,000
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		90,000

Apprentice tax credit		120,000
Total Additions		**65,459,450**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	60,708,643
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	21,112,000
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		904,600
Total Deductions		**85,908,604**
NET INCOME FOR TAX PURPOSES		**10,268,530**
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		**9,634,780**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

PILs Tax Provision - Test Year

						Wires Only	
Regulatory Taxable Income						$ 9,634,780	A
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	B	$ 1,108,000	C = A * B		
Small business credit	Ontario Small Business Threshold	$ 500,000	D				
	Rate reduction	-7.00%	E	-$ 35,000	F = D * E		
Ontario Income tax						$ 1,073,000	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.14%	K = J / A		
	Federal tax rate			15.00%	L		
	Combined tax rate					26.14%	M = K + L
Total Income Taxes						**$ 2,518,217**	N = A * M
Investment Tax Credits						$ 473,100	O
Miscellaneous Tax Credits						$ 227,000	P
Total Tax Credits						**$ 700,100**	Q = O + P
Corporate PILs/Income Tax Provision for Test Year						**$ 1,818,117**	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]				73.86%	S = 1 - M	**$ 643,346**	T = R / S - N
Income Tax (grossed-up)						**$ 2,461,463**	U = R + T

Note:
1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

2011 Income Tax Return

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 85750 3346 RC0002

Corporation's name
002 POWERSTREAM INC.

Address of head office
Has this address changed since the last time we were notified? . . . . 010 1 Yes ☐ 2 No X
(If **yes**, complete lines 011 to 018.)
011 161 Cityview Blvd
012
City: 015 VAUGHAN
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 L4H 0A9

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . 020 1 Yes ☐ 2 No X
(If **yes**, complete lines 021 to 028.)
021 c/o
022 161 Cityview Blvd
023
City: 025 VAUGHAN
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal code/Zip code: 028 L4H 0A9

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . 030 1 Yes ☐ 2 No X
(If **yes**, complete lines 031 to 038.)
031 161 Cityview Blvd
032
City: 035 VAUGHAN
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 L4H 0A9

040 Type of corporation at the end of the tax year
1 X Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ________ YYYY MM DD

To which tax year does this return apply?
Tax year start: 060 2011-01-01 (YYYY MM DD)
Tax year-end: 061 2011-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes ☐ 2 No X

If **yes**, provide the date control was acquired . . . . 065 ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:
subparagraph 88(2)(a)(iv)? . . . . 064 1 Yes ☐ 2 No X
subsection 249(3.1)? . . . . 066 1 Yes ☐ 2 No X

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes ☐ 2 No X

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes ☐ 2 No X
Amalgamation? . . . . 071 1 Yes ☐ 2 No X
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes ☐ 2 No X
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes ☐ 2 No X

Is this the final return up to dissolution? . . . . 078 1 Yes ☐ 2 No X

If an election was made under section 261, state the functional currency used . . . . 079 ________

Is the corporation a resident of Canada?
080 1 Yes X 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ________

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes ☐ 2 No X
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area
095
096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150		9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? . . . . .

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	ELECTRICITY DISTRIBUTION	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295		

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	20,851,429	A
Deduct: Charitable donations from Schedule 2	311	550,089			
Gifts to Canada, a province, or a territory from Schedule 2	312				
Cultural gifts from Schedule 2	313				
Ecological gifts from Schedule 2	314				
Gifts of medicine from Schedule 2	315				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320				
Part VI.1 tax deduction*	325				
Non-capital losses of previous tax years from Schedule 4	331				
Net capital losses of previous tax years from Schedule 4	332				
Restricted farm losses of previous tax years from Schedule 4	333				
Farm losses of previous tax years from Schedule 4	334				
Limited partnership losses of previous tax years from Schedule 4	335				
Taxable capital gains or taxable dividends allocated from a central credit union	340				
Prospector's and grubstaker's shares	350				
Subtotal		550,089	►	550,089	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				20,301,340	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360	20,301,340	
Income exempt under paragraph 149(1)(t)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				20,301,340	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8. Use 3.5 for tax years ending after 2011.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . **400** 20,851,429 A

Taxable income from line 360 on page 3, **minus** 100/28* 3.37312 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 3.77358 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . **405** 20,301,340 B

Business limit (see notes 1 and 2 below) . . . **410** 500,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x **415** ***** 1,656,212 D / 11,250 = . . . 73,609,422 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . **425** F

Small business deduction

Amount A, B, C, or F, whichever is the least x 17 % = . . . **430** G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*			20,301,340	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Personal service business income** 432		D		
Amount used to calculate the credit union deduction from Schedule 17		E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		F		
Aggregate investment income from line 440 on page 6***		G		
Total of amounts B to G		▶		H
Amount A **minus** amount H (if negative, enter "0")			20,301,340	I

Amount I	20,301,340	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 365	x	9 %	=	J
Amount I	20,301,340	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365	x	10 %	=	K
Amount I	20,301,340	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 365 / Number of days in the tax year 365	x	11.5 %	= 2,334,654	L
Amount I	20,301,340	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year 365	x	13 %	=	M

General tax reduction for Canadian-controlled private corporations – Total of amounts J to M . . . 2,334,654 N
Enter amount N on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.
** For tax years beginning after October 31, 2011.
*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				O
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		P		
Amount QQ from Part 13 of Schedule 27		Q		
Personal service business income* 434		R		
Amount used to calculate the credit union deduction from Schedule 17		S		
Total of amounts P to S		▶		T
Amount O **minus** amount T (if negative, enter "0")				U

Amount U		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 365	x	9 %	=	V
Amount U		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365	x	10 %	=	W
Amount U		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 365 / Number of days in the tax year 365	x	11.5 %	=	X
Amount U		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year 365	x	13 %	=	Y

General tax reduction – Total of amounts V to Y . . . Z
Enter amount Z on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	440		x 26 2 / 3 % =		A
Foreign non-business income tax credit from line 632 on page 7					
Deduct: Foreign investment income from Schedule 7	445		x 9 1 / 3 % =		
			(if negative, enter "0")		B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360 on page 3			20,301,340		
Deduct:					
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least					
Foreign non-business income tax credit from line 632 on page 7		x 25/9* 25 / 9 =			
Foreign business income tax credit from line 636 on page 7		x 1(0.38 - X**) 3.77358 =			
			20,301,340		
			x 26 2 / 3 % =	5,413,691	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)				2,732,614	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	450				F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct: Dividend refund for the previous tax year	465			
				G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
				H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3	13,857,000	x 1 / 3	4,619,000	I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8)				

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %		550	7,714,509	A
Recapture of investment tax credit from Schedule 31		602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	20,301,340		
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	20,301,340 ►	20,301,340	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** lines A to C)		7,714,509	D

Deduct:

Small business deduction from line 430 on page 4			1		
Federal tax abatement	608	2,030,134			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains 624					
Additional deduction – credit unions from Schedule 17	628				
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount N on page 5	638	2,334,654			
General tax reduction from amount Z on page 5	639				
Federal logging tax credit from Schedule 21	640				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652	617,107			
Subtotal		4,981,895	►	4,981,895	E

Part I tax payable – Line D **minus** line E	2,732,614	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7			700	2,732,614
Part II surtax payable from Schedule 46			708	
Part III.1 tax payable from Schedule 55			710	
Part IV tax payable from Schedule 3			712	
Part IV.1 tax payable from Schedule 43			716	
Part VI tax payable from Schedule 38			720	
Part VI.1 tax payable from Schedule 43			724	
Part XIII.1 tax payable from Schedule 92			727	
Part XIV tax payable from Schedule 20			728	
			Total federal tax	2,732,614

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	1,976,080		
Provincial tax on large corporations (Nova Scotia Schedule 342)	765			
		1,976,080 ▶		1,976,080
			Total tax payable 770	4,708,694 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780			
Dividend refund from page 6	784			
Federal capital gains refund from Schedule 18	788			
Federal qualifying environmental trust tax credit refund	792			
Canadian film or video production tax credit refund (Form T1131)	796			
Film or video production services tax credit refund (Form T1177)	797			
Tax withheld at source	800			
Total payments on which tax has been withheld 801				
Provincial and territorial capital gains refund from Schedule 18	808			
Provincial and territorial refundable tax credits from Schedule 5	812			
Tax instalments paid	840	7,242,100		
Total credits	890	7,242,100 ▶		7,242,100 B

Refund code 894 1 Overpayment 2,533,406 Balance (line A **minus** line B) -2,533,406

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 Young 951 Carolyn 954 VP FINANCE ,
Last name in block letters / First name in block letters / Position, office, or rank

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 ______ Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 ______ Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☐ 2 No ☒

958 Adam Chiarandini 959 ______
Name in block letters / Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Schedule of Instalment Remittances

Name of corporation contact: Adam Chiarandini
Telephone number: (905) 417-6900

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
2011-01-31	instalment	683,000
2011-02-28		683,000
2011-03-31		609,300
2011-04-30		658,350
2011-05-31		658,350
2011-06-30		658,350
2011-07-31		658,350
2011-08-30		658,350
2011-09-30		658,350
2011-10-31		658,350
2011-11-30		658,350
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	7,242,100 **A**
	Total instalments credited to the taxation year per T9	7,242,100 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	183,604,000	175,909,000
	Total tangible capital assets	2008	+	1,335,735,000	1,246,432,000
	Total accumulated amortization of tangible capital assets	2009	–	645,694,000	604,373,000
	Total intangible capital assets	2178	+	68,561,000	61,801,000
	Total accumulated amortization of intangible capital assets	2179	–	19,166,000	15,078,000
	Total long-term assets	2589	+	64,124,000	85,886,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	987,164,000	950,577,000
	Liabilities				
	Total current liabilities	3139	+	186,168,000	170,877,000
	Total long-term liabilities	3450	+	495,593,000	493,083,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	681,761,000	663,960,000
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	305,403,000	286,617,000
	Total liabilities and shareholder equity	3640	=	987,164,000	950,577,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	53,446,000	36,999,000

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	912,371,000	847,159,000
	Cost of sales	8518	–	751,457,000	691,318,000
	Gross profit/loss	8519	=	160,914,000	155,841,000
	Cost of sales	8518	+	751,457,000	691,318,000
	Total operating expenses	9367	+	135,440,000	128,015,000
	Total expenses (mandatory field)	9368	=	886,897,000	819,333,000
	Total revenue (mandatory field)	8299	+	922,423,000	856,388,000
	Total expenses (mandatory field)	9368	–	886,897,000	819,333,000
	Net non-farming income	9369	=	35,526,000	37,055,000
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	35,526,000	37,055,000
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	5,222,000	10,588,000
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	30,304,000	26,467,000

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . 095 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . 097 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report . . . . 1 [X]

Completed a review engagement report . . . . 2 [ ]

Conducted a compilation engagement . . . . 3 [ ]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . 099 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client) . . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . 101 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . 104 1 Yes [X] 2 No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . . 105 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . 106 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . 107 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . 108 1 Yes [ ] 2 No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . 200 1 Yes ☐ 2 No ☐

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? . . . 250 1 Yes ☐ 2 No ☐

Did the corporation apply hedge accounting during the tax year? . . . 255 1 Yes ☐ 2 No ☐

Did the corporation discontinue hedge accounting during the tax year? . . . 260 1 Yes ☐ 2 No ☐

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . 265 1 Yes ☐ 2 No ☐

If **yes**, you have to maintain a separate reconciliation.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

Assets – lines 1000 to 2599

1060	86,933,000	1120	3,267,000	1480	90,369,000
1484	3,035,000	1599	183,604,000	1600	11,367,000
1680	53,530,000	1681	-8,754,000	1682	659,926,000
1683	-394,555,000	1740	517,019,000	1741	-207,938,000
1900	43,655,000	1901	-32,985,000	1910	18,280,000
1911	-1,462,000	1920	31,958,000	2008	1,335,735,000
2009	-645,694,000	2010	26,018,000	2011	-19,166,000
2012	42,543,000	2178	68,561,000	2179	-19,166,000
2420	14,591,000	2421	49,533,000	2589	64,124,000
2599	987,164,000				

Liabilities – lines 2600 to 3499

2600	8,039,000	2620	116,109,000	2680	3,445,000
2700	40,000,000	2860	11,103,000	2961	1,005,000
2962	6,467,000	3139	186,168,000	3320	495,593,000
3450	495,593,000	3499	681,761,000		

Shareholder equity – lines 3500 to 3640

3500	251,957,000	3600	53,446,000	3620	305,403,000
3640	987,164,000				

Retained earnings – lines 3660 to 3849

3660	36,999,000	3680	30,304,000	3700	-13,857,000
3849	53,446,000				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	912,371,000	**8089**	912,371,000	**8230**	10,052,000
8299	922,423,000				

Cost of sales – lines 8300 to 8519

8320	751,457,000	**8518**	751,457,000	**8519**	160,914,000

Operating expenses – lines 8520 to 9369

8670	46,127,000	**8710**	23,821,000	**9270**	65,492,000
9367	135,440,000	**9368**	886,897,000	**9369**	35,526,000

Farming revenue – lines 9370 to 9659

9659	0

Farming expenses – lines 9660 to 9899

9898	0

Extraordinary items and taxes – lines 9970 to 9999

9970	35,526,000	**9990**	5,222,000	**9999**	30,304,000

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				30,304,000 A
Add:				
Provision for income taxes – current		101	5,222,000	
Amortization of tangible assets		104	45,937,615	
Amortization of intangible assets		106	3,084,541	
Charitable donations and gifts from Schedule 2		112	550,089	
Scientific research expenditures deducted per financial statements		118	352,794	
Non-deductible club dues and fees		120	41,228	
Non-deductible meals and entertainment expenses		121	108,686	
Non-deductible automobile expenses		122	7,387	
Reserves from financial statements – balance at the end of the year		126	18,436,542	
Subtotal of additions			73,740,882 ▶	73,740,882
Other additions:				
Debt issue expense		208	724,238	
Miscellaneous other additions:				
600 Addback re: 12(1)(x)		290	23,862,251	
603 Ontario specific tax credits - CETC	100,039			
Inducement - ITA 12(1)x)	25,968			
Total	126,007	293	126,007	
604 Smart meter OM&A already deducted for tax	888,704			
Depreciation on stranded meters	1,200,704			
IFRS revenue deferred	744,996			
Interest on capital lease - building	1,170,824			
Smart meter revenue - adder collected	475,494			
Ontario specific tax credits - Apprenticeship	111,672			
Total	4,592,394	294	4,592,394	
Subtotal of other additions		199	29,304,890 ▶	29,304,890
Total additions		500	103,045,772 ▶	103,045,772
Deduct:				
Gain on disposal of assets per financial statements		401	253,974	
Capital cost allowance from Schedule 8		403	59,658,035	
Cumulative eligible capital deduction from Schedule 10		405	499,831	
SR&ED expenditures claimed in the year from Form T661 (line 460)		411	1,750,133	
Reserves from financial statements – balance at the beginning of the year		414	17,233,493	
Subtotal of deductions			79,395,466 ▶	79,395,466
Other deductions:				
Miscellaneous other deductions:				
701 S.13(7.4) ELECTION		391	23,862,251	
703 INTEREST CAPITALIZED FOR ACCOUNTING	536,625			
Total	536,625	393	536,625	
704 Loan issue costs	195,636			
IFRS costs deferred	450,560			
Smart meter revenues accounting > tax	5,284,534			
Capital lease treated as operating for tax	1,429,911			
Smart meter refund to customers	455,805			
Smart grid and renewable generation OM&A deferred	598,311			
Equipment rental charges	1,018			

Canadian Renewable & Conservation Expenses	30,908			
OM&A capitalized for accounting - smart meter	240,807			
OM&A capitalized for accounting - smart grid	16,511			
Total	8,704,001	394	8,704,001	
Subtotal of other deductions		499	33,102,877 ▶	33,102,877
Total deductions		510	112,498,343 ▶	112,498,343
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				20,851,429

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- For use by corporations to claim any of the following:
  - charitable donations;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
York University	75,000
Markham Stoufville Hospital	15,000
Alzheimer Society	100
Southlake Regional Health	250,000
Georgian College	150,000
Sick Kids Foundation	100
George Hull Centre Foundation	350
Canadian Cancer Society	100
CanadaHelps	100
Habitat for Humanity	1,725
Yellow Brick House	1,558
GBGH Foundation	1,000
Canadian Cancer Society	100
Princess Margaret Hospital	150
Vaughan in Action	168
Vaughan in Action	120
CanadaHelps	100
Beth Chabad Israeli Community	1,000
Canadian Cancer Society	100
CanadaHelps	100
Canadian Cancer Society	100
Princess Margaret Hospital	100
CanadaHelps	100
Heart & Stroke Foundation	100
Canadian Cancer Society	100
Town of Richmond Hill	1,500
Crime Stoppers	500
Princess Margaret Hospital	1,500
Princess Margaret Hospital	2,500
Princess Margaret Hospital	1,500
Princess Margaret Hospital	1,500
Princess Margaret Hospital	1,500

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Princess Margaret Hospital	1,500
Jewish Women International	150
Children's Wish Foundation	100
Canadian Cancer Society	100
Doane House Hospice	850
Salvation Army	100
Canadian Cancer Society	100
York Central Hospital	7,500
United Way of York Region	31,818
Subtotal	550,089
Add: Total donations of less than $100 each	
Total donations in current tax year	550,089

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year					
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the tax year	240				
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1)	210	550,089			
Subtotal (line 250 **plus** line 210)		550,089		550,089	550,089
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255				
Total charitable donations available		550,089	A	550,089	550,089
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260	550,089		550,089	550,089
Charitable donations closing balance	280				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2005-10-31			
8th prior year	2004-12-31			
9th prior year	2004-05-31			
10th prior year	2003-05-31			
11th prior year	2002-05-31			
12th prior year	2001-05-31			
13th prior year	2000-05-31			
14th prior year	1999-05-31			
15th prior year	1998-05-31			
16th prior year	1997-05-31			
17th prior year	1996-05-31			
18th prior year	1995-05-31			
19th prior year	1994-05-31			
20th prior year	1993-05-31			
21st prior year*	1992-05-31			
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 %			15,638,572	B
Taxable capital gains arising in respect of gifts of capital property included in Part 1**	225	C		
Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01)	227	D		
The amount of the recapture of capital cost allowance in respect of charitable gifts	230			
Proceeds of disposition, less outlays and expenses**		E		
Capital cost**		F		
Amount E or F, whichever is less	235			
Amount on line 230 or 235, whichever is less		G		
Subtotal (**add** amounts C, D, and G)		H		
Amount H **multiplied** by 25 %				I
Subtotal (amount B **plus** amount I)			15,638,572	J
Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less)			550,089	K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

	Line		
Gifts to Canada, a province, or a territory at the end of the previous tax year			
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339		
Gifts to Canada, a province, or a territory at the beginning of the tax year	340		►
Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary	350		
Total current-year gifts made to Canada, a province, or a territory*	310		
Subtotal (line 350 **plus** line 310)			
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	355		
Total gifts to Canada, a province, or a territory available			
Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return).	360		
Gifts to Canada, a province, or a territory closing balance	380		

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

	Line	Federal	Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years*	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2005-10-31			
8th prior year	2004-12-31			
9th prior year	2004-05-31			
10th prior year	2003-05-31			
11th prior year	2002-05-31			
12th prior year	2001-05-31			
13th prior year	2000-05-31			
14th prior year	1999-05-31			
15th prior year	1998-05-31			
16th prior year	1997-05-31			
17th prior year	1996-05-31			
18th prior year	1995-05-31			
19th prior year	1994-05-31			
20th prior year	1993-05-31			
21st prior year*	1992-05-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

	Line	Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years*	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2005-10-31			
8th prior year	2004-12-31			
9th prior year	2004-05-31			
10th prior year	2003-05-31			
11th prior year	2002-05-31			
12th prior year	2001-05-31			
13th prior year	2000-05-31			
14th prior year	1999-05-31			
15th prior year	1998-05-31			
16th prior year	1997-05-31			
17th prior year	1996-05-31			
18th prior year	1995-05-31			
19th prior year	1994-05-31			
20th prior year	1993-05-31			
21st prior year*	1992-05-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal		Québec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year							
Deduct: Additional deduction for gifts of medicine expired after five tax years	639						
Additional deduction for gifts of medicine at the beginning of the tax year	640						
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year **610** ______

Québec

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

Alberta

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

where:

A is the **lesser** of line 2 and line 4

B is the eligible amount of gifts (line 600)

C is the proceeds of disposition (line 602)

		Federal	Québec	Alberta
Subtotal (line 650**plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
Total				

***** These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2010-12-31	
2nd prior year	2009-12-31	
3rd prior year	2008-12-31	
4th prior year	2007-12-31	
5th prior year	2006-12-31	
6th prior year*	2005-12-31	
7th prior year	2005-10-31	
8th prior year	2004-12-31	
9th prior year	2004-05-31	
10th prior year	2003-05-31	
11th prior year	2002-05-31	
12th prior year	2001-05-31	
13th prior year	2000-05-31	
14th prior year	1999-05-31	
15th prior year	1998-05-31	
16th prior year	1997-05-31	
17th prior year	1996-05-31	
18th prior year	1995-05-31	
19th prior year	1994-05-31	
20th prior year	1993-05-31	
21st prior year*	1992-05-31	
Total		

* These gifts expired in the current year.

T2 SCH 2 E (07)

Canada

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205 (Complete if payer corporation is connected)	C Business Number of connected corporation 210 (Complete if payer corporation is connected)	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220 (Complete if payer corporation is connected)	E Non-taxable dividend under section 83 230
				Total (enter on line 402 of Schedule 1)	

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250 (Complete if payer corporation is connected)	H Dividend refund of the connected payer corporation (for tax year in column D)** 260 (Complete if payer corporation is connected)	I Part IV tax before deductions F x 1 / 3 *** 270
					J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter “0” in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation’s tax year ends after the corporation’s balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer’s dividend refund when you calculate the corporation’s Part IV tax payable.

*** For dividends received from connected corporations: $\text{Part IV tax} = \dfrac{\text{Column F} \times \text{Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax		320	
		Subtotal	
Deduct:			
Current-year non-capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)		360	

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation	Business Number	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD	Taxable dividends paid to connected corporations	Eligible dividends (included in column D)
	400	410	420	430	
1	VAUGHAN HOLDINGS INC.		2011-12-31	6,279,300	
2	MARKHAM ENTERPRISES CORPORATION		2011-12-31	4,737,015	
3	BARRIE HYDRO HOLDINGS INC.		2011-12-31	2,840,685	

Note
If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

Total 13,857,000

Total taxable dividends paid in the tax year to other than connected corporations		450	
Eligible dividends (included in line 450)	450a		
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)		460	13,857,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			13,857,000
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	13,857,000
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal		▶	
Total taxable dividends paid in the tax year that qualify for a dividend refund			13,857,000

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ________ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).
** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.
*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
20,301,340		20,301,340	2,348,749

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	2,384,989			
Deduct: Ontario small business deduction (from schedule 500)	402	36,240			
Subtotal		2,348,749	►	2,348,749	A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272				
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)				2,348,749	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414	15,566			
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal		15,566	►	15,566	D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				2,333,183	E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416	145,392	
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				2,187,791	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)			418		
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				2,187,791	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282				
Subtotal			►		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				2,187,791	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	100,039			
Ontario apprenticeship training tax credit (from Schedule 552)	454	111,672			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal		211,711	►	211,711	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	1,976,080	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits **255** 1,976,080

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		443,605,272	280,488		0	140,244	443,745,516	4	0	0	17,749,821	426,135,939
2.	2		61,331,759			0		61,331,759	6	0	0	3,679,906	57,651,853
3.	8		60,062,623	6,026,490		0	3,013,245	63,075,868	20	0	0	12,615,174	53,473,939
4.	10		8,133,839	1,168,456		273,243	447,607	8,581,445	30	0	0	2,574,434	6,454,618
5.	12		1,337,252	3,794,761		0	1,897,381	3,234,632	100	0	0	3,234,632	1,897,381
6.	17		510,202			0		510,202	8	0	0	40,816	469,386
7.		WORK-IN-PROGRESS	25,111,508		5,402,565	0		30,514,073	0	0	0		30,514,073
8.	8	HYDRO VAUGHAN				0			20	0	0		
9.	13	RICHMOND HILL				0			NA	0	0		
10.	13	MARKHAM HYDRO	117,602			0		117,602	NA	0	0	83,187	34,415
11.	45		396,761			0		396,761	45	0	0	178,542	218,219
12.	13	PS Inc - 2005 Additioin				0			NA	0	0		
13.	13		214,981			0		214,981	NA	0	0	89,359	125,622
14.	47		191,680,053	51,866,174		0	25,933,087	217,613,140	8	0	0	17,409,051	226,137,176
15.	50		288,239	1,213,206		0	606,603	894,842	55	0	0	492,163	1,009,282
16.	13	BARRIE HYDRO - right to use su	612,217			0		612,217	NA	0	0	31,395	580,822
17.	13	Addiscott Ops Centre	1,088,026			0		1,088,026	NA	0	0	36,882	1,051,144
18.	43.2	Solar business - Solar Panels	1,158,551	5,688,188	-1,158,551	0	2,844,094	2,844,094	50	0	0	1,422,047	4,266,141
19.	47	Solar business - Distribution Equ	83,529		-83,529	0			8	0	0		
20.	12	Solar business - Software	4,128	8,010	-4,128	0	4,005	4,005	100	0	0	4,005	4,005
21.	52			16,285		0		16,285	100	0	0	16,285	
22.	8	Solar business - Class 8		3,362		0	1,681	1,681	20	0	0	336	3,026
23.		WIP - solar			87,527	0		87,527	0	0	0		87,527
		Totals	795,736,542	70,065,420	4,243,884	273,243	34,887,947	834,884,656				59,658,035	810,114,568

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		70,065,420		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
See attached	+	28,535,078		
Total additions per books	=	98,600,498	▶	98,600,498
Proceeds up to original cost – Schedule 8 regular classes		273,243		
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
See attached	+	2,025,776		
Total proceeds per books	=	2,299,019	– ▶	2,299,019
Depreciation and amortization per accounts – Schedule 1			–	49,022,155
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	253,974
Net change per tax return			=	47,533,298

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		685,526,000
Opening net book value	–	635,976,000
Net change per financial statements	=	49,550,000

If the amounts from the tax return and the financial statements differ, explain why below.

Difference of $2,812 is due to rounding.

Attached Schedule with Total

Tax return – Other – Amount

Title Tax return – Other – Amount (Schedule 8Rec)

Description	Amount	
Capitalized interest deducted for tax purposes	534,781	00
Adjustments to NBV of fixed assets (609,442 - 16,230)	593,212	00
Smart meter additions per books, not included per tax	21,819,983	00
Increase in land rights treated as CEC for tax purposes	28,970	00
Movement in WIP	5,490,092	00
Amounts in solar additions deductible for tax purposes: equip rental + CRCE	68,040	00
Total	28,535,078	00

Attached Schedule with Total

Tax return – Other – Amount

Title Tax return – Other – Amount - S8Rec

Description	Amount	
Other adjustment to wip	3,762	00
Assets transferred out of fixed assets to other accounts for acctg purposes	514,397	00
Solar additions included in Smart grid capital (asset) account	370,637	00
Solar additions included in Renewable generation (asset) account	527,538	00
Deferred charges not included in prior year's fixed asset balance	609,442	00
Total	2,025,776	00

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 7,117,982 A

Add:

Cost of eligible capital property acquired during the taxation year **222** 29,950

Other adjustments **226**

Subtotal (line 222 plus line 226) 29,950 x 3 / 4 = 22,463 B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** x 1 / 2 = C

amount B minus amount C (if negative, enter "0") 22,463 ▶ 22,463 D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** E

Subtotal (add amounts A, D, and E) **230** 7,140,445 F

Deduct:

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** H

Other adjustments . . . . **246** I

(add amounts G,H, and I) x 3 / 4 = **248** J

Cumulative eligible capital balance (amount F minus amount J) . . . . 7,140,445 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249**

amount K 7,140,445

less amount from line 249

Current year deduction . . . . 7,140,445 x 7.00 % = **250** 499,831 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 499,831 ▶ 499,831 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 6,640,614 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988		400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)		401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3		
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4		
Line 3 minus line 4 (if negative, enter "0")			▶	5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7		
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8		
Subtotal (line 7 plus line 8)	409		▶	9	
Line 6 minus line 9 (if negative, enter "0")				▶	O
Line N minus line O (if negative, enter "0")					P
Line 5			x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")					R
Amount R			x 2 / 3 =		S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410	

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	EMPLOYEE FUTURE BENEFITS	14,007,000		1,257,856		15,264,856
2	ALLOWANCE FOR DOUBTFUL A	2,022,930			551,693	1,471,237
3	Unpaid Payroll - 2010	291,043			199,479	91,564
4	Inventory Obsolescence	313,382			111,541	201,841
5	Reserves in accruals	567,320			168,045	399,275
6	Donation accrual	31,818			31,818	
7	Unpaid Payroll - 2011			215,769		215,769
8	Customer over-collections			792,000		792,000
9						
	Reserves from Part 2 of Schedule 13					
	Totals	17,233,493		2,265,625	1,062,576	18,436,542

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations*. References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 (**consolidated**), *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim*.

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITC's is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068-1, 2010 Supplement to the 2006 T4068, Guide for the T5013 Partnership Information Return.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? **102** 1 Yes ☐ 2 No ☒

Contributions to agricultural organizations for SR&ED **103** ______

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.* Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

	CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125
1.					

* CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal ►

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 x 10 % = 240

Credit allocated from a partnership 250

Subtotal ►

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal ►

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures			
Current expenditures (from line 557 on Form T661)	2,790,854		
Add:			
Contributions to agricultural organizations for SR&ED*			
Current expenditures (including contributions to agricultural organizations for SR&ED at line 103 in Part 3)* (from line 557 on Form T661)	2,790,854 ►	350	2,790,854
Capital expenditures (from line 558 on Form T661)		360	294,678
Repayments made in the year (from line 560 on Form T661)		370	
Total (this must equal the amount from line 570 on Form T661)*		380	3,085,532

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes [ ] 2 No [X]

Complete lines 390 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied). 390 32,636,831

Enter your taxable capital employed in Canada for the previous tax year 746,094,157
minus $10 million. If this amount is nil or negative, enter "0".
If this amount is over $40 million, enter $40 million. 398 40,000,000

* If either of the tax years referred to at line 390 is less than 51 weeks, multiply the taxable income by the following result: 365 divided by the number of days in these tax years.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1A: Tax year ends before January 1, 2010.

[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . .

Calculation 1: Tax year starts after December 31, 2009.

[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . .

Calculation 2: Tax year straddles January 1, 2010.

EE + [(FF **minus** EE) x (GG **divided by** HH)] where, ...

EE = [($7,000,000 **minus** (10**A**)) x (($40,000,000 **minus B**) **divided by** $40,000,000)];

FF = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];

GG = number of days in the tax year after December 31, 2009;

HH = number of days in the tax year.

Amount A **408** ________ Amount B **409** ________

A = the greater of:

- $400,000; and
- your taxable income for the last tax year* ending in the previous calendar year (tax years ending in 2008) (prior to any loss carry-backs applied).

B = the taxable capital employed in Canada for the last tax year ending in the previous calendar year (tax years ending in 2008) minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.

* If any of the tax years referred to in **A** above are less than 51 weeks, gross up the taxable incomes for those tax years by the ratio that 365 is of the number of days in those tax years. Use these grossed up amounts when calculating the expenditure limit.

Enter the amount from Calculation 1A, 1 or 2, whichever is applicable ________ G*

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ________ H*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ________ x Number of days in the tax year / 365 = 365 . . . . ________ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . **410** ________

* Amount G or H cannot be more than $3,000,000.

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 %	=		J
Line 350 minus line 410 (if negative, enter "0")	430	2,790,854	x	20 %	=	558,171	K
Line 410 minus line 350 (if negative, enter "0")			L				
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 %	=		M
Line 360 minus line L (if negative, enter "0")	450	294,678	x	20 %	=	58,936	N

Repayments (amount from line 370 in Part 8) . . . . ______

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 %	=	
480		x	20 %	=	
			Total		▶ ______ O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) 617,107

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

	Line	Amount	Line	Amount	
ITC at the end of the previous tax year					
Deduct:					
Credit deemed as a remittance of co-op corporations	510				
Credit expired	515				
Subtotal			▶		
ITC at the beginning of the tax year			520		
Add:					
Credit transferred on amalgamation or wind-up of subsidiary	530				
Total current-year credit	540	617,107			
Credit allocated from a partnership	550				
Subtotal		617,107	▶	617,107	
Total credit available				617,107	
Deduct:					
Credit deducted from Part I tax (enter on line B2 in Part 30)	560	617,107			
Credit carried back to the previous year(s) (from Part 13)			P		
Credit transferred to offset Part VII tax liability	580				
Subtotal		617,107	▶	617,107	
Credit balance before refund					Q
Deduct:					
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)			610		
ITC closing balance on SR&ED			620		

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day		Line	Amount
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)?	650	1 Yes [ ]	2 No [X]
Credit balance before refund (amount Q from Part 12)		R	
Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11)		S	
Refundable credits (amount R or S, whichever is less)*			T
Amount J from Part 11		U	
Subtract: Amount T or U, whichever is less			V
Net amount (if negative, enter "0")			W
Amount W	x 40 %		X
Add: Amount V			Y
Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12)			Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%.
Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12)			AA
Amount J from Part 11		BB	
Subtract: Amount AA or BB, whichever is less			CC
Net amount (if negative, enter "0")			DD
Amount M from Part 11			EE
Amount DD or EE, whichever is less	x 40 %		FF
Add : Amount CC above			GG
Refund of ITC (amounts FF **plus** GG)			HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ______ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

	A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**
1.			

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less
1.			

Subtotal (enter this amount on line MM in Part 17) ______ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) **760** ______ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16		LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above		MM
Recaptured ITC for calculation 3 from line KK in Part 16 above		NN
Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN		OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

	List of minerals 800
1.	

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

	Project name 805	Mineral title 806	Mining division 807
1.			

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

	Description 825	Amount 826
1.		

Add amounts at column 826	►		VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			W W
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired 845

Subtotal ►

ITC at the beginning of the tax year 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Expenditures from line YY in Part 18: 870 x 10 % = 880

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) 885

Credit carried back to the previous year(s) (from Part 20) CCC

Subtotal ►

ITC closing balance from pre-production mining expenditures 890

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	921
2nd previous tax year				Credit to be applied	922
3rd previous tax year				Credit to be applied	923

Total (enter on line CCC in Part 19)

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Attach additional schedules if more space is needed.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.					

Total current-year credit (enter at line 640)

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	612		
Credit expired after 20 tax years	615		
	Subtotal		▶
ITC at the beginning of the tax year		625	
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	630		
ITC from repayment of assistance	635		
Total current-year credit (total of column 605)	640		
Credit allocated from a partnership	655		
	Subtotal		▶
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B4 in Part 30)	660		
Credit carried back to the previous year(s) (from Part 23)		DDD	
	Subtotal		▶
ITC closing balance from apprenticeship job creation expenditures		690	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter on line DDD in Part 22)		

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year	715		EEE
Add: Specified child care start-up expenditures from the current tax year	705		FFF
Total gross eligible expenditures for child care spaces (line 715 **plus** line 705)			GGG
Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG)	725		HHH
Excess (amount GGG **minus** amount HHH) (if negative, enter "0")			III
Add: Repayments of government and non-government assistance	735		JJJ
Total eligible expenditures for child care spaces (amount III **plus** amount JJJ)	745		

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x 25 % =		KKK
Number of child care spaces	755		x $ 10,000 =		LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)					MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
	Subtotal		▶	
ITC at the beginning of the tax year			775	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (amount MMM above)	780			
Credit allocated from a partnership	782			
	Subtotal		▶	
Total credit available				
Deduct:				
Credit deducted from Part I tax (enter on line B5 in Part 30)	785			
Credit carried back to the previous year(s) (from Part 27)			NNN	
	Subtotal		▶	
ITC closing balance from child care spaces expenditures			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2010-12-31	Credit to be applied	941	
2nd previous tax year	2009-12-31	Credit to be applied	942	
3rd previous tax year	2008-12-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a))	792		ZZZ
In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:			
The amount that can reasonably be considered to have been included in the original ITC	795		
25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property	797		
Amount from line 795 or line 797, whichever is less			OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC	799		PPP
Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP Enter amount QQQ on line A2 in Part 29.			QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2 Enter amount A3 on line 602 of the T2 return.		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	617,107	B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)		B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) Enter amount B6 at line 652 of the T2 return.	617,107	B6

Privacy Act, Personal Information Bank number CRA PPU 047

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
617,107	617,107			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2005-10-31				
2004-12-31				
2004-05-31				
2003-05-31				*
2002-05-31				
2001-05-31				
2000-05-31				
1999-05-31				
1998-05-31				
1997-05-31				
1996-05-31				
1995-05-31				
1994-05-31				
1993-05-31				*
Total				

B+C+D+G **Total ITC utilized** 617,107

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
		Provide only one number per shareholder				
1	VAUGHAN HOLDINGS INC.				45.315	
2	MARKHAM ENTERPRISES CORPORATION				34.185	
3	BARRIE HYDRO HOLDINGS INC.				20.500	
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

On: 2011-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	111,921,813 A
Taxable income for the year (DICs enter "0") *	110	20,301,340 B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17) — 120				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * — 130				
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * — 140				
Subtotal (**add** lines 120, 130, and 140) ►		C		
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")	150	20,301,340		
After-tax income (line 150 x general rate factor for the tax year ** 0.7)			190	14,210,938 D
Eligible dividends received in the tax year	200			
Dividends deductible under section 113 received in the tax year	210			
Subtotal (**add** lines 200 and 210) ►				E
GRIP addition:				
Becoming a CCPC (line PP from Part 4)	220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240			
Subtotal (**add** lines 220, 230, and 240) ►			290	F
Subtotal (**add** lines A, D, E, and F)				126,132,751 G
Eligible dividends paid in the previous tax year	300			
Excessive eligible dividend designations made in the previous tax year	310			

Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.

Subtotal (line 300 **minus** line 310) ►				H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)			490	126,132,751
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560	
GRIP at the end of the tax year (line 490 **minus** line 560)			590	126,132,751

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year		32,636,831 J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (**add** lines K1, L1, and M1) ►		N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		32,636,831 ►	32,636,831 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . ______ S1

Subtotal (**add** lines Q1, R1, and S1) ______ ▶ ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ▶ ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.7) . . . . **500** ______

Second previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year 25,556,717 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . ______ M2

Subtotal (**add** lines K2, L2, and M2) ______ ▶ ______ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 25,556,717 ▶ 25,556,717 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . ______ S2

Subtotal (**add** lines Q2, R2, and S2) ______ ▶ ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ▶ ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.7) . . . . **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 18,142,389 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . ______ M3

Subtotal (**add** lines K3, L3, and M3) ______ ▶ ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 18,142,389 ▶ 18,142,389 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ▶ ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ▶ ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.7) . . . . . **540** ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . ______ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ▶ ______ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year			FF
The corporation's money on hand immediately before the end of its previous/last tax year			GG
Unused and unexpired losses at the end of the corporation's previous/last tax year:			
Non-capital losses			
Net capital losses			
Farm losses			
Restricted farm losses			
Limited partnership losses			
Subtotal		►	HH
Subtotal (**add** lines FF, GG, and HH)			II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year		JJ	
Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year		KK	
All the corporation's reserves deducted in its previous/last tax year		LL	
The corporation's capital dividend account immediately before the end of its previous/last tax year		MM	
The corporation's low rate income pool immediately before the end of its previous/last tax year		NN	
Subtotal (**add** lines JJ, KK, LL, MM, and NN)		►	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")			PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	/ 365	=		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 365	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	365 / 365	=	0.70000	SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	=		TT

General rate factor for the tax year (total of lines QQ to TT) . . . . 0.70000 UU

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3		13,857,000		
Total taxable dividends paid in the tax year	100	13,857,000		
Total eligible dividends paid in the tax year	150			A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160		126,132,751	B
Excessive eligible dividend designation (line 150 **minus** line 160)				C
Deduct:				
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	180			D
Subtotal (amount C **minus** amount D)				E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190			F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3				
Total taxable dividends paid in the tax year	200			
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)				G
Deduct:				
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	280			H
Subtotal (amount G **minus** amount H)				I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290			J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	14.00 %	=	%	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	12.00 %	=	5.95068 %	A2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	184 / 365	x	11.50 %	=	5.79726 %	A3

Ontario basic rate of tax for the year (total of rates A1 to A3) 11.74794 ► 11.74794 % A4

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 20,301,340 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A4 from Part 1) . . . . . . 2,384,989 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)	20,851,429	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)	20,301,340	2
Federal business limit before the application of subsection 125(5.1) * (amount from line 410 of the T2 return) ______ x ______ = line 4 on page 4 of the T2 return	500,000	3
Enter the least of amounts 1, 2, and 3	500,000	D

Ontario domestic factor: Ontario taxable income ** / taxable income earned in all provinces and territories *** = 20,301,340.00 / 20,301,340 = 1.00000 E

Amount D x amount E	500,000	a
Ontario taxable income (amount B from Part 2)	20,301,340	b

Ontario small business income (lesser of amount a and amount b) 500,000 F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	8.50 %	= %	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	7.50 %	= 3.71918 %	G2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	184 / 365	x	7.00 %	= 3.52877 %	G3

OSBD rate for the year (total of rates G1 to G3) 7.24795 % G4

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G4) 36,240 H

Enter amount H on line 402 of Schedule 5.

* For 2011 and later tax years, enter the amount from line 410 of the T2 return on line 3 of this schedule. Otherwise, complete the calculation for this line.

** Enter amount B from Part 2.

*** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction*.

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income * I

Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501) . . . . J

Aggregate adjusted taxable income (amount I **plus** amount J) . . . . ▶ K

Deduct:

Ontario business limit 500,000

Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P) L

Small business surtax rate for the year:

$\frac{\text{Number of days in the tax year before July 1, 2010} \quad \_\_\_\_}{\text{Number of days in the tax year} \quad 365}$ x 4.25 % = % M

Amount L **multiplied by** % on line M = ... N

Amount N ______ x $\frac{\text{Ontario small business income (amount F from Part 3)} \quad \_\_\_\_}{500{,}000 \quad 500{,}000}$ = ... O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) . . . . P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Lesser of amount D and amount b from Part 3 . . . . 500,000 Q

$\frac{\text{Surtax payable (amount P from Part 4)} \quad \_\_\_\_}{\text{Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3)} \quad 7.24795\ \% \quad 0.07248}$ = R

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") . . . . 500,000 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17 . . . . ________ T

Deduct:
Ontario adjusted small business income (amount S from Part 5) . . . . ________ U

Subtotal (amount T **minus** amount U) (if negative, enter "0") . . . . ________ V

OSBD rate for the year (rate G6 from Part 3) . . . . 7.24795 %

Amount V **multiplied** by the OSBD rate for the year . . . . ________ W

Ontario domestic factor (amount E from Part 3) . . . . 1.00000 X

Ontario credit union tax reduction (amount W **multiplied** by amount X) . . . . ________ Y

Enter amount Y on line 410 of Schedule 5.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 506

ONTARIO TRANSITIONAL TAX DEBITS AND CREDITS

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- Complete this schedule if you are a specified corporation that is subject to the Ontario transitional tax debit or are claiming the Ontario transitional tax credit.
- Unless otherwise noted, all legislative references are to the federal *Income Tax Act*.
- File this schedule with the *T2 Corporation Income Tax Return*.
- Unless otherwise noted, terms on this page are defined under subsection 46(1) of the *Taxation Act, 2007* (Ontario).
- **Specified corporation** is defined under subsection 46(5) of the *Taxation Act, 2007* (Ontario) as a corporation:
  - that is not exempt at or immediately before its transition time from tax payable under Part I of the federal Act;
  - that has a tax year that ends before 2009 and a tax year that includes January 1, 2009; or has a tax year that begins after 2008 and a tax year that is deemed to end on December 31, 2008, under subsection 249(3) of the federal Act;
  - that has a permanent establishment (PE) in Ontario at its transition time;
  - that had a PE in Ontario at any time in its last tax year ending before 2009, and was subject to tax under Part II of the *Corporations Tax Act* (Ontario) for that tax year; and
  - whose assets have not been distributed in an eligible pre-2009 windup.
- A specified corporation also includes, under subsection 51(1) of *the Taxation Act, 2007* (Ontario), the parent corporation of an eligible post-2008 windup and the new corporation of an eligible amalgamation.
- A specified corporation may be subject to the Ontario transitional tax debit if:
  - the corporation's total federal balance is more than the total Ontario balance at the end of the tax year; or
  - the corporation has a post-2008 scientific research and experimental development (SR&ED) balance, as defined under subsection 49(2) of the *Taxation Act, 2007* (Ontario), and a federal SR&ED transitional balance, as defined under subsection 49(4) of the *Taxation Act, 2007* (Ontario), at the end of the tax year.
- A specified corporation may be able to claim the Ontario transitional tax credit if:
  - the corporation's total Ontario balance is more than the total federal balance at the end of the tax year; or
  - the corporation has an unused transitional tax credit balance from previous tax years.
- **Transition time** means:
  - the beginning of the corporation's first tax year that starts after 2008 if the previous tax year is deemed under subsection 249(3) of the federal Act to end on December 31, 2008, or
  - the beginning of the corporation's tax year that includes January 1, 2009, in any other case.
- An **eligible amalgamation** means an amalgamation or merger of a particular corporation and one or more other corporations to form a new corporation where:
  - the amalgamation or merger occurs after December 31, 2008, and does not occur at the new corporation's transition time;
  - the new corporation has a PE in Ontario immediately after the amalgamation or merger;
  - the particular corporation has a PE in Ontario immediately before the amalgamation or merger;
  - the particular corporation is a specified corporation at its transition time or at any time before the amalgamation or merger;
  - the amalgamation or merger occurs in the amortization period of the new corporation;
  - the amortization period of the new corporation does not end immediately after the beginning of its reference period; and
  - the amortization period of the particular corporation does not end before the amalgamation or merger.
- An **eligible post-2008 windup** means the windup of a subsidiary corporation into its parent corporation under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the time immediately after the completion time is within the amortization periods of the subsidiary and parent;
  - the parent's tax year (during which it received the assets of the subsidiary) ends after December 31, 2008;
  - the subsidiary has a PE in Ontario during its tax year ending at the completion time; and
  - the parent has a PE in Ontario during its tax year in which it received the assets from the subsidiary.
- An **eligible pre-2009 windup** means the windup of a subsidiary under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the parent's tax year (during which it received the assets of the subsidiary) ended before January 1, 2009; or
  - the completion time of the windup is before January 1, 2009, and the parent's tax year (during which it received the assets of the subsidiary) ended after December 31, 2008.
- The **completion time** of a windup means the end of the tax year of the subsidiary during which the subsidiary distributes its assets to the parent for the purposes of paragraph 88(1)(e.2).
- A **specified pre-2009 transfer** under section 52 of the *Taxation Act, 2007* (Ontario) means a transfer of property between corporations not at arm's length that changes the total federal or Ontario balance of either the transferee or the transferor and that occurs:
  - before 2009;
  - at different values under the *Corporations Tax Act* (Ontario) and the federal Act;
  - in a tax year ending after 2008 for either the transferee or the transferor corporation, and that corporation is a specified corporation; and
  - in a tax year of the other corporation ending before 2009, in which the other corporation has a PE in Ontario.

Part 1 – Total federal balance

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Federal balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 220 from Schedule 8, *Capital Cost Allowance (CCA)*)	110	
Charitable donations not yet deducted from income (from line 280 of Schedule 2, *Charitable Donations and Gifts*) (see Note 1)	112	
Gifts to Canada, a province, or a territory (from line 380 of Schedule 2) (see Note 1)	114	
Gifts of certified cultural property (from line 480 of Schedule 2) (see Note 1)	116	
Gifts of certified ecologically sensitive land (from line 580 of Schedule 2) (see Note 1)	118	
Gifts of medicine (from line 680 of Schedule 2) (see Note 1)	120	
Cumulative eligible capital (from line 300 of Schedule 10, *Cumulative Eligible Capital Deduction*)	122	
Federal SR&ED expenditure pool (from line 470 of Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*) (see Note 2 and Note 3)	124	
Cumulative Canadian exploration expense (from line 249 of Schedule 12, *Resource-Related Deductions*) (see Note 2)	128	
Cumulative Canadian development expense (from line 349 of Schedule 12) (see Note 2)	130	
Cumulative Canadian oil and gas property expense (from line 449 of Schedule 12) (see Note 2)	132	

Federal balances at the beginning of the current tax year

Non-capital losses (line 102 of Schedule 4, *Corporation Loss Continuity and Application*, of the current tax year) (see Note 2 and Note 4)	134	
Net capital losses (from line 200 of Schedule 4 of the current tax year x 50 %) (see Note 2 and Note 4)	136	

Amounts included in the calculation of the Ontario income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	150	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario)	152	
Other discretionary deductions claimed for Ontario income tax, but not claimed federally in the tax years ending after December 12, 2006, and before the transition time	154	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, under the federal Act, at the beginning of the tax year (see Note 5)	160	
Gain from a negative adjusted cost base of a partnership interest under subsection 40(3) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario), as if all partnership interests were disposed of at the beginning of the tax year	162	
Amount of farming income specified under paragraph 28(1)(b) in the previous tax year	164	
Federal balance before election (total of lines 110 to 164)		A

Deduct:

Lesser of amount D or amount E from Part 4, if an election is made	170	
Total federal balance (amount A **minus** line 170)	180	

Enter amount on line 300 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 2 – Total Ontario balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Ontario balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 13 from Ontario Schedule 8, *Ontario Capital Cost Allowance*)	210	
Charitable donations (amount I from Ontario *Schedule 2, Ontario Charitable Donations and Gifts*) (see Note 1)	212	
Gifts to Canada, a province, or a territory (total of closing balance amounts from parts 3 and 5 of Ontario Schedule 2) (see Note 1)	214	
Gifts of certified cultural property (closing balance amount from Part 6 of Ontario Schedule 2) (see Note 1)	216	
Gifts of certified ecologically sensitive land (closing balance amount from Part 7 of Ontario Schedule 2) (see Note 1)	218	
Gifts of medicine (see Note 1)	220	
Cumulative eligible capital (amount Q from Ontario *Schedule 10, Ontario Cumulative Eligible Capital Deduction*)	222	
Ontario SR&ED expenditure pool (line 480 from Ontario *CT23 Schedule 161, Ontario Scientific Research and Experimental Development Expenditures*) (see Note 2 and Note 3)	224	
Adjusted Ontario SR&ED incentive balance (see Note 2 and Note 5)	226	
Cumulative Canadian exploration expense (closing balance of Regular Expenses from Part 2 of Ontario *Schedule 12, Ontario Exploration Expenses*) (see Note 2)	228	
Cumulative Canadian development expense (closing balance of Regular Expenses, Canadian CCDE Expenses, from Part 3 of Ontario Schedule 12) (see Note 2)	230	
Cumulative Canadian oil and gas property expense (closing balance of Regular Expenses from Part 4 of Ontario Schedule 12) (see Note 2)	232	
Non-capital losses (from line 709 of Ontario *Corporations Tax Return CT8* or *CT23 Corporations Tax and Annual Return*) (see Note 2 and Note 4)	234	
Net capital losses (from line 719 of CT8 or CT23 x 50 %) (see Note 2 and Note 4)	236	

Amounts included In the calculation of the federal income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv)	250	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii)	252	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, for the purposes of the *Corporations Tax Act* (Ontario), at the beginning of the tax year (see Note 6)	260	
Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) determined as if all partnership interests were disposed of at the beginning of the tax year	262	
Amount of farming income in the previous tax year specified under paragraph 28(1)(b) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	264	
Total Ontario balance (total of lines 210 to 264)	280	

Enter amount on line 340 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted Ontario SR&ED incentive balance under subsection 49(7) of the *Taxation Act, 2007* (Ontario) is the total of federal investment tax credits that:

– have been earned and are available without restriction to the corporation;

– are attributable to qualifying Ontario SR&ED expenditures;

– have not been deducted under subsection 127(5) or (6) of the federal Act at the end of the corporation's tax year ending immediately before its transition time; and

– do not expire in the first tax year ending in 2009 under the 10-year carryforward limit,

divided by the relevant Ontario allocation factor as calculated in Part 11.

Note 6: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 3 – Total federal balance and total Ontario balance at the end of the tax year

Total federal balance:

Total federal balance (amount from line 180 in Part 1, or amount from line 330 in Part 3 of Schedule 506 for the previous tax year)	300	581,525,479		
Add:				
Amount from eligible amalgamation*	310			
Amount from eligible post-2008 windup*	315			
Amount from eligible pre-2009 windup*	320			
Amount from specified pre-2009 transfers*	325			
Total federal balance at the end of the tax year		581,525,479	330	581,525,479

Total Ontario balance:

Total Ontario balance (amount from line 280 in Part 2, or amount from line 370 in Part 3 of Schedule 506 for the previous tax year)	340	582,187,991		
Add:				
Amount from eligible amalgamation*	350			
Amount from eligible post-2008 windup*	355			
Amount from eligible pre-2009 windup*	360			
Amount from specified pre-2009 transfers*	365			
Total Ontario balance at the end of the tax year		582,187,991	370	582,187,991
Transitional balance at the end of the tax year (line 330 **minus** line 370)			390	-662,512

If line 390 is positive, the corporation may be subject to a transitional tax debit. Complete Part 7 of this schedule.
If line 390 is negative, the corporation may be eligible to claim a transitional tax credit. Complete Part 8 of this schedule.

* See page 1 for definitions of eligible amalgamation, eligible post-2008 windup, eligible pre-2009 windup, and specified pre-2009 transfers. To calculate these amounts, you can use *Schedule 507, Ontario Transitional Tax Debits and Credits Calculation*.

Part 4 – Election to reduce federal SR&ED expenditure pool

The corporation may make this election if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Are you making an election under clause (b) of the definition of "I" in paragraph 1 of subsection 48(4) of the *Taxation Act, 2007* (Ontario)? **400** 1 Yes ☐ 2 No ☒

If you answered **no** to the question at line 400, go to Part 5. If you answered **yes** to the question at line 400, complete the following calculation:

Federal SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 124 in Part 1)				B
Deduct:				
Adjusted Ontario SR&ED incentive balance at the end of the previous tax year (amount from line 226 in Part 2)		1		
Ontario SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 224 in Part 2)		2		
Subtotal (amount 1 **plus** amount 2)				C
Subtotal (amount B **minus** amount C) (if negative, enter "0")				D
Federal balance before election (amount A from Part 1)				
Deduct:				
Total Ontario balance (amount from line 280 in Part 2)				
Subtotal (if negative, enter "0")				E

Enter the lesser of amount D and amount E on line 170 in Part 1.

Part 5 – Reference period and amortization period

Reference period

The reference period starts at the beginning of the corporation's first tax year ending after December 31, 2008, and ends on whichever date is earlier:

– five calendar years after the time immediately before the start of the corporation's reference period; or
– December 31, 2013.

Number of days in the corporation's reference period*
(do not include February 29, 2008, and February 29, 2012) . . **410** 1,825

* The number of days in the corporation's reference period is 1825 unless:
– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3). In this case, count the number of days from the beginning of the 2009 tax year to December 31, 2013; or
– the corporation was incorporated or amalgamated after January 1, 2009. In this case, count the number of days from the date of incorporation or date of amalgamation to December 31, 2013.

Amortization period

The amortization period starts at the beginning of the corporation's reference period and ends on whichever date is earlier:

– the end of the corporation's reference period; or
– the early termination date as indicated under line 430.

Number of days in the amortization period that are in the tax year** (do not include February 29, 2008, or February 29, 2012) **420** 365

** The number of days in the amortization period that are in the tax year is the number of days in the tax year unless:
– the tax year-end is later than the end of the reference period. In this case, count the number of days from the beginning of the tax year to the end of the reference period; or
– the corporation terminates the amortization period before the end of the tax year. In this case, count the number of days from the beginning of the tax year to the day of early termination.

Early termination of the amortization period

The amortization period of the corporation usually coincides with the corporation's reference period. However, if the corporation's amortization period ends in the tax year and before the reference period ends, tick the applicable box below to indicate the reason for the early termination.

430 The corporation:

1 ☐ – ceases to have a PE in Ontario in the tax year for any reason other than an eligible amalgamation or eligible post-2008 windup.

2 ☐ – becomes exempt from tax under Part I of the federal Act immediately after the end of the tax year.

3 ☐ – elects under subsection 47(2) of the *Taxation Act, 2007* (Ontario) to prepay the transitional tax debit.
Note: The Ontario Allocation Factor, calculated in Part 6, has to be at least 90% or the amount on line 390 in Part 3 is not more than $10,000.

4 ☐ – does not object to early termination of the amortization period and accelerated payment of the transitional tax credit, under subsection 46(3) of the *Taxation Act, 2007* (Ontario).
Note: Amount T in Part 8 cannot be more than $1,000.

If you ticked one of the above boxes:
– enter the date of the early termination, if the date is different from the tax year-end and you ticked box 1 at line 430 . . . . **435** ______
– enter the number of days from the first day of the tax year to the end of the corporation's reference period (do not include February 29, 2008, or February 29, 2012) . . . . **440** ______

Part 6 – Calculation of Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line F:

$$\frac{\text{Ontario taxable income*}}{\text{Taxable income**}} \quad \_\_\_\_\_\_ = \_\_\_\_\_\_$$

Ontario allocation factor (OAF) . . . . 1.00000 F

* Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If taxable income is nil, calculate the amount in column F as if taxable income were $1,000.

** Enter taxable income from line 360 or amount Z of the T2 return, whichever applies. If taxable income is nil, enter "1,000."

Part 7 – Transitional tax debits

Complete this part if the amount on line 390 in Part 3 is positive.

Amount from line 390 in Part 3			G
Amount G x Ontario basic rate of tax*	11.74794 % =		H
Amount H x OAF (from line F in Part 6)	1.00000		I
Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period from line 410 in Part 5	365 / 1,825 =	0.20000	J

Transitional tax debit before tax on elected reduced SR&ED pool (amount I **multiplied** by amount J)			K
Post-2008 SR&ED balance at the end of the year (amount HH from Part 12)	460		
Federal SR&ED transitional balance at the end of the year (amount QQ from Part 14)	470		
Tax on elected reduced SR&ED pool (the lesser of lines 460 and 470)			L
Total transitional tax debits (amount K **plus** amount L)			M

Enter amount M on line 276 of Schedule 5.

Part 8 – Transitional tax credits

Complete this part if the amount on line 390 in Part 3 is negative.

Amount C6 from Schedule 5		2,348,749	N
Deduct:			
Ontario resource tax credit (from line 404 of Schedule 5)			
Ontario tax credit for manufacturing and processing (from line 406 of Schedule 5)			
Ontario foreign tax credit (from line 408 of Schedule 5)			
Ontario credit union tax reduction (from line 410 of Schedule 5)			
Subtotal	▶		O
Subtotal (amount N **minus** amount 0)		2,348,749	P
Number of days from line 420 in Part 5 / Number of days in the tax year (do not include February 29, 2008, or February 29, 2012)	365 / 365 =	1.00000	Q

Ontario tax payable for purposes of the current year transitional tax credit (amount P **multiplied** by amount Q)	510	2,348,749	

Amount from line 390 in Part 3 (enter as a positive amount)		662,512	R
Amount R x Ontario basic rate of tax*	11.74794 % =	77,832	S
Amount S x OAF (from line F in Part 6)		77,832	T
Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period on line 410 in Part 5	365 / 1,825 =	0.20000	U

Current-year transitional tax credit (amount T **multiplied** by amount U)	520	15,566	
Ontario tax payable for purposes of the unused transitional tax credit carryforward (line 510 **minus** line 520) (if negative, enter "0")	530	2,333,183	

Transitional tax credit:

Lesser of amounts on line 510 and 520	15,566	V
Lesser of unused transitional tax credit available (amount Y from Part 9) and amount on line 530		W
Transitional tax credits (amount V **plus** amount W)	15,566	X

Enter amount X on line 414 of Schedule 5.

* Enter the rate calculated in Part 1 of Schedule 500, *Ontario Corporation Tax Calculation*.

Part 9 – Unused transitional tax credit

Unused transitional tax credit carryforward from previous year (amount from line 580 of the previous year)*			1	
Add:				
Unused transitional tax credit transferred from a predecessor corporation or a subsidiary on an eligible amalgamation or an eligible post-2008 windup*	560		2	
Unused transitional tax credit available (amount 1 **plus** amount 2)			▶	Y
Add:				
Current-year transitional tax credit (amount from line 520 in Part 8)			15,566	Z
Subtotal (amount Y **plus** amount Z)			15,566	3
Deduct:				
Transitional tax credit applied (amount X from Part 8)			15,566	AA
Unused transitional tax credit (available for later years) (amount 3 **minus** amount AA)	580			

* Enter "0" if this is the first tax year ending after 2008.

Complete parts 10 to 14 if the corporation or a predecessor made an election in Part 4 at the transition time.

Part 10 – Federal current SR&ED limit and federal current SR&ED deficit

Current SR&ED expenditures in the year under paragraph 37(1)(a)	610			
Capital SR&ED expenditures in the year under paragraph 37(1)(b)	614			
Repayment of assistance under paragraph 37(1)(c)	618			
Investment tax credit recaptured under subsections 127(27), (29), and (34) in the previous tax year	624			
Subtotal (total of lines 610 to 624)			▶	BB
Deduct:				
Assistance under paragraph 37(1)(d)	638			
Investment tax credits deducted under paragraph 37(1)(e)	644			
Subtotal (line 638 **plus** line 644)			▶	CC
Federal current SR&ED limit or federal current SR&ED deficit (amount BB **minus** amount CC)	650			

If the amount on line 650 is positive, enter it on line II In Part 13.

If the amount on line 650 is negative, enter it as a positive amount on line DD in Part 12.

Part 11 – Relevant OAF

Enter on line 660 whichever of the following amounts is greatest:

– the corporation's OAF for the tax year that includes its transition time (from line F in Part 6) .... %

– the greatest of the corporation's OAFs for a tax year ending in 2006, 2007, and 2008 as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) .... %

– the greatest of the weighted OAFs* of the corporation and its designated corporations** for 2006, 2007, and 2008 .... %

Relevant OAF .... **660** %

* The weighted OAF for two or more corporations for their tax years ending in 2006, 2007, or 2008 is the total of the following for each corporation:

– the corporation's OAF as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) for the tax year **multiplied** by the corporation's and its share of partnerships' qualified Ontario SR&ED expenditures in the tax year, **divided** by the total of all the corporations' and their shares of partnerships' qualified Ontario SR&ED expenditures in the tax year.

Qualified Ontario SR&ED expenditure is defined in section 11.2 of the *Corporations Tax Act* (Ontario).

** A designated corporation in respect of a particular corporation is:

1) a corporation that amalgamated with the particular corporation under section 87;

2) a corporation that wound up into the particular corporation under subsection 88(1); or

3) a designated corporation to a corporation identified in 1) or 2).

Part 12 – Post-2008 SR&ED balance

Federal current SR&ED deficit for the year (amount from line 650 in Part 10, if negative) (enter as a positive amount) . . . . DD

SR&ED expenditure amount deducted in the year under subsection 37(1) **670**

Deduct:
Cumulative post-2008 SR&ED limit at the end of the year (amount LL from Part 13) **675**
Subtotal (line 670 **minus** line 675) (if negative, enter "0") ▶ EE

Subtotal (amount DD **plus** amount EE) FF

Amount FF x 14 % GG

Post-2008 SR&ED balance at the end of the year (amount GG **multiplied** by line 660 from Part 11) . . . . HH
Enter amount HH on line 460 in Part 7.

Part 13 – Cumulative post-2008 SR&ED limit at the end of the year

Federal current SR&ED limit for the year (amount from line 650 in Part 10, if positive) II
Total of all federal SR&ED limits from previous tax years ending after December 31, 2008 . . . . **700**
Subtotal (line II **plus** line 700) JJ

Total of all amounts deducted under subsection 37(1) for previous tax years ending after December 31, 2008 . . . . **705**

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) **710**

Deduct:
Amounts included in line 710 that are reasonably attributable to the federal current SR&ED deficit for the year **715**
Subtotal (line 710 **minus** line 715) **720**

Line 720 / Relevant OAF (from line 660 in Part 11) x 14 % = ... KK

Subtotal (line 705 **minus** amount KK) ▶ **730**

Cumulative post-2008 SR&ED limit at the end of the year (amount JJ **minus** line 730) (if negative, enter "0") LL
Enter amount LL on line 675 in Part 12.

Part 14 – Federal SR&ED transitional balance at the end of the year

Amount from line 170 in Part 1 (see Note) . . . . **735** MM
Relevant OAF (from line 660) (see Note) **multiplied** by amount MM . . . . NN
Amount NN x 14 % . . . . ▶ OO

Federal SR&ED transitional balance transferred on an eligible amalgamation or an eligible post-2008 wind-up **740**
Subtotal (amount OO **plus** line 740) PP

Deduct:
Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) **750**

Federal SR&ED transitional balance at the end of the year (amount PP **minus** line 750) . . . . QQ
Enter amount QQ on line 470 in Part 7.

Note: For tax years ending after 2009, enter the amount from line 170 and the relevant OAF from the 2009 tax year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return.*

Part 1 – Ontario SR&ED expenditure pool

	Line	Amount		Amount	
Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	3,230,924	A		
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105		B		
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		3,230,924	C		
Add: Eligible expenditures transferred to the corporation by another corporation	110		D		
Subtotal (amount C **plus** amount D)		3,230,924	►	3,230,924	E
Deduct: Eligible expenditures the corporation transferred to another corporation	115				F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")	120			3,230,924	G

Part 2 – Calculation of the current part of the ORDTC

	Line	Amount		Rate	Line	Amount	
Ontario SR&ED expenditure pool (amount G in Part 1)		3,230,924	x	4.50 % =	200	145,392	H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *					205		I
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment	210		x	4.50 % =	215		J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment	220	x 1 / 4 =	x	4.50 % =	225		K
Current part of the ORDTC (total of amounts H to K)					230	145,392	L

* If there is a disposal or change of use of eligible property, see Part 6

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year					M
Deduct: ORDTC expired after 20 tax years	300				N
ORDTC at the beginning of the tax year (amount M **minus** amount N)	305				O
Add:					
ORDTC transferred on amalgamation or windup	310				P
Current part of ORDTC (amount L in Part 2)		145,392 Q			
Are you waiving all or part of the current part of the ORDTC? 315 Yes 1 [ ] No 2 [X]					
If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.					
If you answered **no** at line 315, enter "0" on line 320.					
Deduct: Waiver of the current part of the ORDTC	320	R			
Subtotal (amount Q **minus** amount R)		145,392 ▶	145,392		S
ORDTC available for deduction (total of amounts O, P and S)			145,392 ▶	145,392	T
Deduct:					
ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*)			145,392		U
ORDTC carried back to a previous tax year (from Part 4)					V
Subtotal (amount U **plus** amount V)			145,392 ▶	145,392	W
ORDTC balance at the end of the tax year (amount T **minus** amount W)	325				X

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount T); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2010-12-31	Credit to be applied	901	
2nd previous tax year	2009-12-31	Credit to be applied	902	
3rd previous tax year	2008-12-31	Credit to be applied	903	
		Total (enter amount on line V in Part 3)		

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available		Tax year of origin (earliest tax year first) Year Month Day	Credit available
1993-05-31			2003-05-31	
1994-05-31			2004-05-31	
1995-05-31			2004-12-31	
1996-05-31			2005-10-31	
1997-05-31			2005-12-31	
1998-05-31			2006-12-31	
1999-05-31			2007-12-31	
2000-05-31			2008-12-31	
2001-05-31			2009-12-31	
2002-05-31			2010-12-31	
		Current tax year	2011-12-31	

Total (equals line 325 in Part 3) ____________

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

  Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Z Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	AA Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) ____________ BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	DD The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	EE The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	FF Amount determined by the formula (CC x DD) – EE (using the columns above)	GG The federal ITC earned by the transferee for the qualified expenditure that was transferred 750	HH Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) ________ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . 760 ________ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . ________ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . ________ LL

Amount KK **plus** amount LL . . . . ________ x 23.56 % = ________ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . ________ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . ________ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

		Current Expenditures			Capital Expenditures	
Total expenditures for SR&ED		2,305,852			102,568	
Add						
• payment of prior years' unpaid expenses (other than salary or wages)	+					
• prescribed proxy amount (Enter "0" if you use the traditional method)	+	616,509				
• expenditures on shared-use equipment				+	205,995	
• other additions	+			+		
Subtotal	=	2,922,361		=	308,563	
Less						
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–					
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–					
• prescribed expenditures not allowed by regulations	–			–		
• other deductions	–			–		
• non-arm's length transactions						
– expenditures for non-arm's length SR&ED contracts	–					
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–			–		
Subtotal	=	2,922,361	I	=	308,563	II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)				=	3,230,924	III

Enter amount III on line 100 of Schedule 508.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	987,164,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		987,164,000
Total revenue of the corporation for the tax year **	142	922,423,000
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		922,423,000

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.
If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
– Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
– The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
– The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	30,304,000
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	5,222,000		
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		5,222,000	▶	5,222,000 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal			▶	B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	35,526,000

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515	35,526,000	
Deduct:				
CMT loss available (amount R from Part 7)				
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available		▶		C
Net income subject to CMT calculation (if negative, enter "0")		520	35,526,000	

Amount from line 520	35,526,000	x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	4 % =		1
Amount from line 520	35,526,000	x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	365 / 365	x	2.7 % =	959,202	2

Subtotal (amount 1 **plus** amount 2) . . . 959,202 3

Gross CMT: amount on line 3 above x OAF **	540	959,202	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		959,202	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		2,187,791	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** = ______

Ontario allocation factor . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)			►	620	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)					H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)					J
Add:					
Net CMT payable (amount E from Part 3)					
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal			►		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		2,187,791	1		
For a corporation that is not a life insurance corporation:					
CMT after foreign tax credit deduction (amount D from Part 3)	959,202	2			
For a life insurance corporation:					
Gross CMT (line 540 from Part 3)		3			
Gross SAT (line 460 from Part 6 of Schedule 512)		4			
The **greater** of amounts 3 and 4		5			
Deduct: line 2 or line 5, whichever applies:		959,202	6		
Subtotal (if negative, enter "0")		1,228,589	►	1,228,589	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		2,187,791			
Deduct:					
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		211,711			
Subtotal (if negative, enter "0")		1,976,080	►	1,976,080	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)					P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year *		Q		
Deduct:				
CMT loss expired *	700			
CMT loss carryforward at the beginning of the tax year * (see note below)		▶	720	
Add:				
CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below)			750	
CMT loss available (line 720 **plus** line 750)				R
Deduct:				
CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3)				
Subtotal (if negative, enter "0")				S
Add:				
Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount)			760	
CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760)			770	T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
POWERSTREAM INC.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2009-01-01	1677786

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
161	CITYVIEW BLVD	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
VAUGHAN	ON	CA	L4H 0A9

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [ ] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Young (Last name) **451** Carolyn (First name)

454 ______________________, (Middle name(s))

460 1 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information: Adam Chiarandini	**120** Telephone number including area code

Is the claim filed for a CETC earned through a partnership?* . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . **160** ____

Enter the percentage of the partnership's CETC allocated to the corporation . . . **170** ____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 600,001

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	Georgian College	
2.	Georgian College	
3.	Georgian College	
4.	Georgian College	
5.	Seneca College	
6.	Sheridan College	
7.	Georgian College	
8.	Georgian College	
9.	Georgian College	
10.	Humber College	
11.	Centennial College	
12.	Georgian College	
13.	Dalhousie University	
14.	Georgian College	
15.	Fleming College	
16.	McMaster University	
17.	Humber College	
18.	Georgian College	
19.	Georgian College	
20.	Georgian College	
21.	Seneca College	
22.	Georgian College	
23.	Conestoga College	

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
24.	Georgian College	
25.	Georgian College	
26.	Ryerson University	
27.	Georgian College	
28.	Waterloo University	
29.	Georgian College	
30.	Georgian College	
31.	Seneca College	
32.	Georgian College	
33.	Georgian College	
34.	Seneca College	
35.	Georgian College	
36.	Georgian College	
37.	Brock University	
38.	Georgian College	
39.	Sheridan College	
40.	Georgian College	
41.		

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	Corke, Darryl	2011-01-10	2011-04-29
2.	Gervais, Andrew - Term 1	2011-01-04	2011-04-29
3.	Haney, Robert - Term 1	2011-01-04	2011-04-29
4.	Hastie, David	2011-01-01	2011-04-29
5.	Kraft, Leah	2011-01-10	2011-04-29
6.	Lewis, Alexxander	2011-01-04	2011-04-29
7.	Pridham, Cindy	2011-01-04	2011-04-29
8.	Ramos, Lorenzo - Term 1	2011-01-04	2011-04-29
9.	Sirett, Chris - Term 1	2011-01-04	2011-04-29
10.	Thompson, Andrea	2011-01-04	2011-04-29
11.	Tovera, Anna	2011-01-01	2011-04-29
12.	Zaritsky, Zach	2011-01-04	2011-04-29
13.	Arksey, Michelle	2011-05-16	2011-09-02
14.	Brown, Paul	2011-05-25	2011-09-02
15.	Capano, Matthew	2011-04-26	2011-09-02
16.	Casciato, Adam	2011-04-26	2011-09-02
17.	Cogliano, Daniella	2011-05-02	2011-09-02
18.	Cuthbertson, Jason	2011-04-25	2011-09-02
19.	Gray, Brad	2011-04-26	2011-09-02
20.	Hickling, Brad	2011-04-26	2011-09-02
21.	Huestis, Jordan	2011-04-25	2011-09-02
22.	Lacombe, Joel	2011-05-02	2011-09-02
23.	Leibold, Charlie	2011-05-02	2011-09-02
24.	Nolan, Josh	2011-04-25	2011-09-02
25.	Roy, James	2011-04-25	2011-09-02
26.	Todorow, Christopher	2011-04-26	2011-09-02
27.	Tozzo, Bruno	2011-04-26	2011-09-02
28.	Vitelli, Michael	2011-04-26	2011-09-02
29.	Cornett, Keven	2011-08-22	2011-12-30
30.	Cumberland, Chad	2011-08-29	2011-12-30

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
31.	Dorschu, Sandy	2011-08-29	2011-12-30
32.	Gervais, Andrew - Term 2	2011-09-06	2011-12-30
33.	Haney, Robert - Term 2	2011-08-29	2011-12-30
34.	Hart, Kellie	2011-08-24	2011-12-30
35.	Lafrance, Nick	2011-08-29	2011-12-30
36.	Macdonald, Liam	2011-08-22	2011-12-30
37.	Minin, Mikhail	2011-09-12	2011-12-30
38.	Patenaude, Paul	2011-08-22	2011-12-30
39.	Ramos, Lorenzo - Term 2	2011-09-06	2011-12-30
40.	Sirett, Chris - Term 2	2011-08-29	2011-12-30
41.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	11,049	25.000 %		16
2.		10.000 %	10,230	25.000 %		16
3.		10.000 %	10,160	25.000 %		16
4.		10.000 %	10,043	25.000 %		17
5.		10.000 %	8,514	25.000 %		16
6.		10.000 %	8,943	25.000 %		16
7.		10.000 %	10,285	25.000 %		16
8.		10.000 %	8,888	25.000 %		16
9.		10.000 %	9,405	25.000 %		16
10.		10.000 %	32,911	25.000 %		16
11.		10.000 %	21,519	25.000 %		17
12.		10.000 %	23,344	25.000 %		16
13.		10.000 %	9,201	25.000 %		16
14.		10.000 %	11,638	25.000 %		14
15.		10.000 %	12,318	25.000 %		18
16.		10.000 %	13,995	25.000 %		18
17.		10.000 %	21,651	25.000 %		18
18.		10.000 %	10,764	25.000 %		19
19.		10.000 %	9,767	25.000 %		18
20.		10.000 %	9,454	25.000 %		18
21.		10.000 %	10,096	25.000 %		19
22.		10.000 %	1,755	25.000 %		18
23.		10.000 %	15,134	25.000 %		18
24.		10.000 %	9,808	25.000 %		19
25.		10.000 %	11,162	25.000 %		19
26.		10.000 %	5,075	25.000 %		18
27.		10.000 %	11,655	25.000 %		18
28.		10.000 %	10,391	25.000 %		18
29.		10.000 %	11,334	25.000 %		19
30.		10.000 %	10,900	25.000 %		18
31.		10.000 %	9,200	25.000 %		18
32.		10.000 %	10,231	25.000 %		16
33.		10.000 %	10,161	25.000 %		18
34.		10.000 %	8,628	25.000 %		18
35.		10.000 %	9,828	25.000 %		18
36.		10.000 %	9,670	25.000 %		19
37.		10.000 %	9,438	25.000 %		16
38.		10.000 %	10,173	25.000 %		19
39.		10.000 %	8,888	25.000 %		16
40.		10.000 %	9,405	25.000 %		18
41.		10.000 %		25.000 %		

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	2,762	3,000	2,762		2,762
2.	2,558	3,000	2,558		2,558
3.	2,540	3,000	2,540		2,540

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
4.	2,511	3,000	2,511		2,511
5.	2,129	3,000	2,129		2,129
6.	2,236	3,000	2,236		2,236
7.	2,571	3,000	2,571		2,571
8.	2,222	3,000	2,222		2,222
9.	2,351	3,000	2,351		2,351
10.	8,228	3,000	3,000		3,000
11.	5,380	3,000	3,000		3,000
12.	5,836	3,000	3,000		3,000
13.	2,300	3,000	2,300		2,300
14.	2,910	3,000	2,910		2,910
15.	3,080	3,000	3,000		3,000
16.	3,499	3,000	3,000		3,000
17.	5,413	3,000	3,000		3,000
18.	2,691	3,000	2,691		2,691
19.	2,442	3,000	2,442		2,442
20.	2,364	3,000	2,364		2,364
21.	2,524	3,000	2,524		2,524
22.	439	3,000	439		439
23.	3,784	3,000	3,000		3,000
24.	2,452	3,000	2,452		2,452
25.	2,791	3,000	2,791		2,791
26.	1,269	3,000	1,269		1,269
27.	2,914	3,000	2,914		2,914
28.	2,598	3,000	2,598		2,598
29.	2,834	3,000	2,834		2,834
30.	2,725	3,000	2,725		2,725
31.	2,300	3,000	2,300		2,300
32.	2,558	3,000	2,558		2,558
33.	2,540	3,000	2,540		2,540
34.	2,157	3,000	2,157		2,157
35.	2,457	3,000	2,457		2,457
36.	2,418	3,000	2,418		2,418
37.	2,360	3,000	2,360		2,360
38.	2,543	3,000	2,543		2,543
39.	2,222	3,000	2,222		2,222
40.	2,351	3,000	2,351		2,351
41.					

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ x percentage on line 170 in Part 1 ________ % = ... ________ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received.
Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2011-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	120 Telephone number including area code
Adam Chiarandini	

Is the claim filed for an ATTC earned through a partnership? * . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 600,001

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300 } \textbf{minus } 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \left(\frac{\text{amount on line 300 } \textbf{minus } 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
1.	434a	Powerline Technician	HOLMES, CORY
2.	434a	Powerline Technician	WILMOT, MICHAEL
3.	434a	Powerline Technician	HAGAN, CHRISTOPHER
4.	434a	Powerline Technician	WALSH, RYAN
5.	434a	Powerline Technician	SIMPSON, CHRISTOPHER
6.	434a	Powerline Technician	CHARD, ROBERT
7.	434a	Powerline Technician	ROBINSON, STEVEN
8.	434a	Powerline Technician	MAAS, ADAM
9.	434a	Powerline Technician	LONG, JEFF
10.	434a	Powerline Technician	LAMB, TIM
11.	434a	Powerline Technician	WALSH, ADAM
12.	434a	Powerline Technician	FERGUSON, ANDREW
13.	434a	Powerline Technician	JOHNSTON, BOB
14.	434a	Powerline Technician	WHITE, DARRYL
15.	434a	Powerline Technician	FLYNN, ANDREW
16.	434a	Powerline Technician	FOSTER, JORDAN
17.	434a	Powerline Technician	SHINN, JUSTIN
18.	434a	Powerline Technician	GRAY, ROBERT
19.	434a	Powerline Technician	ZARITSKY, ZACH
20.	434a	Powerline Technician	FARIS, JASON
21.	434a	Powerline Technician	SHENNAN, ANDREW
22.	434a	Powerline Technician	VANDERKOOY, LUKE
23.	434a	Powerline Technician	BIDUKE, KEEGAN
24.	434a	Powerline Technician	ZAPP, BRIAN
25.			

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
1.	15005	2006-02-27	2006-02-27	2011-12-31
2.	15004	2006-02-27	2006-02-27	2011-12-31
3.	15002	2006-02-27	2006-02-27	2011-12-31
4.	15003	2006-02-27	2006-02-27	2011-12-31
5.	15006	2006-02-27	2006-02-27	2011-05-27
6.	15007	2006-02-27	2006-02-27	2011-12-31
7.	23972	2007-06-07	2007-03-21	2011-12-31
8.	23971	2007-06-07	2007-03-21	2011-12-31
9.	23970	2007-06-07	2007-03-21	2011-12-31
10.	23973	2007-06-07	2007-04-10	2011-12-31
11.	PC9094	2009-09-28	2009-09-28	2011-12-31
12.	PA4127	2009-09-28	2009-09-28	2011-12-31
13.	PC9201	2009-09-28	2009-09-28	2011-12-31
14.	PC9203	2009-09-28	2009-09-28	2011-12-31
15.	PC9095	2009-09-28	2009-09-28	2011-12-31
16.	PC9093	2009-09-28	2009-09-28	2011-12-31
17.	PC9202	2009-09-28	2009-09-28	2011-12-31
18.	PC9096	2009-09-28	2009-09-28	2011-12-31
19.	PC0305	2011-09-30	2011-09-26	2011-12-31
20.	PC0304	2011-09-30	2011-09-26	2011-12-31
21.	PC0321	2011-10-24	2011-09-26	2011-12-31
22.	PC0306	2011-09-30	2011-09-26	2011-12-31
23.	PC0302	2011-09-30	2011-09-26	2011-12-31
24.	PC0303	2011-09-30	2011-09-26	2011-12-31
25.				

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.				
2.				
3.				
4.				
5.				
6.				
7.		157	157	4,301
8.		157	157	4,301
9.		157	157	4,301
10.		157	157	4,301
11.		365	365	10,000
12.		365	365	10,000
13.		365	365	10,000
14.		365	365	10,000
15.		365	365	10,000
16.		365	365	10,000
17.		365	365	10,000
18.		365	365	10,000
19.		92	92	2,521
20.		92	92	2,521
21.		68	68	1,863
22.		92	92	2,521
23.		92	92	2,521
24.		92	92	2,521
25.				

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.				
2.				
3.				
4.				
5.				
6.				
7.		33,309	33,309	11,658
8.		33,309	33,309	11,658
9.		33,309	33,309	11,658
10.		33,309	33,309	11,658
11.		64,210	64,210	22,474
12.		64,210	64,210	22,474
13.		64,210	64,210	22,474
14.		64,210	64,210	22,474
15.		64,210	64,210	22,474
16.		64,210	64,210	22,474
17.		64,210	64,210	22,474
18.		64,210	64,210	22,474
19.		12,237	12,237	4,283
20.		12,237	12,237	4,283

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
21.		9,044	9,044	3,165
22.		12,237	12,237	4,283
23.		12,237	12,237	4,283
24.		12,237	12,237	4,283
25.				

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.			
2.			
3.			
4.			
5.			
6.			
7.	4,301		4,301
8.	4,301		4,301
9.	4,301		4,301
10.	4,301		4,301
11.	10,000		10,000
12.	10,000		10,000
13.	10,000		10,000
14.	10,000		10,000
15.	10,000		10,000
16.	10,000		10,000
17.	10,000		10,000
18.	10,000		10,000
19.	2,521		2,521
20.	2,521		2,521
21.	1,863		1,863
22.	2,521		2,521
23.	2,521		2,521
24.	2,521		2,521
25.			

Ontario apprenticeship training tax credit (total of amounts in column N) 500 111,672 O or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ______ x percentage on line 170 in Part 1 ______ % = ... ______ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . POWERSTREAM INC.

Taxation Year . . . . 2011-01-01 to 2011-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated . . . . N

Corporation is related . . . . N

Number of associated corporations . . .

Type of corporation . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* . . . . -2,533,406

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		20,851,429
Taxable income		20,301,340
Donations		550,089
Calculation of income from an active business carried on in Canada		20,851,429
Dividends paid		13,857,000
Dividends paid – Regular	13,857,000	
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		111,921,813
Balance of the general rate income pool at the end of the year		126,132,751
Part I tax (base amount)		7,714,509

Credits against part I tax		**Summary of tax**		**Refunds/credits**	
Small business deduction		Part I	2,732,614	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	7,242,100
Investment tax credits	617,107	Other*		Surtax credit	
Abatement/Other*	4,364,788	Provincial or territorial tax	1,976,080	Other*	

Balance due/refund (–) -2,533,406

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Capital dividend amount	2,587,166
Cumulative eligible capital	6,640,614
Financial statement reserve	18,436,542

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	20,851,429		
Taxable income	20,301,340		
% Allocation	100.00		
Attributed taxable income	20,301,340		
Surtax		N/A	N/A
Tax payable before deduction*	2,384,989		
Deductions and credits	197,198		
Net tax payable	2,187,791		
Attributed taxable capital			N/A
Capital tax payable**			N/A
Total tax payable***	2,187,791		
Instalments and refundable credits	211,711		
Balance due/Refund (-)	1,976,080		
Logging tax payable			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
POWERSTREAM INC.	746,094,157	746,094,157	305,403,000	305,403,000
Total	746,094,157	746,094,157	305,403,000	305,403,000

Québec

Corporate name	Paid-up capital used to calculate the deduction relating to income-averaging for forest producers (CO-726.30)	Paid-up capital used to calculate the exemption for small and medium-sized manufacturing businesses (CO-737.18.18)	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total					

Ontario

Corporate name	Taxable capital used to calculate the capital deduction – Ontario capital tax on financial institutions (Schedule 514)	Taxable capital used to calculate the capital deduction – Ontario capital tax on other than financial institutions (Schedule 515)	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
POWERSTREAM INC.			746,094,157
Total			746,094,157

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)	Taxable capital used to calculate the Nova Scotia capital deduction on large corporations (Schedule 343)	Net paid up capital – BC capital tax on financial institutions (FIN 689)	BC paid up capital – BC capital tax on financial institutions (FIN 689)
Total				

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2011-12-31**	**2010-12-31**	**2009-12-31**	**2008-12-31**	**2007-12-31**
Net income	20,851,429	32,813,266	25,815,627	20,170,245	35,400,459
Taxable income	20,301,340	32,636,831	25,556,717	18,142,389	35,294,289
Active business income	20,851,429	32,813,266	25,815,627	20,170,245	33,235,180
Dividends paid	13,857,000	10,532,000	31,082,643	8,513,868	4,736,400
Dividends paid – Regular	13,857,000	10,532,000			
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	111,921,813	89,402,400	72,023,832	59,687,007	37,159,280
GRIP – end of the year	126,132,751	111,921,813	89,402,400	72,023,832	59,687,007
Donations	550,089	176,435	258,910	2,027,856	106,170
Balance due/refund (-)	-2,533,406	505,236	-758,019		

Federal taxes

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Part I before surtax	2,732,614	5,333,992	4,343,215	3,537,766	7,415,086
Surtax					395,296
Part I.3					
Part IV					
Part I & Surtax	2,732,614	5,333,992	4,343,215	3,537,766	7,810,382
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Small business deduction					
M&P deduction					
Foreign tax credit					
Political contribution					558
Investment tax credit	617,107	540,638	512,560		292,078
Abatement/other*	4,364,788	6,527,366	4,855,777	3,356,342	5,848,460

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
ITC refund					
Dividend refund					577,408
Instalments	7,242,100	9,246,731	10,026,123	3,537,766	7,232,974
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2011-12-31	2010-12-31	2009-12-31	2008-12-31	2007-12-31
Net income	20,851,429	32,813,266	25,815,627	19,878,167	35,091,498
Taxable income	20,301,340	32,636,831	25,556,717	17,850,311	34,985,328
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income	20,301,340	32,636,831	25,556,717	17,850,311	34,985,328
Surtax		39,979	42,500	42,500	34,000
Income tax payable before deduction	2,384,989	4,240,109	3,577,940	2,499,044	4,897,946
Income tax deductions /credits	197,198	184,750	181,957	128,433	121,916
Net income tax payable	2,187,791	4,095,338	3,438,483	2,413,111	4,810,030
Taxable capital		746,094,157	747,642,639	585,300,617	535,601,747
Capital tax payable		543,814	1,648,446	1,283,176	1,490,840
Total tax payable*	2,187,791	4,639,152	5,086,929	3,696,287	6,300,870
Instalments and refundable credits	211,711	221,177	162,040	9,716,625	6,933,283
Balance due/refund**	1,976,080	4,417,975	4,924,889	-6,020,338	-632,413

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Canada Revenue Agency / Agence du revenu du Canada

Code 1101

SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED) EXPENDITURES CLAIM

Use this form:

- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:

- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

Part 1 – General information

010 Name of claimant: POWERSTREAM INC.

Enter one of the following:

Business Number (BN): 85750 3346 RC0002

Social Insurance Number (SIN):

Tax year
From: 2011-01-01 (Year Month Day)
To: 2011-12-31 (Year Month Day)

050 Total number of projects you are claiming this tax year: 7

100 Contact person for the financial information: Adam Chiarandini	**105** Telephone number/extension: (905) 417-6900	**110** Fax number:
115 Contact person for the technical information: Adam Chiarandini	**120** Telephone number/extension:	**125** Fax number:

151 If this claim is filed for a partnership, was Form T5013 filed? . . . . . 1 [ ] Yes 2 [X] No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Name of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 [X] I elect to use the proxy method
(Enter "0" on line 360. Complete Part 5 and you do not need to track any expenditure incurred for overhead)

162 [ ] I choose to use the traditional method
(Enter "0" on line 355. Complete line 360, and track any expenditure incurred for overhead)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

	Line		Amount
• SR&ED portion of salary or wages of employees directly engaged in the SR&ED:			
a) Employees other than specified employees for work performed in Canada	300	+	1,022,849
b) Specified employees for work performed in Canada	305	+	
Subtotal (add lines 300 and 305)	306	=	1,022,849
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	307	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	309	+	
• Salary or wages identified on line 315 in prior years that were paid in this tax year	310	+	
• Salary or wages incurred in the year but not paid within 180 days of the tax year end	315		
• Cost of materials consumed in performing SR&ED	320	+	
• Cost of materials transformed in performing SR&ED	325	+	
• Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts	340	+	1,273,003
b) Non-arm's length contracts	345	+	
• Lease costs of equipment used:			
a) All or substantially all (90% of the time or more) for SR&ED	350	+	5,000
b) Primarily (more than 50% of the time but less than 90%) for SR&ED. (Enter 50% of lease costs if you use the proxy method or enter "0" if you use the traditional method)	355	+	
• Overhead and other expenditures (enter "0" if you use the proxy method)	360	+	
• Third-party payments (complete Form T1263*)	370	+	5,000
Total current SR&ED expenditures (add lines 306 to 370; do not add line 315) (Corporations need to adjust line 118 of schedule T2SCH1)	380	=	2,305,852
• **Capital Expenditures** (see guide for what qualifies for SR&ED) (Do not include these capital expenditures on schedule T2SCH8)	390	+	102,568
Total allowable SR&ED expenditures (add lines 380 and 390)	400	=	2,408,420

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

	Line		Amount
Amount from line 400	420		2,408,420
Deduct			
• provincial government assistance for expenditures included on line 400	429	–	117,649
• other government assistance for expenditures included on line 400	431	–	
• non-government assistance for expenditures included on line 400	432	–	
• SR&ED ITCs applied and/or refunded in the prior year (see guide)	435	–	540,638
• sale of SR&ED capital assets and other deductions	440	–	
Subtotal (line 420 minus lines 429 to 440)	442	=	1,750,133
Add			
• repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	445	+	
• prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	450	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
• amount of SR&ED ITC recaptured in the prior year	453	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	455	=	1,750,133
• Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	460	–	1,750,133
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	470	=	

* Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Enter the breakdown between current and capital expenditures (to the nearest dollar)

	Line	Current Expenditures	Line	Capital Expenditures
Total expenditures for SR&ED (from line 380 and 390)	492	2,305,852	496	102,568
Add				
• payment of prior years' unpaid amounts (other than salary or wages)	500 +			
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	502 +	616,509		
• expenditures on shared-use equipment (see guide)			504 +	205,995
• qualified expenditures transferred to you (complete Form T1146**)	508 +		510 +	
Subtotal (add lines 492 to 508, and add lines 496 to 510)	511 =	2,922,361	512 =	308,563
Deduct				
• provincial government assistance	513 –	131,507	514 –	13,885
• other government assistance	515 –		516 –	
• non-government assistance and contract payments	517 –		518 –	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	520 –			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	528 –			
• prescribed expenditures not allowed by regulations (see guide)	530 –		532 –	
• other deductions (see guide)	533 –		535 –	
• non-arm's length transactions				
– assistance allocated to you (complete Form T1145*)	538 –		540 –	
– expenditures for non-arm's length SR&ED contracts (from line 345)	541 –			
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	542 –		543 –	
– qualified expenditures you transferred (complete Form T1146**)	544 –		546 –	
Subtotal (line 511 minus lines 513 to 544 and line 512 minus lines 514 to 546)	557 =	2,790,854	558 =	294,678
Qualified SR&ED expenditures (add lines 557 and 558)			559 =	3,085,532
Add				
• repayments of assistance and contract payments made in the year			560 +	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)			570 =	3,085,532

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162).
You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from line 300 and 307)	810	+	1,022,849
Deduct			
Bonuses, remuneration based on profits, and taxable benefits that were included on line 810	812	–	74,374
Subtotal (line 810 minus 812)	814	=	948,475

Salary or wages of specified employees

850	852	854	856	858	860
Column 1	**Column 2**	**Column 3**	**Column 4**	**Column 5**	**Column 6**
Name of Specified Employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816) **816** +

Salary base (total of lines 814 and 816) **818** = 948,475

Section B – Prescribed proxy amount (PPA)

Enter 65% of the salary base (line 818 x 65%) **820** = 616,509

Enter the amount from line 820 on line 502 in Part 4 unless the overall cap on PPA applies to you.

(See the guide for explanation and example of the overall cap on PPA)

Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

750	752	754	756
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)
1. P1: System assets, equipment and apparatus improvement	66,293		82,495
2. Power transformer stations and DG connection facilitation	165,664		132,823
3. Electric power distribution systems	219,479		32,205
4. P4: Smart metering and PSI facility energy conservation	194,793		285,038
5. OMS develop. &op. telecom infrastructure improvements	31,646		181,851
6. Smart Grid (SG) initiatives development	209,666		63,515
7. P7: Sustainable generation systems design and developmen	135,309		495,077
Total	1,022,850		1,273,004

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 400 minus lines 307, 309, 340, 345, and 370) **605** 1,130,417

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

	Line	Canadian (%)	Line	Foreign (%)
Internal	600	100.000		
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

Enter the number of SR&ED personnel in full-time equivalents (FTE):

	Line	
Scientists and engineers	632	8
Technologists and technicians	634	
Managers and administrators	636	
Other technical supporting staff	638	

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form X
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 X
3. completed Part 2 for each project X
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures X
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable X

To expedite the processing of your claim, make sure you have:

1. completed Form T2, *Corporation Income Tax Return* or Form T1, *Income Tax and Benefit Return* X
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable X
3. retained documents to support the SR&ED expenditures you claimed X
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 X

* Form T1145, *Agreement ta Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement ta Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

*** Form T1174, *Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)*

**** Form T1263, *Third·Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 9 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 Carolyn Young
Name of authorized signing officer of the corporation, or individual

Signature

170
Date

175 Deloitte & Touche LLP
Name of person/firm who completed this form

Canada Revenue Agency / Agence du revenu du Canada

THIRD-PARTY PAYMENTS FOR SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED)

Complete this form for each third-party payment and attach it to Form T661.

For more information on third-party payments:
- See line 370 of Guide to Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
- Application Policy SR&ED 1996-04, *Payments to third parties for SR&ED*;
- Application Policy SR&ED 2001-01, *Research Chairs*;
- Interpretation Bulletin IT-151R5, *Scientific Research and Experimental Development Expenditures*;
- Consult our Web site: **www.cra.gc.ca/sred**.

Required Information

1. Identification

701 Name of the third party
University of Waterloo

702 Address (Street number and name)
200 University Avenue

City	Province / Territory	Postal Code
Toronto	ON CA	N2L 3G1

704 Total amount paid in the year
$ 5,000

Provide a list of the research projects which relate to the third-party entity

706 Project title (and identification code if applicable)
1 P2 Power Transformer Stations

Check the appropriate box to indicate the type of entity:

711	Approved association	1 Yes	
712	Non-profit SR&ED corporation resident in Canada	1 Yes	
714	An approved university, college, research institute, or other similar institution	1 Yes	X
716	Granting council	1 Yes	
718	Other corporation resident in Canada	1 Yes	
721	Are you dealing at arm's length with the recipient?	1 Yes	X	2 No ☐

2. Nature of payment

Check the appropriate box to indicate the type of work:

The payment is for:

731	Experimental development	1 Yes	X
732	Applied research	1 Yes	
734	Basic research	1 Yes	

736 Briefly explain what the payment is for:
To carry out a study into the protection requirement that
should be implemented distribution generation units and
connected to an electrical power distribution network

738 Briefly explain how the SR&ED is related to a business that you carry on:
PSI is in the business of electrical power distribution.
To facilitate OPA approved distributed generation system and
protect the existing network

740 Briefly explain how you are entitled to exploit the results of the SR&ED:
Using the study result will help it to improve its practices and procedures
and detailed design of the interconnection between DG units of different
types and sizes, and the PSI network

T1263 E (08)

Canada

Part 2 - Project information (continued)

Project number **1**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

P1: System assets, equipment and apparatus improvement

202 Project start date: 2007-01 (Year Month)

204 Completion or expected completion date: 2012-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project

210 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

	220 Names of the businesses	**221** BN
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		

The work was carried out (check any that apply)

223 1 [ ] In a laboratory

226 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility

228 1 [X] Others, specify **229** Field failures sites and subs's facilities

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [ ]	**236** 1 [ ]
The improvement of existing	**237** 1 [X]	**238** 1 [ ]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

```
1.  PSI sought to acquire the knowledge/knowhow to create one set of merged
2.  standards and materials specifications (SMS) for its entire service area to
3.  replace two existing sets, which reflected different design details and
4.  construction practices.  A reconciliation of these differences was needed. The
```

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

single set of SMS would likely include a mix of original & modified elements from the existing sets as well as entirely new ones. PSI also sought to find out the extent to which the concepts of standardization could be applied in the creation of a single set of SMS to reduce the proliferation of components and materials that are required to maintain its existing system, and to design and build system upgrades and additions. Efforts to standardize SMS and use modular construction methods need, of course, to meet all technical, safety and operating requirements and should, when properly applied, lead to more cost effective asset management from leveraging PSI s purchasing power. Last year, progress was made establishing methodologies, creating a software tool to facilitate the migration & merger of the materials standards & stock codes, and then dealing with about 35% of the items that had to be examined. In addition, PSI has to increase and deepen its existing understanding of the causes of failures with items in service like U/G cable splices, overhead switches, solid dielectric (SD) switchgear, distribution transformers of all types, and PDH switchgear, so that (1) its specifications can be used with assurance to acquire new items of these types whose failure rate in service approaches zero, (2) its construction engineering standards can be improved and made more robust, e.g. its O/H system hardened, so that the probability of the future occurrence of similar failures is minimized to the extent practical, and (3) alternative technical solution options for systemic failure issues can be developed. A related subsidiary advance is better capability to (a) create engineering equipment specifications and installation designs for items that have passed field acceptance trials, and (b) undertake preliminary investigations of new items with potential for inclusion in field trials.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

The basic obstacle in 2011 to continuing the merging two distinct sets of SMS into a single state-of-the-art one was how to reconcile different technical approaches that might have been taken in the same areas that the new single integrated set of SMS has to cover. Other subsidiary issues were how obsolescence should be handled, what the review and approval process should entail, and how much weight should be given to the consequences of implementing a new specific SMS when it is under development. Similar challenges exist with standardization efforts to reduce item and materials proliferation.

When an in-service item fails, it is important that the appropriate level of investigative effort and analysis is undertaken to determine why the item failed, and how similar types of failures can be prevented in future. Very often such work is undertaken with representatives of the supplier or manufacturer of the failed items. Typically too, other LDC experience is accessed where appropriate, as such input often provides additional perspectives on a specific incident that is being investigated, especially when forensic examination yields limited clues to possible causes due to the extent of the damage involved. Suppliers to the electric power distribution industry sector develop new items and components, which they hope will become industry-approved standard items. Because an item/component is used successfully by one LDC, it does not automatically mean that it will do the same in a similar application for other LDCs. Differences in distribution system characteristics, operations and maintenance practices, as well as environmental conditions, may have an impact on the outcome. PSI experience has shown that it needs to both conduct a detailed technical review of the new item/component s design characteristics, and a successful field trial before any new item/component is accepted as a standard part for use in new construction and existing asset maintenance.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

The 3-person team of subcontractor personnel formed last year - to merge existing sets of SMS formerly used in the north and south service areas - continued their efforts over the entire year. SMS integration, whose status going into the year was 35% complete, ended the year at the 85% complete level. To facility SMS, use was made of the information available from the Utility Standards Forum, e.g. with regard to street lighting. The Standards Committee (SC) met periodically throughout the year to monitor progress and resolve issues. A notable example of the work done was the review and analysis of SMS for transformers. From the existing 434 separate items in the JDE system, the re-engineering/re-development resulted in only about 100 being created in the new SMS. Access to SMS for all internal staff was improved by making them available through the InFlow application. Initial thinking was to replicate this access for external subcontractors in 2012. Reviews and approvals were also carried out of transformer test reports, shop drawings and subdivision packages.

The ENG-SD-08 standard was revised and the PUPI 4000 series cross-arms were approved. A Re-use of Equipment procedure was also developed. PSI staff attended a new product development meeting. Efforts were also made to progress the resolution of failed spring in a specific manufacturer s switchgear that was one of the six issues carried over from last year. Despite meetings with the supplier, the broken spring switch issues were not completely resolved by the yearend.

The field trial of the SD switchgear with a modified design that was started last year to resolve early failures of the prior design continued over the year, as did the field trial for a fibreglass cross-arm. In October a fibreglass switch bracket was subject to a field trial that involved 12 3 and 2 1 item installations. The items weighed half of the existing component. Other new items considered during the year were lightning arrestors, and self-supporting poles. Composite material poles (versus the modular ones involved in trials a few years ago) were investigated. The SC reviewed the options and deferred a field trial until next year.

An issue arose with the SMD-20 switch. Old & new design tests were performed by the manufacturer. After external, PSI approved the new design. A first application of Reliability Centered Maintenance (RCM) was performed on a circuit switcher. More RCM applications are likely in 2012.

Digital fault indicators were reviewed & tested in the P&C workshop then deployed in a field trial. The DFI communicates via the existing AMI. A new RTU was specified to replace obsolete existing units. The new design included a proven IED and EPS with sophisticated battery management. After prototype shop testing, a field trial was started.

Two subcontractors worked on cable issues. One performed failure analysis/assessments on 3 cables. The other carried out measurements/comparative tests on cable samples. Consideration was given to starting cable testing program. From analysis of the options available, PSI decided to base its program on the Tan Delta non-destructive testing method to determine overall health of its cables. The method is not new to the industry, but it is to PSI, who would be the first LDC in Ontario to apply the technique. The necessary equipment would be bought and the planned program launched in 2012. Another subcontractor performed an analysis of SMD-20 Transformer Power Mounting Fuses. Forensic analyses were also performed on two failed transformers at the supplier s facility. Subsequently the fusing was changed to external from internal. At yearend several items were awaiting SC decisions. One was using copper clad ground conductor as a substitute for missing traditional ground replacements.

PSI also participated as a funding sponsor in two investigations undertaken by the Centre for Energy Advancement through Technological Innovation (CEATI). They were: (1) Composite Poles in Transmission and Distribution Experience and Issues; and (2) Non-Wood Cross-Arm Electrical Testing Requirements, led by

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

59. the Distribution Life Cycle Assets Management Interest Group.External
60. contractors (see Section D, line 268) were also directly engaged in these
61. experimental development activities and/or related support activities.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

1.
2.
3.
4.

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
2.
3.
4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [ ] Employee directly involved in the project	**254** Name		
255 1 [ ] Other employee of the company	**256** Name		
257 1 [X] External consultant	**258** Name: Deloitte & Touche LLP	**259** Firm: Deloitte & Touche LLP	

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Doug Fairchild	P.Eng., 22 years' experience, Manager, Planning & Standards
2	Alex Cestra	C.E.T. , 15 years' experience, Plng. & Stds. Technician
3	Dan Deschamps	C.E.T., 25 years' experience, Plng. & Stds. Technician

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	Brosz and Associated	83432 2661 RC0001
2	Ceati International	89131 9899 RC0001
3	Exova	88129 0324 RC0001
4	Joe Crozier	86110 6631 RC0001
5	MGA Consulting	89357 9367 RC0001
6	Roan International Inc	10456 6062 RC0001
7	SkunkWorks Laboratories Inc	85244 0791 RC0001
8		
9		
10		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents	276	1	X	Progress reports, minutes of project meetings
271	1	X	Records of resources allocated to the project, time sheets	277	1	X	Test protocols, test data, analysis of test results, conclusions
272	1		Design of experiments	278	1	X	Photographs and videos
273	1	X	Project records, laboratory notebooks	279	1	X	Samples, prototypes, scrap or other artefacts
274	1		Design, system architecture and source code	280	1	X	Contracts
275	1	X	Records of trial runs	281	1		Others, specify 282

Part 2 - Project information (continued)

Project number **2**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

Power transformer stations and DG connection facilitation

202 Project start date: 2007-01 (Year Month)

204 Completion or expected completion date: 2012-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project   **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

	220 Names of the businesses	**221** BN
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		

The work was carried out (check any that apply)

223 1 [ ] In a laboratory   **226** 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility   **228** 1 [X] Others, specify **229** at field sites

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [ ]	**236** 1 [ ]
The improvement of existing	**237** 1 [X]	**238** 1 [ ]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. For 2011, PSI wanted to advance its knowledge, know-how, capabilities, and
2. understanding: (1) Whether or not appropriate fault levels were in use at PSI
3. s TS (whose feeders were involved during distributed generation (DG)
4. connection impact assessments (CIAs)), how connected DG systems, 250kW

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

upwards, can be remotely monitored and tripped, how DG connection impacts protection planning coordination, and should limitations be placed on DG penetration; (2) To complete and commission a super-highway for high priority systems data communications; (3) A capacitor bank design to specifically dampen transients and improve power quality for PSI s largest customer; and (4) To extend its applications of automatic restoration of feeder.

In 2010, PSI had developed its methodology to perform CIAs for applications it received under the OPA s FIT/micro-FIT Programs to ensure network accommodation of their implementation with the appropriate protection, metering and control arrangements. However, its understanding of the impact of embedded generation on its network was still incomplete. Also, for monitoring all connected DG systems with a capacity of 250kW or greater, a design configuration incorporating 1.8GHz WiMax technology was developed for remote tripping and monitoring. Proof of concept testing was started using the PSI s 55 Patterson Road site in Barrie to implement functions for remote trip & generator end open, and generator status/output monitoring, but it was incomplete going into 2011. In addition, to enhance PSI s communications infrastructure, two proprietary Synchronous Optical Network (SONet) Rings used as the data highway between PSI s key facilities and its SCADA servers by implementing a Gigabyte Ethernet Ring acting as a superhighway for high priority system data ? were built, one for SCADA and one for PSI corporate communications. Acceptance testing/trials were still in progress at the end of 2010. Similarly the detailed design of a capacitor bank incorporating a non -standard switch, which was needed to improve the power supply quality, was also in progress going into 2011. In this year, PSI also planned to investigate how it could extend applications of automatic restorations of feeders.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

Last year PSI completed the development and commissioning of Markham Transformer Station (MTS) #4 in August. It had better Metering, Relay and Control (MRC) systems that went beyond what had been achieved before, and a better local interface design with PSI s SCADA system with a new approach from that used previously. Piloting of on-line monitoring of individual power transformer physical condition using PSI s SCADA system was completed at MTS#3. It is now embedded within PSI s standard practice for all TS. A new municipal station, also commissioned last year, had a new capability introduced into its integrated control arrangement for its 44kV 3-wire to 13.8kV 4-wire configuration using a sub-routine for checking for blown fuses on the 44kV side.

This year, PSI s development activities had more of a DG facilitation focus.

The obstacles PSI had to resolve were: (1) Determining the adequacy of its fault levels at its TS; (2) The impacts of DG on protection planning and whether or not limits to the penetration of DG should be set; (3) Implementing in-service monitoring & control of connection for the larger DG systems implemented; (4) Completing testing of its 2 new SONet rings, and commissioning & testing an innovative design for a transient smoothing capacitor bank; and (5) Deciding how more applications of automatic restoration of feeders could be developed.

Facilitating the connection of DG systems to its network is a mandated responsibility for PSI. In the process of doing so, it must ensure its network is capable of handling these supply sources in a safe and stable manner without also exposing the DG equipment to any risk of damage caused by faults and other incidents on its network.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

During the year, while CIAs were being performed, it was observed that the fault levels in use were too high at MTS #1 and MTS #2. Following internal discussions it was decided that a separate study should exam the situation. Consequently a specialist subcontractor was retained to undertake the work. This study was still in progress at the end of the year. The actual applications submitted to the OPA for the PSI service area for renewables at the end of 2011 were 1,896 in total for 69.4MW in aggregate capacity, with a FIT/micro-FIT split of 288/1608 and 57.7/11.7MW respectively. Only 32/208 applications for 4.7 and 1.3 MW had actually been connected by year end. The total was very small compared to the PSI peak demand of 1,900MW. However, by the end of 2015 it was forecast that as much as 160MW could be connected.

Work in earlier years had established that remote monitoring and control can reduce the impact of embedded DG from (1) tripping to prevent islanding in areas with high levels of penetration, (2) shutdown during feeder maintenance for safety, (3) real time monitoring of output to aid power flow management, and of DG unit status to identify when units have not properly shutdown. Five different options were evaluated against requirements for bandwidth for communicating with up to 50 DG units, point to multi-point, security, interference avoidance, latency, range and cost. The WiMax solution being implemented was the preferred choice for DG monitoring, and was therefore chosen for detailed design and implementation. Two of the 5 base stations needed for coverage in Markham and Vaughan were in place at the end of 2011 with a third due for completion in Q1 in 2012 and the final two to follow later in 2012. A sixth tower might be needed, depending on actual experience of propagation. The PSI DG system in Barrie would be one of the first sites monitored.

As a member of the Utility Standards Forum, PSI had discussed the pros and cons of participating in the funding of two research projects to be undertaken by the University of Waterloo. PSI first agreed in 2010 to act as the principal sponsor for one of the studies, an investigation into Protection co -ordination planning with DG and the impact of DG on safety, equipment and distribution system operation . A start up for the study was planned for Q2 of 2011. In addition, in October the University of Waterloo submitted a proposal for a collaborative investigation into The effects of increasing DG penetration level on distribution systems . PSI was interested because it foresaw problems with multiple microFIT DGs connected to the same distribution transformer feeding 9 to 10 dwellings. Prior to the year end, PSI agreed to proceed with revised terms of reference and scope.

The non-standard capacitor bank design for the TS feeding PSI s largest customer was completed & performed well after installation.

During the year efforts were made to specify requirements for a high speed automatic feeder restoration (AFR) simulator. An order was placed with a supplier for its detailed design and construction. Acceptance testing was satisfactorily completed at the supplier s facilities on November 21/22. Although the simulator was shipped and invoiced in late December, the unit was not received and available for use at PSI until early 2012. Prior to delivery, a proof of concept application was planned for 2012 with 28kV feeders. Although AFR could be demonstrated with as few as 2 re-closers, it was decided that using 6 re-closers on 3 feeders would be a better test. The implementation of automatic feeder restoration is dependent on WiMax coverage.

The design, development and deployment of a WiMax system for DG monitoring and control opened the door to implementing automatic feeder restoration.

Experience with the pilot implemented with the Buttonville 12M3 radial feeder, divided into thirds with two re-closer switches, was found to be much better than expected. It had used different wireless communication methods. Reliability in terms of average annual customer outage hours in 2009-2010 was actually 88% better than in 2006-2008, versus an anticipated level of just 45%.External contractors (see Section D, line 268) were also directly engaged

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

59. in these experimental development activities and/or related support
60. activities.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

1.
2.
3.
4.

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
2.
3.
4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 ☐ Employee directly involved in the project	**254** Name		
255 1 ☐ Other employee of the company	**256** Name		
257 1 ☒ External consultant	**258** Name Deloitte & Touche LLP	**259** Firm Deloitte & Touche LLP	

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Glenn Allen	P.Eng., 29 years' experience, Mgr., Stations Design & Construction
2	Gerry Reesor	P.Eng., 19 years' experience, Stations Engineer
3	Dave Burns	P.Eng., 12 years' experience, Project Engineer

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . 1 ☐ Yes 2 ☒ No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . 1 ☐ Yes 2 ☒ No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . 1 ☒ Yes 2 ☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	7528973 Canada Inc	81641 0062 RC0001
2	Kinectrics	86402 0920 RC0001
3	T.& W. Info-Systems ltd	10542 9591 RC0001
4	K-Tek Electro services	10288 9789 RC0001
5	Utilities Standards Forum	81614 2145 RC0001
6		
7		
8		
9		
10		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents	276	1	X	Progress reports, minutes of project meetings
271	1	X	Records of resources allocated to the project, time sheets	277	1	X	Test protocols, test data, analysis of test results, conclusions
272	1	X	Design of experiments	278	1	X	Photographs and videos
273	1	X	Project records, laboratory notebooks	279	1	X	Samples, prototypes, scrap or other artefacts
274	1	X	Design, system architecture and source code	280	1	X	Contracts
275	1	X	Records of trial runs	281	1		Others, specify 282

Part 2 - Project information (continued)

Project number **3**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

Electric power distribution systems

202 Project start date: 2007-05 (Year Month)

204 Completion or expected completion date: 2012-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 | Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project   **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes   2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	221 BN
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	

The work was carried out (check any that apply)

223 1 [ ] In a laboratory   **226** 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility   **228** 1 [X] Others, specify   **229** Other

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	235 1 [ ]	236 1 [ ]
The improvement of existing	237 1 [X]	238 1 [ ]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. PSI sought to make incremental advances in and with: (1) The knowledge to make
2. additional improvements to its existing methodology/techniques for asset
3. condition assessment (ACA) whose application will lead to sustain the
4. performance of all classes of assets; (2) Increased understanding of current

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

loading imbalances on transformers and feeders and the need for system reconfiguration and of the likely future technical evolution of PSI s distribution network, for example with respect to increased embedded generation, CDM programs, load growth and the implications for more transformation capacity, and how simulation modeling with CYME tools facilitates effective solution development; (3) More comprehensive understanding of PSI s network performance in all respects, e.g. losses, reliability, etc., and the effective measures that could be developed and implemented to result in measurable improvements in performance; and (4) The knowledge and knowhow to create and implement further enhancements to S/W tools and processes for facilities management, including preparing engineering design drawings for network additions & modifications, and exporting such design data. Last year, PSI made improvements to its existing ACA methodology, but more improvements were needed, e.g. for U/G cables, and completed a cable injection pilot for 414m of primary cable. It also incorporated consideration of the impact of DG into its system planning practice for load forecasting, recognizing that the DG offset would need to be updated in annual load forecasts. PSI augmented its CYMDIST S/W simulation tool by adding a new module for automating the extraction of quality data from PSI s GIS. It was used it in service area reconfiguration planning to balance loading on TS and feeders (within 170MVA and 400A guidelines), incorporate new feeders, and deal with seasonal effects. Further work in this area was needed in 2011. The same applies to efforts made in the areas of reliability improvements to build on last year s study work on how to reach to reach its target of Five 9 s performance by yearend 2015. GIS/ArcFM Designer improvements were also made in 2010, e.g. merging north and south service area data, but better integration and data exporting capabilities were needed.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

Going into 2011, PSI had a formal methodology to support the technical management of its network assets, but its use and upgrading in 2010 had shown that further improvements were needed. Its basic framework for ACA needed to be improved, and the specific model for wooden poles had to be enhanced. Better decision support was needed for prioritizing U/G cable replacement and refurbishment. PSI uses S/W tools to model its network and run simulations of potential changes to it, e.g. to accommodate new loads, and investigate what improvements might be made to improve performance. While the work done in 2010 to ensure in this year that its TS, feeders would operate in a balance fashion within acceptable guidelines, and new connections could be accommodated, there was no guarantee that the same would be the case for 2011. Circumstances change, load growth occurs, more DG units go into service, and new infrastructure additions happen. As a consequence, new modeling and simulation studies must be undertaken using the latest available input data. PSI also wanted to know which of two different design approaches was to be preferred for supplying commercial/industrial loads. The OEB is charged with ensuring LDCs focus on improving their network reliability, and expects LDCs like PSI to report its progress. Such progress can only be made if PSI pushes beyond its standard practice regarding reliability improvements. Last year PSI established a very aggressive target reliability level of 99.999%. Just how the target would be achieved by the end of 2015 was not completely clear. While PSI had made progress with its use of S/W tools for designing system changes in an integrated way within its GIS & Designer environment, its efforts were incomplete going into 2011. Issues were integrating Designer with its materials management system and finishing the inter-changeability of design data with AutoCAD.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

In Q1 of the year, PSI updated its ACA methodology. It had originally been developed with the help of two subcontractors in 2009. For the update, covering 11 asset classes, only internal staff members were involved. In Q3, the ACA model criteria and weighting factors for wood poles were re-developed following a review of the latest results from field inspection & testing. In addition, a scoring system for U/G cable replacement was established to assist in prioritizing candidates for replacement or treatment.

At the start of the year, PSI staff began participating in the York Region Supply study. Various meetings were held throughout the year to progress the study, which would continue into 2012. System reconfigurations plans for the north and south service areas were developed using the CYMDIST S/W simulation tool and reviewed with Operations Department staff. The same tool was used for a voltage study. A staff member attended the user conference to keep current with the evolution of the family of CYME products including CYMDIST.

Later on in the year in Q3, alternative loop designs for commercial/industrial loads one using switchgear and the other cable splices ? were contrasted and compared from different perspectives to establish their advantages and disadvantages, and then determine whether or not a preferred design could be recommended as the choice for all future installations. The work done, while noting that both designs have served PSI very well in the past, led to a recommendation that the splice configuration was to be preferred. A program was launched to remediate all existing Delta Services and address the issue of non-compliance with EAS directives.

PSI s Reliability Committee (RC) met nine times to conduct performance reviews & comparisons, to consider analysis methods results, to discuss causes of recent failures and actions taken to address past failures, to consider potential actions for short term improvement, and monitor progress with the 18 initiatives identified last year as milestones on the journey to achieve the 99.999% reliability level. As well as performing forensic investigations of failures during the year, PSI staff explored and developed a new testing program for in-service U/G cables. Further details are included in claim project #1. How pad-mounted transformers can be protected from corrosion was investigated as well. Several CLD group sessions were attended to share experience related to reliability issues and equipment failures, and to gain insights on potential solutions that PSI could adopt or adapt, and potentially explore through conducting its own field trials. The experience PSI had last year with its cable rejuvenation pilot was the topic of a presentation given at an industry conference.

Further work was carried out on the integration of the Designer S/W tool and integration with the JDE materials management system. The same applied to upgrading the capability of exporting Designer tool data in the AutoCAD format. The subcontractor involved last year continued its participation with these efforts. To facilitate finding splice locations on U/G cable in the future, it was agreed that for all new ones made, that their locations via GPS would be recorded in PSI s GIS.

As per prior years, PSI participated as a funding sponsor in several investigations being undertaken by the Centre for Energy Advancement through Technological Innovation (CEATI). All of these exercises were being undertaken by the Distribution Life Cycle Assets Management (DALCM) Interest Group and were: (1) Best Practices for a Risk-Based Approach to Vegetation Management of Distribution Lines; and (2) Distribution Roadmap Update. In addition, PSI staff conducted comprehensive reviews of the chapters included in the latest draft of the DALCM Distribution Planner s Manual and attended various DALCM meetings.External contractors (see Section D, line 268) were also directly engaged in these experimental development activities and/or related support activities.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

1.
2.
3.
4.

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
2.
3.
4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [ ] Employee directly involved in the project	**254** Name	
255 1 [ ] Other employee of the company	**256** Name	
257 1 [X] External consultant	**258** Name Deloitte & Touche LLP	**259** Firm Deloitte & Touche LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Doug Fairchild	P.Eng., 24 years' experience, Manager, Planning & Standards
2	Richard Wang	P.Eng., 12 years' experience, Engineer, Asset Condition Assessment
3	Riaz Shaikh	P.Eng., 14 years' experience, Engineer, Reliability

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	CEATI International	89131 9899 RC0001
2	CYME International Ltd	14543 9956 RC0001
3	ESRI Canada	89521 0979 RC0001
4		
5		
6		
7		
8		
9		
10		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents	276	1	X	Progress reports, minutes of project meetings
271	1	X	Records of resources allocated to the project, time sheets	277	1	X	Test protocols, test data, analysis of test results, conclusions
272	1		Design of experiments	278	1	X	Photographs and videos
273	1	X	Project records, laboratory notebooks	279	1	X	Samples, prototypes, scrap or other artefacts
274	1		Design, system architecture and source code	280	1		Contracts
275	1	X	Records of trial runs	281	1	X	Others, specify 282 Emails, internal reports...

Part 2 - Project information (continued)

Project number **4**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

P4: Smart metering and PSI facility energy conservation

202 Project start date: 2007-01 (Year Month)

204 Completion or expected completion date: 2012-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 | Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project

210 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

	220 Names of the businesses	**221** BN
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		

The work was carried out (check any that apply)

223 1 [ ] In a laboratory

224 1 [ ] In a dedicated research facility

226 1 [X] In a commercial plant or facility

228 1 [X] Others, specify **229** at field sites and subcontractors locations

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [ ]	**236** 1 [ ]
The improvement of existing	**237** 1 [X]	**238** 1 [X]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. PSI wanted to: (1) Advance its capability and methodology for smart metering
2. (SM) for all classes of customers, with seamless & reliable end-to-end data
3. communications for settlement, that also facilitates load control; (2)
4. Leverage its existing Advanced Metering Infrastructure (AMI) through piloting

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

transformer SM; (3) Establish a closed-loop test bed for trials of further potential enhancements to its AMI; (4) Understand its new Service Centre building performance to assure its certification; and (5) Gain insights on small scale sustainable generation system O&M from its H.O. location pilot system. While PSI had established a base level of capability with regard to SM, particularly at the front end of the process, and some development of the middle and back end processes had been undertaken, further work was needed for aspects like suite metering. Full integration of SM read data with the processing of this data for purposes such as time-of-use billing & settlement, and 2-way interfacing with the provincially run Meter Data Management Repository (MDMR) still had to be achieved. In addition, PSI had no means of testing or investigating potential enhancements to its AMI, independent of its production systems. In 2010, PSI continued with its development activities to integrate smart metering internally and externally, began its trials with the smart metering of pad-mounted transformers, started creating new metering standards for approved DG connections with 2-way power flows, and designed and commenced installation of a dedicated closed loop testing system using a set of 80 meters. Activities related to all of the foregoing would continue into 2011. Last year, PSI also commissioned its new Service Centre building, but its performance still had to be measured and verified to confirm its LEED targeted levels were met. The field trial of the pilot sustainable generation system at its H.O. would also continue over 2011. The knowledge gained was important to PSI, as it stepped up its efforts in 2011 to develop more commercially viable sustainable generation systems, particularly of a Solar PV nature, as described in claim project #7.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

At the start of the year and during the course of carrying out its activities, PSI appreciated that it would have to resolve a number of problems, unknowns, challenges, issues and obstacles. They included:

1. Proven robust processes and error-free 2-way communications of read data between PSI and the MDMR for all customer classes

2. Completion of the modifications required to settlement and billing software tools to leverage the mass implementation of smart meters for all non-residential customers

3. Establishing the advantages and disadvantages from extending PSI s first field trial of smart metering applied to U/G distribution pad mounted transformers

4. The methods and metering arrangements that would be used to connect distributed generation systems, particularly for approved FIT applications, embedded within the PSI network territory, and the S/W tool modifications to accommodate connecting all approved DG units

5. Completing installation, commissioning and running a dedicated testing system to investigate problems and potential improvements to PSI s existing AMI, and

6. Verification of PSI s Service Centre s actual performance vis-a-vis its targets for LEED certification, and sustaining the operation of a pilot, small scale sustainable generation system at the PSI H.O.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

Development activities for integrating smart metering processes internally and externally were carried over from last year. The focus continued to be on process improvement, continuing with testing and proving the quality of 2-way data exchanges with the provincially run MDMR, the workforce management system for handhelds intended to eliminate all field paperwork connected with SM, further integration of suite SM, and with the design, programming and testing of all code modifications to existing S/W tools to enable them to handle,

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

store and process reads from smart meters and generate time-of-use bills, and produce any reports PSI required for its SM efforts. New code creation and testing was an integral part of this effort. The same 4 subcontractors involved last year provided support and contributed to these development activities. By year end, substantially all residential and commercial customers apart from approx. 1,000 delinquents in each case ? had SM and were on TOU billing. However, only read data for residential and commercial (<50KW) customers was being exchanged with the MDMR. The small pilot trial of the application of SM to 10 pad-mounted distribution transformers that started last year was extended. It involved installing a different meter - from the same supplier of the residential customer meter - and use of the same existing communications infrastructure that was in place for the residential customer meters. By the end of the year, 322 units, almost exclusively 1 , out of a total population of about 42,000 in the PSI system had been included in the pilot trial. The focus was on covering all the transformers being fed by one of the 20 distribution feeders at the Lazenby Transformer Station. Data only on power flows and electrical parameters was accumulated and no physical condition variables ? was accumulated through the end of the year, but not analyzed and reviewed due to lack of staff resources and other priorities. The intent was to conduct the analysis required in 2012. From the results obtained, the intent was to develop recommendations to capture the benefits this application can bestow. Discussions were held with a pad-mounted transformer supplier to incorporate plug-in capability for smart metering as an integral part of transformer design, but no decisions were made on field trialing a prototype. Activities to further SM application to transformers would continue in 2012.

To complement the work done last year to create a new standard for the SM of approved micro-FIT DG units, a new SM standard was established this year for approved FIT DG units to resolve safety and settlement concerns. Two registers are needed for such DG. The standards covered different connection arrangements for DG within the area of the PSI network, i.e. in series with 2 meters, in parallel with 2 meters, and with one meter on a net basis. Meter base standards also had to be created. The new standards drove developing changes to software tools as these DG connections involved two KWhr registers. Development of the standards and the S/W tool modifications were both completed within the year. At its end, approximately 200 micro-FIT and 30 FIT Program DG systems had been connected to the PSI network. Development and installation was completed for the closed loop testing system for SM related investigations. It was started last year. The test bed arrangement consisted of a set of 80 meters (5 kinds from 3 suppliers) with motor loads for the meters with its own Tower Gateway Base Station and Remote Network Interface. The first tests/trials were performed in May and many more were carried out for different purposes, prior to year end. The TOU schedule was added to the test bed programming so it could fully emulate meters in individual residences. In 2012, it was expected that the CDM Program would make use of the test bed facilities. With respect to PSI facilities energy conservation, the same two subcontractors who were involved last year provided support this year. One focused on measurement and verification of the new Service Centre s as-built performance (versus its design s targets). The second subcontractor concentrated on monitoring and maintaining the sustainable generation system previously installed at PSI s H.O. on a pilot basis.

External contractors (see Section D, line 268) were also directly engaged in these experimental development activities and/or related support activities.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

2.
3.
4.

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
2.
3.
4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 ☐ Employee directly involved in the project	**254** Name	
255 1 ☐ Other employee of the company	**256** Name	
257 1 ☒ External consultant	**258** Name Deloitte & Touche LLP	**259** Firm Deloitte & Touche LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Rick Lapp	C.E.T., 37 years' experience, ex-Manager Metering
2	Roger Ersil	C.E.T., 22 years' experience, Supervisor, Metering
3	Alan Davis	B.Sc. 17 years' experience, Manager CIS Services

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 ☐ Yes 2 ☒ No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 ☐ Yes 2 ☒ No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 ☒ Yes 2 ☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	Enermodal Engineering Ltd	10163 8849 RC0001
2	Enviro-Energy Technologies Inc	84639 3874 RC0001
3	Ideaca	89614 8210 RC0001
4	SilverBlaze Solutions Inc	86742 4426 RC0001
5	Sky Energy Consulting	82960 0220 RC0001
6	T.& W. Info-Systems ltd	10542 9591 RC0001
7	Util-Assist	84277 2741 RC0001
8		
9		
10		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents	276	1		Progress reports, minutes of project meetings
271	1	X	Records of resources allocated to the project, time sheets	277	1	X	Test protocols, test data, analysis of test results, conclusions
272	1		Design of experiments	278	1		Photographs and videos
273	1	X	Project records, laboratory notebooks	279	1	X	Samples, prototypes, scrap or other artefacts
274	1	X	Design, system architecture and source code	280	1	X	Contracts
275	1	X	Records of trial runs	281	1	X	Others, specify **282** Emails, sub s reports, etc..

Part 2 - Project information (continued)

Project number **5**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

OMS develop. &op. telecom infrastructure improvements

202 Project start date: 2009-01 (Year Month)

204 Completion or expected completion date: 2011-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

	220 Names of the businesses	**221** BN
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		

The work was carried out (check any that apply)

223 1 [ ] In a laboratory **226** 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility **228** 1 [X] Others, specify **229** Subcontractors locations

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [ ]	**236** 1 [ ]
The improvement of existing	**237** 1 [X]	**238** 1 [X]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. It is the knowledge, expertise and capability to design, develop and implement
2. an OMS tool with a configuration, functionality and features, whose use leads
3. to improvements in network reliability performance and reduces the size of
4. service interruptions. Such a tool would also (1) facilitate better

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

management of outages and distribution network operations from a central control centre, (2) provide system operators with a near real-time view of the state of PSI s network, and (3) establish a platform for future operational and work force automation initiatives. This advance requires a comprehensive understanding of the essential interfaces to PSI s CIS, GIS, SCADA, and AMI. These interfaces had to be created, custom coded and tested to ensure seamless performance. In prior years, PSI selected a core tool (Responder) for its OMS. Interfaces were developed with a new released GIS, with its CIS, SCADA and AMI. Then PSI performed OMS acceptance testing. Once database issues, GIS bugs and the addition of filters to the AMI interface were resolved, and further testing completed, the OMS went live in March 2010. The old system ran in parallel with OMS for verification purposes & confirmed the performance of OMS. When customer calls are automated via an Interactive Voice Recognition (IVR) System in 2011, the OMS would have to accommodate this change. Defining/designing the interface between the IVR and OMS began. With a hosted solution selected, the design phase of the integration of the OMS and the IVR solution was started for a web services, bi-directional interface. The detailed development, testing and deployment phases of the OMS/IVR interface to integrate their operations would continue in 2011. Earlier in 2010, the original reporting capabilities of OMS were improved and augmented. The transition was also started of the internal analog based communications infrastructure to digital technology. Several issues arose with existing/possible new towers that would be used, some technical and others logistical/access related. Establishing digital profiles was involved, as was much testing using a mock platform. While some progress was made with installing the new equipment, the cutover from analog to digital would not occur until 2011.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

For 2011 they were:

1. The implementation of a new interface for the OMS that would integrate it with the IVR system that PSI was implementing
2. Improving (i) the graphics capabilities for the OMS/SCADA interface, and (ii) the outage notification process
3. The creation of scripts that could be used for both simulation and training purposes, and upgrading a S/W tool used in conjunction with OMS, and
4. A successful transition of the existing analog telecommunications infrastructure used by PSI s system operations staff to digital technology.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

The development, testing and deployment phases of the implementation of the OMS/IVR interface to integrate their operations would continue from last year. Following a design phase, the subcontractor involved proceeded with detailed development, testing and deployment of the interface, which was completed by mid-year. Additional improvements to OMS were undertaken by the same subcontractor, who also started a custom web application for outage communications. A second subcontractor contributed to the development of outages notification.

A third subcontractor, who developed the Operations Heat S/W tool used as an adjunct to OMS on a standalone basis, which was first introduced in 2009, was retained to upgrade its capabilities due to all the changes that had occurred since its initial development and use for prioritization and deficiency reporting.

The fourth subcontractor, the supplier of PSI s SCADA system was also involved with completing the OMS development. It installed a set of computerized graphics that had been previously created to support the OMS/SCADA interface. In addition, this subcontractor developed OTS Scripts for simulation and

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

18. training purposes. PSI tested the application of the scripts for simulation
19. purposes, and also attended the supplier s TechFest event to discuss the
20. latest improvements in SCADA system technology and its interfacing with tools
21. such as an OMS.
22.
23. Work also continued with the transition to digital technology of the
24. operations telecommunications network that was started last year. After
25. completion of more testing, the cutover from analog to digital technology was
26. successfully completed.
27.
28. As all the obstacles with the OMS tool and the transition to digital
29. technology for operations communications were resolved during the year, the
30. claim project was closed at the end of the year.
31. External contractors (see Section D, line 268) were also directly engaged in
32. these experimental development activities and/or related support activities.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

1.
2.
3.
4.

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
2.
3.
4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [ ] Employee directly involved in the project	**254** Name
255 1 [ ] Other employee of the company	**256** Name
257 1 [X] External consultant	**258** Name: Deloitte & Touche LLP — **259** Firm: Deloitte & Touche LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 Jack Jacoby	C.E.T., 22 years' experience, Manager, System Control
2 John McClean	C.E.T., 27 years' experience, Director of Operations
3	

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1 SilverBlaze Solutions Inc	86742 4426 RC0001
2 Survalent Technology Corp	13119 7386 RC0001

268	Names of individuals or companies	269 BN
3	Kifinti Solutions Inc	87845 1103 RC0001
4	ESRI Canada	89521 0979 RC0001
5		
6		
7		
8		
9		
10		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

- 270 1 [X] Project planning documents
- 271 1 [X] Records of resources allocated to the project, time sheets
- 272 1 [ ] Design of experiments
- 273 1 [X] Project records, laboratory notebooks
- 274 1 [ ] Design, system architecture and source code
- 275 1 [X] Records of trial runs
- 276 1 [X] Progress reports, minutes of project meetings
- 277 1 [X] Test protocols, test data, analysis of test results, conclusions
- 278 1 [X] Photographs and videos
- 279 1 [X] Samples, prototypes, scrap or other artefacts
- 280 1 [X] Contracts
- 281 1 [X] Others, specify 282 Emails, subs' reports etc...

Part 2 - Project information (continued)

Project number **6**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

Smart Grid (SG) initiatives development

202 Project start date: 2009-01 (Year Month)

204 Completion or expected completion date: 2015-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project
210 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

	220 Names of the businesses	**221** BN
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		

The work was carried out (check any that apply)

223 1 [ ] In a laboratory
226 1 [X] In a commercial plant or facility
224 1 [ ] In a dedicated research facility
228 1 [X] Others, specify **229** at field sites and subcontractor facilities

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [ ]	**236** 1 [ ]
The improvement of existing	**237** 1 [X]	**238** 1 [X]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. The knowledge and capability to deploy and implement a range of SG concepts
2. and technologies across PSI s existing distribution network to transition it
3. to one that has a fully intelligent infrastructure with: (1) Compatible,
4. durable and reliable equipment with built-in sensing and intelligent

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

electronic devices for monitoring, fault diagnosis, and self-restoration capabilities; (2) Fail-safe, robust, fast, high band-width, 2-way advanced communications from customers to the grid control centre; (3) Centralized monitoring and control utilizing integrated data bases for customer information, for asset records including their geographic locations, for the management of outages, for grid operations, and for making physical changes to the grid infrastructure; (4) Informed and intelligent operators and customers regarding electricity use and the assets for local generation, distribution and storage, and initiatives to facilitate wise consumption for system-wide benefits; and (5) Unrestricted capability to accommodate, electric vehicles, distributed generation (DG), and potentially energy storage. An SG therefore supports 2-way flows of electricity, data & information.

In 2009&10, PSI had: explored SG concepts and technologies; investigated and rejected the development of a smart business park with a dedicated closed loop distribution network; implemented on a pilot basis a software tool for Fault Detection, Isolation and Restoration (FDIR), which was still in progress going into 2011; developed an SG strategy and plan within which its SG initiatives could be identified, initially assessed, integrated and prioritized; transitioned on-line condition monitoring of power transformers into its standard practice; and started preparation for a plug-in electric vehicle (EV) charging trial that would start in 2011. As well as preparation for the EV pilot, PSI was contemplating other initiatives such as expanding a pilot of transformer smart metering that the Metering Department had started in 2010 in claim project #4, digital fault indicators using Flexnet, more distribution automation re-closer switches, a grid optimization & management pilot, high impedance GFP, and the feasibility of energy storage systems using batteries and flywheels.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

Going into 2011, PSI was continuing with the pilot application of the FDIR tool and preparing for the start of an EV charging pilot. It did have, as already noted, a comprehensive plan with an integrated set of initiatives that it would use to facilitate transitioning its existing power distribution system into a modern one, as defined by the Ontario SG Forum, that Uses sensors, monitoring, communications, automation and computers to improve the flexibility, security, reliability, efficiency and safety of the electricity supply system .

For 2011, the obstacles faced by PSI were:

1. Achieving success with the pilot application of the FDIR tool, that started in November 2010, to a portion of its network to demonstrate using the tool in semi-automatic mode did improve overall system performance, beyond what traditional Control Room practices could achieve, and that the pilot should be extended to cover the automatic mode of operation. When the tool is configured to suit a particular network, the programming identifies the faulted portion of a feeder, initiates automatic operation of devices to effectively isolate the faulted portion, and re-energizes the healthy sections of the feeder again through the automatic operation of other switching devices. A tool feature is that it can be used in automatic mode or semi-automatic mode. With the latter method of operation, the system controller reviews and authorizes intended switching operations

2. Establishing the impact of increasing penetration of EVs in its service area would have on its existing network infrastructure by participating in a Provincially sponsored plug-in EV charging field trial and working with academic institutions

3. Exploring the advantages & disadvantages of deploying digital fault indicators, and

4. Deciding whether or not the SG strategy and 5-year plan, approved in

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

September 2010, to set out the technical areas in which PSI should focus its SG development efforts, integrate and prioritize them, should be upgraded before the end of 2011.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

The FDIR pilot trial continued all year in semi-automatic mode for Richmond Hill TS#1 and #2 feeders, creating analysis reports and switching orders when initiated. Every review period covered 4 to 8 weeks. Progress was slow initially, but success was achieved with one feeder in May. Application logic had to be modified by the vendor. More success was realized with analysis and switching orders on two occasions. Further progress was made and more logic changes were developed over the balance of the year. Time stamping issues were raised and still had to be resolved at year end. Changing the connectivity model in FDIR to be the same as the system connectivity status and considering a forced poll scheme for feeder in-line devices were also still outstanding. The pilot continued into 2012, when fully automatic mode on selected feeders would be contemplated.

PSI participated as one of two utility partners in a plug-in EV charging trial and field demonstration project organized to facilitate understanding of the impact of EV use on the grid. Two similar vehicles, each with 24 kWh batteries, were acquired and trialed across and within the PSI service territory. This effort started at the end of February and continued through to the end of February 2012. A charging network of 14 charge points at 6 locations was used in the field trial along with a centrally managed charging network run by the subcontractor retained by the Province. Three of the locations were in the PSI service territory. The network operations centre (NOC) was located in California and could communicate with each intelligent charging spot site and therefore was able to identify which spots were in use, and how much electricity was being provided to the vehicle being charged. Data was collected from two sources, the NOC system and on-board vehicle systems. The NOC developed a log of charging spot usage to facilitate analysis of historical demand patterns and consumption. This data helps intelligent management of electricity supply and demand to align with grid capabilities. On-board vehicle systems recorded energy consumption and other data such as trip time and distance, which enable the efficiency of electric vehicles to be analyzed and more accurate predictions of future energy demand. The NOC was fully operational at the beginning of June. The network connectivity of one of the charge spot sites was a challenge due to low and fluctuating signal strength that had to be addressed using a local landline. During the year smart charging tests were conducted to demonstrate the NOC s capability to shed load and modulate power in response to grid capacity constraints.

While the field trial just discussed was in progress, PSI also facilitated and supported a study by a team of students from Queen s University into the potential impact plug-in EVs will have on its grid. The study analyzed potential strategies to encourage off-peak charging, and the technologies that could be used to help mitigate peak loading issues. In addition, the impact on transformers was modeled under a variety of scenarios and alternative strategies were suggested to prevent infrastructure failures for PSI to consider in more detail. The study report was issued in mid-April. An EV partnership with Georgian College was also launched in the year.

While the feasibility of an investigation/field study involving energy storage was discussed, decisions on implementation were deferred until 2012. A pilot field trial using digital fault indicators was planned for implementation and shop trialed. It would couple a new digital fault indicator (DFI) with the existing Sensus Flexnet AMI communications technology and assess its performance with regard to delivering fault location, magnitude and other information to the control room. Twenty 3 DFIs would be installed for the

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

53. field trial, and the one used for preliminary investigation would be
54. permanently located in the P&C workshop.
55. The PSI SG strategy and plan was updated in October. Staff actively
56. participated regularly in SG related sessions with the IESO, the OEB, peers,
57. and interest groups to exchange and share information about its SG plan,
58. initiatives and intentions, and to learn from the SG efforts of members of the
59. Coalition of Large Distributors. External contractors (see Section D, line
60. 268) were also directly engaged in these experimental development activities
61. and/or related support activities.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

1.
2.
3.
4.

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
2.
3.
4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 ☐ Employee directly involved in the project	**254** Name		
255 1 ☐ Other employee of the company	**256** Name		
257 1 ☒ External consultant	**258** Name: Deloitte & Touche LLP	**259** Firm: Deloitte & Touche LLP	

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	John Mulrooney	P.Eng., 35 years' experience, Director, Smart Grid Technologies
2	Ted Wojcinski	P.Eng., 29 years;' experience, VP, Engineering Planning
3	Ed Chatten	P.Eng., 31 years' experience , SVP, SG & Strategic Support

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 ☐ Yes 2 ☒ No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 ☐ Yes 2 ☒ No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 ☒ Yes 2 ☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	Naviguant	88310 1511 RC0001
2	Survalent Technology Corp	13119 7386 RC0001
3		
4		
5		
6		
7		

268 Names of individuals or companies	269 BN
8	
9	
10	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 X	Project planning documents	276 1 X	Progress reports, minutes of project meetings
271 1 X	Records of resources allocated to the project, time sheets	277 1 X	Test protocols, test data, analysis of test results, conclusions
272 1	Design of experiments	278 1 X	Photographs and videos
273 1 X	Project records, laboratory notebooks	279 1 X	Samples, prototypes, scrap or other artefacts
274 1	Design, system architecture and source code	280 1 X	Contracts
275 1 X	Records of trial runs	281 1 X	Others, specify 282 Queen's, Better Place, FDIR Update etc...

Part 2 - Project information (continued)

Project number **7**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

P7: Sustainable generation systems design and development

202 Project start date: 2009-01 (Year Month)

204 Completion or expected completion date: 2015-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project   **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	

The work was carried out (check any that apply)

223 1 [ ] In a laboratory   **226** 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility   **228** 1 [X] Others, specify **229** At various field sites

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [ ]	**236** 1 [ ]
The improvement of existing	**237** 1 [X]	**238** 1 [ ]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. PSI wanted to substantially increase its knowledge & understanding, and the
2. application, of sustainable generation technologies, particularly with Solar
3. PV, and the variables that are critical for such systems to be technically &
4. commercially viable. It wanted this capability in order to develop a robust

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

methodology that it could use to investigate and qualify potential locations for either custom designed or pre-engineered sustainable generation systems, which it could then implement. Before 2011, PSI staff had undertaken many studies/investigations of multiple sites with potential, especially those of a Solar PV nature. For potential roof top mounted systems, a large number of structural reviews/analyses were performed, and preliminary designs prepared. Entering 2010, none of these opportunities were close to implementation. During 2010, PSI continued to focus on Solar PV systems development. Many more investigations/studies were conducted. Simultaneously, PSI started to develop its first commercial scale Solar PV system on the roof of its own facilities at 55 Patterson Road in Barrie. The intent at the outset was to use a set of sub-systems for trial purposes and also to export power under a FIT contract. Over Phases 1 and 2, a total of 9 sub-systems would be designed and installed with a nominal aggregate capacity of 243kW. The 9 sub-systems would each be unique combinations of panels and racking/panel supporting frames supplied by different manufacturers, so that their performance could be closely monitored and differences established under the same set of conditions. By the early fall, Phase 1 for about 40kW was completed. Phase 2 was still in progress at the end of the year. In 2010, PSI also created a strategy for the development of sustainable generation facilities for the next few years. By year s end, with the preliminary design and development work performed for a number of opportunities being implemented amounting to about 8MW in total PSI was confident some of these systems would be in-service in 2011. A dedicated group of 4 staff had been established in Q4 of 2010 to develop & install renewable generation systems and deal with the issues that would arise from their implementation.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

The obstacles that PSI had to overcome were as follows:

1. Completing the build, commissioning and enhancing the monitoring capabilities of PSI s first commercial scale Solar PV system that would serve as a test bed and holding trials to investigate sub-system performance and system operating characteristics
2. Confirming that the performance in terms of electricity production of in-service as-built PV Solar systems matches the levels used in developing their designs
3. Extending its existing methodology for the front end of the implementation of sustainable generation systems to accommodate the back end aspects of the process consisting of the detailed design, build, develop, inspect, commissioning and monitoring in-service operation and asset condition
4. Qualifying new locations for the detailed design, engineering and construction of renewable generation systems, and
5. Deciding if the strategy created last year for the development and operation of sustainable generating facilities, primarily using Solar PV technologies, needed to be reviewed, and if so, what upgrading would be involved.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

PSI continued developing its first commercial scale Solar PV systems on the roof of its own facilities at 55 Patterson Road in Barrie. Phase 2 was completed and the overall system and its equipment were subsequently hooked up and went into service for trials and energy exporting purposes in April. Subcontractor support was involved in the overall system s implementation. Over the summer months, trials were conducted with the system to investigate the impact of (1) mounting systems/panel temperature, and (2) panel tilt angle on electricity production, and thereafter on how to maximize AC kWh produced

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

through performance testing. Additional instrumentation was added during the year for panel string monitoring and visual monitoring of the system. The facility also provided Georgian College students a field site for study and investigations.

In addition to the 55 Paterson Road system, the development of a further 16 Solar PV systems were completed and commissioned during the year. Collectively they represented about 1MW in capacity. Their detailed engineering and design was undertaken by a few EPC subcontractors, some of whom also contributed to pre-feasibility and feasibility activities at potential new locations. These subcontractors also assisted with the development of the methodology for systems implementation. The documentation involved EPC RFP/Contract ? went through 9 iterations. Other methodology developments undertaken were: (1) A detailed engineering and construction process that captured all the activities and best practices that PSI wanted to become part of its standard practice for implementing Solar PV systems; (2) Best practices for managing roof integrity; (3) Anti-islanding test procedure; (4) AC kWh Performance Test, and (5) O&M Procedure for in-service PV Solar systems.

Two subcontractors participated in pre-commissioning inspections of the larger Solar PV systems.

During the year, the PSI project team continued with their efforts to identify, investigate and qualify roof tops and sites for renewable generation systems development. They were predominantly for Solar PV systems, but 16MW wind and 10MW bio-gas opportunities were also involved and considered. Two licenses for the PVSYST modeling S/W tool were acquired to facilitate site investigations. Guidelines were developed for its use and for interpreting modeling results so that application consistency was assured. A series of 7 specialist subcontractors participated in site investigations, evaluations and assessments. They carried out pre-feasibility reviews, feasibility studies, roof inspections, structural feasibility studies, structural analysis & reinforcement designs, structural modification drawings, pre-qualification assessments, and methodology contributions.

The strategy established last year for the development of sustainable generation facilities was reviewed and updated because of the expected hold to be placed on submissions for new applications made under the FIT and micro-FIT programs. The same specialist consulting subcontractor, who contributed last year, participated in the upgrading effort. External contractors (see Section D, line 268) were also directly engaged in these experimental development activities and/or related support activities.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [ ] Employee directly involved in the project	254 Name
255 1 [ ] Other employee of the company	256 Name
257 1 [X] External consultant	258 Name: Deloitte & Touche LLP — 259 Firm: Deloitte & Touche LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	261 Qualifications/experience and position title
1	Ron Mantay	P.Eng., 19 years' experience, VP Solar Engineering & Construction
2	Frank Varao	P.Eng., 17 years' experience, Manager, Renewable Generation
3	Oxana Robertson	P.Eng., 15 years' experience, Manager, Renewable Generation

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	269 BN
1	Carmanah Technologies Corp	87135 8362 RC0001
2	Crossey Engineering Ltd	10121 0516 RC0001
3	Davroc Associated	10129 5079 RC0001
4	Enviro-Energy Technologies Inc	84639 3874 RC0001
5	Home Energy Solutions	82804 1152 RC0001
6	Naviguant	88310 1511 RC0001
7	RESCo Energy Inc	84530 3726 RC0001
8	Steenhof Building Services Group	87707 4815 RC0001
9	Tremco Canada Division	86527 3122 RC0001
10	Stantec Consulting Ltd	88725 1288 RC0001

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents	276 1 [X] Progress reports, minutes of project meetings
271 1 [X] Records of resources allocated to the project, time sheets	277 1 [X] Test protocols, test data, analysis of test results, conclusions
272 1 [X] Design of experiments	278 1 [X] Photographs and videos
273 1 [X] Project records, laboratory notebooks	279 1 [X] Samples, prototypes, scrap or other artefacts
274 1 [ ] Design, system architecture and source code	280 1 [X] Contracts
275 1 [X] Records of trial runs	281 1 [X] Others, specify 282 Emails, subs' reports, etc...

Detach and return this REMITTANCE FORM with your payment.

Remittance Advice - Payment-in-Lieu (PIL

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Ontario
Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Account No.
1800047

35
PX5003

BARRIE HYDRO DISTRIBUTION INC.
C/O BARB GRAY
55 PATTERSON RD

BARRIE ON
L4M 4V8

Taxation Year End: (YYYYMMDD)

Payment Amount: $

Taxation Year End: (YYYYMMDD) 2 0 0 8 1 2 3 1

Payment Amount: $

Total Payment Enclosed: $

Ontario
Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2008/01/01 **to** 2008/12/31

	Account No.	Assessment Date (year, month, day)	Page
BARRIE HYDRO DISTRIBUTION INC.	**1800047**	2009/07/03	1 of 1

ASSESSMENT NO. 262

Tax: Federal and Provincial PIL		3,950,545.00
Assessment Interest		28,280.30CR
Total Assessment Liability		3,922,264.70

SUMMARY OF 2008/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	5,743,166.52CR	
Sub-Total		5,743,166.52CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		1,820,901.82CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800391

35
PX5005

Taxation Year End: (YYYYMMDD)

Payment Amount: $

Taxation Year End: (YYYYMMDD) 2 0 0 8 1 2 3 1

Payment Amount: $

Total Payment Enclosed: $

POWERSTREAM INC.
C/O GERI YIN
161 CITYVIEW BLVD.

VAUGHAN ON
L4H 0A9

10 HPL

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Reassessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2008/01/01 **to** 2008/12/31

	Account No.	Reassessment Date (year, month, day)	Page
POWERSTREAM INC.	1800391	2010/08/19	1 of 1

REASSESSMENT NO. 192 REPLACING ASSESSMENT DATED: 2009/08/28

Tax: Federal and Provincial PIL	6,055,344.00
Assessment Interest	117,639.10CR
Total Reassessment Liability	5,937,704.90

SUMMARY OF 2008/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	12,541,704.62CR	
Refunds	5,407,226.24	
Sub-Total		7,134,478.38CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR (SR&ED)		1,196,773.48CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

As per amended return.

Detach and return this REMITTANCE FORM with your payment.

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800391

35
PX5003

POWERSTREAM INC.
C/O GERI YIN
161 CITYVIEW BLVD.

VAUGHAN ON
L4H 0A9

Taxation Year End: (YYYYMMDD)

Payment Amount: $

Taxation Year End: (YYYYMMDD) 2 0 0 8 1 2 3 1

Payment Amount: $

Total Payment Enclosed: $

Keep this portion for your records.

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2008/01/01 **to** 2008/12/31

	Account No.	Assessment Date (year, month, day)	Page
POWERSTREAM INC.	1800391	2009/08/28	1 of 1

ASSESSMENT NO. 157

Tax: Federal and Provincial PIL		7,234,053.00
Assessment Interest		102,270.09CR
Total Assessment Liability		7,131,782.91

SUMMARY OF 2008/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	13,254,391.36CR	
Sub-Total		13,254,391.36CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		6,122,608.45CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

Please note Annual Returns for tax years ending before Jan 1, 2009 must be received at MoR by Sep 30, 2009 to be processed by MoR.

PX5003 004

2009

Ontario

Ministry of Finance
33 King St W
PO Box 622
Oshawa ON L1H 8H6

Issue Date	03-Jul-2012
Business No.	857503346TW0001
Reference No.	L1086105472

HPL - tL060

0000011

POWERSTREAM INC.
POWERSTREAM INC.
ATTENTION: C/O ADAM CHIARANDINI MANAGER, F
161 CITYVIEW BLVD.
VAUGHAN ON L4H 0A9

Notice of Re-Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

We have received and processed your return for the period ending 31-Dec-2009. Based on the information provided, your return has been corrected as follows:

	Previous	Revised
Total Federal Tax	$4,343,215.00	$4,343,215.00
Total Ontario Tax	$5,226,386.00	$5,226,386.00
Total Credits	$0.00	($301,350.00)
Loss Carry-back	$0.00	$0.00
Total Tax Payable	$9,268,251.00	$9,268,251.00
Interest		$1.92
Current Penalty		$0.00
Credits/Payments		($9,268,252.92)
Total Assessment		**$0.00**

As of 03-Jul-2012, including the amount assessed above, you have an overall credit balance on your account of ($5,321,794.50).

If you have any questions concerning this Notice of Re-Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this re-assessment you have the right to file a Notice of Objection with the Objections and Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the re-assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Finance at the number listed below.

Ministry use only

Detach and return this REMITTANCE FORM with your payment.

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

FS - 13/29

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800418

35
PX5003

Taxation Year End: (YYYYMMDD)

Payment Amount: $

Taxation Year End: (YYYYMMDD) 2 0 0 9 1 2 3 1

Payment Amount: $

Total Payment Enclosed: $

POWERSTREAM INC.
C/O GERI YIN
161 CITYVIEW BLVD.

VAUGHAN ON
L4H 0A9

10 HPL

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2009/01/01 to 2009/12/31

	Account No.	Assessment Date (year, month, day)	Page
POWERSTREAM INC.	1800418	2010/10/07	1 of 1

ASSESSMENT NO. 22

Tax: Federal and Provincial PIL		9,268,251.00
Assessment Interest		10,399.10CR
Total Assessment Liability		9,257,851.90

SUMMARY OF 2009/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	10,026,123.48CR	
Sub-Total		10,026,123.48CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		768,271.58CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Adjustment to the computation of Total Tax payable.

Adjustment to the computation of Net Income Tax

Mathematical error in the computation of Net CMT payable.

Adjustment to Income Tax before CMT credit.

NEW AMALGAMATION: Instalments based on grossed up/aggregate of predecessor companies.

Ontario

Ministry of Revenue
33 King St W
PO Box 622
Oshawa ON L1H 8H6

HPL - tL059

0000002

POWERSTREAM INC.
POWERSTREAM INC.
ATTENTION: C/O ADAM CHIARANDINI MANAGER, F
161 CITYVIEW BLVD.
VAUGHAN ON L4H 0A9

Issue Date	28-Sep-2011
Identification No.	1800418
Reference No.	L1015922048

Notice of Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

Your account has been assessed resulting in a balance as indicated below.

Period Ending: 31-Dec-2010	**Return As Filed**
Total Federal Tax	$5,333,992.00
Total Ontario Tax	$4,639,152.00
Total Credits	($221,177.00)
Loss Carry-back	$0.00
Total Tax Payable	$9,751,967.00
Interest	$15,925.81
Current Penalty	$0.00
Credits/Payments	($9,767,892.81)
Total Assessment	**$0.00**

As of 28-Sep-2011, including the amount assessed above, you have an overall credit balance on your account of ($5,316,341.44).

If you have any questions concerning this Notice of Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this assessment you have the right to file a Notice of Objection with the Tax Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Revenue at the number listed below.

Ministry use only

Ontario

Ministry of Finance
33 King St W
PO Box 622
Oshawa ON L1H 8H6

HPL - tL060

000010

POWERSTREAM INC.
POWERSTREAM INC.
ATTENTION: C/O ADAM CHIARANDINI MANAGER, F
161 CITYVIEW BLVD.
VAUGHAN ON L4H 0A9

Issue Date	04-Jul-2012
Business No.	857503346TW0001
Reference No.	L0675288960

Notice of Re-Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

We have received and processed your return for the period ending 31-Dec-2011. Based on the information provided, your return has been corrected as follows:

	Previous	Revised
Total Federal Tax	$0.00	$2,732,614.00 ✓
Total Ontario Tax	$2,187,791.00	$2,187,791.00 ✓
Total Credits	($211,711.00)	($211,711.00) ✓
Loss Carry-back	$0.00	$0.00
Total Tax Payable	$7,242,100.00	$4,708,694.00 ✓
Interest		$0.00
Current Penalty		$0.00
Credits/Payments		($4,708,694.00)
Total Assessment		**$0.00**

As of 04-Jul-2012, including the amount assessed above, you have an overall credit balance on your account of ($2,588,150.50).

If you have any questions concerning this Notice of Re-Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this re-assessment you have the right to file a Notice of Objection with the Objections and Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the re-assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Finance at the number listed below.

Agreed to tax return ✓

Ministry use only

Summary of Merger Savings by Department

Summary of Savings by Department

Savings	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016	Year 2017	Year 2018
Department										
Human Resources	143,000	195,304	195,304	195,304	195,304	195,304	195,304	195,304	195,304	195,304
Corporate	658,218	1,252,237	1,303,116	1,321,316	1,336,601	1,336,601	1,336,601	1,336,601	1,336,601	1,213,234
Finance	155,000	638,006	523,006	523,006	523,006	523,006	523,006	523,006	523,006	523,006
Information Technology	415,795	869,000	981,795	981,795	981,795	981,795	981,795	981,795	981,795	981,795
Regulatory - Rates	311,880	442,755	367,755	367,755	475,255	400,255	400,255	475,255	400,255	400,255
Customer Service	-	426,994	386,994	386,994	413,285	413,285	413,285	413,285	413,285	413,285
Eng. Planning	309,489	394,489	394,489	464,489	464,489	464,489	464,489	464,489	464,489	464,489
Design	-	335,383	335,383	335,383	335,383	335,383	335,383	335,383	335,383	335,383
Purchasing	20,000	216,167	216,167	216,167	216,167	216,167	216,167	216,167	216,167	216,167
Metering	288,582	658,014	658,014	658,014	658,014	658,014	658,014	658,014	658,014	658,014
Operational Effectiveness	-	153,000	213,000	213,000	213,000	213,000	213,000	213,000	213,000	213,000
Operations	339,587	539,785	607,676	607,676	607,676	607,676	607,676	607,676	607,676	607,676
Total Savings	2,641,551	6,121,134	6,182,699	6,270,899	6,419,975	6,344,975	6,344,975	6,419,975	6,344,975	6,221,608
On-Going Cost Increases										
Total On-Going Cost Increases (Salaries, Benefits, Contingencies)	(760,000)	(760,000)	(760,000)	(760,000)	(760,000)	(760,000)	(760,000)	(760,000)	(760,000)	(760,000)
Total Net Savings	**1,881,551**	**5,361,134**	**5,422,699**	**5,510,899**	**5,659,975**	**5,584,975**	**5,584,975**	**5,659,975**	**5,584,975**	**5,461,608**
Capital Savings										
Human Resources	-	-	-	-	-	-	-	-	-	-
Corporate	-	-	-	-	-	-	-	-	-	-
Finance	-	-	5,000	-	-	-	-	-	-	-
Information Technology	3,636,000	290,000	290,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000
Regulatory - Rates	-	-	-	-	-	-	-	-	-	-
Customer Service	85,000	-	-	-	-	-	-	-	-	-
Eng. Planning	250,000	-	-	-	-	-	-	-	-	-
Design	-	-	-	-	-	-	-	-	-	-
Purchasing	357,000	318,000	77,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
Metering	300,000	300,000	-	-	-	-	-	-	-	-
Operational Effectiveness	-	-	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000
Operations	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Total Capital Savings	**4,678,000**	**958,000**	**562,000**	**392,000**	**392,000**	**392,000**	**392,000**	**392,000**	**392,000**	**392,000**
Transition Costs										
Human Resources	-	-	-	-	-	-	-	-	-	-
Corporate	(3,571,718)	(350,000)	-	-	-	-	-	-	-	-
Finance	-	-	-	-	-	-	-	-	-	-
Information Technology	(350,000)	-	-	-	-	-	-	-	-	-
Rates	(265,000)	-	-	-	-	-	-	-	-	-
Customer Service	-	-	-	-	-	-	-	-	-	-
Eng. Planning	(10,000)	-	-	-	-	-	-	-	-	-
Design	-	-	-	-	-	-	-	-	-	-
Purchasing	-	-	-	-	-	-	-	-	-	-
Metering	-	-	-	-	-	-	-	-	-	-
Operational Effectiveness	-	-	-	-	-	-	-	-	-	-
Operations	(105,000)	-	-	-	-	-	-	-	-	-
Total Transition Costs	**(4,301,718)**	**(350,000)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

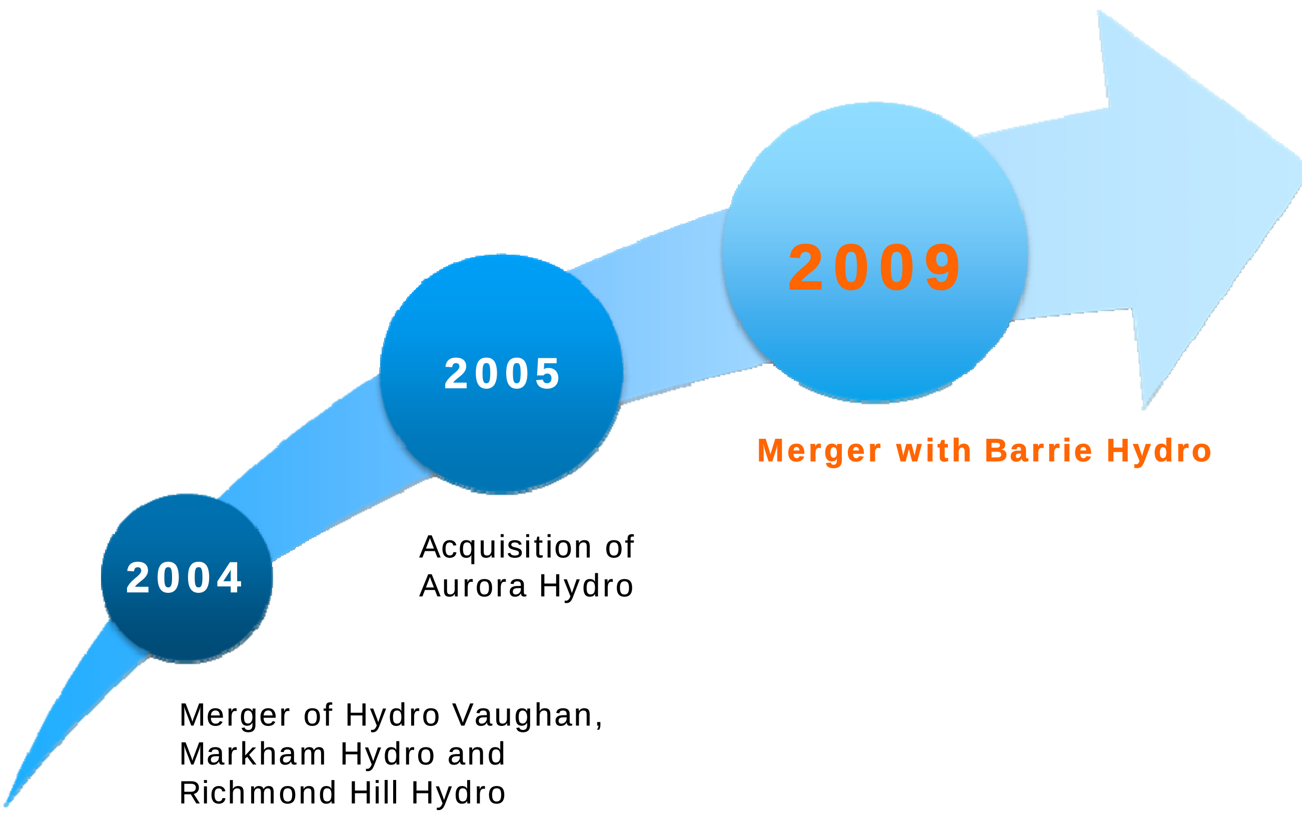
Discount Rate

BUILDING
EXCELLENCE
SUCCEEDING
TOGETHER

ANOTHER SUCCESSFUL STORY

Merger of

PowerStream and Barrie Hydro



PowerStream

Merger Synergy Report

Table of Contents

The Creation of Synergies

1 Background

Since 2007 significant work has been completed to develop and confirm synergy savings realized from the merger of Barrie Hydro and PowerStream. Negotiations between the two utilities 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, PowerStream Inc. and Barrie Hydro Distribution Inc. merged on January 1, 2009 to become the second largest municipally owned LDC in Ontario owned by the City of Barrie, the Town of Markham and the City of Vaughan.

Based on the “Merger Business Case”, the synergies realized through combining these companies and achieving economies of scale would result in operating savings of between $5 and $5.5 million annually, and $0.4 million in annual capital savings. Merger transition costs (i.e. the one time costs to integrate the previous 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 in which employee relations, health & safety and customer service were our highest priorities. A “best practice” business process philosophy was adopted which was consistent with the initial strategic direction and intent.

We established a 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 integration plans.

The initial focus of the Merger Integration Team was to identify critical milestones and establish timelines for each functional area and for information systems projects. While the focus was to complete the critical milestones of the “first 90-day plan”, all areas of integration and transition were identified and documented.

1 Background

Taking a best practice business process philosophy, the Merger Integration Team developed a planned approach to integration using four categories:

- People
- Processes
- Technology
- Communications

Examples of the critical milestones identified under these categories included:

- People
  - Harmonize wages and benefits
  - Change management
  - Corporate training
- Technology
  - Geographic Information System (GIS) integration
  - Supervisory Control and Data Acquisition (SCADA) integration
  - Customer Information System (CIS) integration
  - Local Area Networks (LANS), Wide Area Networks (WANS) & radio communication
  - Enterprise Resource Planning (ERP) system integration
  - Smart meter installation
- Processes
  - Integrate operating policies and procedures
  - International Financial Reporting Standards (IFRS) planning
  - Integrate health and safety
  - Procurement inventory consolidation
- Communications
  - Co-branding
  - Advertising campaign – Barrie and area
  - Conservation & Demand Management (CDM) marketing communications
  - Customer communications

2 Key Merger Milestone Achievements

- Creation of a new, Vision, Mission and Values and improved Corporate Balanced Scorecard was completed.
- Our Enterprise Resource Planning system/JD Edwards's integration project (finance, work orders etc) was achieved on target.
- The integration of the Avalanche System to enable the control room to take after hour calls in the North was achieved. This enhanced customer service for the former Barrie Hydro customers.
- The Customer Information System conversion was completed according to plan. Billing activity was harmonized ahead of schedule. This was a significant amount of work lead by a cross-functional transition team consisting primarily of customer service and information services staff.
- Conditions of Service and Offer to Connect processes and documents were finalized and the economic evaluation model was updated.
- A new corporate web based GIS viewer was developed and implemented.
- Consolidation of the operating and capital budgets was completed.
- Negotiations of a transitional agreement and a three-year Collective Agreement consolidating three collective agreements into one were achieved.
- Integration of a management compensation structure and revised position profiles were completed.
- Integration of all Human Resources and Health & Safety policies was achieved.
- Implementation of a co-branding strategy to assist customers in the transition was achieved.
- Integration of the phones, email, internet and intranet sites was completed.
- Installation of a fibre network to link the north and south locations enabling local voice and data connectivity was performed.
- Creation of a “Champions of Change” team to demonstrate, influence and promote a positive culture for the new Corporation was achieved.
- Achievement of many honours and awards including OEA's Company of the Year, Ministry of the Environment's Ontario Leaders Program, EDA's LDC Performance Excellence and Environmental Excellence Awards, Vaughan Chamber Commerce's Business of the Year and the United Way of Greater Simcoe County's Campaign Merit Award.
- We have also achieved excellent financial & operational results while working on the merger transition.

3 Financial Achievements

Successful completion of any project entails the tracking and recording of all aspects of the process from savings, costs, meeting of timelines and detailed project plans.

To this end, the Merger Integration Dashboard was established to ensure we measured and delivered the synergies identified in the Merger Business Case. It measures the actual operating and capital savings and transition costs as compared to what was outlined in our original Merger Business Case presented to our Board and Shareholders.

In the Merger Business Case for 2010, the gross savings to be achieved were $6.1 million less some ongoing new costs of $0.8 million for a net total of $5.4 million. As of December 31, 2010 we had achieved $6.2 million in net savings.

The annual capital savings in the Business Case was $0.4 million and the actual achieved was $0.8 million. The one time capital savings in the 2010 merger business case was $0.6 million and the actual achieved was $1.8 million.

The 2010 transition costs in the Business Case were $0.4 million and the actual was $1.7 million. Many of the transition costs that were originally included in the Business Case in 2009 were delayed into 2010. In order to understand the transition costs accurately we have combined the costs for both 2009 and 2010. Our combined transitions costs for 2009 and 2010 in the Business Case were $4.6 million and the actual was $5.2 million.

4 Ongoing Cost Savings

Each year it becomes increasingly difficult to segregate the merger savings due to organic growth and the impact of government, regulatory and other changes on our business. In order to complete our analysis of the merger savings for the Board, we have reviewed the savings we project to achieve in 2011 and beyond, that are considered “ongoing”. We have determined that the estimated amount of ongoing savings of at least $5.0 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 & Internal Audit reviewed the 2010 synergy savings and transition costs and has also reviewed the net estimated savings for 2011 and beyond, and has determined that the assumptions and amount are reasonable.

5 Beyond the Transition

The Shareholders' Agreement set out a geographic footprint for the continued growth and expansion of PowerStream and we remain committed to looking for those opportunities. Our scale, scope, and track record of proven results allow us to offer many benefits to other potential LDC merger or acquisition partners. In addition, we have made a significant investment in the successful launch of the Solar PV business and other related Renewable Generation projects. Our work in the area of Smart Grid development along with the pilot testing of electric vehicles are two other exciting developments presently underway. As the business model for LDCs continues its rapid transition from its more traditional "poles and wires" legacy towards that of a more complete "energy services provider", we plan to be at the forefront leading this transformation.

Confidential
Item #7(c) for Information

POWERSTREAM INC. BOARD OF DIRECTOR'S MEETING – APRIL 27, 2011

MERGER FINAL REPORT

Report by the President & CEO and EVP Corporate Services & Secretary

Recommendation

The President & CEO and EVP Corporate Services & Secretary recommend that the Merger Final Report be received for information by the Board of Directors.

Background

Since 2007 significant work has been completed to develop and confirm synergy savings realized due to the merger of Barrie and PowerStream. Negotiations between the two utilities 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, PowerStream Inc. and Barrie Hydro Distribution Inc. merged January 1, 2009 to become the second largest LDC in Ontario owned by the City of Barrie, the Town of Markham and the City of Vaughan.

Based on the "Merger Business Case", the synergies realized through combining these companies and achieving economies of scale would result in operating savings of between $5 and $5.5 million annually, and $.4 million in annual capital savings. Merger transition costs (i.e. the one time costs to integrate the previous 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 in which employee relations, health & safety and customer service were our highest priorities. A best practice business process philosophy was adopted which was consistent with the initial strategic direction and intent.

We established a 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 integration plans.

The initial focus of the Merger Integration Team was to identify critical milestones and establish timelines for each functional area and for information systems projects. While the focus was to complete the critical milestones of the "first 90-day plan", all areas of integration and transition were identified and documented.

Taking a best practice business process philosophy, the Merger Integration Team developed a planned approach to integration using four categories:

- People
- Processes
- Technology
- Communications

Examples of the critical milestones identified under these categories included:

- People
  - Harmonize wages and benefits
  - Change management
  - Corporate training

- Technology
  - Graphical Interface System (GIS) integration
  - Supervisory Control and Data Acquisition (SCADA) integration
  - Customer Information System (CIS) integration
  - Local Area Networks (LANS), Wide Area Networks (WANS) & radio communication
  - Enterprise Resource Planning (ERP)system integration
  - Smart metering

- Processes
  - Integrate operating policies and procedures
  - International Financial Reporting Standards (IFRS) planning
  - Integrate health and safety
  - Procurement inventory consolidation

- Communications
  - Co-branding
  - Advertising campaign – Barrie and area merger
  - CDM marketing communications
  - Customer Communications

Key Merger Milestones

- Creation of a new Mission, Vision and Values and improved Corporate Balanced Scorecard was completed.
- Our Enterprise Resource Planning system JD Edwards's integration project (finance, work orders etc) was achieved on target.
- The integration of the Avalanche System to enable the control room to take after hour's calls in the North was achieved. This enhanced customer service for the former Barrie Hydro customers.
- The Customer Information System conversion was completed according to plan despite some unexpected hurdles related to water billing. Billing activity was harmonized ahead of schedule. This was a significant amount of work lead by a cross functional transition team consisting primarily of customer service and information services staff.
- Conditions of Service and Offer to Connect processes and documents were finalized and the economic evaluation model was updated.
- ARC GIS server phase 2 was achieved with the deployment of a new web based GIS viewer.
- Consolidation of the operating and capital budgets was completed.
- Negotiations of a transitional agreement and a three year Collective Agreement consolidating three collective agreements into one was achieved.
- Integration of a management compensation structure and revised position profiles was completed.
- Integration of all Human Resources and Health & Safety policies was achieved.
- Implementation of a co-branding strategy to assist customers in the transition was achieved.
- Integration of the phones, email, and internet and intranet sites was completed.
- Installation of a fibre network to link the north and south enabling local voice and data connectivity was performed.
- Creation of a Champions of Change team to demonstrate, influence and promote a positive culture for the new Corporation was achieved.
- Achievement of many awards such as OEA Company of the year, Ministry Of Environment Leaders award and EDA Environment award and EDA Performance award.
- We have also achieved excellent financial & operational results while working on the merger transition.

Financial Achievements

Successful completion of any project entails the tracking and recording of all aspects of the process from savings, costs, meeting of timelines and detailed project plans.

To this end, the Merger Integration Dashboard was established to ensure we measured and delivered the synergies identified in the Merger Business Case. It measures the actual operating and capital savings and transition costs as compared to what was outlined in our original Merger Business Case presented to our Board and Shareholders.

In the Merger Business Case for 2010, the gross savings to be achieved were $6.1 million less some ongoing new costs of $.8 million for a net total of $5.4 million. As of December 31, 2010 we have achieved $6.2 million in net savings.

The annual capital savings in the Business Case was $.4 million and the actual achieved was $.8 million. The one time capital savings in the 2010 merger business case was $.6 million and the actual achieved was $1.8 million.

The 2010 transition costs in the Business Case were $.4 million and the actual was $1.7 million. Many of the transition costs that were originally included in the Business Case in 2009 were delayed to 2010. In order to understand the transition costs accurately we have combined the costs for both 2009 and 2010. Our combined transitions costs for 2009 & 2010 in the Business Case were $4.6 million and the actual was $5.2 million. The unfavourable variance of $.6 million is due to post retirement benefits as a result of union negotiations.

Dec-10 Category	PowerStream Business Case	Actual	Variance Fav/(UnFav)
Total Synergy Savings - Labour	$ 3.1	$ 4.0	$ 1.0
Total Synergy Savings - Other	$ 0.8	$ 0.7	$ 0.0
ONE TIME Synergy Savings	$ 0.0	$ 0.0	$ 0.0
Total Synergy Savings	$ 3.9	$ 4.8	$ 0.9
			$ 0.0
Total Avoided Costs - Labour	$ 1.7	$ 1.7	$ 0.0
Total Avoided Costs - Other	$ 0.3	$ 0.3	$ 0.0
ONE TIME Avoided Costs	$ 0.3	$ 0.2	- $ 0.1
Total Avoided Costs	$ 2.2	$ 2.1	- $ 0.1
			$ 0.0
TOTAL Operating Savings	$ 6.1	$ 6.9	$ 0.8
			$ 0.0
Total On-Going Cost Increases	- $ 0.8	- $ 0.7	$ 0.0
			$ 0.0
TOTAL NET Operating Savings	$ 5.4	$ 6.2	$ 0.8
			$ 0.0
Total Transition Costs - (OM&A)	- $ 0.4	- $ 1.7	- $ 1.4
Total Transition Costs - (Capital)	$ 0.0	$ 0.0	$ 0.0
Total Transition Costs	- $ 0.4	- $ 1.7	- $ 1.4
			$ 0.0
Total Annual Capital Savings	$ 0.4	$ 0.8	$ 0.5
Total ONE TIME Capital Savings	$ 0.6	$ 1.8	$ 1.2
Total Capital	$ 1.0	$ 2.6	$ 1.6

Dec-10 Category	PowerStream Business Case	Actual	Variance Fav/(UnFav)
Deliver Business Case Results:	$ 5.4	$ 6.2	$ 0.8

Dec-10 Category	PowerStream Business Case	Actual	Variance Fav/(UnFav)
Labour Savings			
Synergy:	$ 3.1	$ 4.0	$ 1.0
Avoided:	$ 1.7	$ 1.7	$ 0.0
Total Labour Savings:	$ 4.8	$ 5.8	$ 1.0
Salary/Benefits Additions:	- $ 0.8	- $ 0.7	$ 0.0
Grand Total Labour:	$ 4.0	$ 5.0	$ 1.0

Labour Cost Savings

An integral part of the merger savings was PowerStream's ability to commit to reducing staff levels. Progress was tracked and regularly reported to Board of Directors throughout the transition period**.** From a starting staff level of 522, by December 31, 2010 PowerStream had reached 466 staff positions ahead of its target (excluding the impact of new requirements driven by organic growth and regulatory requirements)

Each year it becomes increasing difficult to analyse the merger savings due to organic growth and the impact of government, regulatory and other changes on our business. In order to complete our analysis of the merger savings for the Board we have reviewed the savings we project to achieve in 2011 and beyond that are considered “ongoing”. We have 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 & Internal Audit reviewed the 2010 synergy savings and transition costs and has also reviewed the net estimated savings for 2011 and beyond and has determined that the assumptions and amount are reasonable.

Confidential
Item #12 for Information

POWERSTREAM INC. BOARD OF DIRECTORS MEETING – APRIL 30, 2010

FINAL 2009 MERGER TRANSITION RESULTS

Report by the Senior VP Human Resources & Organizational Effectiveness

Recommendation

The Senior VP Human Resources & Organizational Effectiveness recommends that the Final 2009 Merger Transition Results Report be received for information by the Board of Directors.

Background

Management continually monitored the merger savings and costs in 2009 to ensure each area reached its milestones and delivered the business case synergies PowerStream had promised. 2009 was a great success in terms of accomplishing merger integration activities as well as the achievements of all our balanced scorecard initiatives.

The following chart summarizes our 2009 accomplished merger savings as compared to our merger business case and has been reviewed by Carolyn Young, Director of Enterprise Risk and Internal Audit, who has reviewed the attached report and is in agreement with the achieved costs and savings as identified by management.

Dec-09	PowerStream		
	Business		
Category	***Case***	***Actual***	***Variance***
Total Synergy Savings - Labour	***$ 589,776***	***$ 1,486,470***	***$ (896,694)***
Total Synergy Savings - Other	***$ 450,880***	***$ 433,285***	***$ 17,595***
ONE TIME Synergy Savings	***$ -***	***$ -***	***$ -***
Total Synergy Savings	**$ 1,040,656**	**$ 1,919,755**	**$ (879,099)**
Total Avoided Costs - Labour	***$ 1,218,896***	***$ 1,160,607***	***$ 58,289***
Total Avoided Costs - Other	***$ 282,000***	***$ 255,000***	***$ 27,000***
ONE TIME Avoided Costs	***$ 100,000***	***$ 150,000***	***$ (50,000)***
Total Avoided Costs	**$ 1,600,896**	**$ 1,565,607**	**$ 35,289**
TOTAL Operating Savings	**$ 2,641,552**	**$ 3,485,362**	**$ (843,810)**
Total On-Going Cost Increases	***$ (760,000)***	***$ (491,912)***	***$ (268,088)***
TOTAL NET Operating Savings	**$ 1,881,552**	**$ 2,993,450**	**$(1,111,898)**
Total Transition Costs - (OM&A)	***$(4,301,718)***	***$(2,941,246)***	***$(1,360,472)***
Total Transition Costs - (Capital)	***$ -***	***$ (590,000)***	***$ 590,000***
Total Transition Costs	**$(4,301,718)**	**$(3,531,246)**	**$ (770,472)**
Total Annual Capital Savings	***$ 393,000***	***$ 246,000***	***$ 147,000***
Total ONE TIME Capital Savings	***$ 4,285,000***	***$ 2,841,800***	***$ 1,443,200***
Total Capital	**$ 4,678,000**	**$ 3,087,800**	**$ 1,590,200**

In the Merger Business Case for 2009, the gross savings to be achieved were $2.641 million, less ongoing costs of $.760 million, for a net total of $1.9 million. As of December 31, 2009, we achieved $3.485 million in savings, and incurred $.492 million of ongoing costs for a net savings of $2.993 million. This is 1.1 million over achieved the business case.

We reduced 15 FTE positions from the 2009 budgets compared to 11 FTE positions expected in the business case. The one time capital savings in the Merger Business Case was $4.285 million and we achieved $2.841 million savings with a one time capital savings of $1.5 million for CIS being delayed until 2010. In addition we achieved $.246 million of annual capital savings compared to $.393 million in the business case. Our transition costs were $4.3 million in the business case and we spent $2.941million operating and $.590,million capital for a total of $3,531 million in transition costs.

Back to Index

File Number:	EB-2012-0161
Exhibit:	H
Tab:	6
Schedule:	3
Page:	
Date:	31-Aug-12

2013 EDR Model

PowerStream South

Bill Impacts - Monthly Consumptions

Customer Class: **Residential**

Consumption 800 **kWh**

		Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Fix_R	Monthly Service Charge	monthly	$ 11.99	1	$ 11.99	$ 13.60	1	$ 13.60	$ 1.61	13.43%
SMR_R	Smart Meter Rate Adder	monthly	$ 1.28	1	$ 1.28	$ -	1	$ -	-$ 1.28	-100.00%
GEA_R	GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
SMIRR_R	Service Charge Rate Rider(s)	monthly	$ 0.1400	1	$ 0.14	$ -	1	$ -	-$ 0.14	-100.00%
Var_R	Distribution Volumetric Rate	per kWh	$ 0.0135	800	$ 10.80	$ 0.0151	800	$ 12.08	$ 1.28	11.85%
LV_R	Low Voltage Rate Adder	per kWh	$ 0.0001	800	$ 0.08	$ 0.0003	800	$ 0.24	$ 0.16	200.00%
	Volumetric Rate Adder(s)	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Tax_R	Volumetric Rate Rider(s)	per kWh	-$ 0.0004	800	-$ 0.32	$ -	800	$ -	$ 0.32	-100.00%
SMCD_R	Smart Meter Disposition Rider	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
LRAM_R	LRAM & SSM Rate Rider	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Reg_R	Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
			$ -		$ -	$ -		$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 23.97**			**$ 26.12**	**$ 2.15**	**8.97%**
TN_R	RTSR - Network	per kWh	$ 0.0073	824	$ 6.01	$ 0.0071	828	$ 5.88	-$ 0.14	-2.31%
TC_R	RTSR - Line and Transformation Connection	per kWh	$ 0.0027	824	$ 2.22	$ 0.0032	828	$ 2.65	$ 0.42	19.05%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 32.21**			**$ 34.64**	**$ 2.44**	**7.56%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	824	$ 4.28	$ 0.0052	828	$ 4.30	$ 0.02	0.45%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	824	$ 0.91	$ 0.0011	828	$ 0.91	$ 0.00	0.45%
	Special Purpose Charge	per kWh	$ -	824	$ -	$ -	828	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
	Energy Tier 1	per kWh	$ 0.0750	750	$ 56.25	$ 0.0750	750	$ 56.25	$ -	0.00%
	Energy Tier 2	per kWh	$ 0.0880	74	$ 6.50	$ 0.0880	78	$ 6.83	$ 0.32	4.98%
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 106.00**			**$ 108.79**	**$ 2.78**	**2.62%**
	HST		13%		$ 13.78	13%		$ 14.14	$ 0.36	2.62%
	Total Bill (including Sub-total B)				**$ 119.79**			**$ 122.93**	**$ 3.14**	**2.62%**
	OCEB				-$ 11.98			-$ 12.29	-$ 0.31	2.59%
	Total Bill (including OCEB)				**$ 107.81**			**$ 110.64**	**$ 2.83**	**2.62%**
	Loss Factor (%)		2.99%			3.45%				
	Threshold		750			750				

Notes:

Back to Index

2013 EDR Model

PowerStream South

Bill Impacts - Monthly Consumptions

File Number:	EB-2012-0161
Exhibit:	H
Tab:	6
Schedule:	3
Page:	
Date:	31-Aug-12

Customer Class: **General Service Less Than 50 kW**

Consumption 2000 **kWh**

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_GS	Monthly Service Charge	monthly	$ 28.64	1	$ 28.64	$ 27.97	1	$ 27.97	-$ 0.67	-2.34%
SMR_GS	Smart Meter Rate Adder	monthly	$ 1.0100	1	$ 1.01	$ -	1	$ -	-$ 1.01	-100.00%
GEA_GS	GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
SMIRR_GS	Service Charge Rate Rider(s)	monthly	$ 3.3700	1	$ 3.37	$ -	1	$ -	-$ 3.37	-100.00%
Var_GS	Distribution Volumetric Rate	per kWh	$ 0.0116	2,000	$ 23.20	$ 0.0149	2,000	$ 29.80	$ 6.60	28.45%
LV_GS	Low Voltage Rate Adder	per kWh	$ 0.0001	2,000	$ 0.20	$ 0.0003	2,000	$ 0.60	$ 0.40	200.00%
	Volumetric Rate Adder(s)	per kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Tax_GS	Volumetric Rate Rider(s)	per kWh	-$ 0.0003	2,000	-$ 0.60	$ -	2,000	$ -	$ 0.60	-100.00%
SMCD_GS	Smart Meter Disposition Rider	per kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
LRAM_GS	LRAM & SSM Rate Rider	per kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Reg_GS	Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	2,000	$ -	-$ 0.0012	2,000	-$ 2.40	-$ 2.40	
			$ -		$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 55.82**			**$ 56.17**	**$ 0.35**	**0.63%**
TN_GS	RTSR - Network	per kWh	$ 0.0066	2,060	$ 13.59	$ 0.0065	2,069	$ 13.45	-$ 0.15	-1.08%
TC_GS	RTSR - Line and Transformation Connection	per kWh	$ 0.0024	2,060	$ 4.94	$ 0.0028	2,069	$ 5.79	$ 0.85	17.19%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 74.36**			**$ 75.41**	**$ 1.05**	**1.42%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2,060	$ 10.71	$ 0.0052	2,069	$ 10.76	$ 0.05	0.45%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2,060	$ 2.27	$ 0.0011	2,069	$ 2.28	$ 0.01	0.45%
	Special Purpose Charge	per kWh	$ -	2,060	$ -	$ -	2,069	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
	Energy	per kWh	$ 0.0750	750	$ 56.25	$ 0.0750	750	$ 56.25	$ -	0.00%
			$ 0.0880	1,310	$ 115.26	$ 0.0880	1,319	$ 116.07	$ 0.81	0.70%
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 273.10**			**$ 275.02**	**$ 1.92**	**0.70%**
	HST		13%		$ 35.50	13%		$ 35.75	$ 0.25	0.70%
	Total Bill (including Sub-total B)				**$ 308.60**			**$ 310.77**	**$ 2.17**	**0.70%**
	OCEB				-$ 30.86			-$ 31.08	-$ 0.22	0.71%
	Total Bill (including OCEB)				**$ 277.74**			**$ 279.69**	**$ 1.95**	**0.70%**
	Loss Factor (%)		2.99%			3.45%				
	Threshold		750			750				

Notes:

Back to Index

2013 EDR Model

PowerStream South

Bill Impacts - Monthly Consumptions

File Number:	EB-2012-0161
Exhibit:	H
Tab:	6
Schedule:	3
Page:	
Date:	31-Aug-12

Customer Class: **General Service Greater Than 50 kW**

Consumption	**80,000**	**kWh**
Load	**250**	**kW**

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_GSL	Monthly Service Charge	monthly	$ 84.45	1	$ 84.45	$ 148.52	1	$ 148.52	$ 64.07	75.87%
	Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA_GSL	GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Var_GSL	Distribution Volumetric Rate	per kW	$ 3.5036	250	$ 875.90	$ 3.5524	250	$ 888.10	$ 12.20	1.39%
LV_GSL	Low Voltage Rate Adder	per kW	$ 0.0472	250	$ 11.80	$ 0.1191	250	$ 29.78	$ 17.98	152.33%
	Volumetric Rate Adder(s)	per kW	$ -	250	$ -	$ -	250	$ -	$ -	
Tax_GSL	Volumetric Rate Rider(s)	per kW	-$ 0.0501	250	-$ 12.53	$ -	250	$ -	$ 12.53	-100.00%
	Smart Meter Disposition Rider	per kW	$ -	250	$ -	$ -	250	$ -	$ -	
LRAM_GSL	LRAM & SSM Rate Rider	per kW	$ -	250	$ -	$ -	250	$ -	$ -	
Reg_GSL	Deferral/Variance Account Disposition Rate Rider	per kW	$ -	250	$ -	-$ 0.5397	250	-$ 134.93	-$ 134.93	
Reg_GSL	GA Variance Account Disposition Rate Rider (Non-RPP)	per kWh	$ -	1	$ -	$ 0.0017	80,000	$ 136.00	$ 136.00	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 959.63**			**$ 1,067.67**	**$ 108.05**	**11.26%**
TN_GSL	RTSR - Network	per kW	$ 2.6667	250	$ 666.68	$ 2.6030	250	$ 650.75	-$ 15.93	-2.39%
TC_GSL	RTSR - Line and Transformation Connection	per kW	$ 0.9755	250	$ 243.88	$ 1.0984	250	$ 274.60	$ 30.73	12.60%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 1,870.18**			**$ 1,993.02**	**$ 122.85**	**6.57%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	82,392	$ 428.44	$ 0.0052	82,760	$ 430.35	$ 1.91	0.45%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	82,392	$ 90.63	$ 0.0011	82,760	$ 91.04	$ 0.40	0.45%
	Special Purpose Charge	per kWh	$ -	82,392	$ -	$ -	82,760	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	80,000	$ 560.00	$ 0.0070	80,000	$ 560.00	$ -	0.00%
	Energy	per kWh	$ 0.0820	750	$ 61.50	$ 0.0820	750	$ 61.50	$ -	0.00%
	Energy	per kWh	$ 0.0820	81,642	$ 6,694.64	$ 0.0820	82,010	$ 6,724.82	$ 30.18	0.45%
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 9,705.64**			**$ 9,860.98**	**$ 155.34**	**1.60%**
	HST		13%		$ 1,261.73	13%		$ 1,281.93	$ 20.19	1.60%
	Total Bill (including Sub-total B)				**$ 10,967.37**			**$ 11,142.91**	**$ 175.54**	**1.60%**
	Loss Factor (%)		2.99%			3.45%				
	Threshold		750			750				

Notes:

For the Bill impact calculation purposes, the energy price is assumed to be the average of current tier prices

Back to Index

2013 EDR Model

PowerStream South

Bill Impacts - Monthly Consumptions

File Number:	EB-2012-0161
Exhibit:	H
Tab:	6
Schedule:	3
Page:	
Date:	31-Aug-12

Customer Class: **Large Use**

Consumption	**2,800,000** kWh
Load	**7,350** kW

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_LU	Monthly Service Charge	monthly	$ 2,173.63	1	$ 2,173.63	$ 6,022.70	1	$ 6,022.70	$ 3,849.07	177.08%
SM_LU	Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA_LU	GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Var_LU	Distribution Volumetric Rate	per kW	$ 1.0484	7,350	$ 7,705.74	$ 1.7980	7,350	$ 13,215.30	$ 5,509.56	71.50%
LV_LU	Low Voltage Rate Adder	per kW	$ 0.0558	7,350	$ 410.13	$ 0.1439	7,350	$ 1,057.67	$ 647.54	157.89%
	Volumetric Rate Adder(s)	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
Tax_LU	Volumetric Rate Rider(s)	per kW	-$ 0.0175	7,350	-$ 128.63	$ -	7,350	$ -	$ 128.63	-100.00%
	Smart Meter Disposition Rider	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
LRAM_LU	LRAM & SSM Rate Rider	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
Reg_LU	Deferral/Variance Account Disposition Rate Rider	per kW	$ -	7,350	$ -	-$ 0.1895	7,350	-$ 1,392.83	-$ 1,392.83	
Reg_LU	GA Variance Account Disposition Rate Rider (Non-RPP)	per kWh			$ -	$ 0.0017	2,800,000	$ 4,760.00	$ 4,760.00	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 10,160.88**			**$ 23,663.04**	**$ 13,502.17**	**132.88%**
TN_LU	RTSR - Network	per kW	$ 3.1285	7,350	$ 22,994.48	$ 3.0886	7,350	$ 22,701.21	-$ 293.26	-1.28%
TC_LU	RTSR - Line and Transformation Connection	per kW	$ 1.1529	7,350	$ 8,473.82	$ 1.1266	7,350	$ 8,280.51	-$ 193.31	-2.28%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 41,629.17**			**$ 54,644.76**	**$ 13,015.60**	**31.27%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2,840,600	$ 14,771.12	$ 0.0052	2,840,600	$ 14,771.12	$ -	0.00%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2,840,600	$ 3,124.66	$ 0.0011	2,840,600	$ 3,124.66	$ -	0.00%
	Special Purpose Charge	per kWh	$ -	2,840,600	$ -	$ -	2,840,600	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2,800,000	$ 19,600.00	$ 0.0070	2,800,000	$ 19,600.00	$ -	0.00%
	Energy	per kWh	$ 0.0820	750	$ 61.50	$ 0.0820	750	$ 61.50	$ -	0.00%
	Energy	per kWh	$ 0.0820	2,839,850	$ 232,867.70	$ 0.0820	2,839,850	$ 232,867.70	$ -	0.00%
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 312,054.40**			**$ 325,069.99**	**$ 13,015.59**	**4.17%**
	HST		13%		$ 40,567.07	13%		$ 42,259.10	$ 1,692.03	4.17%
	Total Bill (including Sub-total B)				**$ 352,621.47**			**$ 367,329.09**	**$ 14,707.62**	**4.17%**

	Current	Proposed
Loss Factor (%)	1.45%	1.45%
Threshold	750	750

Notes:

For the Bill impact calculation purposes, the energy price is assumed to be the average of current tier prices

Back to Index

2013 EDR Model

PowerStream South

Bill Impacts - Monthly Consumptions

File Number: EB-2012-0161
Exhibit: H
Tab: 6
Schedule: 3
Page:
Date: 31-Aug-12

Customer Class: **Unmetered Scattered Load**

Consumption 150 **kWh**

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_USL	Monthly Service Charge	monthly	$ 14.32	1	$ 14.32	$ 8.09	1	$ 8.09	-$ 6.23	-43.51%
SM_USL	Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA_USL	GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Var_USL	Distribution Volumetric Rate	per kWh	$ 0.0087	150	$ 1.31	$ 0.0156	150	$ 2.34	$ 1.04	79.31%
LV_USL	Low Voltage Rate Adder	per kWh	$ 0.0001	150	$ 0.02	$ 0.0003	150	$ 0.05	$ 0.03	200.00%
	Volumetric Rate Adder(s)	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
Tax_USL	Volumetric Rate Rider(s)	per kWh	-$ 0.0007	150	-$ 0.11	$ -	150	$ -	$ 0.11	-100.00%
	Smart Meter Disposition Rider	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
	LRAM & SSM Rate Rider	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
Reg_USL	Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	150	$ -	-$ 0.0022	150	-$ 0.33	-$ 0.33	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 15.54**			**$ 10.35**	**-$ 5.19**	**-33.41%**
TN_USL	RTSR - Network	per kWh	$ 0.0066	154	$ 1.02	$ 0.0064	155	$ 0.99	-$ 0.03	-2.60%
TC_USL	RTSR - Line and Transformation Connection	per kWh	$ 0.0027	154	$ 0.42	$ 0.0031	155	$ 0.48	$ 0.06	15.33%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 16.97**			**$ 11.82**	**-$ 5.15**	**-30.36%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	154	$ 0.80	$ 0.0052	155	$ 0.81	$ 0.00	0.45%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	154	$ 0.17	$ 0.0011	155	$ 0.17	$ 0.00	0.45%
	Special Purpose Charge	per kWh	$ -	154	$ -	$ -	155	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	150	$ 1.05	$ 0.0070	150	$ 1.05	$ -	0.00%
	Energy Tier 1	per kWh	$ 0.0750	154	$ 11.59	$ 0.0750	155	$ 11.64	$ 0.05	0.45%
	Energy Tier 2	per kWh	$ 0.0880	-	$ -	$ 0.0880	-	$ -	$ -	
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 30.83**			**$ 25.73**	**-$ 5.10**	**-16.53%**
	HST		13%		$ 4.01	13%		$ 3.35	-$ 0.66	-16.53%
	Total Bill (including Sub-total B)				**$ 34.84**			**$ 29.08**	**-$ 5.76**	**-16.53%**
	Loss Factor (%)		2.99%			3.45%				
	Threshold		750			750				

Notes:

Back to Index

2013 EDR Model

PowerStream South

Bill Impacts - Monthly Consumptions

File Number:	EB-2012-0161
Exhibit:	H
Tab:	6
Schedule:	3
Page:	
Date:	31-Aug-12

Customer Class: **Sentinel**

Consumption	**180**	**kWh**
Load	**1.0**	**kW**

			Current Board-Approved			**Proposed**			**Impact**	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_SE	Monthly Service Charge	monthly	$ 2.00	1	$ 2.00	$ 3.52	1	$ 3.52	$ 1.52	76.00%
SM_SE	Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA_USL	GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Var_SE	Distribution Volumetric Rate	per kW	$ 9.3917	1.0	$ 9.39	$ 8.7646	1.0	$ 8.76	-$ 0.63	-6.68%
LV_SE	Low Voltage Rate Adder	per kW	$ 0.0401	1.0	$ 0.04	$ 0.1033	1.0	$ 0.10	$ 0.06	157.61%
	Volumetric Rate Adder(s)	per kW	$ -	1.0	$ -	$ -	1.0	$ -	$ -	
Tax_SE	Volumetric Rate Rider(s)	per kW	-$ 0.1458	1.0	-$ 0.15	$ -	1.0	$ -	$ 0.15	-100.00%
	Smart Meter Disposition Rider	per kW	$ -	1.0	$ -	$ -	1.0	$ -	$ -	
	LRAM & SSM Rate Rider	per kW	$ -	1.0	$ -	$ -	1.0	$ -	$ -	
Reg_SE	Deferral/Variance Account Disposition Rate Rider	per kW	$ -	1.0	$ -	-$ 0.7433	1.0	-$ 0.74	-$ 0.74	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 11.29**			**$ 11.84**	**$ 0.56**	**4.95%**
TN_SE	RTSR - Network	per kW	$ 2.0378	1.0	$ 2.04	$ 2.0118	1.0	$ 2.01	-$ 0.03	-1.28%
TC_SE	RTSR - Line and Transformation Connection	per kW	$ 0.8272	1.0	$ 0.83	$ 0.8084	1.0	$ 0.81	-$ 0.02	-2.27%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 14.15**			**$ 14.66**	**$ 0.51**	**3.63%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	185	$ 0.96	$ 0.0052	186	$ 0.97	$ 0.00	0.45%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	185	$ 0.20	$ 0.0011	186	$ 0.20	$ 0.00	0.45%
	Special Purpose Charge	per kWh	$ -	185	$ -	$ -	186	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	180	$ 1.26	$ 0.0070	180	$ 1.26	$ -	0.00%
	Energy Tier 1	per kWh	$ 0.0750	185	$ 13.90	$ 0.0750	186	$ 13.97	$ 0.06	0.45%
	Energy Tier 2	per kWh	$ 0.0880	-	$ -	$ 0.0880	-	$ -	$ -	
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 30.73**			**$ 31.31**	**$ 0.58**	**1.89%**
	HST		13%		$ 4.00	13%		$ 4.07	$ 0.08	1.89%
	Total Bill (including Sub-total B)				**$ 34.73**			**$ 35.38**	**$ 0.65**	**1.87%**

	Current	Proposed
Loss Factor (%)	2.99%	3.45%
Threshold	750	750

Notes:

Back to Index

File Number:	EB-2012-0161
Exhibit:	H
Tab:	6
Schedule:	3
Page:	
Date:	31-Aug-12

2013 EDR Model

PowerStream South

Bill Impacts - Monthly Consumptions

Customer Class: **Street Lighting**

Consumption	**280** kWh
Load	**1.00** kW

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_SL	Monthly Service Charge	monthly	$ 0.84	1	$ 0.84	$ 1.35	1	$ 1.35	$ 0.51	60.71%
SM_SL	Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
	Service Charge Rate Adder(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Var_SL	Distribution Volumetric Rate	per kW	$ 4.8616	1.00	$ 4.86	$ 5.8617	1.00	$ 5.86	$ 1.00	20.57%
LV_SL	Low Voltage Rate Adder	per kW	$ 0.0367	1.00	$ 0.04	$ 0.0918	1.00	$ 0.09	$ 0.06	150.14%
	Volumetric Rate Adder(s)	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
Tax_SL	Volumetric Rate Rider(s)	per kW	-$ 0.1276	1.00	-$ 0.13	$ -	1.00	$ -	$ 0.13	-100.00%
	Smart Meter Disposition Rider	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
	LRAM & SSM Rate Rider	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
Reg_SL	Deferral/Variance Account Disposition Rate Rider	per kW	$ -	1.00	$ -	-$ 0.6372	1.0	-$ 0.64	-$ 0.64	
Reg_SL	GA Variance Account Disposition Rate Rider (Non-RPP)	per kW			$ -	$ 0.0017	1.0	$ 0.00	$ 0.00	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 5.61**			**$ 6.67**	**$ 1.06**	**18.84%**
TN_SL	RTSR - Network	per kW	$ 2.0174	1.00	$ 2.02	$ 1.9798	1.00	$ 1.98	-$ 0.04	-1.86%
TC_SL	RTSR - Line and Transformation Connection	per kW	$ 0.7584	1.00	$ 0.76	$ 0.8901	1.00	$ 0.89	$ 0.13	17.37%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 8.39**			**$ 9.54**	**$ 1.15**	**13.73%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	288.37	$ 1.50	$ 0.0052	290	$ 1.51	$ 0.01	0.45%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	288.37	$ 0.32	$ 0.0011	290	$ 0.32	$ 0.00	0.45%
	Special Purpose Charge	per kWh	$ -	288.37	$ -	$ -	290	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	280	$ 1.96	$ 0.0070	280	$ 1.96	$ -	0.00%
	Energy Tier 1	per kWh	$ 0.0750	288	$ 21.63	$ 0.0750	290	$ 21.72	$ 0.10	0.45%
	Energy Tier 2		$ 0.0880	-	$ -	$ 0.0880	-	$ -	$ -	
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 34.04**			**$ 35.30**	**$ 1.26**	**3.69%**
	HST		13%		$ 4.43	13%		$ 4.59	$ 0.16	3.69%
	Total Bill (including Sub-total B)				**$ 38.47**			**$ 39.89**	**$ 1.42**	**3.69%**

	Current	Proposed
Loss Factor (%)	2.99%	3.45%
Threshold	800	800

Notes:

Back to Index

2013 EDR Model

PowerStream Barrie

Bill Impacts - Monthly Consumptions

File Number:	EB-2012-0161
Exhibit:	H
Tab:	6
Schedule:	3
Page:	
Date:	31-Aug-12

monthly **Customer Class:** **Residential**

per kWh
per kW

Consumption 800 kWh

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_R	Monthly Service Charge	monthly	$ 15.34	1	$ 15.34	$ 13.60	1	$ 13.60	-$ 1.74	-11.34%
	Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA_R	GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
SMIRR_R	Service Charge Rate Rider(s)	monthly	$ 1.78	1	$ 1.78	$ -	1	$ -	-$ 1.78	-100.00%
Var_R	Distribution Volumetric Rate	per kWh	$ 0.0137	800	$ 10.96	$ 0.0151	800	$ 12.08	$ 1.12	10.22%
LV_R	Low Voltage Rate Adder	per kWh	$ 0.0008	800	$ 0.64	$ 0.0003	800	$ 0.24	-$ 0.40	-62.50%
	Volumetric Rate Adder(s)	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Tax_R	Volumetric Rate Rider(s)	per kWh	-$ 0.0006	800	-$ 0.48	$ -	800	$ -	$ 0.48	-100.00%
SMCD_R	Smart Meter Disposition Rider	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
LRAM_R	LRAM & SSM Rate Rider - effective until Apr 30, 2013	per kWh	$ 0.0004	800	$ 0.32	$ 0.0004	800	$ 0.32	$ -	0.00%
Reg_R	Deferral/Variance Account Disposition Rate Rider (2012) - effective until Apr 30, 2013	per kWh	-$ 0.0006	800	-$ 0.48	-$ 0.0006	800	-$ 0.48	$ -	0.00%
Reg_R	Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kWh			$ -	$ 0.0008	800	$ 0.64	$ 0.64	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 28.08**			**$ 26.60**	**-$ 1.48**	**-5.27%**
TN_R	RTSR - Network	per kWh	$ 0.0069	845	$ 5.83	$ 0.0071	828	$ 5.88	$ 0.04	0.76%
TC_R	RTSR - Line and Transformation Connection	per kWh	$ 0.0054	845	$ 4.56	$ 0.0032	828	$ 2.65	-$ 1.92	-41.97%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 38.48**			**$ 35.12**	**-$ 3.35**	**-8.71%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	845	$ 4.40	$ 0.0052	828	$ 4.30	-$ 0.09	-2.08%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	845	$ 0.93	$ 0.0011	828	$ 0.91	-$ 0.02	-2.08%
	Special Purpose Charge	per kWh	$ -	845	$ -	$ -	828	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
	Energy Tier 1	per kWh	$ 0.0750	800	$ 60.00	$ 0.0750	800	$ 60.00	$ -	0.00%
	Energy Tier 2	per kWh	$ 0.0880	45	$ 3.98	$ 0.0880	28	$ 2.43	-$ 1.55	-38.94%
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 113.63**			**$ 108.62**	**-$ 5.01**	**-4.41%**
	HST		13%		$ 14.77	13%		$ 14.12	-$ 0.65	-4.41%
	Total Bill (including Sub-total B)				**$ 128.40**			**$ 122.74**	**-$ 5.66**	**-4.41%**
	OCEB				-$ 12.84			-$ 12.27	$ 0.57	-4.44%
	Total Bill (including OCEB)				**$ 115.56**			**$ 110.47**	**-$ 5.09**	**-4.40%**

	Current	Proposed
Loss Factor (%)	5.65%	3.45%
Threshold	800	800

Notes:

Back to Index

2013 EDR Model

PowerStream Barrie

Bill Impacts - Monthly Consumptions

File Number:	EB-2012-0161
Exhibit:	H
Tab:	6
Schedule:	3
Page:	
Date:	31-Aug-12

monthly **Customer Class:** **General Service Less Than 50 kW**

per kWh **Consumption** **2000** **kWh**

per kW

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_GS	Monthly Service Charge	monthly	$ 16.11	1	$ 16.11	$ 27.97	1	$ 27.97	$ 11.86	73.62%
GEA_GS	GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
SMIRR_GS	Service Charge Rate Adder(s)	monthly	$ 4.7300	1	$ 4.73	$ -	1	$ -	-$ 4.73	-100.00%
	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Var_GS	Distribution Volumetric Rate	per kWh	$ 0.0164	2,000	$ 32.80	$ 0.0149	2,000	$ 29.80	-$ 3.00	-9.15%
LV_GS	Low Voltage Rate Adder	per kWh	$ 0.0007	2,000	$ 1.40	$ 0.0003	2,000	$ 0.60	-$ 0.80	-57.14%
	Volumetric Rate Adder(s)	per kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Tax_GS	Volumetric Rate Rider(s)	per kWh	-$ 0.0004	2,000	-$ 0.80	$ -	2,000	$ -	$ 0.80	-100.00%
	Smart Meter Disposition Rider	per kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
LRAM_GS	LRAM & SSM Rate Rider - effective until Apr 30, 2013	per kWh	$ 0.0007	2,000	$ 1.40	$ 0.0007	2,000	$ 1.40	$ -	0.00%
Reg_GS	Deferral/Variance Account Disposition Rate Rider (2012) - effective until Apr 30, 2013	per kWh	-$ 0.0004	2,000	-$ 0.80	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Reg_GS	Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kWh		2,000	$ -	-$ 0.0009	2,000	-$ 1.80	-$ 1.80	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 54.84**			**$ 57.37**	**$ 2.53**	**4.61%**
TN_GS	RTSR - Network	per kWh	$ 0.0063	2,113	$ 13.31	$ 0.0065	2,069	$ 13.45	$ 0.14	1.03%
TC_GS	RTSR - Line and Transformation Connection	per kWh	$ 0.0048	2,113	$ 10.14	$ 0.0028	2,069	$ 5.79	-$ 4.35	-42.88%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 78.29**			**$ 76.61**	**-$ 1.68**	**-2.15%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2,113	$ 10.99	$ 0.0052	2,069	$ 10.76	-$ 0.23	-2.08%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2,113	$ 2.32	$ 0.0011	2,069	$ 2.28	-$ 0.05	-2.08%
	Special Purpose Charge	per kWh	$ -	2,113	$ -	$ -	2,069	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
	Energy Tier 1	per kWh	$ 0.0750	750	$ 56.25	$ 0.0750	750	$ 56.25	$ -	0.00%
	Energy Tier 2	per kWh	$ 0.0880	1,363	$ 119.94	$ 0.0880	1,319	$ 116.07	-$ 3.87	-3.23%
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 282.05**			**$ 276.22**	**-$ 5.83**	**-2.07%**
	HST		13%		$ 36.67	13%		$ 35.91	-$ 0.76	-2.07%
	Total Bill (including Sub-total B)				**$ 318.72**			**$ 312.13**	**-$ 6.59**	**-2.07%**
	OCEB				-$ 31.87			-$ 31.21	$ 0.66	-2.07%
	Total Bill (including OCEB)				**$ 286.85**			**$ 280.92**	**-$ 5.93**	**-2.07%**
	Loss Factor (%)		5.65%			3.45%				
	Threshold		750			750				

Notes:

Back to Index

2013 EDR Model

PowerStream Barrie

Bill Impacts - Monthly Consumptions

File Number:	EB-2012-0161
Exhibit:	H
Tab:	6
Schedule:	3
Page:	
Date:	31-Aug-12

monthly **Customer Class:** **General Service Greater Than 50 kW**

per kWh **Consumption** 80,000 kWh

per kW **Load** 250 kW

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_GSL	Monthly Service Charge	monthly	$ 395.68	1	$ 395.68	$ 148.52	1	$ 148.52	-$ 247.16	-62.46%
SM_GSL	Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA_GSL	GEA funding rate adder	monthly	$ -	1	$ -	$ 0.2000	1	$ 0.20	$ 0.20	
	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Var_GSL	Distribution Volumetric Rate	per kW	$ 1.8393	250	$ 459.83	$ 3.5524	250	$ 888.10	$ 428.28	93.14%
LV_GSL	Low Voltage Rate Adder	per kW	$ 0.2913	250	$ 72.83	$ 0.1191	250	$ 29.78	-$ 43.05	-59.11%
	Volumetric Rate Adder(s)	per kW	$ -	250	$ -	$ -	250	$ -	$ -	
Tax_GSL	Volumetric Rate Rider(s)	per kW	-$ 0.0650	250	-$ 16.25	$ -	250	$ -	$ 16.25	-100.00%
	Smart Meter Disposition Rider	per kW	$ -	250	$ -	$ -	250	$ -	$ -	
LRAM_GSL	LRAM & SSM Rate Rider - effective until Apr 30, 2013	per kW	$ 0.0012	250	$ 0.30	$ 0.0012	250	$ 0.30	$ -	0.00%
Reg_GSL	Deferral/Variance Account Disposition Rate Rider (2012) - effective until Apr 30, 2013	per kW	-$ 0.0705	250	-$ 17.63	-$ 0.0705	250	-$ 17.63	$ -	0.00%
Reg_GSL	GA Variance Account Disposition Rate Rider (Non-RPP)	per kW		250	$ -	$ 0.0030	80,000	$ 240.00	$ 240.00	
Reg_GSL	Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kWh			$ -	-$ 0.5536	250	-$ 138.40	-$ 138.40	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 894.76**			**$ 1,150.87**	**$ 256.12**	**28.62%**
TN_GSL	RTSR - Network	per kW	$ 2.4796	250	$ 619.90	$ 2.6030	250	$ 650.75	$ 30.85	4.98%
TC_GSL	RTSR - Line and Transformation Connection	per kW	$ 1.8993	250	$ 474.83	$ 1.0984	250	$ 274.60	-$ 200.23	-42.17%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 1,989.48**			**$ 2,076.22**	**$ 86.74**	**4.36%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	84,520	$ 439.50	$ 0.0052	82,760	$ 430.35	-$ 9.15	-2.08%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	84,520	$ 92.97	$ 0.0011	82,760	$ 91.04	-$ 1.94	-2.08%
	Special Purpose Charge	per kWh	$ -	84,520	$ -	$ -	82,760	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	80,000	$ 560.00	$ 0.0070	80,000	$ 560.00	$ -	0.00%
	Energy	per kWh	$ 0.0820	750	$ 61.50	$ 0.0820	750	$ 61.50	$ -	0.00%
	Energy	per kWh	$ 0.0820	83,770	$ 6,869.14	$ 0.0820	82,010	$ 6,724.82	-$ 144.32	-2.10%
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 10,012.85**			**$ 9,944.18**	**-$ 68.67**	**-0.69%**
	HST		13%		$ 1,301.67	13%		$ 1,292.74	-$ 8.93	-0.69%
	Total Bill (including Sub-total B)				**$ 11,314.52**			**$ 11,236.92**	**-$ 77.60**	**-0.69%**
	Loss Factor (%)		5.65%			3.45%				
	Threshold		750			750				

Notes:

For the Bill impact calculation purposes, the energy price is assumed to be the average of current tier prices

Back to Index

2013 EDR Model

PowerStream Barrie

Bill Impacts - Monthly Consumptions

File Number:	EB-2012-0161
Exhibit:	H
Tab:	6
Schedule:	3
Page:	
Date:	31-Aug-12

monthly **Customer Class:** **Large Use**

per kWh		**Consumption**	2,800,000	kWh						
per kW		**Load**	7,350	kW						
			Current Board-Approved			**Proposed**			**Impact**	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_LU	Monthly Service Charge	monthly	$ 9,690.24	1	$ 9,690.24	$ 6,022.70	1	$ 6,022.70	-$ 3,667.54	-37.85%
SM_LU	Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA_LU	GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Var_LU	Distribution Volumetric Rate	per kW	$ 0.5918	7,350	$ 4,349.73	$ 1.7980	7,350	$ 13,215.30	$ 8,865.57	203.82%
LV_LU	Low Voltage Rate Adder	per kW	$ 0.3886	7,350	$ 2,856.21	$ 0.1439	7,350	$ 1,057.67	-$ 1,798.55	-62.97%
	Volumetric Rate Adder(s)	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
Tax_LU	Volumetric Rate Rider(s)	per kW	-$ 0.0764	7,350	-$ 561.54	$ -	7,350	$ -	$ 561.54	-100.00%
	Smart Meter Disposition Rider	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
LRAM_LU	LRAM & SSM Rate Rider	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
Reg_LU	Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kW	$ -	7,350	$ -	-$ 0.0829	7,350	-$ 609.32	-$ 609.32	
Reg_LU	GA Variance Account Disposition Rate Rider (Non-RPP)	per kWh			$ -	$ 0.0001	2,800,000	$ 280.00	$ 280.00	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 16,334.64**			**$ 19,966.55**	**$ 3,631.91**	**22.23%**
TN_LU	RTSR - Network	per kW	$ 3.1192	7,350	$ 22,926.12	$ 3.0886	7,350	$ 22,701.21	-$ 224.91	-0.98%
TC_LU	RTSR - Line and Transformation Connection	per kW	$ 2.5775	7,350	$ 18,944.63	$ 1.1266	7,350	$ 8,280.51	-$ 10,664.12	-56.29%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 58,205.39**			**$ 50,948.27**	**-$ 7,257.12**	**-12.47%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2,840,600	$ 14,771.12	$ 0.0052	2,840,600	$ 14,771.12	$ -	0.00%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2,840,600	$ 3,124.66	$ 0.0011	2,840,600	$ 3,124.66	$ -	0.00%
	Special Purpose Charge	per kWh	$ -	2,840,600	$ -	$ -	2,840,600	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2,800,000	$ 19,600.00	$ 0.0070	2,800,000	$ 19,600.00	$ -	0.00%
	Energy	per kWh	$ 0.0820	750	$ 61.50	$ 0.0820	750	$ 61.50	$ -	0.00%
	Energy	per kWh	$ 0.0820	2,839,850	$ 232,867.70	$ 0.0820	2,839,850	$ 232,867.70	$ -	0.00%
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 328,630.62**			**$ 321,373.50**	**-$ 7,257.11**	**-2.21%**
	HST		13%		$ 42,721.98	13%		$ 41,778.56	-$ 943.42	-2.21%
	Total Bill (including Sub-total B)				**$ 371,352.59**			**$ 363,152.06**	**-$ 8,200.53**	**-2.21%**
	Loss Factor (%)		1.45%			1.45%				
	Threshold		750			750				

Notes:

For the Bill impact calculation purposes, the energy price is assumed to be the average of current tier prices

Back to Index

File Number:	EB-2012-0161
Exhibit:	H
Tab:	6
Schedule:	3
Page:	
Date:	31-Aug-12

2013 EDR Model

PowerStream Barrie

Bill Impacts - Monthly Consumptions

monthly

per kWh
per kW

Customer Class: **Unmetered Scattered Load**

Consumption 150 **kWh**

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_USL	Monthly Service Charge	monthly	$ 7.95	1	$ 7.95	$ 8.09	1	$ 8.09	$ 0.14	1.76%
SM_USL	Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA_USL	GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Var_USL	Distribution Volumetric Rate	per kWh	$ 0.0161	150	$ 2.42	$ 0.0156	150	$ 2.34	-$ 0.08	-3.11%
LV_USL	Low Voltage Rate Adder	per kWh	$ 0.0007	150	$ 0.11	$ 0.0003	150	$ 0.05	-$ 0.06	-57.14%
	Volumetric Rate Adder(s)	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
Tax_USL	Volumetric Rate Rider(s)	per kWh	-$ 0.0005	150	-$ 0.08	$ -	150	$ -	$ 0.08	-100.00%
	Smart Meter Disposition Rider	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
LRAM_USL	LRAM & SSM Rate Rider	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
Reg_USL	Deferral/Variance Account Disposition Rate Rider (2012) - effective until Apr 30, 2013	per kWh	-$ 0.0009	150	-$ 0.14	-$ 0.0009	150	-$ 0.14	$ -	0.00%
Reg_USL	Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kWh			$ -	-$ 0.0014	150	-$ 0.21	-$ 0.21	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 10.26**			**$ 10.33**	**$ 0.07**	**0.68%**
TN_USL	RTSR - Network	per kWh	$ 0.0063	158	$ 1.00	$ 0.0064	155	$ 0.99	-$ 0.01	-0.53%
TC_USL	RTSR - Line and Transformation Connection	per kWh	$ 0.0048	158	$ 0.76	$ 0.0031	155	$ 0.48	-$ 0.28	-36.76%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 12.02**			**$ 11.80**	**-$ 0.21**	**-1.79%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	158	$ 0.82	$ 0.0052	155	$ 0.81	-$ 0.02	-2.08%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	158	$ 0.17	$ 0.0011	155	$ 0.17	-$ 0.00	-2.08%
	Special Purpose Charge	per kWh	$ -	158	$ -	$ -	155	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	150	$ 1.05	$ 0.0070	150	$ 1.05	$ -	0.00%
	Energy Tier 1	per kWh	$ 0.0750	158	$ 11.89	$ 0.0750	155	$ 11.64	-$ 0.25	-2.08%
	Energy Tier 2	per kWh	$ 0.0880	-	$ -	$ 0.0880	-	$ -	$ -	
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 26.20**			**$ 25.72**	**-$ 0.48**	**-1.84%**
	HST		13%		$ 3.41	13%		$ 3.34	-$ 0.06	-1.84%
	Total Bill (including Sub-total B)				**$ 29.61**			**$ 29.06**	**-$ 0.55**	**-1.86%**
	Loss Factor (%)		5.65%			3.45%				
	Threshold		750			750				

Notes:

Back to Index

2013 EDR Model

PowerStream Barrie

Bill Impacts - Monthly Consumptions

File Number: EB-2012-0161
Exhibit: H
Tab: 6
Schedule: 3
Page:
Date: 31-Aug-12

monthly | **Customer Class:** | **Street Lighting**

per kWh | **Consumption** | **280** | kWh
per kW | **Load** | **1.00** | kW

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Fix_SL	Monthly Service Charge	monthly	$ 3.02	1	$ 3.02	$ 1.35	1	$ 1.35	-$ 1.67	-55.30%
SM_SL	Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
	Service Charge Rate Adder(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Var_SL	Distribution Volumetric Rate	per kW	$ 11.2961	1.00	$ 11.30	$ 5.8617	1.00	$ 5.86	-$ 5.43	-48.11%
LV_SL	Low Voltage Rate Adder	per kW	$ 0.2301	1.00	$ 0.23	$ 0.0918	1.00	$ 0.09	-$ 0.14	-60.10%
	Volumetric Rate Adder(s)	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
Tax_SL	Volumetric Rate Rider(s)	per kW	-$ 0.4780	1.00	-$ 0.48	$ -	1.00	$ -	$ 0.48	-100.00%
	Smart Meter Disposition Rider	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
LRAM_SL	LRAM & SSM Rate Rider	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
Reg_SL	Deferral/Variance Account Disposition Rate Rider (2012) - effective until Apr 30, 2013	per kW	-$ 0.1545	1.00	-$ 0.15	-$ 0.1545	1.00	-$ 0.15	$ -	0.00%
Reg_SL	Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kW			$ -	-$ 0.4548	1.00	-$ 0.45	-$ 0.45	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
					$ -			$ -	$ -	
	Sub-Total A - Distribution				**$ 13.91**			**$ 6.69**	**-$ 7.22**	**-51.89%**
TN_SL	RTSR - Network	per kW	$ 1.9589	1.00	$ 1.96	$ 1.9798	1.00	$ 1.98	$ 0.02	1.07%
TC_SL	RTSR - Line and Transformation Connection	per kW	$ 1.5002	1.00	$ 1.50	$ 0.8901	1.00	$ 0.89	-$ 0.61	-40.67%
	Sub-Total B - Delivery (including Sub-Total A)				**$ 17.37**			**$ 9.56**	**-$ 7.81**	**-44.95%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	295.82	$ 1.54	$ 0.0052	290	$ 1.51	-$ 0.03	-2.08%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	295.82	$ 0.33	$ 0.0011	290	$ 0.32	-$ 0.01	-2.08%
	Special Purpose Charge	per kWh	$ -	295.82	$ -	$ -	290	$ -	$ -	
	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	280	$ 1.96	$ 0.0070	280	$ 1.96	$ -	0.00%
	Energy Tier 1	per kWh	$ 0.0750	296	$ 22.19	$ 0.0750	290	$ 21.72	-$ 0.46	-2.08%
	Energy Tier 2	per kWh	$ 0.0880	-	$ -	$ 0.0880	-	$ -	$ -	
					$ -			$ -	$ -	
	Total Bill (before Taxes)				**$ 43.63**			**$ 35.32**	**-$ 8.31**	**-19.04%**
	HST		13%		$ 5.67	13%		$ 4.59	-$ 1.08	-19.04%
	Total Bill (including Sub-total B)				**$ 49.31**			**$ 39.92**	**-$ 9.39**	**-19.04%**
	Loss Factor (%)		5.65%			3.45%				
	Threshold		750			750				

Notes:

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.1. Are PowerStream's economic and business planning assumptions appropriate?

BOARD STAFF INTERROGATORY #7:

Reference(s): Ref: E A3/ T1/ S1, p.1

It is stated that:
"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."

Please provide the key economic assumptions on which the forecast underpinning this application was based.

RESPONSE:

Please refer to Appendix C in this Exhibit - presentation to PowerStream's Board of Directors dated Dec 14, 2011 - provided in response to CCC's IR #1b) found below. Appendix C details PowerStream's five-year budget outlook. Slides # 4, 5 and 6 show the key assumptions used in the two-year budget and the five-year outlook.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.1. Are PowerStream's economic and business planning assumptions appropriate?

CCC INTERROGATORY #1:

Reference(s): (A3/T1/S1/p. 4)

Please provide all materials provided to PowerStream's Board of Directors related to the following:

a) the 2013 rate application;
b) the detailed budgets for 2012 and 2013.

Please explain the process undertaken to obtain approval from the Board of Directors for the 2013 rate application.

RESPONSE:

a) Reports related to the 2013 rate application were provided to PowerStream's Board of Directors on September 21, 2011 and April 25, 2012. These materials are attached as Appendix A.

   The rate application is not formally approved by the Board of Directors prior to filing. The reports noted above were provided for information. The Board of Directors did, however, approve the 2013 budget that underpins the application. They also approved the 2011 financial results, which are another key aspect of the application.

b) The detailed budgets for 2012 and 2013 were completed in 2011. The following documents are attached:

   1. Appendix B - presentation entitled "2012/2013 Budget Guidelines & Financial Outlook", given to PowerStream's Board of Directors as an update on September 21, 2011;

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.1. Are PowerStream's economic and business planning assumptions appropriate?

2. Appendix C - presentation entitled "2012 Budget Guidelines & Financial Outlook", given to PowerStream's Board of Directors on December 14, 2011 for approval; and
3. Appendix D - update to the 2013 budget with revisions to the capital budget, presented to the Board of Directors on April 25, 2012 for approval.

Note that the information related to PowerStream Solar and CDM, that are not included in the applied-for revenue requirement in this rate application, have been removed from these presentations.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.1. Are PowerStream's economic and business planning assumptions appropriate?

CCC INTERROGATORY #2:

Reference(s): (A3/T1/S1/p. 4)

Please provide all materials provided to PowerStream's Executive Management Team ("EMT") related to the following:

a) the 2013 rate application;

b) the detailed budgets for 2012 and 2013.

RESPONSE:

a) Presentations were made to PowerStream's Executive on March 4, 2011, January 31, 2012 and February 15, 2012. These materials are attached as Appendix E. On March 23, 2012 the Executive met to finalize the financial inputs to the rate application, prior to the April 25, 2012 Board of Directors meeting and subsequent filing.

b) Please see the attached Appendix F for the presentations given to the Executive Management Team regarding the 2012/2013 Budget.

- June 9, 2011, entitled 2012/2013 Preliminary Budget Guidelines;
- June 13, 2011, entitled 2012/2013 Budget Guidelines – Budget Kick-off;
- September 7, 2011, entitled 2012/2013 Preliminary Budget Guidelines;
- September 22, 2011, entitled 2012/2013 Budget Guidelines & Financial Outlook;
- October 13, 2011 entitled 2012/2013 Budget Guidelines & Financial Outlook;
- October 13, 2011 entitled Capital Budget; and
- October 20, 2011 entitled 2012 Budget Guidelines and Financial Outlook.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.1. Are PowerStream's economic and business planning assumptions appropriate?

CCC INTERROGATORY #3:

Reference(s): (A2/T1/S1/p. 1)

The evidence indicates that, subject to OEB approval, PowerStream will purchase a half interest in Collingwood Utility Services Corp., the holding company for Collus Power. Please explain why PowerStream is seeking approval to acquire a half interest in Collingwood Utility Services Corp. Please provide copies of all materials provided to the Board of Directors and the EMT related to the purchase of a half interest in Collingwood Utility Services Corp. How will the purchase impact the operations of PowerStream? Is the acquisition impacting the 2013 revenue requirement in any way? Please explain. What benefits will the acquisition provide to PowerStream's customers?

RESPONSE:

The above noted transaction was approved by the OEB in a Decision dated July 12, 2012 under docket number EB-2012-0056. The reference to this transaction in this rebasing application was not meant to be a request for approval as part of this rebasing application, but rather for disclosure.

It is not known at this time if the acquisition will have an impact on PowerStream's 2013 revenue requirement, pending discussion of the nature and content of a Service Level Agreement (SLA). It is anticipated that this SLA will take many months to prepare and may ultimately have a minimal financial impact on PowerStream given its size relative to Collus Power.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.1. Are PowerStream's economic and business planning assumptions appropriate?

CCC INTERROGATORY #4:

Reference(s): (A3/T1/S1/p. 3)

Please explain what activities are captured by the comment, "Pursue Business Growth Opportunities." Please indicate where in the 2013 revenue requirement the costs of these activities are set out.

RESPONSE:

Areas captured in "Pursue Business Growth Opportunities" in the core utility business include the areas of mergers and acquisitions, suite metering, and other activities permitted by the Green Energy Act. The costs for these initiatives are not tracked separately from the core business. The cost for all renewable generation (i.e., Solar) projects are tracked and kept separate.

Confidential
Item # 6(a) for Information

POWERSTREAM INC. BOARD OF DIRECTORS MEETING – SEPTEMBER 21, 2011

2013 RATE FILING

Report by the President & CEO, EVP & Chief Financial Officer and the VP, Rates & Regulatory Affairs

Recommendation

The President & CEO, EVP & Chief Financial Officer and the VP, Rates & Regulatory Affairs recommend that the Board of Directors receive this report for information purposes.

Report

The Ontario Energy Board's (OEB) rate making framework indicates that distributors must periodically undergo a full examination of costs (referred to as a cost of service review or rebasing). After rebasing, distributors are subject to incentive regulation for a period of three years until the next cost of service review. The next rebasing for PowerStream is in 2013 based on this schedule.

In the December 2008 OEB decision on the Barrie – PowerStream merger, PowerStream was allowed to postpone rebasing until 2014 to further recoup the costs of the merger. A number of factors have caused PowerStream's to rebase in 2013 rather than 2014:

- Forecast increases in operating expenses for additional staff needed in key areas and for operational requirements
- Increased capital spending required to replace aging infrastructure and for strategic information technology investments
- Rate base has increased by $100M since the last rebasing and PowerStream is not earning a return on these additions
- Updates to economic growth as measured by GDP continue to decline reflecting ongoing weakness in the economy

In the spring of 2012, staff will be submitting an application for rates effective January 1, 2013. The lead time is needed by the OEB for the rate review process. Note that in this application we will also seek to harmonize rates between Barrie and PowerStream.

Preparation of the rate application is an onerous task that engages most departments in PowerStream. Defending the application is also challenging and may lead to staff providing sworn testimony at the OEB.

Staff will provide a verbal update at the meeting.

Confidential
Item # 3(c) for Information

POWERSTREAM INC. BOARD OF DIRECTORS MEETING APRIL 25, 2012

COST OF SERVICE RATE APPLICATION

Report by the Chair of the Audit & Finance Committee, the President & CEO, the EVP & Chief Financial Officer and the VP, Rates & Regulatory Affairs

Recommendation

The Chair of the Audit & Finance Committee, the President & CEO, EVP & Chief Financial Officer and the VP, Rates & Regulatory Affairs recommend that the Board of Directors receive this report for information purposes.

Report

The Ontario Energy Board's (OEB) rate making framework indicates that distributors must periodically undergo a full examination of costs (referred to as a cost of service review or rebasing). After rebasing, distributors are subject to incentive regulation for a period of three years until the next cost of service review. The next rebasing for PowerStream is in 2013 based on this schedule.

Preparation of a cost of service rate application is a complex process that involves the participation of many departments. It is planned to file the application at the end of April or early May and seek updated rates for January 1, 2013. The application will have the following key elements:

- An increase in operating expenses for additional staff needed in key areas and for operational requirements
- Increased capital spending required to replace aging infrastructure and for strategic information technology investments
- Asset additions of approximately $150M since the last rebasing to start earning a return
- Harmonization of rates between the former Barrie Hydro and PowerStream, consistent with the agreements made at the time of the merger

Under the sponsorship of executive management, an approach has been taken whereby key senior staff is responsible for specific parts of the application. These staff prepared evidence to be filed in the application. In the OEB review process that follows the application, they will defend their evidence, which could include providing testimony at oral hearings.

Staff will provide more information in a verbal update at the meeting.

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 1
Schedule 1.1
Appendix B
11 Pages
Filed: August 31, 2012

POWERSTREAM INC.

2012/2013 Budget Guidelines & Financial Outlook

Core Business

Board of Directors Presentation

September 21, 2011

Table of Contents

Board Approved 2011 Budget and Financial Outlook – Core Business

	GAAP	GAAP	IFRS	IFRS	IFRS	IFRS	IFRS
Prelim Summarized Statement of Operations							
	Actual	**Budget**	**Budget**	**Outlook**	**Outlook**	**Outlook**	**Outlook**
	Core	**Core**	**Core**	**Core**	**Core**	**Core**	**Core**
(in Millions of Dollars)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2015**
Cost of Power	691.3	747.3	766.9	789.9	813.6	838.0	838.0
Distribution Revenue	155.8	165.7	167.4	175.7	183.1	187.8	187.8
Other Revenue	9.2	7.4	7.5	7.7	7.9	8.0	8.0
OM&A	58.0	64.5	77.4	79.7	81.8	83.5	83.5
Depreciation Expense	46.3	47.6	39.0	40.7	42.5	44.4	44.4
Interest Expense	21.9	24.5	25.5	25.8	26.4	26.5	26.5
EBT	38.9	36.5	33.1	37.3	40.3	41.5	41.5
Provision for Income Taxes	11.2	8.6	4.2	5.1	6.9	7.3	7.3
Net Income	**27.7**	**27.9**	**28.9**	**32.2**	**33.3**	**34.2**	**34.2**
Deemed ROE - Approved Rate Base	10.0%	9.8%	10.2%	9.4%	9.7%	10.0%	10.0%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	8.9%	9.7%	9.7%	9.8%	9.7%
Working Capital Ratio	0.8%	8.7%	10.4%	11.3%	12.4%	12.9%	12.9%
Net Capital	55.4	75.0	61.0	61.0	61.0	61.0	61.0
Statutory Tax Rate	31.0%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	711	711	856	856	856	856
Rate Base - Real Time	701	784	810	835	858	874	879

2012 Preliminary Budget – Significant Changes from Approved 2012 Outlook

External Factors:

- Distribution Revenue pressure: ($3.8M) due to a lower GDP that underpinned the forecast; CDM impacts and slower than expected customer growth
- Smart Meter: ($1.3M) due to lower costs and hence lower revenue requirement
- IFRS: ($2.0M) due to asset de-recognition offset by reclassification of Contributed Capital & Damage claim

Internal Factors:

- Cost pressure: ($5.0M)
- Depreciation: decreased $2.5M due to assets being reclassified to longer useful life
- Interest expense: decreased $1.5M due to lower interest rates and debt refinancing in Aug 2012

Taxes

- Income Taxes decreased $3.2M (lower EBT & higher CCA deduction primarily related to CIS)

Key Assumptions

	CGAAP **2011** Budget	CGAAP **2011** Projection	MIFRS **2012** Budget	MIFRS **2013** Outlook
Wage Increase	3.0%	3.0%	3.0%	3.0%
Customer Growth	2.3%	2.0%	2.2%	2.2%
Distribution Rev Growth (Rev from Rates)	2.4%	1.0%	2.3%	2.4%
Interest Rate – Long Term	6.0%	6.0%	5.0%	5.0%
Interest Rate – Short Term	4.0%	3.0%	3.0%	3.5%
Deemed Equity/Rate Base	40%	40%	40%	40%
Tax Rate (statutory)	28.25%	28.25%	26.25%	25.50%

2012/2013 OM&A Budget Guidelines – Key Assumptions

- Assume Rate filing in 2013 for rates effective on Jan 1, 2013
- Bottom Build budget will be used to build the 2012 budget and 2013 Revenue Requirement
- Modified IFRS adopted for 2012 Budget and 2013-2016 Outlook
- 2011 year to date forecast used as a starting point, calendarized to reflect increase in rates effective May 1 for 2012
- Budget guidelines were developed based on:
  - 3.0% increase for 60% of OM&A (payroll related)
  - 2% inflationary increase for 40% (Other Expenses)
  - Debt refinancing plan in 2012
  - Preliminary Capex 5 yr business plan including IS strategy

2012/2013 Budget Guidelines – Key Assumptions

Rates Application : The story we'll have to tell:

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

- In preparation for the Rate filling, the bottom-up build budget has to be solid and firm for both 2012 and 2013
- Keep discretional spend flat. Any incremental increase in OM&A and Capital spend, needs to be identified separately and justified diligently
- Take into account historical spending trend when building the 2012/2013 detailed budget

Preliminary 2012 Budget & 5 Year Outlook – Core Business

	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Prelim Summarized Statement of Operations									
(in Millions of Dollars)	**Actual Core 2010**	**Budget Core 2011**	**Q3 Frcst Core 2011**	**Mock Core 2011**	**Budget Core 2012**	**Outlook Core 2013**	**Outlook Core 2014**	**Outlook Core 2015**	**Outlook Core 2016**
Cost of Power	691.3	747.3	747.3	747.3	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	155.8	165.7	162.1	162.1	160.3	179.2	184.6	190.1	195.8
Other Revenue	9.2	7.4	7.9	10.2	9.6	10.4	11.1	11.8	12.6
OM&A	58.0	64.5	63.4	79.7	86.2	88.0	91.2	93.9	96.3
Depreciation Expense	46.3	47.6	46.4	36.0	36.0	40.6	44.0	47.3	51.5
Interest Expense	21.9	24.5	23.7	24.0	24.8	25.8	27.7	29.2	31.0
Budget Gap					-1.8		-4.5	-6.5	-8.5
EBT	38.9	36.5	36.5	32.7	24.6	35.2	37.3	38.0	38.1
Provision for Income Taxes	11.2	8.6	8.6	4.0	1.0	2.9	5.0	5.9	6.0
Net Income	**27.7**	**27.9**	**27.9**	**28.7**	**23.6**	**32.3**	**32.3**	**32.1**	**32.1**
Deemed ROE - Approved Rate Base	9.9%	9.4%	8.9%	9.7%	8.0%	9.4%	9.4%	9.4%	9.4%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.0%	9.3%	*8.0%	9.4%	8.9%	8.4%	8.0%
Working Capital Ratio	0.8%	8.7%	0.4%	0.4%	4.2%	5.4%	5.6%	5.8%	6.3%
Net Capital	55.4	75.0	68.8	68.8	76.7	99.9	83.1	100.7	94.3
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	741	741	741	741	856	856	856	856
Rate Base - Real Time	701	784	771	771	814	857	906	953	1,000

***Note: To achieve 8.0% ROE on real time Rate Base, the Budget Gap in 2012 would be $4.9M**

2012 Preliminary Budget Guidelines - Process Summary

- June /September – Development of detailed departmental budgets
- September – Preliminary budget guidelines submit to AFC & Board of Directors
- Oct/Nov – Detailed budget review by EOC/EMT and preparation for final budget submission
- December – AFC & Board of Directors to approve Final 2012 Budget

Risks

- Prolonged weak economy and customer growth not achieved at 2.3%
- Budgeted distribution revenue based on stable weather pattern; risk of warmer winter and cooler summer
- Potential of rate freeze
- Additional regulatory requirements imposed on LDC's
- Interest rate risks
- Energy conservation pressure on distribution revenue
- 2011 Smart meter rate filing
- Impact of implementing IFRS

Conclusion

- In spite a result of continued weakening economy and continued cost pressure, targeting to achieve the current PS deemed regulated rate of return of 8.0% on our approved rate base
- The corporation will continue to examine process improvements and opportunities for reductions in OM&A across the organization
- Expected growth and diversified customer base will allow us to achieve beyond target as the economy recovers

POWERSTREAM INC.

2012 Budget Guidelines & Financial Outlook

Board of Directors Presentation

Private & Confidential

December 14, 2011

Table of Contents

2012 Preliminary Budget Guidelines - Process Summary

- June /September – Development of detailed departmental budgets
- September – Preliminary budget guidelines submitted to AFC & Board of Directors
- Oct/Nov – Detailed budget review by EOC/EMT and preparation for final budget submission
- December – AFC & Board of Directors asked to approve Final 2012 Budget

2012/2013 OM&A Budget Guidelines – Key Assumptions

- Assume Rate filing in 2013 for rates effective on Jan 1, 2013

- Bottom Build budget will be used to build the 2012 budget and 2013 Revenue Requirement

- Modified IFRS adopted for 2012 Budget and 2013-2016 Outlook

- 2011 year to date forecast used as a starting point, calendarized to reflect increase in rates effective May 1, 2012

- Budget guidelines were developed based on:
    - 3.0% increase for 60% of OM&A (payroll related)
    - 2% inflationary increase for 40% (other expenses)
    - Debt refinancing plan in 2012
    - Preliminary Capex 5 yr business plan including IS strategy

2012/2013 Budget Guidelines – Key Assumptions

Rates Application : The story we'll have to tell:

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

- In preparation for the Rate filling, the bottom-up build budget has to be solid and firm for both 2012 and 2013
- Keep discretional spend flat. Any incremental increase in OM&A and Capital spend, needs to be identified separately and justified diligently
- Take into account historical spending trend when building the 2012/2013 detailed budget

Key Assumptions

	CGAAP **2011** Budget	CGAAP **2011** Projection	MIFRS **2012** Budget	MIFRS **2013** Outlook
Wage Increase	3.0%	3.0%	3.0%	3.0%
Customer Growth	2.3%	2.0%	2.5%	2.2%
Distribution Rev Growth	2.4%	1.6%	0.8%*	Rebase
Interest Rate – Long Term	6.0%	6.0%	5.0%	5.0%
Interest Rate – Short Term	4.0%	3.0%	3.0%	3.5%
Deemed Equity/Rate Base	40%	40%	40%	40%
Tax Rate (statutory)	28.25%	28.25%	26.25%	25.50%

* Previously 2.3% in the September A&FC presentation

Preliminary 2012 Budget & 5 Year Outlook – Core Business - Sep. 14th' 2011 AFC

	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Prelim Summarized Statement of Operations									
(in Millions of Dollars)	**Actual Core 2010**	**Budget Core 2011**	**Q3 Frcst Core 2011**	**Mock Core 2011**	**Budget Core 2012**	**Outlook Core 2013**	**Outlook Core 2014**	**Outlook Core 2015**	**Outlook Core 2016**
Cost of Power	691.3	747.3	747.3	747.3	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	155.8	165.7	162.1	162.1	160.3	179.2	184.6	190.1	195.8
Other Revenue	9.2	7.4	7.9	10.2	9.6	10.4	11.1	11.8	12.6
OM&A	58.0	64.5	63.4	79.7	86.2	88.0	91.2	93.9	96.3
Depreciation Expense	46.3	47.6	46.4	36.0	36.0	40.6	44.0	47.3	51.5
Interest Expense	21.9	24.5	23.7	24.0	24.8	25.8	27.7	29.2	31.0
Budget Gap					-1.8		-4.5	-6.5	-8.5
EBT	38.9	36.5	36.5	32.7	24.6	35.2	37.3	38.0	38.1
Provision for Income Taxes	11.2	8.6	8.6	4.0	1.0	2.9	5.0	5.9	6.0
Net Income	**27.7**	**27.9**	**27.9**	**28.7**	**23.6**	**32.3**	**32.3**	**32.1**	**32.1**
Deemed ROE - Approved Rate Base	9.9%	9.4%	8.9%	9.7%	8.0%	9.4%	9.4%	9.4%	9.4%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.0%	9.3%	*8.0%	9.4%	8.9%	8.4%	8.0%
Working Capital Ratio	0.8%	8.7%	0.4%	0.4%	4.2%	5.4%	5.6%	5.8%	6.3%
Net Capital	55.4	75.0	68.8	68.8	76.7	99.9	83.1	100.7	94.3
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	741	741	741	741	856	856	856	856
Rate Base - Real Time	701	784	771	771	814	857	906	953	1,000

***Note: To achieve 8.0% ROE on real time Rate Base, the Budget Gap in 2012 would be $4.9M**

Power Stream YOUR CURRENT CONNECTION

2012 Preliminary Budget – Changes Affecting Net Income from Preliminary Budget presented to AFC Sep14'11

External Factors:

- Distribution Revenue pressure: ($1.0M) primarily due to a lower GDP that underpinned the forecast
- IFRS in Other Revenue: +$1.3M due to finalization of IFRS treatment

Internal Factors:

- OM&A cost cut by $1.4M as a result of detailed review of the executive team
- Depreciation: decreased $3.4M due to finalizing IFRS treatment of fixed asset useful life and de-recognition
- Interest expense: decreased $0.6M due to lower interest rates forecast

Taxes

- Income Taxes increased $1.5M due to higher earnings before taxes

2012/2013 Preliminary Budget – Where we are now

	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Prelim Summarized Statement of Operations									
	Actual	**Budget**	**Oct Frcst**	**Oct Mock**	**Budget**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
	Core	**Core**	**Core**	**Core**	**Core**	**Core**	**Core**	**Core**	**Core**
(in Millions of Dollars)	**2010**	**2011**	**2011**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Cost of Power	691.3	747.3	771.7	771.7	774.4	822.8	847.5	872.9	899.1
Distribution Revenue	155.8	165.7	161.8	161.8	159.3	170.7	175.8	181.1	186.5
Other Revenue	9.2	7.4	8.1	12.7	10.9	11.3	11.4	11.6	11.8
OM&A	58.0	64.5	63.5	80.1	84.8	89.0	91.7	94.4	97.3
Depreciation Expense	46.3	47.6	45.7	35.3	32.6	34.7	37.2	40.3	44.4
Interest Expense	21.9	24.5	23.5	23.9	24.2	25.0	27.3	29.9	32.8
EBT	38.9	36.5	37.2	35.2	28.6	33.2	31.0	28.0	23.9
Provision for Income Taxes	11.2	8.6	8.2	4.4	2.5	0.7	0.1	1.3	0.3
Budget Gap - Net Income *							-3.6	-10.0	-15.8
Net Income	**27.7**	**27.9**	**29.0**	**30.8**	**26.1**	**32.5**	**34.5**	**36.7**	**39.4**
Deemed ROE - Approved Rate Base *	10.0%	9.8%	10.2%	10.8%	9.2%	9.4%	10.0%	10.7%	11.4%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.4%	9.9%	8.0%	9.4%	9.4%	9.4%	9.4%
Net Capital	55.4	69.7	63.2	51.7	76.7	94.7	94.4	113.4	106.3
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	711	711	711	711	862	862	862	862
Rate Base - Real Time	701	784	772	774	815	862	915	979	1,047

Power Stream
YOUR CURRENT CONNECTION

* Note: Excludes the impact of potential annual rebasing on capital

Sponsorship & Donations - in 2012 OM&A

	Recoverable	Non-rcvr'ble*	Total
Sponsorships	52,000	273,000	325,000
Donations	200,000	210,000	410,000
	252,000	**483,000**	**735,000**

*Georgian College $150K included as non recoverable only for 2012

2010 Comparators

(CGAAP)	2010 PwrS'm	2010 Ottawa	2010 Enrsr'e	2010 Horizon	2010 Toronto
OM&A/Customer ($)	172.0	183.7	242.6	165.2	300.0
OM&A/MW.h ($/MW.h)	6.7	7.3	6.1	6.8	8.5
CapEx / Customer ($)	286.0	297.6	259.1	165.5	601.4
CapEx % of Total Assets	10.1%	12.7%	7.9%	8.6%	14.8%
# of Customers/ Employee	614	537	482	598	423

2012 Capital Budget - Capital Process

Two Years – Projects for 2012 and 2013

Owner identifies project need

- **Identified through full or mini business case and Optimizer questions answered**

Business Case Approval Received

PMO Project Review

Capital Projects Scored and Optimized

- **ALL PROJECTS Using Optimizer**
- **Projects scored on Value, Risk Consequence and Risk Probability against 12 Success Criteria**

Capital Portfolio Approved by EOC/EMT

PowerStream YOUR CURRENT CONNECTION

2012 Capital Budget - Our Asset Investment Strategy

To effectively define the portfolio of investments, to achieve the company's strategic value expectations, within defined risk tolerance boundaries

This includes:

Making effective, short-term (one-year) and long-term (2-5 years) investment decisions, to maximize the value of the assets to the company

Developing and implementing disciplined policies, processes, and standards for maintaining the assets of the company

Defining the risk tolerance boundaries of the company

2012 Capital Budget - Non Controllable & Controllable Capital

Non-Controllable Capital

- Capital initiatives that are typically driven by needs of parties other than PowerStream.

Controllable Capital

- Capital initiatives that are initiated by PowerStream, as a result of corporate objectives, and needs to enhance system reliability, capacity, operational efficiency, operational effectiveness and health and safety.

2012 & 2013 Capital Budget

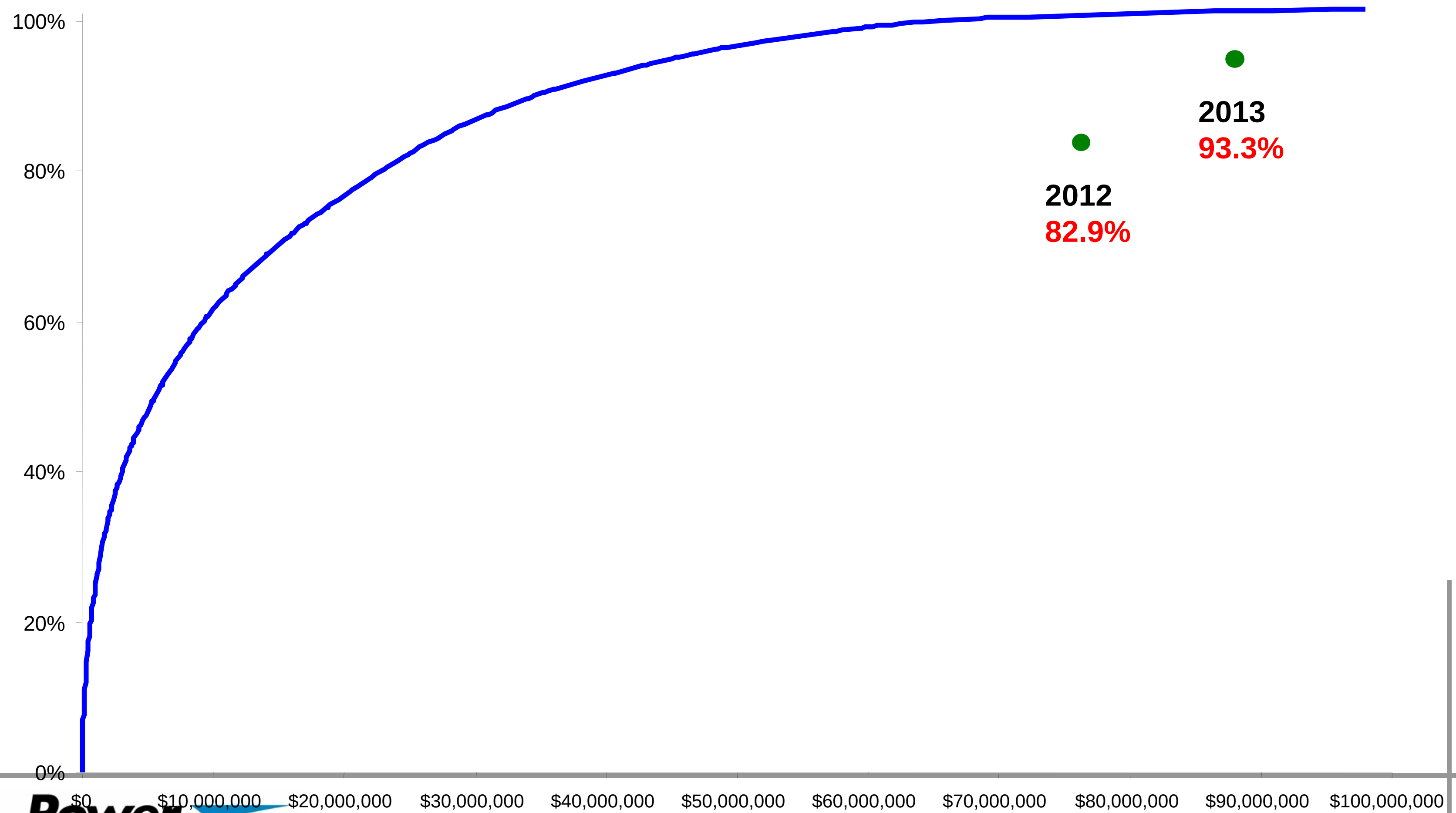
	2012	2013
SUSTAINMENT CAPITAL (Sustain our system)		
Non-Controllable	$ 12.7M	$11.6M
Controllable	7.3M	34.6M
DEVELOPMENT CAPITAL (Support our growth)		
Non-Controllable	$17.6M	$19.2M
Controllable	3.4M	11.3M
OPERATIONS CAPITAL (All Other)		
Non-Controllable	$2.6M	$1.8M
Controllable	23.1M	16.2M
TOTAL CAPITAL	**$76.7M**	$94.7M

- Optimizer Team: R. Antennuci – Director Supply Chain Services; S. Cunningham – SVP Engineering Services; T D'Onofrio – Capital Budget Supervisor; L. Gautier – Director Organizational Effectiveness; M. Henderson – EVP Asset Management & COO; M. Matthews – SVP Operations & Construction; J. McClean – Director Operations; J. Mulrooney – Director Smart Grid; D. Petrucci – Manager Rates & Revenue; B. Schmidt – VP Information Services; T. Wojcinski – VP Engineering Planning

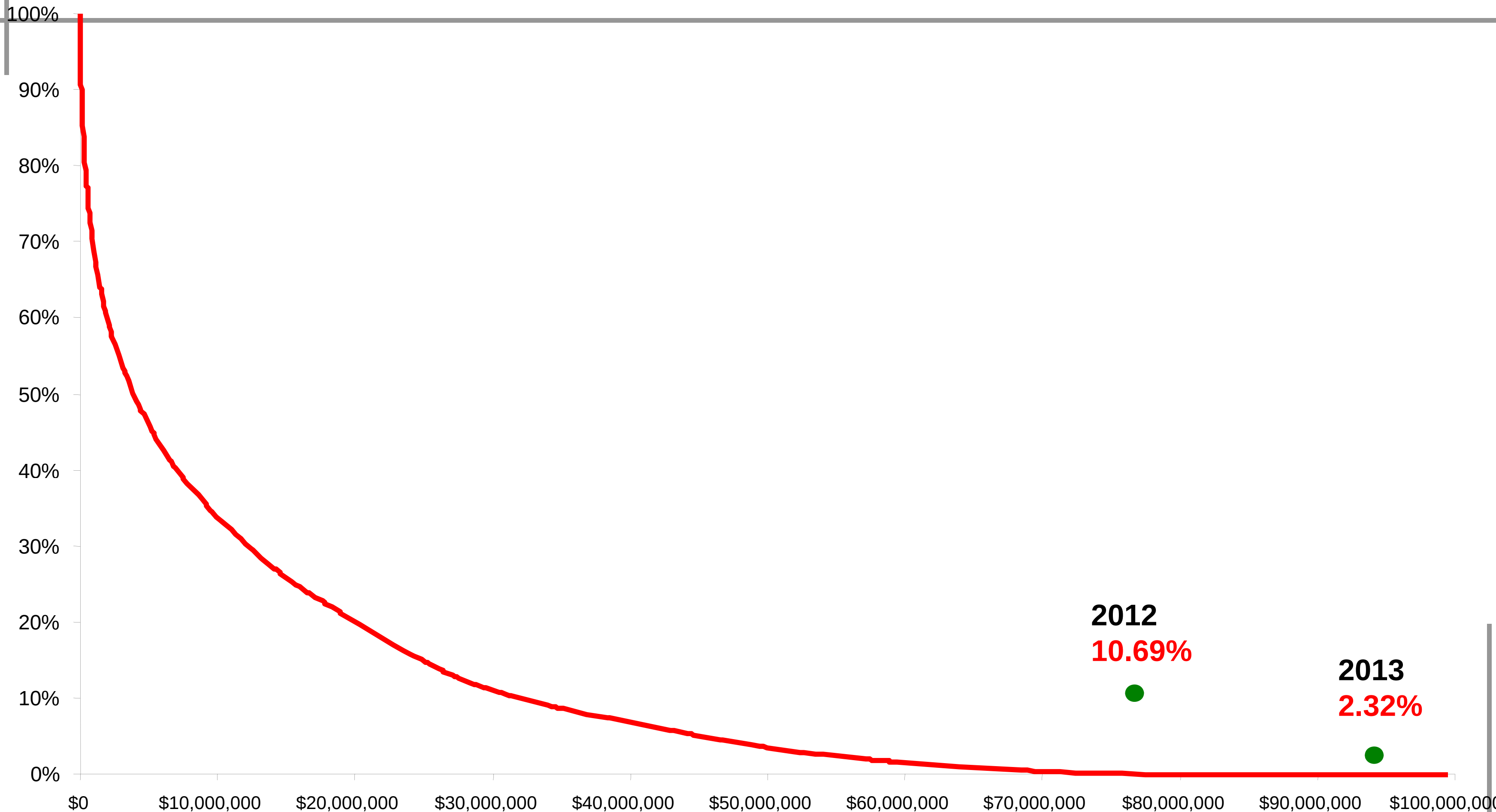
2012 Capital Budget - Strategic Objectives and Success Criteria Weightings

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 %
		SQI	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%

2012 Capital Budget – Efficient Frontier - Value



2012 Capital Budget - Efficient Frontier - Risk



Power Stream
YOUR CURRENT CONNECTION

2012 & 2013 Capital Budget Compared to 2011

	2011 Budget (CGAP)	2011 Budget (IFRS)	2012 Budget (IFRS)	2013 Budget (IFRS)
SUSTAINMENT CAPITAL				
Non-Controllable	$10.4 M	$9.6 M	$12.7 M	$11.6 M
Controllable	$22.4 M	$17.2 M	$17.3 M	$34.6 M
DEVELOPMENT CAPITAL				
Non-Controllable	$17.3 M	$15.0 M	$17.6 M	$19.2 M
Controllable	$5.8 M	$3.6 M	$3.4 M	$11.3 M
OPERATIONS CAPITAL				
Non-Controllable	$1.5 M	$1.5 M	$2.6 M	$1.8 M
Controllable	$12.3 M	$12.0 M	$23.1 M	$16.2 M
TOTAL CAPITAL	$ 69.7 M**	$58.9 M	$76.7 M	$94.7 M

**Note: The 2011 Capital Budget Approved by the Board is $75 M. $1.65 M for Smart Meters was reallocated to Deferral Account. The remaining $3.6 M can be attributed to a difference in allocation of burdens which was presented as preliminary at budget time.

Changes 2012 Capital Budget Compared to 2011

- Sustainable Capital
  - Delta Transformer Replacement + $0.4 M (Non-Controllable)
  - Increase Pole replacements + $1.5 M (Controllable)
  - Installation of Fault Indicators + $0.5 M (Controllable)
  - Reduction Cable Replacements - $1.5 M (Controllable)
- Developmental Capital
  - U/G Subdivisions/Services Increase + $2.7 M (Non-Controllable)
  - Increase Road Authority + $1.4 M (Non-Controllable)
- Operations Capital
  - New CIS system + $12.9 M (Controllable)
  - Increase Vehicle Replacements + $0.8 M (Controllable)

**** Note: comparison made 2012 (IFRS) to 2011 (IFRS)**

Changes 2013 Capital Budget Compared to 2012

- Sustainable Capital
  - Increase in Cable Rehabilitation (Injection & Replacement) + 13.8 M (Controllable)
  - Increase Pole replacements + $1.2M (Controllable)
  - Increase Sustainment Transformer/Municipal Station Projects + $1.6 M (Controllable)
- Developmental Capital
  - Increase Subdivisions +1.8 M (Non-Controllable)
  - Construction of New Municipal Station in Barrie + $3.8 M (Controllable)
  - Purchase Property for New Vaughan TS + $2.0 M (Controllable)
  - New 44 kV Feeder from Midhurst TS + $2.5 M (Controllable)
- Operations Capital
  - New CIS system - $5.3 M (Controllable)
  - Reduction in IT related projects - $2.5 M (Controllable)
  - Reduction in Building Related Projects - $ 1.0 M (Controllable)
  - Increase Vehicle Replacements + $0.9 M (Controllable)

Work in Progress

Hwy 7, Leslie to East Beaver for YRRT

Hwy 7 at Rodick Rd
Markham TS #4 Feeders

Work in Progress

Pole Installation by Crane
Hwy 7 West of Leslie for YRRT

Markham TS #4 Feeders

Cash Flow & Ratios – Core Business

(in millions of dollars)	Actual 2010	Forecast 2011	Budget 2012	Forecast 2013	Forecast* 2014	Forecast* 2015	Forecast* 2016	Rqr'd
Cash from Operation:								
Funds from Operations	80.1	77.3	61.0	69.0	70.2	69.2	70.3	
Change in reg liabilities	(21.9)	5.2	4.9	(2.6)	(5.3)	(1.6)	0.6	
Change in working cap	(13.8)	(13.4)	(12.4)	(8.0)	(2.2)	(2.3)	(2.4)	
Cash from Financing:								
New Borrowing	-	-	**35.0**	**45.0**	**50.0**	**60.0**	**50.0**	
Refinance existing loans			15.0					
Dividends	(10.5)	(13.9)	(14.5)	(13.0)	(16.3)	(15.5)	(13.4)	
Cash from Investing:								
Capital Expenditure	(70.3)	(63.2)	(76.7)	(94.7)	(94.4)	(113.4)	(106.3)	
Total Change of Cash:	**(36.4)**	**(8.1)**	**12.3**	**(4.4)**	**2.0**	**(3.7)**	**(1.1)**	
Cash beginning balance:	**42.6**	**6.2**	**(1.9)**	**10.4**	**6.0**	**8.0**	**4.3**	
Cash ending balance:	**6.2**	**(1.9)**	**10.4**	**6.0**	**8.0**	**4.3**	**3.2**	
S&P debt/equity ratio	60.5%	59.3%	60.3%	61.1%	62.4%	64.0%	65.2%	60.0%
Debt to rate base	58.7%	53.7%	55.2%	57.4%	59.5%	61.7%	62.4%	60.0%
WC/(COP + OMA)	**2.5%**	**1.1%**	**4.0%**	**4.1%**	**4.5%**	**4.2%**	**4.2%**	15.0%
Short term %	**5.6%**	**5.5%**	**3.2%**	**3.0%**	**2.8%**	**2.6%**	**2.4%**	4.0%

* Note: Excludes the impact of potential annual rebasing on capital

PowerStream
YOUR CURRENT CONNECTION

Risks - Core

- Prolonged weak economy and customer growth not achieved
- Budgeted distribution revenue based on stable weather pattern; risk of warmer winter and cooler summer
- Additional regulatory requirements imposed on LDC's
- Interest rate risks
- Energy conservation pressure on distribution revenue
- Impact of implementing IFRS
- Cash flow constraint for future capital funding requirement
- Outcome of 2013 rate basing & OEB review of regulatory regime

Conclusion

- In spite a result of continued weakening economy and continued operating & capital cost pressures, targeting to achieve the current PS deemed regulated rate of return of 9.2% on our approved rate base and 8.0% on real time rate base

- The corporation will continue to examine process improvements and opportunities for operational efficiency across the organization

- Expected growth and diversified customer base should allow us to achieve beyond target as the economy recovers

Confidential
Item #3(d) for Approval

POWERSTREAM INC. BOARD OF DIRECTORS MEETING – APRIL 25, 2012

2013 OUTLOOK REVISION

Report by the Chair of the Audit & Finance Committee, the President & CEO, the EVP & Chief Financial Officer and the VP Finance

Recommendation

The Chair of the Audit & Finance Committee, the President & CEO, the EVP & Chief Financial Officer and the VP, Finance recommend that the Board of Directors approve the updated 2013 Outlook to be included in the 2013 Cost of Service Application. This report was presented at the Audit & Finance Committee on April 11, 2012.

Background

Although the timing for this request for approval is not consistent with PowerStream's normal forecast/budget process, in order to support its 2013 Cost of Service Application PowerStream is recommending changes to its approved 2013 Outlook. The recommended changes are for specific capital budget items. The focus of the update is related to three material adjustments regarding changes in capital budget assumptions for the new Customer Information System (CIS) cost and its targeted implementation date and an increase in Road Authority project costs.

The 2013 estimated costs for the new CIS have been revised upward by approximately $11.4M from the approved Outlook amounts of $5.2M. The overall increase in CIS project costs is mainly attributable to an increase from budget for the System Integrator costs. Request for Proposal (RFP) submissions were received in late February. It became evident that the cost per customer used to estimate the System Integrator costs in the initial budget were too low compared to the proposed pricing of the proponents. In addition, clarity resulting from the RFP submission regarding staffing resources required for CIS implementation caused a further refinement related to internal labour and resource costs. A detailed report on the CIS is provided in Section 7b).

Also, additional capital costs arising from overhead to underground plant relocation ($3.0M) and the progression of the York Region Rapid Transit project ($4.2M), have increased the capital outlook spend by $7.2M. These three material changes in the capital outlook assumptions and the related adjustment required for interest capitalization have increased the capital outlook by $19.6M ($18.6M capital increases + $1.0M interest capitalization) for a total 2013 capital spend of $114.3M.

The OEB has adjusted the allowable ROE to 9.12% for May 1, 2012 rebasing as part of its cost of capital update. This is down from the ROE of 9.42%, which was applicable for January 1, 2012 rates. It is assumed that there will be further updates to the OEB allowable ROE as we progress through our cost of service application process.

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 1
Schedule 1.1
Appendix E
36 Pages
Filed: August 31, 2012

2013 Rate Application

Approach & Key Deliverables

Colin Macdonald
VP, Rates & Regulatory Affairs
March, 2011

Go Green with PowerStream

2013 Rate Application – Why are we working on it now?

Power Stream
YOUR CURRENT CONNECTION

- **Successful Rate Application is a key in achieving revenue and net income targets**

- Must be prepared to file by March 31, 2012, for rates effective January 1st, 2013; the OEB needs 280 days to review/process the application

- The OEB has continued to issue new filing requirements and has "raised the bar" significantly:
  - More detailed variance analysis
  - Asset management plan
  - Capital budgets 2 years beyond test year (i.e. 2014/2015)
  - More details on compensation

- Starting now allows us to compile the parts of the evidence that are subject to little change and to analyse historic data

Go Green with PowerStream

2013 Rate Application - Unique challenges

- Merger and related data collection/ analysis
- Rate harmonization
- IFRS implementation/ timing of the accounting changes
- Change to January as an effective date (vs. May)
- Tracking back to last approved application (6 years of data)
- Barrie historical information
- New/pending regulatory changes

The story we'll have to tell:

	2008 Approved	2008 Actual	2009 Approved	2009 Actual	2010 Actual	2011 Actual	2011 Actual	2012 Budget	2013 Forecast
	Canadian GAAP						*IFRS*		
PowerStream South									
PowerStream North									
PowerStream Combined									

Approach – Ownership/Witnesses

- Want to identify rate application content owners/potential witnesses <u>now</u>.

- Witnesses experience three main phases:
  - Application/evidence preparation (2011/2012)
  - Interrogatory responses (2012)
  - Testimony as a witness before the OEB (2012)

- Witnesses will necessarily need to form their own small teams in order to fulfill the above tasks

- Other work and vacations will have to priortized/planned at certain times – we are often at the mercy of the schedule imposed by the OEB

Witnesses Support

- Witnesses will get support early in the process – coaching from experts

- Legal support will be selected through an RFP process

- Specific witness training will be provided – what to expect, how to behave, how to testify

- *This is like preparing and studying for the most difficult school exam that you can imagine*

Go Green with PowerStream

Key Witnesses

Witnesses "own" a section of the application, prepare responses to interrogatories and provide testimony as needed:

- Colin - overall Application, continuity, "quarterback"
- Shelly – capital budgets, asset management process, GEA Plan
- Lucy – OM&A budget process , administration budget, financing, taxes, depreciation, IFRS, burden policies
- Barb – merger savings, compensation & benefits
- Mike – operations and maintenances practices and budgets

Go Green with PowerStream

Witness Strategy- SME's

We will also need Subject Matter Experts to prepare sections of the application, prepare responses to interrogatories and provide testimony as needed as witnesses:

- Bill – IS strategy and projects
- Ed B – customer service, joint services
- Dianne – load forecast and CDM
- Tom – regulatory assets and liabilities, cost allocation, rate harmonization, rate design
- John M – Smart Grid Strategy
- Ted – Distribution System Plan (re:GEA)

These staff would be part of the witness teams identified earlier

What do Witnesses and Their Teams Do?

- Provide historic actual and budget /planning data
- Provide background information (policies, business cases, etc.)
- Provide analysis and explanation of changes/ trends
- Coordination with budget/planning process:
  - Time
  - Resources
  - Data changes
- Ownership of the relevant section of the Application:
  - Write up or assistance with write up
  - Prepare to be witness before OEB

<u>Examples:</u>

- Capital spending – write up by Engineering Services team
- Operating and Maintenance – write up by Operations & Construction team
- Administrative Expenses – write up by Finance team
- Compensation & Benefits – write up by HR team

A Note on Budgets

- The 2013 operating and capital budgets are as important as the 2012 budgets!
- The 2013 budgets underpin the rate application

2013 Rate Application - Sections

A. Overview

B. Rate Base (capital, working capital allowance)

C. Revenue (load forecast, other revenue)

D. OM&A Costs (includes depreciation, compensation & benefits, PILS)

E. Deferral & Variance Accounts

F. Cost of Capital and Rate of Return

G. Revenue Deficiency

H. Cost Allocation (revenue to cost ratios)

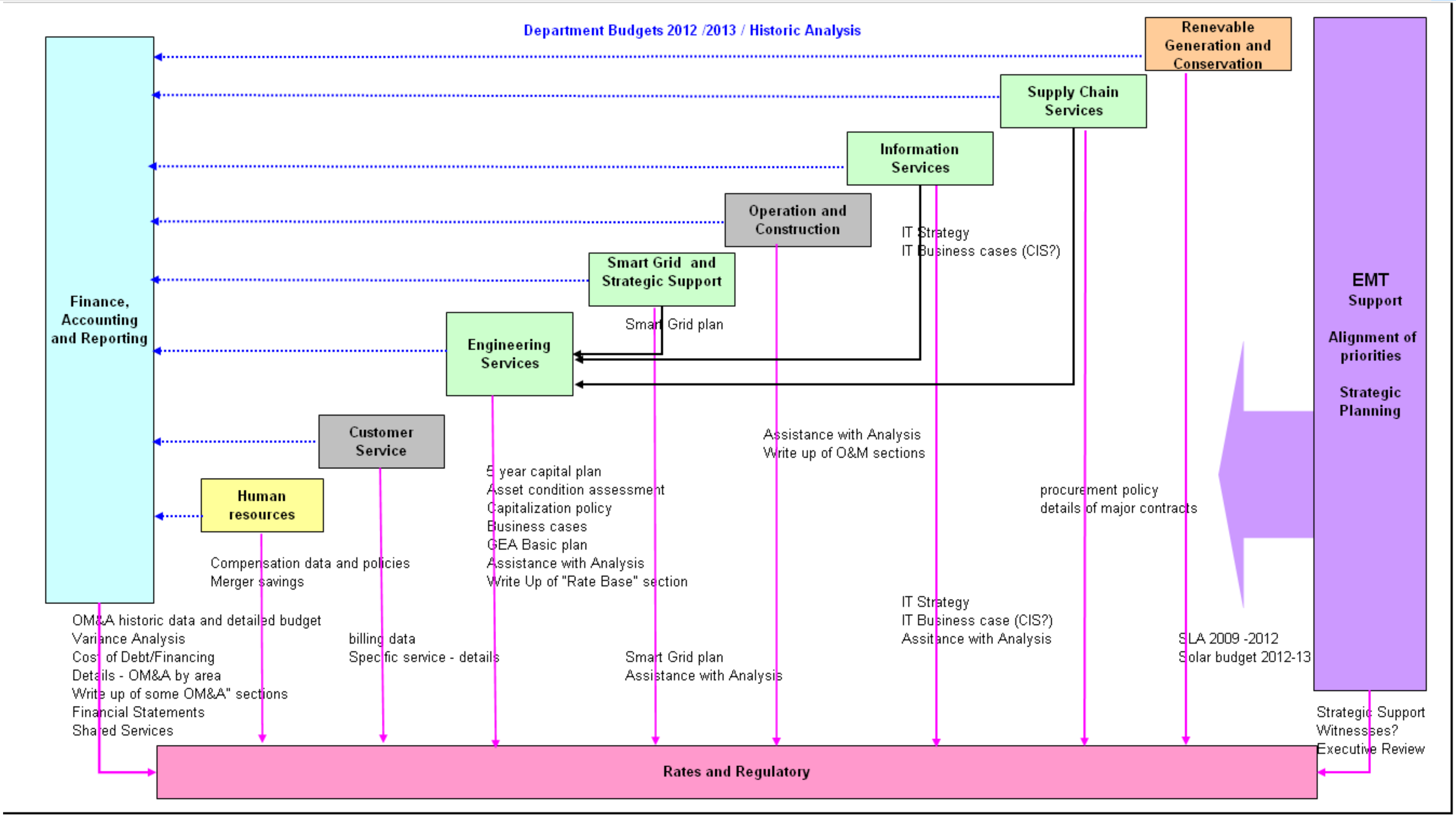
I. Rate Design

Accountabilities

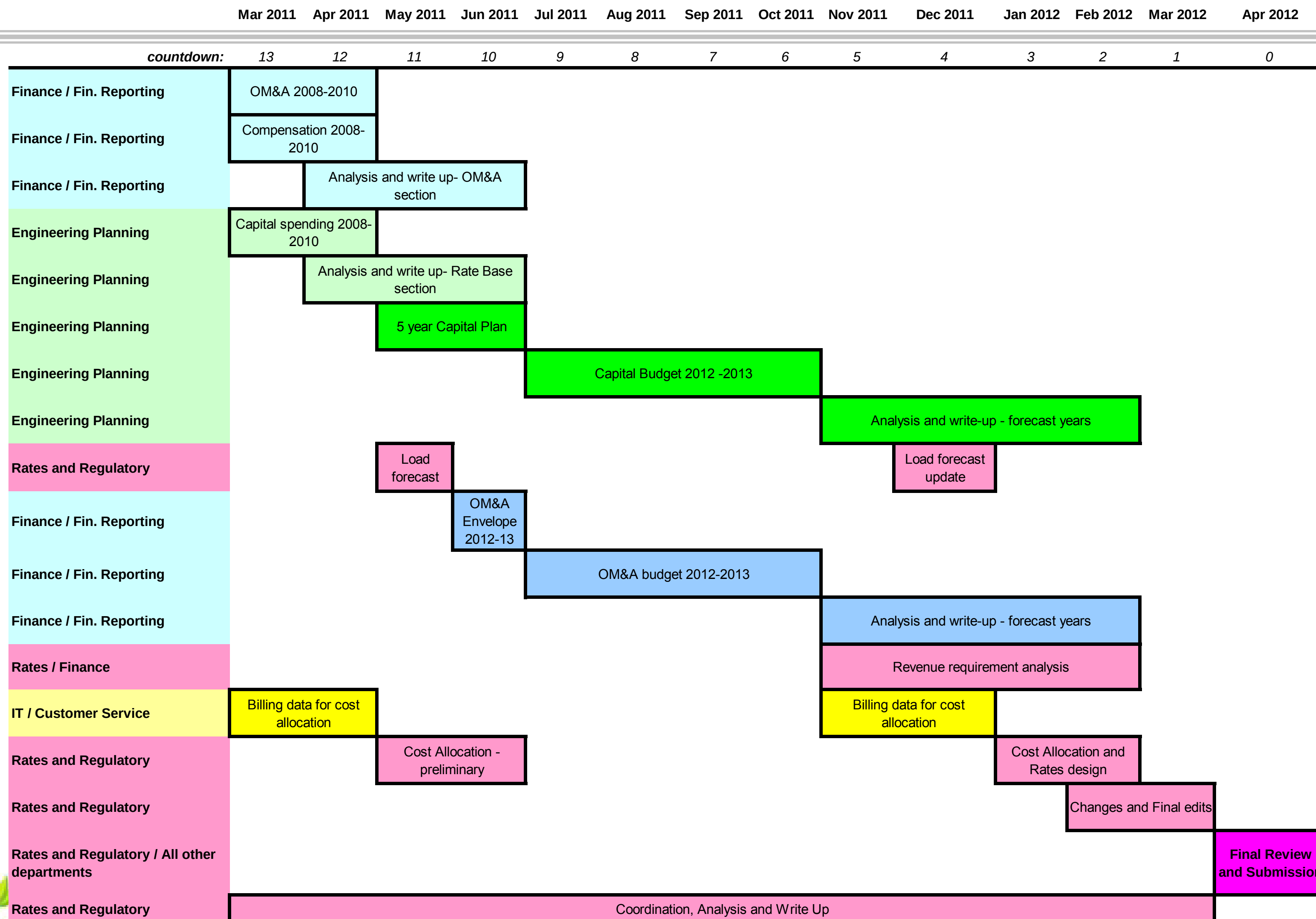
Income Statement	*$M*	
Revenue Requirement	153	Dianne –load forecast, Colin – revenue at current rates, revenue deficiency
Other Revenue	7	Lucy – interest amounts, Ed B – customer service charges, Dianne - CDM
Operating Expenses	(62)	Lucy – budget process, admin budget, IFRS impact, burden policies, Mike – O&M practices and budgets, Barb – headcount and compensation, merger savings, Ed B – cust service, joint services
Depreciation	(45)	Lucy – depreciation amounts and policies, IFRS impact; Shelly – asset management approach and capital budgets, GEA Plan, Bill – IS strategy and projects
Interest Expense	(22)	Lucy – debt approach and amounts
PILs	(11)	Lucy – tax calculations
Net income	15	Colin – allowed return

Note: Colin – Solar business separation

2013 Rate Application – Information flow



2013 Rate Application – High Level Timeline



2013 Cost of Service
Rate Application

Update for EMT-SLT-SMT

NOT FOR DISTRIBUTION

Colin Macdonald
VP, Rates & Regulatory Affairs
January 31, 2012

Topics

- Recent Happenings
- Some Numbers
- Where are We?
- Themes
- Next Steps

Ratemaking Framework Revisited

- The OEB conducts regular very detailed reviews of distributors’ costs and establishes the required revenue and “just and reasonable rates”. This process is referred to as a *cost of service* review or *rebasing*.

- After rebasing, distributors’ rates are adjusted by a formula for the following 3 years. This is called incentive regulation.

- Barrie Hydro rebased in 2008. PowerStream rebased in 2009. (We continue to have 2 “rate zones” until rates are harmonized between Barrie and PowerStream.)

- *PowerStream is applying in 2012 to rebase rates in 2013. Rates will also be harmonized.*

Recent Happenings

Toronto Hydro:

- Rebased in 2011 and then applied to rebase again in 2012. The OEB held a hearing on this request and said “no”. Criticized TH for not making necessary productivity improvements.
- Toronto Hydro did not meet the test to rebase early
- Concerns about IRM not providing sufficient revenue to support capital requirements were valid – PowerStream will face same situation
- Toronto Hydro fought issue in media before and after decision – has not sat well with OEB and many in the industry

Hydro Ottawa:

- Rebasing for 2012 went fairly well. Major issues went to an oral hearing.
- Compensation levels criticized in OEB decsion. OM&A cut by about 5%

Some Numbers

- In our application, two calculations of revenue requirement are compared:
  - Apply current rates to a forecast (by customer class) of 2013 consumption. (Called *revenue at current rates*.) Preliminary estimate is $160M
  - A calculation of revenue requirement based on a 2013 "budget build". (net income + PILs + interest + deprecation + OM&A = revenue requirement.) Preliminary estimate is $176M
- Revenue deficiency is $16M or about 10% (2% on total bill)

Drivers for Rebasing

- Although PowerStream can rebase as late as 2014, a 2013 rebasing is necessary due to:
  - Upward pressure on OM&A spending due to key staff additions and increasing operational needs
  - Increased capital spending to upgrade aging infrastructure to maintain reliability and for strategic IT investments
  - Ratebase additions of $140M since last rebasing are not earning a return
  - Economic growth continues to be lower than forecast reflecting the ongoing weak economy

The Key Steps

1. Filing of application – April/May
2. Newspaper notice and registration of intervenors - June
3. Technical Conference – July?
4. Interrogatories – July/August?
5. Settlement Conference – September?
6. Oral hearing – September/October?

The Key Steps

7. Final written arguments – October?

8. Decision – November?

9. Rate Order – December?

2013 Rate Application - Sections

A. Overview

B. Rate Base (capital, working capital allowance)

C. Revenue (load forecast, other revenue)

D. OM&A Costs (includes depreciation, compensation & benefits, PILS)

E. Deferral & Variance Accounts

F. Cost of Capital and Rate of Return

G. Revenue Deficiency

H. Cost Allocation (revenue to cost ratios)

I. Rate Design

Where Are We?

- Kick-off in March – "living our rate application"

- Early start has paid off, evidence drafted (in various stages) for:
  - Overall Planning Process
  - Dividend Policy
  - Capitalization Policy
  - Burden Process
  - IFRS
  - Shared Services
  - Ratebase/capital
  - Five Year Capital Plan
  - Green Energy Plan/Smart Grid Plan
  - Working Capital
  - Load Forecast
  - OM&A – Overview, Drivers, Compensation & Benefits

Where Are We?

- A number of areas are necessarily done at the end:
  - PILs
  - Cost Allocation
  - Rate Design
  - Summary – Requested Rate Relief
- Mock Hearing – November
- Selected legal firm through RFP
- 2011 Actual CGAAP and 2011 Actual MIFRS are key
- Working to review/finalize sections

Themes

- Ongoing weak economy – not much growth anticipated in 2013 energy sales
- Increasing need to replace aging capital infrastructure
- Focus on productivity improvement – Journey to Excellence
- OM&A may be increasing by slightly more that OEB “envelope” of 5% per year but can be explained by business drivers
- Adoption of IFRS means take care in year over year comparisons
- Significant ratebase additions

Next Steps

- Continue to finalize evidence – “test” tricky areas with experts.
- Check with SLT and EMT (late February) – does our story hold together? What are the “soft spots” and risks?
- Very shortly after filing, solidify witnesses and their support teams. Ensure each team has all of their filed and support material.
- Start witness training – will help with Technical Conference and Interrogatories

2013 Cost of Service Rate Application

EOC – Strategic Discussion 1

NOT FOR DISTRIBUTION

Colin Macdonald
VP, Rates & Regulatory Affairs
February 15, 2012

Topics

- Anticipated rate increase & drivers
- OM&A trend
- Capital additions trend
- Key issues
- Next Steps

Information is preliminary!

Anticipated Rate Increase

- Revenue at current rates = $155M
- Revenue per budget build = $172M
- Revenue deficiency is $17M
- Rate increase of 11% (2% on total bill)
- Impact of regulatory assets/liabilities minimal

Revenue Deficiency Drivers – 2013 vs 2009 OEB Approved

Driver	Amount ($M)	Notes
Rate base increase	13	
OM&A increase	31	12M inc. for IFRS, 4M inc. for IRM
Depreciation decrease	(11)	12M dec for IFRS
PILS decrease	(9)	IFRS impacts and lower tax rates
Revenue offset increase	1	
Offset by revenue per forecast	(9)	6M in load growth, 2M in IRM increases
Net deficiency	**17**	

OM&A Trend

As per Rate Application

	Barrie	PowerStream South	Total	PowerStream Combined					
	2008	**2009**		**2009**	**2010**	**2011**	**2011**	**2012**	**2013**
	Board Approved			Actual				Forecast	
	CGAAP						**MIFRS**		
Total OM&A	$ 10.0	$ 43.2	$ 53.3	$ 59.7	$ 56.6	$ 62.1	$ 74.1	$ 81.5	$ 85.6
YOY % change				12%	-5%	10%	19%	10%	5%
2013 vs "Total Approved"									61%
% change 2013 vs 2011									15%

OM&A Trend – "Normalized"

"Normalized" for the impact of MIFRS

	Barrie	PowerStream South	Total	PowerStream Combined				
	2008	2009		2009	2010	2011	2012	2013
	Board Approved			Actual			Forecast	
	CGAAP							
Total OM&A	$ 10.0	$ 43.2	$ 53.3	$ 59.7	$ 56.6	$ 62.1	$ 69.5	$ 73.6
YOY % change				12%	-5%	10%	12%	6%
2013 vs "Total Approved"								38%
% change 2013 vs 2011								18%

Go Green with PowerStream

Capital Additions Trend

Capital Additions (Net of Smart meters), $M - 2013 Rate Application

		Budget		Actual				Actual vs Budget
		Capital Additions, $M	YOY % change	Capital Additions, $M	YOY % change	2013 vs Board Approved	2013 vs 2011	
Barrie	2008 BA	14.6						
PowerStream South	2009 BA	85.2						
Total	**Board Approved**	**99.8**		**99.8**				
PowerStream Combined	2009	96.5	-3%	59.7	-40%			(37)
	2010	**59.4**	-38%	90.6	52%			31
	2011	**69.7**	17%	63.2	-30%			(7)
	2011 MIFRS	**57.7**	-17%	51.7	-18%			(6)
	2012 MIFRS	**63.8**	11%	**63.8**	23%			-
	2013 MIFRS	**89.5**	**40%**	**89.5**	**40%**	**-10%**	**73%**	**-**

Notes:

1.Capital additions are net of Customer Contributions

2. Capital Additions are net of Smart Meters added to rate base in 2009-2011 and net of Addiscott Capital Lease ($18.3M in 2010)

3. The Capital additions in 2012-2013 do not include CIS (12.9M in 2012 and $5.3M in 2013)

Capital Additions Trend – "Normalized"

Capital Additions "normalized" for the impact of mIFRS, $M - 2013 Rate Application

		Budget		Actual				Actual vs Budget
		Capital Additions, $M	YOY % change	Capital Additions, $M	YOY % change	2013 vs Board Approved	2013 vs 2011	
Barrie	2008 BA	14.6						
PowerStream South	2009 BA	85.2						
Total	**Board Approved**	**99.8**		**99.8**				
PowerStream Combined	2009	96.5	-3%	**59.7**	-40%			(37)
	2010	59.4	-38%	**90.6**	52%			31
	2011	69.7	17%	**63.2**	-30%			(7)
	2012	75.8	9%	**75.8**	20%			-
	2013	**101.5**	**34%**	**101.5**	**34%**	**2%**	**61%**	**-**

Go Green with PowerStream

Key Areas

- OM&A and capital trend explanations
- Load forecast assumptions
- Headcount increases, compensation increases
- Solar and other renewable generation projects
- Barrie merger savings
- Collus strategic partnership
- Inadequacies of IRM – possible capital rate adder for 2014, 2015 & 2016

Next Steps

- Update draft evidence with 2011 MIFRS data – available March 1
- Review/finalize evidence, legal review
- “Stress test” key areas with Bob Betts/Paul Vlahos
- Further strategic reviews – are we comfortable?
- April AFC & Board meeting presentations

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 1
Schedule 1.1
Appendix F
102 Pages
Filed: August 31, 2012

POWERSTREAM INC.

2012/2013 Preliminary Budget Guidelines

EOC

June 09, 2011

Private and Confidential

2012/2013 Preliminary Budget Scenarios

Budget Scenario - No Rate Basing

ROE	Budget Core 2012	Outlook Core 2013	Outlook Core 2014	Outlook Core 2015	Outlook Core 2016
	+$1M OMA	+$1M OMA			
Base scenario, $61M Capex	8.7%	9.1%	9.3%	9.3%	9.2%
IS & Other Capex scenario	8.2%	7.4%	7.2%	6.8%	6.3%
IS & Oth Capex & 2012 Refinancing	8.1%	8.0%	7.6%	7.2%	6.6%

Budget Scenario - Rate Basing

IS & Oth Capex & 2012 Refinancing with Rebasing	8.1%	10.0%	9.6%	9.2%	8.3%

OEB allowed ROE as of May'11	9.58%	9.58%	9.58%	9.58%	9.58%
IS Spend ($M)	13.0	11.8	5.6	7.9	8.5
Total Capex	78.8	95.0	77.0	97.0	86.0

Budget Risks

- Distribution Revenue requirement includes recovery for PILs. The impact on PILs resulting from MIFRS has not yet been determined by the OEB. Possibly the Distribution Revenue maybe subject to further change.

- The difference and associated impact on actual Income Tax Provision between MIFRS and IFRS needs to be further assessed, which may have a direct impact on the net income.

- Our refinancing plan has assumed a certain interest rate which is subject to any future interest rate fluctuations.

- The bottom-up build detailed OM&A and Capex budget can differ from the high level top-down target which will affect the Revenue Requirement.

- Reminder that during rate filing, LDCs don't normally get what they ask for (albeit vigorous defend of OM&A, Capital Spend, Revenue Requirement, etc.)

2012/2013 Preliminary Budget - Base Case – No Rebasing

Prelim Summarized Statement of Operations					
	Budget	**Outlook**	**Outlook**	**Outlook**	**Outlook**
	Core	**Core**	**Core**	**Core**	**Core**
(in Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**
Cost of Power	757.5	778.8	802.1	826.2	851.0
Distribution Revenue	162.9	167.5	172.6	177.6	182.6
Other Revenue	13.4	14.3	15.0	15.9	16.9
OM&A	81.8	84.4	86.4	88.6	90.8
Depreciation Expense	36.8	37.8	38.8	40.9	43.6
Interest Expense	25.7	25.8	26.7	26.7	26.7
EBT	32.0	33.9	35.7	37.3	38.4
Provision for Income Taxes	3.8	3.6	3.9	4.6	5.3
Net Income	**28.2**	**30.3**	**31.8**	**32.8**	**33.1**
Deemed ROE	8.7%	9.1%	9.3%	9.3%	9.2%
Working Capital Ratio	5.8%	5.4%	4.9%	5.1%	5.8%
Net Capital	61.0	61.0	61.0	61.0	61.0
Statutory Tax Rate	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base	808	835	859	881	901

2012/2013 Preliminary Budget - Base Case Rebasing in 2013 (3.5% Revenue Increase)

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Prelim Summarized Statement of Operations					
	Budget Core	**Outlook Core**	**Outlook Core**	**Outlook Core**	**Outlook Core**
(in Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**
Cost of Power	757.5	778.8	802.1	826.2	851.0
Distribution Revenue	162.9	173.4	178.6	184.0	187.6
Other Revenue	13.4	14.3	15.0	15.9	16.9
OM&A	81.8	84.4	86.4	88.6	90.8
Depreciation Expense	36.8	37.8	38.8	40.9	43.6
Interest Expense	25.7	25.8	26.7	26.7	26.7
EBT	32.0	39.8	41.7	43.7	43.4
Provision for Income Taxes	3.8	5.1	5.4	6.2	6.5
Net Income	**28.2**	**34.7**	**36.3**	**37.6**	**36.9**
Deemed ROE	8.7%	10.4%	10.6%	10.7%	10.2%
Working Capital Ratio	5.8%	5.9%	5.6%	6.1%	7.0%
Net Capital	61.0	61.0	61.0	61.0	61.0
Statutory Tax Rate	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base	808	835	859	881	901

2012/2013 Preliminary Budget - IS & Other Capex
Rebasing in 2013 (7.0% Revenue Increase)

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Prelim Summarized Statement of Operations					
(in Millions of Dollars)	**Budget Core 2012**	**Outlook Core 2013**	**Outlook Core 2014**	**Outlook Core 2015**	**Outlook Core 2016**
Cost of Power	757.5	778.8	802.1	826.2	851.0
Distribution Revenue	162.9	179.1	184.5	190.0	193.8
Other Revenue	13.3	14.3	15.2	16.1	16.9
OM&A	81.8	84.4	86.4	88.6	90.8
Depreciation Expense	37.4	41.3	43.7	46.5	49.9
Interest Expense	26.9	27.6	28.4	29.4	30.0
EBT	30.1	40.2	41.1	41.5	39.9
Provision for Income Taxes	3.5	6.0	6.5	7.0	7.2
Net Income	**26.6**	**34.1**	**34.7**	**34.5**	**32.7**
Deemed ROE	8.2%	9.9%	9.6%	9.2%	8.4%
Working Capital Ratio	3.5%	4.2%	4.2%	4.5%	4.7%
Net Capital	78.8	95.0	77.0	97.0	86.0
Statutory Tax Rate	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base	814	862	906	936	976

2012/2013 Preliminary Budget - IS, Other Capex & Refinancing Rebasing in 2013 (5.5% revenue increase)

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Prelim Summarized Statement of Operations					
	Budget	**Outlook**	**Outlook**	**Outlook**	**Outlook**
	Core	**Core**	**Core**	**Core**	**Core**
(in Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**
Cost of Power	757.5	778.8	802.1	826.2	851.0
Distribution Revenue	162.9	176.8	182.1	187.6	191.3
Other Revenue	13.3	14.3	15.2	16.1	16.9
OM&A	81.8	84.4	86.4	88.6	90.8
Depreciation Expense	37.4	41.3	43.7	46.5	49.9
Interest Expense	27.0	24.7	26.0	26.9	27.9
EBT	30.0	40.7	41.2	41.6	39.6
Provision for Income Taxes	3.4	6.2	6.5	7.0	7.1
Net Income	**26.5**	**34.5**	**34.7**	**34.6**	**32.4**
Deemed ROE	8.1%	10.0%	9.6%	9.2%	8.3%
Working Capital Ratio	3.5%	4.2%	4.8%	5.6%	5.7%
Net Capital	78.8	95.0	77.0	97.0	86.0
Statutory Tax Rate	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base	814	862	906	936	976

Table of Contents

2012/2013 Preliminary OM&A Budget Guidelines

- Assume Rate filing in 2013 for rates effective on Jan 1, 2013
  - Firm budget required for 2012 & 2013
  - Bottom Build budget will be used to build for Revenue Requirement for 2013
- Modified IFRS adopted for 2012 Budget and 2013-2016 Outlook
- 2011 year to date forecast used as a starting point, calendarized to reflect increase in rates effective May 1 for 2012

2012/2013 Preliminary OM&A Budget Guidelines

Key Assumptions

	GAAP **2011** Budget	MIFRS **2012** Budget	MIFRS **2013** Outlook
Wage Increase	3.0%	3.0%	3.0%
Customer Base (Y/E)	336,181	343,787	351,430
Customer Growth	2.3%	2.3%	2.2%
Distribution Revenue Growth	2.4%	2.7%	3.2%
Rates Increase	1.0%	1.0%	Per filing
Deemed Equity/Rate Base	40%	40%	40%
Prelim Headcount –Consolidated (FTE)	495.6	506.6	516.6
-- Core*	486.6	497.6	507.6
-- CDM*	9	9	9
Tax Rate (statutory)	28.3%	26.3%	25.5%

*Note: Headcount split to be validated

2012/2013 Preliminary OM&A Budget Guidelines

OM&A Budget Assumption:

- OM&A 2012-2016:
  - 3.0% increase for 60% of OM&A (payroll related)
  - 2% inflationary increase for 40% (Other Expenses)
- Headcount FTE:
  - 2012 : 506.6
  - 2013 : 516.6
- Include non rate – non-recoverable expenses:
  - sponsorship and donation

2012/2013 Preliminary OM&A Budget Guidelines

2012 OM&A Target – Base Case:

2011 Forecast	$64.4	
IFRS compliance	+12.0	(Reclassification due to IFRS)
Joint Service to Oth Rv	+ 4.4	(Reclassification due to IFRS)
11 Additional FTE	+ 1.1 *	
Hiring lag	(0.5)*	
OMA- Other	+ 0.4 *	
2012 OM&A Budget	**$81.8**	

*Note: base case includes $1.0M net incremental OM&A primarily related to FTEs

2012/2013 Preliminary OM&A Budget Guidelines

OM&A Target – Sensitivities:

- o 2012/2013:
  - o FTE assumptions
  - o Incremental OM&A costs of $2M and $2.5M for each of 2012 & 2013

2012/2013 Preliminary OM&A Budget Guidelines

Capital Budget Target – Sensitivities:

- 2012/2013 : Capital budget at $61M (Base Case)
- Run sensitivity scenarios
    1. IS strategy (Incl. CIS) – Per IS Strategy Deck
    2. CIS (Assume no IS Strategy)
    3. Other – To be discussed – Asset Management

2012 / 2013 HR Staff Budget Request

Assumptions

- Staff count is based on 2011 Budget and 2011 approvals
- 2012/2013 Salary Rate: determined by HR
- Same HR process to request additional hiring in 2012/2013

2012 / 2013 HR Staff Budget Request

New Headcount Budget process

- BU head completes the Request form and submits it to HR
- HR will review and consolidate the requests
- HR/Finance will assess the financial impact on budget
- HR presents to EOC/EMT the headcount requests and its impact
- EOC/EMT final approval based on the budget limit and corporate objectives

2012 / 2013 Headcount Request Form

Business Unit: **715 Human Resources**

Position	Group	2011 Budget	2012 FTE Change Request	2012 Proposed Budget	2013 FTE Change Request	2013 Proposed Budget
Dir Human Resources	Mgmt	1	0	1	0	1
HR Administrative Assistant	Mgmt	1	0	1	0	1
Human Resources Generalist	Mgmt	1	0	1	0	1
Human Resources Officer	Mgmt	1	0	1	0	1
Mgr Human Resources	Mgmt	1	0	1	0	1
		5	0	5	0	5

Completed by | Date | EVP Approval | Date

Please return this form after approval to Connie Leung by email before July 29,2011. Late submissions may not be accepted.

Click to view the information sheet

Complete the following section for any request of headcount changes to the 2011 budget for the year 2012 and 2013.

Position Dir Human Resources **Group** Mgmt **2011 Budget** 1

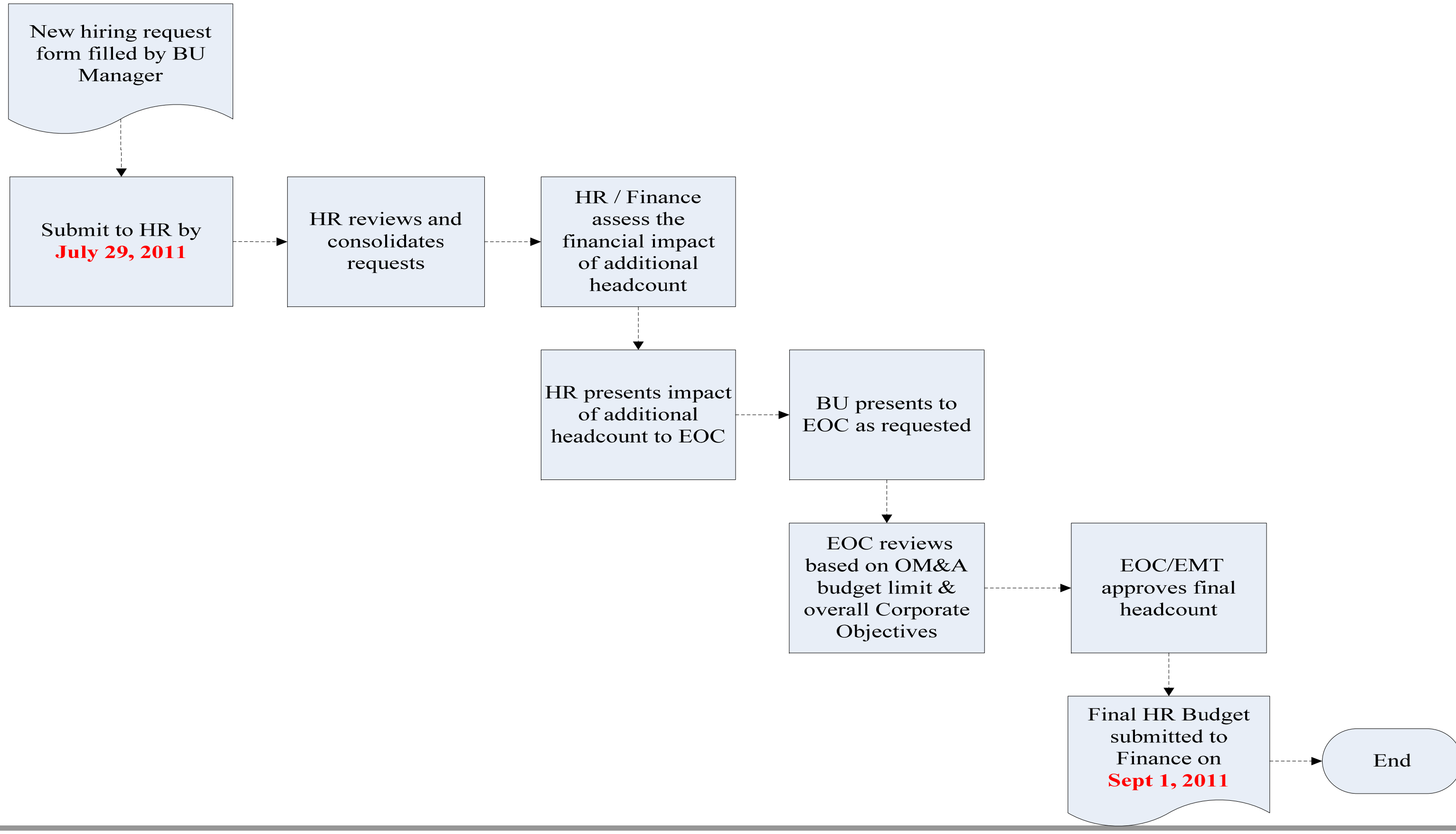
2012 Headcount Request			Proposed 2012 Budget	2013 Headcount Request			Proposed 2013 Budget
Action	BU	FTE		Action	BU	FTE	
Select...		0	1	Select...		0	1
Associated Cost		Amount		Associated Cost		Amount	

Strategic Focus Areas | **Business Rational** *(Briefly discuss the business rational for each change in position/funding)*

Risk Factor *(please state any impact that would be on your BU/Corporation if the above headcount request is not approved)*

2012 / 2013 HR Staff Budget Request

HR Headcount Request for 2012/2013 Budget



Capital – Points to Note

- No large capital kick off meeting this year with project leads
- Continue with small group meetings scheduled for June
- Changes this year include:
  - New Database – access through "Capital Tab" on Inflow
  - Also access Business Cases through "Capital Tab" on Inflow
  - Updated Optimizer questions
  - Optimizer questions completed by Manager in conjunction with Capital Budget Supervisor or Coordinator
  - Two stage completion dates – August 1st – Programs; Sept 1st – Specific Projects
  - Heading into a rate year so the documentation needs to be done well

Capital – Points to Note cont'd

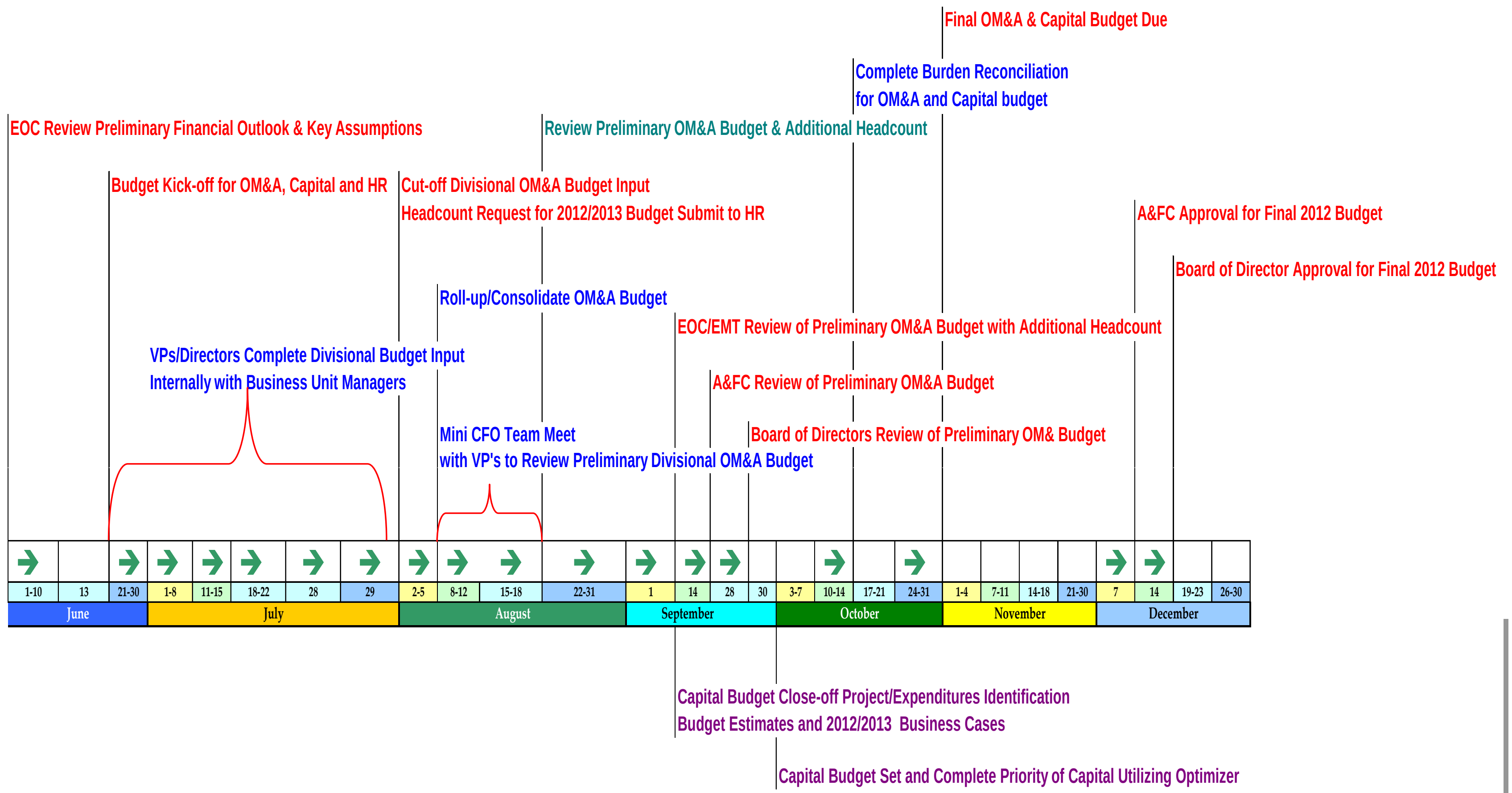
- Remember a full Business Case is required for non-program work > $500 K
- Business Cases must be completed and approved by September 1st
- Remember there is no formal sign off for programs or projects under $500 K, Director level still needs to review and approve
- All projects must have all details entered and optimizer questions answered by September 1st

To be successful this year there can be no straggling projects. Your assistance in getting your team members to complete their part, complete it well and on-time is appreciated!

Budget Calendar-Submission Timeline

Early Jun	EOC Review Preliminary Financial Outlook & Key Assumptions
Jun 13	Kick-off 2012/2013 Budget (OM&A, Capital and HR budgets)
Jul 29	Cut-off : Divisional OM&A Budget input Cut-off :Additional Headcount Request to HR
Aug 02–05	Roll-up/Consolidate OM&A Budgets Corporate wide
Aug 08–17	Mini CFO Team Meet with VPs to Review Preliminary Divisional OM&A Budgets
Aug 18	Preliminary Review OM&A Budget & Additional Headcount Request
Sep 01	EOC/EMT Review of Preliminary OM&A Budget with Additional Headcounts
Sep 01	Cut –off : Capital Budget Project/Expenditures Identification, Budget Estimates and 2012/2013 Business Cases
Sep 14/28	AFC / Board Review of Preliminary OM&A Budget
Sep 30	Capital Budget Set and Complete Priority of Capital Utilizing Optimizer
Oct 14	Complete Burden Reconciliation for OM&A & Capital Budget
Oct 31	Final OM&A & Capital Budget due
Dec 7/14	AFC / Board to approve Final 2012 Budget

2012 Budget Guideline - Timeline



POWERSTREAM INC.

2012/2013 Budget Guidelines

Budget Kickoff

June 13, 2011

Lucy Lombardi
Shelly Cunningham
Barb Gray

Table of Contents

2012/2013 OM&A Budget Guidelines – Key Assumptions

- Assume Rate filing in 2013 for rates effective on Jan 1, 2013
- Bottom Build budget will be used to build the 2013 Revenue Requirement
- Modified IFRS adopted for 2012 Budget and 2013-2016 Outlook
- 2011 year to date forecast used as a starting point, calendarized to reflect increase in rates effective May 1 for 2012
- Top town budget sensitivities were evaluated based on:
    - 3.0% increase for 60% of OM&A (payroll related)
    - 2% inflationary increase for 40% (Other Expenses)
    - Debt refinancing plan in 2012
    - Preliminary Capex 5 yr business plan including IS strategy

2012/2013 OM&A Budget Guidelines – Key Assumptions

Rates Application : The story we'll have to tell:

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

- In preparation for the Rate filling, the bottom-up build OM&A budget has to be solid and firm for both 2012 and 2013
- Keep discretional spend flat. Any incremental increase in OM&A spend, needs to be identified separately and justified diligently
- Take into account historical spending trend when building the 2012/2013 detailed budget

Budget Risks

- Our refinancing plan has assumed a certain interest rate of 5% which is subject to any future interest rate fluctuations.

- The bottom-up build detailed OM&A and Capex budget can differ from the high level top-down target which will affect the Revenue Requirement.

- The 2013 Distribution Revenue requirement includes recovery for PILs. The impact on PILs resulting from MIFRS has not yet been determined by the OEB. Possibly the Distribution Revenue maybe subject to further change.

- The difference and associated impact on actual Income Tax Provision between MIFRS and IFRS needs to be further assessed, which may have a direct impact on the net income

- Reminder that during rate filing, LDCs don't normally get what they ask for (albeit vigorous defend of OM&A, Capital Spend, Revenue Requirement, etc.) – as such we may need to revisit and curtail OM&A and/or Capital spend

Capital Budget Guidelines

- No large capital kick off meeting this year with project leads
- Continue with small group meetings scheduled for June
- Changes this year include:
  - New Database – access through “Capital Tab” on Inflow
  - Also access Business Cases through “Capital Tab” on Inflow
  - Updated Optimizer questions
  - Optimizer questions completed by Manager in conjunction with Capital Budget Supervisor or Coordinator
  - Two stage completion dates – August 1st – Programs; Sept 1st – Specific Projects
  - Heading into a rate year so the documentation needs to be done well

Capital Budget Guidelines cont'd

- Remember a full Business Case is required for non-program work > $500 K
- Business Cases must be completed and approved by September 1st
- Remember there is no formal sign off for programs or projects under $500 K, Director level still needs to review and approve
- All projects must have all details entered and optimizer questions answered by September 1st

To be successful this year there can be no straggling projects. Your assistance in getting your team members to complete their part, complete it well and on-time is appreciated!

2012 / 2013 HR Staff Budget Request

Assumptions

- Staff count is based on 2011 Budget and 2011 approvals

- 2012/2013 Salary Rate: determined by HR

- Same HR process to request additional hiring in 2012/2013

2012 / 2013 HR Staff Budget Request

New Headcount Budget process

- ❑ BU head completes the Request form and submits it to HR
- ❑ HR will review and consolidate the requests
- ❑ HR/Finance will assess the financial impact on budget
- ❑ HR presents to EOC/EMT the headcount requests and its impact
- ❑ EOC/EMT final approval based on the budget limit and corporate objectives

2012 / 2013 Headcount Request Form

Power Stream YOUR CURRENT CONNECTION

Business Unit: **715 Human Resources**

			2012		2013	
Position	Group	2011 Budget	FTE Change Request	Proposed Budget	FTE Change Request	Proposed Budget
Dir Human Resources	Mgmt	1	0	1	0	1
HR Administrative Assistant	Mgmt	1	0	1	0	1
Human Resources Generalist	Mgmt	1	0	1	0	1
Human Resources Officer	Mgmt	1	0	1	0	1
Mgr Human Resources	Mgmt	1	0	1	0	1
		5	0	5	0	5

Completed by	Date	EVP Approval	Date

Please return this form after approval to Connie Leung by email before July 29,2011. Late submissions may not be accepted.

Click to view the information sheet

Complete the following section for any request of headcount changes to the 2011 budget for the year 2012 and 2013.

Position Dir Human Resources **Group** Mgmt **2011 Budget** 1

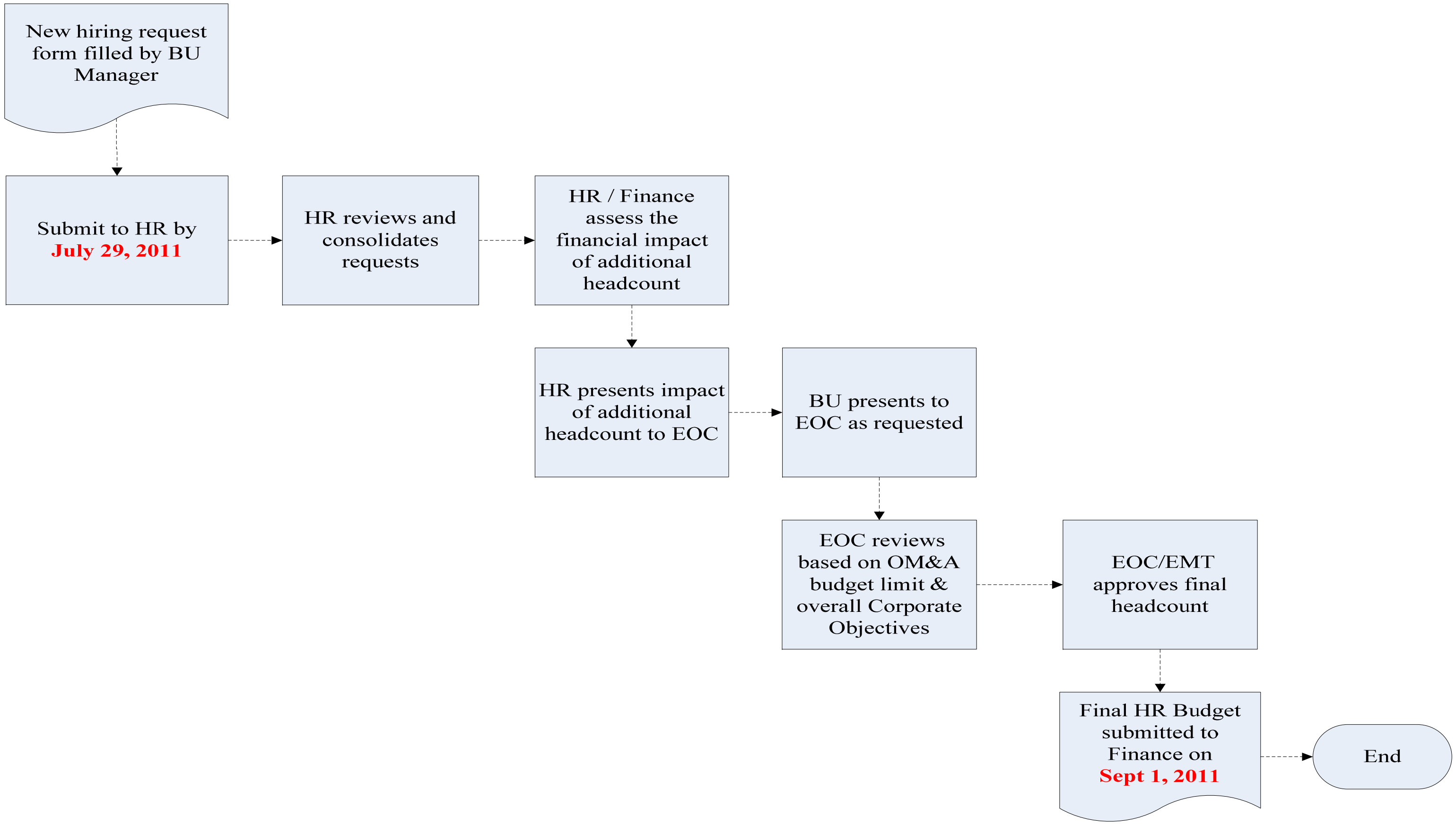
2012 Headcount Request			Proposed 2012 Budget	2013 Headcount Request			Proposed 2013 Budget
Action	BU	FTE		Action	BU	FTE	
Select...		0	1	Select...		0	1
Associated Cost		Amount		Associated Cost		Amount	

Strategic Focus Areas | **Business Rational** *(Briefly discuss the business rational for each change in position/funding)*

Risk Factor *(please state any impact that would be on your BU/Corporation if the above headcount request is not approved)*

2012 / 2013 HR Staff Budget Request

HR Headcount Request for 2012/2013 Budget



PMO Project Request – OM&A Related

Which OM&A Expenditures belong in the PMO?

1. Construction Maintenance Projects – NO
2. Cross Functional Process Improvement Projects – YES
   - More than one dept involved (excluding IS)
   - Change Mgmt required (ie. if there will be a fundamental change to jobs, work activities, work processes)

   These types of expenditures require PMO approval before being considered for budget approval – please review project with PMO prior to July 29th.

If your project falls into category #2:

Please contact the PMO or Louise Gauthier X4477 for direct guidance and assistance with the PMO processes.

PMO Project Request – Capital Related

<u>Which Capital Projects belong in the PMO?</u>

1. Construction Projects – NO
2. Capital Tools & Equipment – NO
3. Technology projects – YES some do
   - High strategic value
   - More than one department involved (not including IS)
   - Change Mgmt required (will there will be a fundamental change to jobs, work activities, work processes and require significant amt of training?)

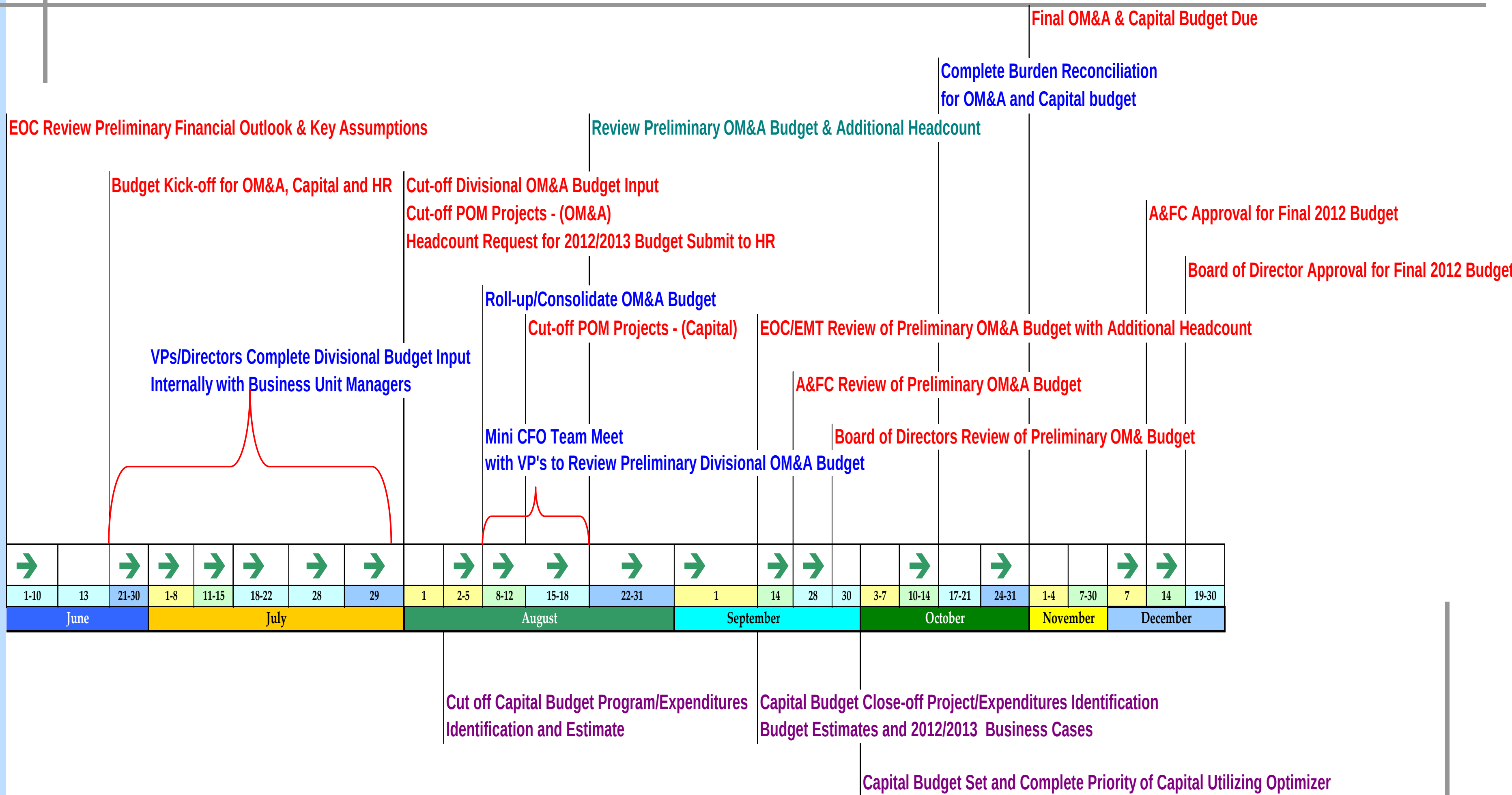
These types of capital requests **require PMO approval** before being considered for capital budget approval. Please submit completed project plan to PMO for approval by Aug 15th.

If you think your project might fall into category #3:
Please contact the PMO or Louise Gauthier X4477 for guidance and assistance with the PMO processes.

Budget Calendar-Submission Timeline

Early Jun	EOC Review Preliminary Financial Outlook & Key Assumptions
Jun 13	Kick-off 2012/2013 Budget (OM&A, Capital and HR budgets)
Jul 29	Cut-off : Divisional OM&A Budget input Cut-off : Additional Headcount Request to HR & PMO Projects (OM&A Related)
Aug 01	Cut-off : Capital Budget Program/Expenditures Identification & Estimates
Aug 02–05	Roll-up/Consolidate OM&A Budgets Corporate wide
Aug 08–17	Mini CFO Team Meet with VPs to Review Preliminary Divisional OM&A Budgets
Aug 15	Cut-off : Complete Project Plan to PMO (Capital Related)
Aug 18	Preliminary Review OM&A Budget & Additional Headcount Request
Sep 01	EOC/EMT Review of Preliminary OM&A Budget with Additional Headcounts
Sep 01	Cut –off : Capital Budget Project/Expenditures Identification, Budget Estimates and 2012/2013 Business Cases
Sep 14/28	AFC / Board Review of Preliminary OM&A Budget
Sep 30	Capital Budget Set and Complete Priority of Capital Utilizing Optimizer
Oct 14	Complete Burden Reconciliation for OM&A & Capital Budget
Oct 31	Final OM&A & Capital Budget due
Dec 7/14	AFC / Board to approve Final 2012 Budget

Budget Calendar-Submission Timeline



Budget Calendar-Submission Timeline

- In support of the OM&A budget process, after the Budget Kick-off today, the MiniCFO team will schedule working sessions with each division:
  - Assist the managers in extracting & review historical information through Insights – Executive Console
  - Build budget input templates to ease the budget data input
  - Support division head in budget review, analysis and justification.
  - Financial Service – Mini CFO contacts:

    Asset Management/Metering………Tracy Martin/Roger Bullock
    Finance/Board………………………..Nicole Fan
    Corporate Services…………………. Grace Anlian

POWERSTREAM INC.

2012/2013 Preliminary Budget Guidelines

EOC Update

Sept 7, 2011

Private and Confidential

Go Green with PowerStream

2012/2013 Preliminary Budget Scenarios – Per EOC Jun'11

Budget Scenario - No Rate Basing

ROE	Budget Core 2012	Outlook Core 2013	Outlook Core 2014	Outlook Core 2015	Outlook Core 2016
	+$1M OMA	+$1M OMA			
Base scenario, $61M Capex	8.7%	9.1%	9.3%	9.3%	9.2%
IS & Other Capex scenario	8.2%	7.4%	7.2%	6.8%	6.3%
IS & Oth Capex & 2012 Refinancing	8.1%	8.0%	7.6%	7.2%	6.6%

Budget Scenario - Rate Basing

IS & Oth Capex & 2012 Refinancing with Rebasing	8.1%	10.0%	9.6%	9.2%	8.3%

OEB allowed ROE as of May'11	9.58%	9.58%	9.58%	9.58%	9.58%
IS Spend ($M)	13.0	11.8	5.6	7.9	8.5
Total Capex	78.8	95.0	77.0	97.0	86.0

2012/2013 Preliminary Budget - IS, Other Capex & Refinancing Rebasing in 2013 (5.5% revenue increase) – Per EOC Jun'11

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Prelim Summarized Statement of Operations					
(in Millions of Dollars)	**Budget Core 2012**	**Outlook Core 2013**	**Outlook Core 2014**	**Outlook Core 2015**	**Outlook Core 2016**
Cost of Power	757.5	778.8	802.1	826.2	851.0
Distribution Revenue	162.9	176.8	182.1	187.6	191.3
Other Revenue	13.3	14.3	15.2	16.1	16.9
OM&A	81.8	84.4	86.4	88.6	90.8
Depreciation Expense	37.4	41.3	43.7	46.5	49.9
Interest Expense	27.0	24.7	26.0	26.9	27.9
EBT	30.0	40.7	41.2	41.6	39.6
Provision for Income Taxes	3.4	6.2	6.5	7.0	7.1
Net Income	**26.5**	**34.5**	**34.7**	**34.6**	**32.4**
Deemed ROE	8.1%	10.0%	9.6%	9.2%	8.3%
Working Capital Ratio	3.5%	4.2%	4.8%	5.6%	5.7%
Net Capital	78.8	95.0	77.0	97.0	86.0
Statutory Tax Rate	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base	814	862	906	936	976

2012 Preliminary Budget – Significant Changes from June EOC Presentation

Revenue

- Distribution Revenue decreased $2.6M (lower GDP)
- Other revenue decreased $3.7M (de-recognition impact $2.6M)

Expense

- OM&A increased $4.5M (before incorporation of additional headcount)
- Depreciation decreased $1.4M (extension of useful lives)
- Interest expense decreased $2.2M (assuming refinancing Aug'15)

Taxes

- Income Taxes decreased $2.6M (higher CCA deduction primarily related to CIS)

2012/2013 Preliminary Budget – Base Case - No Rebasing Aug 31'11 Update - Without Add'l FTE Draft

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Prelim Summarized Statement of Operations					
	Budget	**Outlook**	**Outlook**	**Outlook**	**Outlook**
	Core	**Core**	**Core**	**Core**	**Core**
(in Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**
Cost of Power	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	160.3	164.1	169.1	174.0	179.0
Other Revenue	9.6	10.4	11.1	11.8	12.6
OM&A	85.3	85.9	88.1	90.4	92.8
Depreciation Expense	36.0	40.6	44.0	47.3	51.5
Interest Expense	24.8	25.8	27.7	29.2	31.0
EBT	23.7	22.2	20.4	18.9	16.3
Provision for Income Taxes	0.8	-0.4	0.8	1.2	0.7
Net Income	**22.9**	**22.6**	**19.6**	**17.7**	**15.6**
Deemed ROE	7.0%	6.6%	5.4%	4.6%	3.9%
Working Capital Ratio	4.2%	4.2%	3.6%	2.9%	2.5%
Net Capital	76.7	99.9	83.1	100.7	94.3
Statutory Tax Rate	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Real Time	814	856	905	952	999

2012/2013 Preliminary Budget – Base Case With Rebasing Aug 31'11 Update - Without Add'l FTE (Rate Increase 7.9%) Draft

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Prelim Summarized Statement of Operations					
	Budget	**Outlook**	**Outlook**	**Outlook**	**Outlook**
	Core	**Core**	**Core**	**Core**	**Core**
(in Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**
Cost of Power	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	160.3	177.1	182.4	187.9	193.5
Other Revenue	9.6	10.4	11.1	11.8	12.6
OM&A	85.3	85.9	88.1	90.4	92.8
Depreciation Expense	36.0	40.6	44.0	47.3	51.5
Interest Expense	24.8	25.8	27.7	29.2	31.0
EBT	23.7	35.2	33.7	32.8	30.8
Provision for Income Taxes	0.8	2.9	4.1	4.7	4.3
Net Income	**22.9**	**32.3**	**29.6**	**28.1**	**26.5**
Deemed ROE	7.0%	9.4%	8.2%	7.4%	6.6%
Working Capital Ratio	4.2%	5.3%	5.3%	5.2%	5.3%
Net Capital	76.7	99.9	83.1	100.7	94.3
Statutory Tax Rate	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Real Time	814	856	905	952	999

2012 Preliminary Budget – Core – ROE Draft

ROE - Base Scenario (No Add'l FTE) Without the Budget Gap	**2012**
Net Income after tax	**$22.9**
Real time Ratebase	**814**
ROE on real time Ratebase	7.0%
ROE on 2009 approved Ratebase plus Smart Meter filings $741M	7.7%

2012/2013 Preliminary Budget – Base Case With Rebasing Sept 2'11 Update – With Budget Gap & No Add'l FTE Draft

Prelim Summarized Statement of Operations					
	Budget Core	Outlook Core	Outlook Core	Outlook Core	Outlook Core
(in Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**
Cost of Power	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	160.3	177.1	182.4	187.9	193.5
Other Revenue	9.6	10.4	11.1	11.8	12.6
OM&A	85.3	85.9	88.1	90.4	92.8
Depreciation Expense	36.0	40.6	44.0	47.3	51.5
Interest Expense	24.8	25.8	27.7	29.2	31.0
Budget Gap	-1.0		-3.6	-5.6	-7.7
EBT	24.7	35.2	37.3	38.4	38.5
Provision for Income Taxes	1.1	2.9	5.0	6.1	6.3
Net Income	**23.6**	**32.3**	**32.3**	**32.3**	**32.3**
Deemed ROE - Approved Rate Base	8.0%	9.4%	9.4%	9.4%	9.4%
Deemed ROE - Real Time Rate Base	*8.0%				
Working Capital Ratio	4.5%	5.5%	5.5%	5.4%	5.5%
Net Capital	76.7	99.9	83.1	100.7	94.3
Statutory Tax Rate	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	741	856	856	856	856
Rate Base - Real Time	814				

***Note: To achieve 8.0% ROE on real time Rate Base, the Budget Gap in 2012 would be $4M**

2012/2013 Preliminary Budget – Base Case With Rebasing Sept 2'11 Update – With Budget Gap & No Add'l FTE – Remove Non-Rec'ble Sponsorship/Donation ($0.5M) Draft

Prelim Summarized Statement of Operations					
(in Millions of Dollars)	Budget Core 2012	Outlook Core 2013	Outlook Core 2014	Outlook Core 2015	Outlook Core 2016
Cost of Power	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	160.3	177.1	182.4	187.9	193.5
Other Revenue	9.6	10.4	11.1	11.8	12.6
OM&A	84.8	85.4	87.6	89.9	92.2
Depreciation Expense	36.0	40.6	44.0	47.3	51.5
Interest Expense	24.8	25.8	27.7	29.2	31.0
Budget Gap	-1.0		-3.6	-5.6	-7.7
EBT	25.2	35.7	37.8	38.9	39.1
Provision for Income Taxes	1.1	3.1	5.1	6.2	6.4
Net Income	**24.1**	**32.7**	**32.7**	**32.7**	**32.7**
Deemed ROE - Approved Rate Base	8.1%	9.5%	9.5%	9.5%	9.5%
Deemed ROE - Real Time Rate Base	*8.0%				
Working Capital Ratio	4.6%	5.6%	5.9%	6.1%	6.6%
Net Capital	76.7	99.9	83.1	100.7	94.3
Statutory Tax Rate	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	741	856	856	856	856
Rate Base - Real Time	814				

***Note: To achieve 8.1% ROE on real time Rate Base, the Budget Gap in 2012 would be $4M**

2012/2013 Preliminary Budget – Add'l FTE Scenarios Update Aug 31'11 Draft

CALCULATIONS BASED ON AVERAGE OM&A COST AND SCENARIOS									OM&A Payroll Increase in Budget Year				
Scenarios Based on HR Data	NET FTE 2012	2012 OM&A Increase	NET FTE 2013	2013 OM&A Increase	NET FTE 2014	2014 OM&A Increase	NET FTE	Net OM&A Increase	2012	2013	2014	2015	2016
Scenarios #1 - Requests Added in Year Requested								-					
Average HC Added January 1st	39	2,856,254	10	657,836			49	3,514,090	2.9 M	3.5 M	3.5 M	3.5 M	3.5 M
Average HC Added July 1st (1/2 year lag)		1,428,127		328,918				1,757,045	1.4 M	3.2 M	3.5 M	3.5 M	3.5 M
								-					
Scenario #2 - Add 20 in 2012 Remaining in 2013 of 2012 Requests								-					
Mandatory & Offsetting	5	54,487	0	45,976			5	100,463					
2012 Requests	20	1,648,098	14	1,153,669			34	2,801,767					
2013 Requests			10	611,860			10	611,860					
								-					
	25	1,702,586	24	1,811,505			49	3,514,090					
Average HC Added January 1st								-	1.7 M	3.5 M	3.5 M	3.5 M	3.5 M
Average HC Added July 1st (1/2 year lag)		851,293		905,752				1,757,045	0.9 M	2.6 M	3.5 M	3.5 M	3.5 M
Scenario #3 - Add 20 in 2012 / 10 in 2013 & Remaining in 2014 of 2012 Requests								-					
Mandatory & Offsetting	5	54,487	0	45,976		-	5	100,463					
2012 Requests	20	1,648,098	10	824,049	4	329,620	34	2,801,767					
2013 Requests				-	10	611,860	10	611,860					
								-					
	25	1,702,586	10	870,025	14	941,480	49	3,514,090					
Average HC Added January 1st								-	1.7 M	2.6 M	3.5 M	3.5 M	3.5 M
Average HC Added July 1st (1/2 year lag)		851,293		435,013		470,740		1,757,045	0.9 M	2.1 M	3.0 M	3.5 M	3.5 M

2012/2013 Preliminary Budget – Base Case With Rebasing Sept 2'11 Update – With Budget Gap & Add'l FTE – Scenario#3 – ½ Year

Prelim Summarized Statement of Operations					
(in Millions of Dollars)	Budget Core 2012	Outlook Core 2013	Outlook Core 2014	Outlook Core 2015	Outlook Core 2016
Cost of Power	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	160.3	179.2	184.6	190.1	195.8
Other Revenue	9.6	10.4	11.1	11.8	12.6
OM&A	86.2	88.0	91.2	93.9	96.3
Depreciation Expense	36.0	40.6	44.0	47.3	51.5
Interest Expense	24.8	25.8	27.7	29.2	31.0
Budget Gap	-1.8		-4.5	-6.5	-8.5
EBT	24.6	35.2	37.3	38.0	38.1
Provision for Income Taxes	1.0	2.9	5.0	5.9	6.0
Net Income	**23.6**	**32.3**	**32.3**	**32.1**	**32.1**
Deemed ROE - Approved Rate Base	8.0%	9.4%	9.4%	9.4%	9.4%
Deemed ROE - Real Time Rate Base	*8.0%				
Working Capital Ratio	4.2%	5.4%	5.6%	5.8%	6.3%
Net Capital	76.7	99.9	83.1	100.7	94.3
Statutory Tax Rate	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	741	856	856	856	856
Rate Base - Real Time	814				

***Note: To achieve 8.0% ROE on real time Rate Base, the Budget Gap in 2012 would be $4.9M**

2012/2013 Preliminary Budget – OM&A Bottom-Up Build Update
Sept 1'11 Without Add'l FTE Draft

($M's)		
2012 IFRS Target		**80.8**
OM&A Increases related to...		
	Critical Success Factor	1.0
	Corporate Initiatives	1.4
	Normal Business	3.0
	Hiring Lag ($250k estimated)	0.3
	Smart Meter	-1.0
	CDM SLA	-0.2
2012 IFRS Bottom Up Build		**85.3**

2012/2013 Preliminary Budget – OM&A Bottom-Up Build Update Sept 1'11 Without Add'l FTE –Draft For Discussion

($000's)			Division				
High Level Category	**Sub Category**	**Details**	**Corp Serv**	**Finance**	**SM&SS**	**Ops & Const**	**Grand Total**
Critical Success Factors	Customer Satisfaction	Reliability: 2012 Planned Switch mtce & Forestry; 2013 Pole testing2				405	405
		Execution of strategies to achieve customer focused communication	120				120
		Develop a new customer newsletter to deliver outage mgt, payment opportunities, rates and self service applications.		50			50
		Social media, community investment assessment consulting	45				45
	Environmental Sustainability	Soil Remediation: Remaining stations & Phase 4 assessment				220	220
	NQI	Automated telephone and web based customer survey		60			60
		NQI Platinum membership and training	25				25
	Health & Safety	WSIB certificate, wellness program, lunch & learn	27				27
Critical Success Factors Total			217	110		625	952

2012/2013 Preliminary Budget – OM&A Bottom-Up Build Update Sept 1'11 Without Add'l FTE –Draft For Discussion

($000's)			Division				
High Level	**Sub Category**	**Details**	**Corp Serv**	**Finance**	**SM&SS**	**Ops & Cons**	**Grand Total**
Corporate Initiative	Implement planned CIS initiative	Oracle CIS license maintenance	500				500
	Implement planned IS initiative	IS Strategy Consulting	139				139
		Business continuity planning 2 years project	100				100
		EA for IS (will be removed if approved in 2012 HC)	100				100
		Additional IS project manager costs	25				25
	Facilities overflow	Rental space required for potential staff relocation	155				155
	Develop a skilled and engaged workforce	Develop training modules, leadership forum and union performance evaluation review	115				115
	Rate Application	Legal/Consulting/Support for Rate Application		112			112
	M&A	Consulting costs BDR		85			85
	Bill re-design	New bill layout to support customer communication		60			60
	Improve service levels - Mobile Payment Pilot	Develop a mobile payment application		20			20
	Electrical Emergency Preparedness Plan	Provide timely response in the event of electrical emergency		20			20
Corporate Initiative Total			1,134	297			1,431

2012/2013 Preliminary Budget – OM&A Bottom-Up Build Update
Sept 1'11 Without Add'l FTE –Draft For Discussion

($000's)			Division						
High Level	**Sub**	**Details**	**Board**	**Corp Serv**	**Engineering**	**Finance**	**SM&SS**	**Ops & Cons**	**Grand Total**
Normal Business	Trend	Pay - Historical w/o Act vs Bud (burnoffs, storm damage, etc)						456	456
		Contract - Historical e.g. Primary Cable Fault						300	300
		Software Mtce		124				79	203
		Locates Volume due to Customer Demand			201				201
		E-regs, Easements & legal registration		130					130
		Facility costs increase due to patrol and mtce		99					99
		Formerly Capital - IT training, TX painting		35				60	95
		Other		13	23		(7)	54	83
		Contract - Security						75	75
		Training increase in procurement		27					27
		Training		0					0
		Pay - Historical w/o Act vs Bud (misc w/o)			(18)		5	0	(13)
		Rail Agreements			(34)				(34)
		Eliminate Winter Warm Donation net of increase in advertising		(44)					(44)
		Consulting			(56)				(56)
		Reduction on postage and e-billing				(90)			(90)
	Rate increase	Burden rates - vehicle rate increased			47		34	281	362
		Fuel/407 costs increase		203					203
		Bad Debt				166			166
		Courier and payment processing costs				108			108
		Payroll related	89						89
		Coffee/café services		84					84
		Increase training & conference costs	39						39
		Office Supplies		28					28
		Courier, Postage, Stationary, etc				0			0
	Staffing Requ	IT Director approved HC in 2011 no fund		210					210
		OT in Control room - historically over budget						134	134
		Extra studs in environmental, purchasing and IT		86					86
		Control room - planner						30	30
Normal Business Total			**128**	**995**	**163**	**184**	**32**	**1,469**	**2,971**

Budget Risks & Opportunities

Risks

- Our refinancing plan has assumed a certain interest rate of 5% which is subject to any future interest rate fluctuations.
- Locates has been estimated based on historical trends and the best knowledge at this point of time – potential for increase as we are regulated to meet demand ($150K - $200K)
- Others?

Opportunities

- SR&ED Claim for 2012/2013: $500K each year – subject to the amount of spending qualified as SR&ED and any future tax rule changes.
- Business Continuity Planning 2012/213: $100K each year
- Others?

Next Steps

- Finalize strategy for the AFC and Board presentations
- Detail budget reviews by each division – OM&A, Capital, and Headcount
- ???
- Next meeting September 22nd, 2011

POWERSTREAM INC.

2012/2013 Budget Guidelines & Financial Outlook

Core Business

SLT Presentation

September 22, 2011

Private and Confidential

Table of Contents

Board Approved 2011 Budget and Financial Outlook – Core Business

	GAAP	GAAP	IFRS	IFRS	IFRS	IFRS	IFRS
Prelim Summarized Statement of Operations							
	Actual	**Budget**	**Budget**	**Outlook**	**Outlook**	**Outlook**	**Outlook**
	Core	**Core**	**Core**	**Core**	**Core**	**Core**	**Core**
(in Millions of Dollars)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2015**
Cost of Power	691.3	747.3	766.9	789.9	813.6	838.0	838.0
Distribution Revenue	155.8	165.7	167.4	175.7	183.1	187.8	187.8
Other Revenue	9.2	7.4	7.5	7.7	7.9	8.0	8.0
OM&A	58.0	64.5	77.4	79.7	81.8	83.5	83.5
Depreciation Expense	46.3	47.6	39.0	40.7	42.5	44.4	44.4
Interest Expense	21.9	24.5	25.5	25.8	26.4	26.5	26.5
EBT	38.9	36.5	33.1	37.3	40.3	41.5	41.5
Provision for Income Taxes	11.2	8.6	4.2	5.1	6.9	7.3	7.3
Net Income	**27.7**	**27.9**	**28.9**	**32.2**	**33.3**	**34.2**	**34.2**
Deemed ROE - Approved Rate Base	10.0%	9.8%	10.2%	9.4%	9.7%	10.0%	10.0%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	8.9%	9.7%	9.7%	9.8%	9.7%
Working Capital Ratio	0.8%	8.7%	10.4%	11.3%	12.4%	12.9%	12.9%
Net Capital	55.4	75.0	61.0	61.0	61.0	61.0	61.0
Statutory Tax Rate	31.0%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	711	711	856	856	856	856
Rate Base - Real Time	701	784	810	835	858	874	879

2012 Preliminary Budget Guidelines - Process Summary

- June /September – Development of detailed departmental budgets
- September – Preliminary budget guidelines submit to AFC & Board of Directors
- Oct/Nov – Detailed budget review by EOC/EMT and preparation for final budget submission
- December – AFC & Board of Directors to approve Final 2012 Budget

2012/2013 OM&A Budget Guidelines – Key Assumptions

- Assume Rate filing in 2013 for rates effective on Jan 1, 2013
- Bottom Build budget will be used to build the 2012 budget and 2013 Revenue Requirement
- Modified IFRS adopted for 2012 Budget and 2013-2016 Outlook
- 2011 year to date forecast used as a starting point, calendarized to reflect increase in rates effective May 1 for 2012
- Budget guidelines were developed based on:
  - 3.0% increase for 60% of OM&A (payroll related)
  - 2% inflationary increase for 40% (Other Expenses)
  - Debt refinancing plan in 2012
  - Preliminary Capex 5 yr business plan including IS strategy

2012/2013 Budget Guidelines – Key Assumptions

Rates Application : The story we'll have to tell:

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

- In preparation for the Rate filling, the bottom-up build budget has to be solid and firm for both 2012 and 2013
- Keep discretional spend flat. Any incremental increase in OM&A and Capital spend, needs to be identified separately and justified diligently
- Take into account historical spending trend when building the 2012/2013 detailed budget

Key Assumptions

	CGAAP **2011** Budget	CGAAP **2011** Projection	MIFRS **2012** Budget	MIFRS **2013** Outlook
Wage Increase	3.0%	3.0%	3.0%	3.0%
Customer Growth	2.3%	2.0%	2.2%	2.2%
Distribution Rev Growth (Rev from Rates)	2.4%	1.0%	2.3%	2.4%
Interest Rate – Long Term	6.0%	6.0%	5.0%	5.0%
Interest Rate – Short Term	4.0%	3.0%	3.0%	3.5%
Deemed Equity/Rate Base	40%	40%	40%	40%
Tax Rate (statutory)	28.25%	28.25%	26.25%	25.50%

2012 Preliminary Budget – Significant Changes from Approved 2012 Outlook

External Factors:

- Distribution Revenue pressure: ($3.8M) due to a lower GDP that underpinned the forecast; CDM impacts and slower than expected customer growth
- Smart Meter: ($1.3M) due to lower costs and hence lower revenue requirement
- IFRS: ($2.0M) due to asset de-recognition offset by reclassification of Contributed Capital & Damage claim

Internal Factors:

- Cost pressure: ($5.0M)
- Depreciation: decreased $2.5M due to assets being reclassified to longer useful life
- Interest expense: decreased $1.5M due to lower interest rates and debt refinancing in Aug 2012

Taxes

- Income Taxes decreased $3.2M (lower EBT & higher CCA deduction primarily related to CIS)

OMA Comparison – Budget Outlook $77.4M to $86.2M Bottom Up Build

($M's)		
2012 Outlook (MIFRS)		**77.4**
	Joint Services Reclass	3.1
	Add'l loss on Joint Services	0.4
2012 MIFRS Target		**80.8**
OM&A Increases related to…		
	Critical Success Factor	1.0
	Corporate Initiatives	1.4
	Normal Business	3.0
2012 MIFRS Bottom Up Build		**86.2**

PowerStream YOUR CURRENT CONNECTION

Private and Confidential

8/22/2012 9:19 PM

2012/2013 Preliminary Budget – OM&A Bottom-Up Build Update
Draft For Discussion

($000's)			Division				
High Level Category	Sub Category	Details	Corp Serv	Finance	SM&SS	Ops & Const	Grand Total
Critical Success Factors	Customer Satisfaction	Reliability: 2012 Planned Switch mtce & Forestry; 2013 Pole testing2				405	405
		Execution of strategies to achieve customer focused communication	120				120
		Develop a new customer newsletter to deliver outage mgt, payment opportunities, rates and self service applications.		50			50
		Social media, community investment assessment consulting	45				45
	Environmental Sustainability	Soil Remediation: Remaining stations & Phase 4 assessment				220	220
	NQI	Automated telephone and web based customer survey		60			60
		NQI Platinum membership and training	25				25
	Health & Safety	WSIB certificate, wellness program, lunch & learn	27				27
Critical Success Factors Total			217	110		625	952

2012/2013 Preliminary Budget – OM&A Bottom-Up Build Update

Draft For Discussion

($000's)			Division				
High Level	**Sub Category**	**Details**	**Corp Serv**	**Finance**	**SM&SS**	**Ops & Cons**	**Grand Total**
Corporate Initiative	Implement planned CIS initiative	Oracle CIS license maintenance	500				500
	Implement planned IS initiative	IS Strategy Consulting	139				139
		Business continuity planning 2 years project	100				100
		EA for IS (will be removed if approved in 2012 HC)	100				100
		Additional IS project manager costs	25				25
	Facilities overflow	Rental space required for potential staff relocation	155				155
	Develop a skilled and engaged workforce	Develop training modules, leadership forum and union performance evaluation review	115				115
	Rate Application	Legal/Consulting/Support for Rate Application		112			112
	M&A	Consulting costs BDR		85			85
	Bill re-design	New bill layout to support customer communication		60			60
	Improve service levels - Mobile Payment Pilot	Develop a mobile payment application		20			20
	Electrical Emergency Preparedness Plan	Provide timely response in the event of electrical emergency		20			20
Corporate Initiative Total			1,134	297			1,431

2012/2013 Preliminary Budget – OM&A Bottom-Up Build Update
Draft For Discussion

($000's)			Division						
High Level	**Sub**	**Details**	**Board**	**Corp Serv**	**Engineering**	**Finance**	**SM&SS**	**Ops & Cons**	**Grand Total**
Normal Business	Trend	Pay - Historical w/o Act vs Bud (burnoffs, storm damage, etc)						456	456
		Contract - Historical e.g. Primary Cable Fault						300	300
		Software Mtce		124				79	203
		Locates Volume due to Customer Demand			201				201
		E-regs, Easements & legal registration		130					130
		Facility costs increase due to patrol and mtce		99					99
		Formerly Capital - IT training, TX painting		35				60	95
		Other		13	23		(7)	54	83
		Contract - Security						75	75
		Training increase in procurement		27					27
		Training		0					0
		Pay - Historical w/o Act vs Bud (misc w/o)			(18)		5	0	(13)
		Rail Agreements			(34)				(34)
		Eliminate Winter Warm Donation net of increase in advertising		(44)					(44)
		Consulting			(56)				(56)
		Reduction on postage and e-billing				(90)			(90)
	Rate increase	Burden rates - vehicle rate increased			47		34	281	362
		Fuel/407 costs increase		203					203
		Bad Debt				166			166
		Courier and payment processing costs				108			108
		Payroll related	89						89
		Coffee/café services		84					84
		Increase training & conference costs	39						39
		Office Supplies		28					28
		Courier, Postage, Stationary, etc				0			0
	Staffing Requ	IT Director approved HC in 2011 no fund		210					210
		OT in Control room - historically over budget						134	134
		Extra studs in environmental, purchasing and IT		86					86
		Control room - planner						30	30
Normal Business Total			**128**	**995**	**163**	**184**	**32**	**1,469**	**2,971**

2012/2013 Preliminary Budget – Add'l FTE Scenarios Update Draft

CALCULATIONS BASED ON AVERAGE OM&A COST AND SCENARIOS									OM&A Payroll Increase in Budget Year				
Scenarios Based on HR Data	NET FTE 2012	2012 OM&A Increase	NET FTE 2013	2013 OM&A Increase	NET FTE 2014	2014 OM&A Increase	NET FTE	Net OM&A Increase	2012	2013	2014	2015	2016
Scenarios #1 - Requests Added in Year Requested								-					
Average HC Added January 1st	39	2,856,254	10	657,836			49	3,514,090	2.9 M	3.5 M	3.5 M	3.5 M	3.5 M
Average HC Added July 1st (1/2 year lag)		1,428,127		328,918				1,757,045	1.4 M	3.2 M	3.5 M	3.5 M	3.5 M
								-					
Scenario #2 - Add 20 in 2012 Remaining in 2013 of 2012 Requests								-					
Mandatory & Offsetting	5	54,487	0	45,976			5	100,463					
2012 Requests	20	1,648,098	14	1,153,669			34	2,801,767					
2013 Requests			10	611,860			10	611,860					
								-					
	25	1,702,586	24	1,811,505			49	3,514,090					
Average HC Added January 1st								-	1.7 M	3.5 M	3.5 M	3.5 M	3.5 M
Average HC Added July 1st (1/2 year lag)		851,293		905,752				1,757,045	0.9 M	2.6 M	3.5 M	3.5 M	3.5 M
Scenario #3 - Add 20 in 2012 / 10 in 2013 & Remaining in 2014 of 2012 Requests								-					
Mandatory & Offsetting	5	54,487	0	45,976		-	5	100,463					
2012 Requests	20	1,648,098	10	824,049	4	329,620	34	2,801,767					
2013 Requests				-	10	611,860	10	611,860					
								-					
	25	1,702,586	10	870,025	14	941,480	49	3,514,090					
Average HC Added January 1st								-	1.7 M	2.6 M	3.5 M	3.5 M	3.5 M
Average HC Added July 1st (1/2 year lag)		851,293		435,013		470,740		1,757,045	0.9 M	2.1 M	3.0 M	3.5 M	3.5 M

Preliminary 2012 Budget & 5 Year Outlook – Core Business

	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Prelim Summarized Statement of Operations									
(in Millions of Dollars)	**Actual Core 2010**	**Budget Core 2011**	**Q3 Frcst Core 2011**	**Mock Core 2011**	**Budget Core 2012**	**Outlook Core 2013**	**Outlook Core 2014**	**Outlook Core 2015**	**Outlook Core 2016**
Cost of Power	691.3	747.3	747.3	747.3	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	155.8	165.7	162.1	162.1	160.3	179.2	184.6	190.1	195.8
Other Revenue	9.2	7.4	7.9	10.2	9.6	10.4	11.1	11.8	12.6
OM&A	58.0	64.5	63.4	79.7	86.2	88.0	91.2	93.9	96.3
Depreciation Expense	46.3	47.6	46.4	36.0	36.0	40.6	44.0	47.3	51.5
Interest Expense	21.9	24.5	23.7	24.0	24.8	25.8	27.7	29.2	31.0
Budget Gap					-1.8		-4.5	-6.5	-8.5
EBT	38.9	36.5	36.5	32.7	24.6	35.2	37.3	38.0	38.1
Provision for Income Taxes	11.2	8.6	8.6	4.0	1.0	2.9	5.0	5.9	6.0
Net Income	**27.7**	**27.9**	**27.9**	**28.7**	**23.6**	**32.3**	**32.3**	**32.1**	**32.1**
Deemed ROE - Approved Rate Base	9.9%	9.4%	8.9%	9.7%	8.0%	9.4%	9.4%	9.4%	9.4%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.0%	9.3%	*8.0%	9.4%	8.9%	8.4%	8.0%
Working Capital Ratio	0.8%	8.7%	0.4%	0.4%	4.2%	5.4%	5.6%	5.8%	6.3%
Net Capital	55.4	75.0	68.8	68.8	76.7	99.9	83.1	100.7	94.3
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	741	741	741	741	856	856	856	856
Rate Base - Real Time	701	784	771	771	814	857	906	953	1,000

***Note: To achieve 8.0% ROE on real time Rate Base, the Budget Gap in 2012 would be $4.9M**

2012/2013 Preliminary Budget Scenario #1– Full Capex $35M new debt

Prelim Summarized Statement of Operations									
	Actual	Budget	Q3 Frcst	Mock	Budget	Outlook	Outlook	Outlook	Outlook
	Core	Core	Core	Core	Core	Core	Core	Core	Core
(in Millions of Dollars)	2010	2011	2011	2011	2012	2013	2014	2015	2016
Cost of Power	691.3	747.3	747.3	747.3	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	155.8	165.7	162.1	162.1	159.3	173.1	178.3	183.6	189.2
Other Revenue	9.2	7.4	7.9	10.2	10.8	11.6	12.3	13.0	13.8
OM&A	58.0	64.5	63.4	79.7	86.2	88.0	91.2	93.9	96.3
Depreciation Expense	46.3	47.6	46.4	36.0	33.0	35.7	38.3	41.6	45.8
Interest Expense	21.9	24.5	23.7	24.0	25.1	26.5	28.3	29.8	31.5
Budget Gap							-3.1	-10.2	-15.0
EBT	38.9	36.5	36.5	32.7	25.8	34.4	35.9	41.6	44.3
Provision for Income Taxes	11.2	8.6	8.6	4.0	1.7	0.8	1.5	5.2	6.0
Net Income	**27.7**	**27.9**	**27.9**	**28.7**	**24.0**	**33.7**	**34.4**	**36.4**	**38.4**
Deemed ROE - Approved Rate Base	10.0%	9.8%	9.8%	10.1%	8.5%	9.8%	10.0%	10.6%	11.1%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.0%	9.2%	7.4%	9.8%	9.4%	9.4%	9.4%
Working Capital Ratio	0.8%	8.7%	0.4%	0.4%	6.3%	7.0%	6.7%	6.6%	6.9%
Net Capital	55.4	75.0	68.8	68.8	76.7	99.9	83.1	100.7	94.3
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	711	711	711	711	862	862	862	862
Rate Base - Real Time	701	784	771	779	816	862	917	969	1,022

2012/2013 Preliminary Budget Scenario #2 – $65M Capex $35M new debt

	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Prelim Summarized Statement of Operations									
(in Millions of Dollars)	**Actual Core 2010**	**Budget Core 2011**	**Q3 Frcst Core 2011**	**Mock Core 2011**	**Budget Core 2012**	**Outlook Core 2013**	**Outlook Core 2014**	**Outlook Core 2015**	**Outlook Core 2016**
Cost of Power	691.3	747.3	747.3	747.3	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	155.8	165.7	162.1	162.1	159.3	170.2	175.3	180.6	186.0
Other Revenue	9.2	7.4	7.9	10.2	10.2	11.5	12.1	12.8	13.5
OM&A	58.0	64.5	63.4	79.7	85.3	88.0	91.2	93.9	96.3
Depreciation Expense	46.3	47.6	46.4	36.0	32.8	34.8	36.5	38.8	41.9
Interest Expense	21.9	24.5	23.7	24.0	24.7	25.6	27.4	27.6	28.1
Budget Gap							-2.6	-6.7	-8.2
EBT	38.9	36.5	36.5	32.7	26.8	33.3	34.9	39.7	41.4
Provision for Income Taxes	11.2	8.6	8.6	4.0	2.3	1.1	2.2	5.8	6.6
Net Income	**27.7**	**27.9**	**27.9**	**28.7**	**24.5**	**32.2**	**32.8**	**33.9**	**34.8**
Deemed ROE - Approved Rate Base	10.0%	9.8%	9.8%	10.1%	8.6%	9.5%	9.7%	10.1%	10.3%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.0%	9.2%	7.5%	9.5%	9.4%	9.4%	9.4%
Working Capital Ratio	0.8%	8.7%	0.4%	0.4%	6.2%	10.7%	9.8%	9.7%	9.7%
Net Capital	55.4	75.0	68.8	68.8	65.0	65.0	65.0	65.0	65.0
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	711	711	711	711	842	842	842	842
Rate Base - Real Time	701	784	771	779	812	842	872	901	926

Risks

- Prolonged weak economy and customer growth not achieved at 2.2%
- Budgeted distribution revenue based on stable weather pattern; risk of warmer winter and cooler summer
- Potential of rate freeze
- Additional regulatory requirements imposed on LDC's
- Interest rate risks
- Energy conservation pressure on distribution revenue
- 2011 Smart meter rate filing
- Impact of implementing IFRS

Conclusion

- In spite a result of continued weakening economy and continued cost pressure, targeting to achieve the current PS deemed regulated rate of return of 8.0% on our approved rate base
- The corporation will continue to examine process improvements and opportunities for reductions in OM&A across the organization
- Expected growth and diversified customer base will allow us to achieve beyond target as the economy recovers

POWERSTREAM INC.

2012/2013 Budget Guidelines & Financial Outlook

Core Business

EOC

October 13, 2011

Private and Confidential

2012/2013 Preliminary Budget Scenario #1– Full Capex $35M new debt Per SLT

Prelim Summarized Statement of Operations									
(in Millions of Dollars)	Actual Core 2010	Budget Core 2011	Q3 Frcst Core 2011	Mock Core 2011	Budget Core 2012	Outlook Core 2013	Outlook Core 2014	Outlook Core 2015	Outlook Core 2016
Cost of Power	691.3	747.3	747.3	747.3	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	155.8	165.7	162.1	162.1	159.3	173.1	178.3	183.6	189.2
Other Revenue	9.2	7.4	7.9	10.2	10.8	11.6	12.3	13.0	13.8
OM&A	58.0	64.5	63.4	79.7	86.2	88.0	91.2	93.9	96.3
Depreciation Expense	46.3	47.6	46.4	36.0	33.0	35.7	38.3	41.6	45.8
Interest Expense	21.9	24.5	23.7	24.0	25.1	26.5	28.3	29.8	31.5
Budget Gap							-3.1	-10.2	-15.0
EBT	38.9	36.5	36.5	32.7	25.8	34.4	35.9	41.6	44.3
Provision for Income Taxes	11.2	8.6	8.6	4.0	1.7	0.8	1.5	5.2	6.0
Net Income	**27.7**	**27.9**	**27.9**	**28.7**	**24.0**	**33.7**	**34.4**	**36.4**	**38.4**
Deemed ROE - Approved Rate Base	10.0%	9.8%	9.8%	10.1%	8.5%	9.8%	10.0%	10.6%	11.1%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.0%	9.2%	7.4%	9.8%	9.4%	9.4%	9.4%
Working Capital Ratio	0.8%	8.7%	0.4%	0.4%	6.3%	7.0%	6.7%	6.6%	6.9%
Net Capital	55.4	75.0	68.8	68.8	76.7	99.9	83.1	100.7	94.3
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	711	711	711	711	862	862	862	862
Rate Base - Real Time	701	784	771	779	816	862	917	969	1,022

2012/2013 Preliminary Budget Sc'n#2 – New Full Capex $35M new debt

Prelim Summarized Statement of Operations

(in Millions of Dollars)	Actual Core 2010	Budget Core 2011	Q3 Frcst Core 2011	Mock Core 2011	Budget Core 2012	Outlook Core 2013	Outlook Core 2014	Outlook Core 2015	Outlook Core 2016
Cost of Power	691.3	747.3	747.3	747.3	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	155.8	165.7	162.1	162.1	159.3	171.0	176.1	181.4	186.9
Other Revenue	9.2	7.4	7.9	10.2	11.0	11.3	11.4	11.6	11.8
OM&A	58.0	64.5	63.4	79.7	85.2	88.0	91.2	93.9	96.3
Depreciation Expense	46.3	47.6	46.4	36.0	33.2	35.5	38.1	41.2	45.3
Interest Expense	21.9	24.5	23.7	24.0	24.5	25.2	27.5	29.6	32.5
Budget Gap									
EBT	38.9	36.5	36.5	32.7	27.4	33.6	30.8	28.3	24.6
Provision for Income Taxes	11.2	8.6	8.6	4.0	1.8	0.9	0.1	1.6	0.7
Net Income	**27.7**	**27.9**	**27.9**	**28.7**	**25.6**	**32.7**	**30.6**	**26.7**	**24.0**
Deemed ROE - Approved Rate Base	10.0%	9.8%	9.8%	10.1%	9.0%	9.5%	8.9%	7.8%	7.0%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.0%	9.2%	7.8%	9.5%	8.4%	6.8%	5.7%
Net Capital	55.4	75.0	68.8	68.8	76.7	95.0	94.4	113.4	106.3
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	711	711	711	711	860	860	860	860
Rate Base - Real Time	701	784	771	779	815	860	916	978	1,043

2012/2013 Preliminary Budget Scenario #3– OM&A reduced to achieve 8% ROE

Prelim Summarized Statement of Operations									
(in Millions of Dollars)	Actual Core 2010	Budget Core 2011	Q3 Frcst Core 2011	Mock Core 2011	Budget Core 2012	Outlook Core 2013	Outlook Core 2014	Outlook Core 2015	Outlook Core 2016
Cost of Power	691.3	747.3	747.3	747.3	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	155.8	165.7	162.1	162.1	159.3	171.0	176.1	181.4	186.9
Other Revenue	9.2	7.4	7.9	10.2	11.0	11.3	11.4	11.6	11.8
OM&A	58.0	64.5	63.4	79.7	84.6	88.0	91.2	93.9	96.3
Depreciation Expense	46.3	47.6	46.4	36.0	33.2	35.5	38.1	41.2	45.3
Interest Expense	21.9	24.5	23.7	24.0	24.5	25.2	27.4	29.3	31.7
Budget Gap									
EBT	38.9	36.5	36.5	32.7	28.0	33.6	30.8	28.7	25.4
Provision for Income Taxes	11.2	8.6	8.6	4.0	2.0	0.9	0.2	1.7	0.9
Net Income	**27.7**	**27.9**	**27.9**	**28.7**	**26.0**	**32.7**	**30.7**	**27.0**	**24.5**
Deemed ROE - Approved Rate Base	10.0%	9.8%	9.8%	10.1%	9.1%	9.5%	8.9%	7.8%	7.1%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.0%	9.2%	8.0%	9.5%	8.4%	6.9%	5.9%
Net Capital	55.4	75.0	68.8	68.8	76.7	95.0	94.4	113.4	106.3
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	711	711	711	711	860	860	860	860
Rate Base - Real Time	701	784	771	779	815	860	916	978	1,043

2012/2013 Preliminary Budget Scenario #4– $70M Capex & OM&A reduced to achieve 8% ROE

Prelim Summarized Statement of Operations

(in Millions of Dollars)	Actual Core 2010	Budget Core 2011	Q3 Frcst Core 2011	Mock Core 2011	Budget Core 2012	Outlook Core 2013	Outlook Core 2014	Outlook Core 2015	Outlook Core 2016
Cost of Power	691.3	747.3	747.3	747.3	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	155.8	165.7	162.1	162.1	159.3	169.7	174.8	180.0	185.4
Other Revenue	9.2	7.4	7.9	10.2	11.0	11.3	11.4	11.6	11.8
OM&A	58.0	64.5	63.4	79.7	84.7	88.0	91.2	93.9	96.3
Depreciation Expense	46.3	47.6	46.4	36.0	33.1	35.3	37.9	41.0	45.1
Interest Expense	21.9	24.5	23.7	24.0	24.4	25.0	27.3	29.4	32.2
Budget Gap									
EBT	38.9	36.5	36.5	32.7	28.1	32.8	29.9	27.4	23.7
Provision for Income Taxes	11.2	8.6	8.6	4.0	2.1	0.9	0.1	1.6	0.6
Net Income	**27.7**	**27.9**	**27.9**	**28.7**	**26.0**	**31.9**	**29.8**	**25.9**	**23.1**
Deemed ROE - Approved Rate Base	10.0%	9.8%	9.8%	10.1%	9.1%	9.4%	8.8%	7.6%	6.8%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.0%	9.2%	8.0%	9.3%	8.2%	6.7%	5.6%
Net Capital	55.4	75.0	68.8	68.8	70.0	95.0	94.4	113.4	106.3
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	711	711	711	711	849	849	849	849
Rate Base - Real Time	701	784	771	779	813	855	910	972	1,037

2012/2013 Cash Flow Sc'n#2 – New Full Capex $35M new debt

Cash Flow Forecast

(Updated as of Oct11'2011)

Linked to FS tab

(in millions of dollars)	2010	2011	2012	2013	2014	2015	2016	Rqr'd
Cash from Operation:								
Funds from Operations	80.1	77.8	61.1	70.0	70.7	70.1	71.6	
Change in reg liabilities	(21.9)	5.2	4.9	(2.6)	(5.3)	(1.6)	0.6	
Change in working cap	(13.8)	(8.8)	(12.1)	(1.3)	(1.9)	(1.9)	(2.0)	
Cash from Financing:								
Borrowing needed	-	-	**50.0**	**50.0**	**40.0**	**60.0**	**50.0**	
Overdraft Protection								
Dividends	(10.5)	(13.9)	(14.4)	(12.8)	(16.4)	(15.3)	(13.4)	
Cash from Investing:								
Capital Expenditure	(70.3)	(68.8)	(76.7)	(95.0)	(94.4)	(113.4)	(106.3)	
Total Change of Cash:	**(36.4)**	**(8.6)**	**12.8**	**8.2**	**(7.3)**	**(2.2)**	**0.5**	
Cash beginning balance:	**42.6**	**6.2**	**(2.4)**	**10.4**	**18.6**	**11.3**	**9.1**	
Cash ending balance:	**6.2**	**(2.4)**	**10.4**	**18.6**	**11.3**	**9.1**	**9.7**	
S&P debt/equity ratio	60.5%	59.3%	60.4%	61.4%	62.2%	63.9%	65.0%	60.0%
Debt to rate base	58.7%	53.8%	55.2%	58.1%	58.8%	61.2%	62.2%	60.0%
WC/(COP + OMA)	**2.5%**	**5.5%**	**2.1%**	**3.1%**	**2.4%**	**2.3%**	**2.5%**	15.0%

2012/2013 Cash Flow Scenario #3– OM&A reduced to achieve 8% ROE

Cash Flow Forecast

(Updated as of Sep15'2011)

Linked to FS tab

(in millions of dollars)	2010	2011	2012	2013	2014	2015	2016	Rqr'd
Cash from Operation:								
Funds from Operations	80.1	77.8	61.5	70.0	70.7	70.1	71.6	
Change in reg liabilities	(21.9)	5.2	4.9	(2.6)	(5.3)	(1.6)	0.6	
Change in working cap	(13.8)	(8.8)	(12.1)	(1.3)	(1.9)	(1.9)	(2.0)	
Cash from Financing:								
Borrowing needed	-	-	**50.0**	**50.0**	**40.0**	**60.0**	**50.0**	
Overdraft Protection								
Dividends	(10.5)	(13.9)	(14.4)	(13.0)	(16.4)	(15.3)	(13.4)	
Cash from Investing:								
Capital Expenditure	(70.3)	(68.8)	(76.7)	(95.0)	(94.4)	(113.4)	(106.3)	
Total Change of Cash:	**(36.4)**	**(8.6)**	**13.2**	**8.0**	**(7.3)**	**(2.2)**	**0.5**	
Cash beginning balance:	**42.6**	**6.2**	**(2.4)**	**10.8**	**18.8**	**11.5**	**9.4**	
Cash ending balance:	**6.2**	**(2.4)**	**10.8**	**18.8**	**11.5**	**9.4**	**9.9**	
S&P debt/equity ratio	60.5%	59.3%	60.4%	61.4%	62.2%	63.8%	65.0%	60.0%
Debt to rate base	58.7%	53.8%	55.2%	58.1%	58.8%	61.2%	62.2%	60.0%
WC/(COP + OMA)	**2.5%**	**5.5%**	**2.1%**	**3.2%**	**2.5%**	**2.4%**	**2.6%**	15.0%

2012/2013 Cash Flow Scenario #4 – $70M Capex & OM&A reduced to achieve 8% ROE

Cash Flow Forecast

(Updated as of Oct11'2011)

Linked to FS tab

(in millions of dollars)	2010	2011	2012	2013	2014	2015	2016	Rqr'd
Cash from Operation:								
Funds from Operations	80.1	77.8	61.3	68.9	69.5	69.0	70.5	
Change in reg liabilities	(21.9)	5.2	4.9	(2.6)	(5.3)	(1.6)	0.6	
Change in working cap	(13.8)	(8.8)	(12.1)	(1.1)	(1.8)	(1.9)	(2.0)	
Cash from Financing:								
Borrowing needed	-	-	**45.0**	**50.0**	**40.0**	**60.0**	**50.0**	
Overdraft Protection								
Dividends	(10.5)	(13.9)	(14.4)	(13.0)	(16.0)	(14.9)	(12.9)	
Cash from Investing:								
Capital Expenditure	(70.3)	(68.8)	(70.0)	(95.0)	(94.4)	(113.4)	(106.3)	
Total Change of Cash:	**(36.4)**	**(8.6)**	**14.8**	**7.2**	**(8.0)**	**(2.8)**	**(0.1)**	
Cash beginning balance:	**42.6**	**6.2**	**(2.4)**	**12.4**	**19.6**	**11.6**	**8.8**	
Cash ending balance:	**6.2**	**(2.4)**	**12.4**	**19.6**	**11.6**	**8.8**	**8.7**	
S&P debt/equity ratio	60.5%	59.3%	60.1%	61.2%	62.1%	63.8%	65.0%	60.0%
Debt to rate base	58.7%	53.8%	54.7%	57.8%	58.7%	61.1%	62.0%	60.0%
WC/(COP + OMA)	**2.5%**	**5.5%**	**2.3%**	**3.2%**	**2.4%**	**2.3%**	**2.4%**	15.0%

CAPITAL BUDGET

Agenda

- Capital Process & Strategic Scoring
- Proposed Capital Portfolio
- Highlights of Large Projects
- Highlights of Deferred Projects
- 2 Alternative Portfolios
- Affect on Smart Grid Strategy and Reliability Goal

Capital Process

PowerStream
YOUR CURRENT CONNECTION

Two Years – Projects for 2012 and 2013

Owner identifies project need

- Identified through full or mini business case and Optimizer questions answered

Business Case Approval Received

PMO Project Review

Capital Projects Scored and Optimized

- ALL PROJECTS Using Optimizer

- Projects scored on Value, Risk Consequence and Risk Probability against 12 Success Criteria

Capital Portfolio Approved by EOC/EMT

- Optimizer Team: Tony D'Onofrio, Shelly Cunningham, Mark Henderson, Bill Schmidt, Rob Antennuci, Louise Gautier, Dianne Petrucci, John McLean, Mike Matthews, Ted Wojcinski, John Mulrooney

Go Green with PowerStream

Strategic Objectives and Success Criteria Weightings

Strategic Objective	Weighting	Success Criteria	Weighting	Overall 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 %
		SQI	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%

Go Green with PowerStream

Recommended Capital Spend 2012 & 2013 (NET $K)

Recommended Capital Spend 2012 & 2013 ($K)		2012	2013
SUSTAINMENT CAPITAL			
Non-Controllable		10,830	9,883
Controllable		17,083	35,919
DEVELOPMENT CAPITAL			
Non-Controllable		19,317	19,126
Controllable		3,468	11,350
OPERATIONS CAPITAL			
Non-Controllable		2,641	1,354
Controllable		23,360	17,113
TOTAL CAPITAL		76,699	94,645
OTHER			
Smart Grid – deferral		1,250	650
Distributed Generation Customer Initiated - deferral		756	0
Historical Rebates (Economic Model) – cash flow		2,063	1,500

Highlight of Projects > $500 K

Highlight of Projects > $500 K		2012	2013
SUSTAINMENT CAPITAL			
Replacement of Failed (end of useful life) Distribution Equipment		5,104	5,234
Replacement of Failed Switchgear		1,675	675
Emerging U/G Cable		1,967	1,967
Buttonville Metering		968	
Circuit Breaker Replacements		1,518	909
Planned Pole Replacement		2,532	4,038
Planned Switchgear Replacement		785	1,159
Planned Submersible Vault and Transformer Replacement		1,105	1,501
Flowervale Cable Replacement		1,789	
Romfield Cable Replacement		1,890	1,755
TBD Cable Replacement Projects			12,912

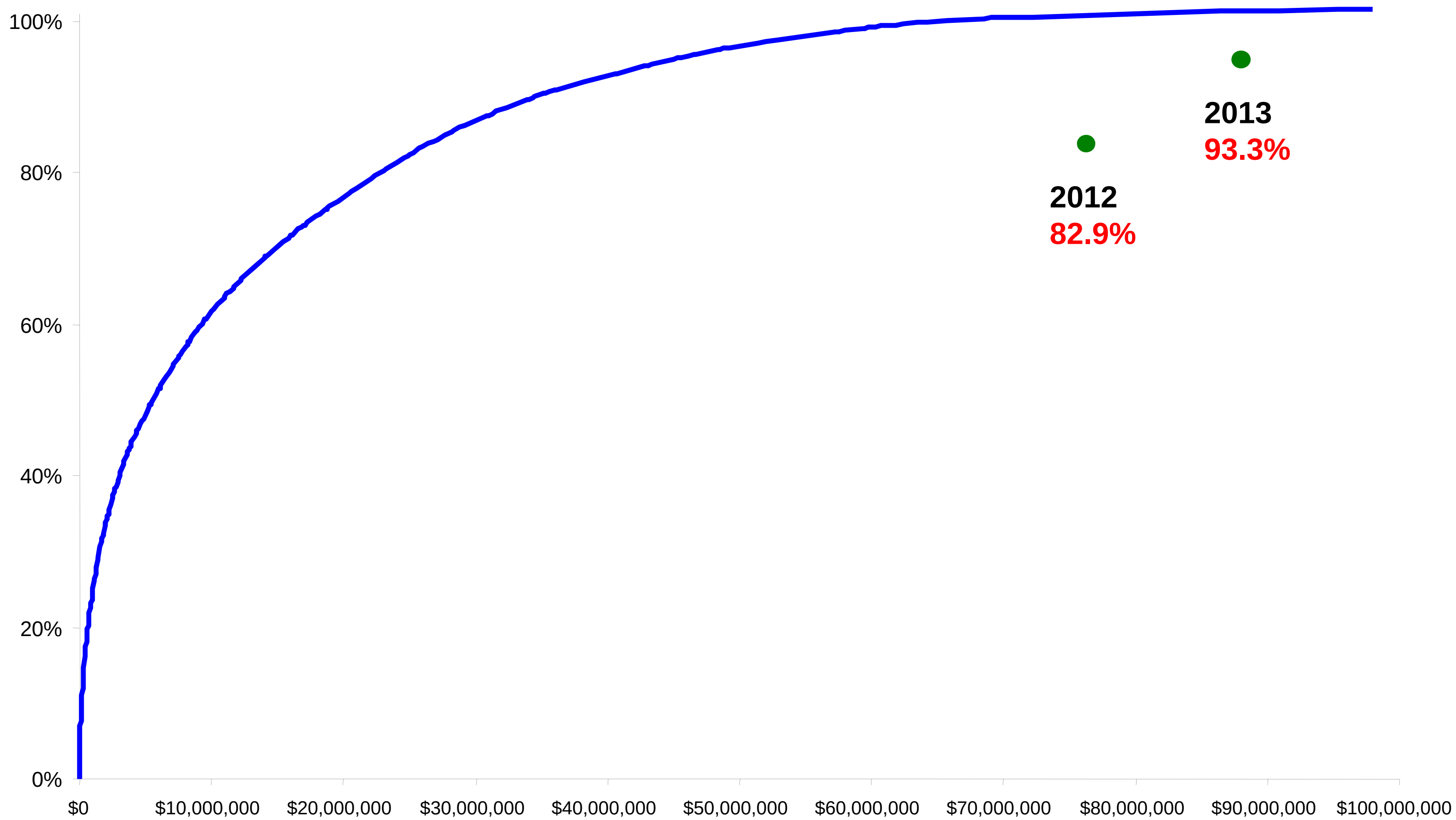
Highlight of Projects > $500 K

Highlight of Projects > $500 K		2012	2013
SUSTAINMENT CAPITAL cont'd			
Cable Injection		554	3,983
Distribution Automation		813	766
Penetanguishene 44 kV Tie			579
Unforeseen PowerStream Initiated		864	877
Sustainment Carryover		1,200	1,200
DEVELOPMENT CAPITAL			
Subdivision & Subdivision Laterals		7,013	9,008
Road Authority		6,675	5,844
Dufferin St. Pole Line		650	650
New 44 kV Feeder Midhurst		1,500	4,227
Sandringham MS		550	3,783

Highlight of Projects > $500 K

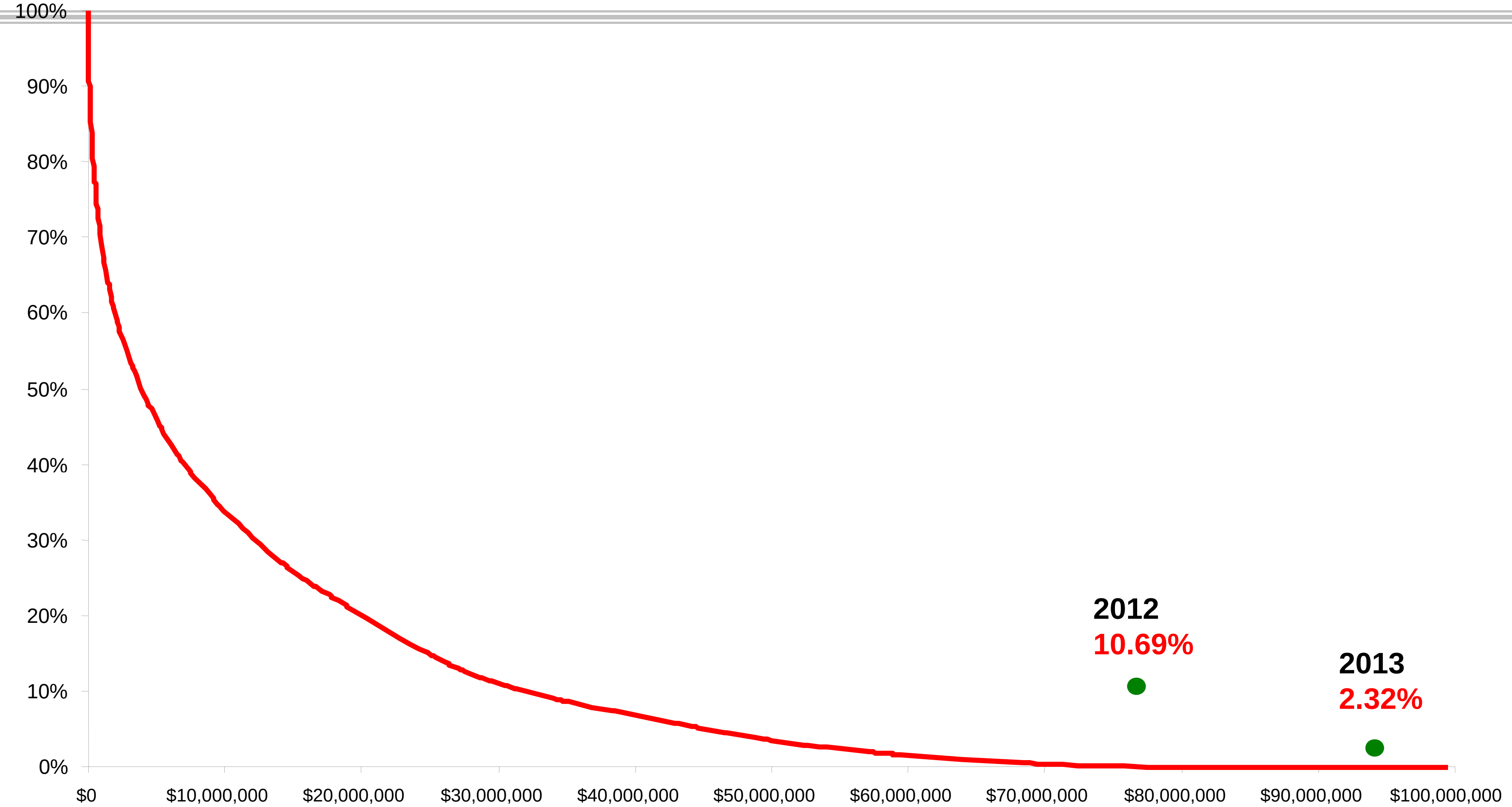
Highlight of Projects > $500 K		2012	2013
DEVELOPMENT CAPITAL cont'd			
Vaughan TS Land Purchase			2,200
Unforeseen Customer Projects		560	435
Development Carryover		2,500	1,000
OPERATIONS CAPITAL			
Smart Suite Meters		893	893
CIS Replacement		12,693	5,092
Large Vehicle Replacement		1,100	1,155
Small & Medium Vehicle Replacement		748	1,738

Efficient Frontier - Value



Go Green with PowerStream

Efficient Frontier - Risk



Deferred Projects

- Sustainment Projects Deferred
  - Cable replacement Varden – 2012 project deferred to 2013
  - Oil Containment – 2012 project deferred to 2013
  - Penetanguishene Tie – 2012 project deferred to 2013
  - Amber MS Feeder Conv. – 2012 project deferred to ??
  - CN Rail Buy Out – 2012 project deferred to ??
  - Distribution Automation – 2012 & 2013 cut in half
  - Refurbish 13.8 kV Station Aurora – 2013 project deferred
  - PLUS 24 smaller projects

- Major Development Projects Deferred
  - Extend 27.6 kV Circuits 14th Ave. – 2012 project deferred to ??
  - Harvie Rd MS – 2013 project deferred
  - Double Cct Reesor Rd – 2013 project deferred
  - PLUS 2 smaller projects

Go Green with PowerStream

Deferred Projects

- Operations Projects Deferred
    - 1 Large Truck – 2012 project deferred to 2013
    - Small & Medium Vehicles – 2012 project cut in half
    - Designer for Service Layout team – 2012 project deferred to ??
    - PLUS 30 smaller projects

Comparison possible scenarios

	RISK	VALUE
Scenario 1 76.7 M – 2012 95 M – 2013	10.7 % - 2012 2.3 % - 2013	82.9 % - 2012 93.3 % - 2013
Scenario 2 73 M – 2012 90 M – 2013	DNF – 2012 9.2 % - 2013	DNF – 2012 84.9 % - 2013
Scenario 3 80 M – 2012 99 M – 2013	3.5 % - 2012 1.5 % - 2013	93.7 % - 2012 97.6 % - 2013

Go Green with PowerStream

Comparison possible scenarios

Scenario 2 – Major Projects Excluded

- 17 projects in 2012
  - Distribution Automation
  - Midhurst 44 kV Feeder
  - Sandringham Property Purchase
  - Outdoor Storage Area Barrie
  - Fault Indicators
  - RTU Proactive replacements
  - JDE – Inventory Explosion project
- 30 projects in 2013
  - Replace 2 Aerial Devices
  - Planned Switchgear Replacement Program
  - Load Interrupter Switches for Feeder Balancing
  - Automatic Feeder Restoration VTS#1
  - Penetanguishene Tie

Comparison possible scenarios

Scenario 3 – Major Projects Included

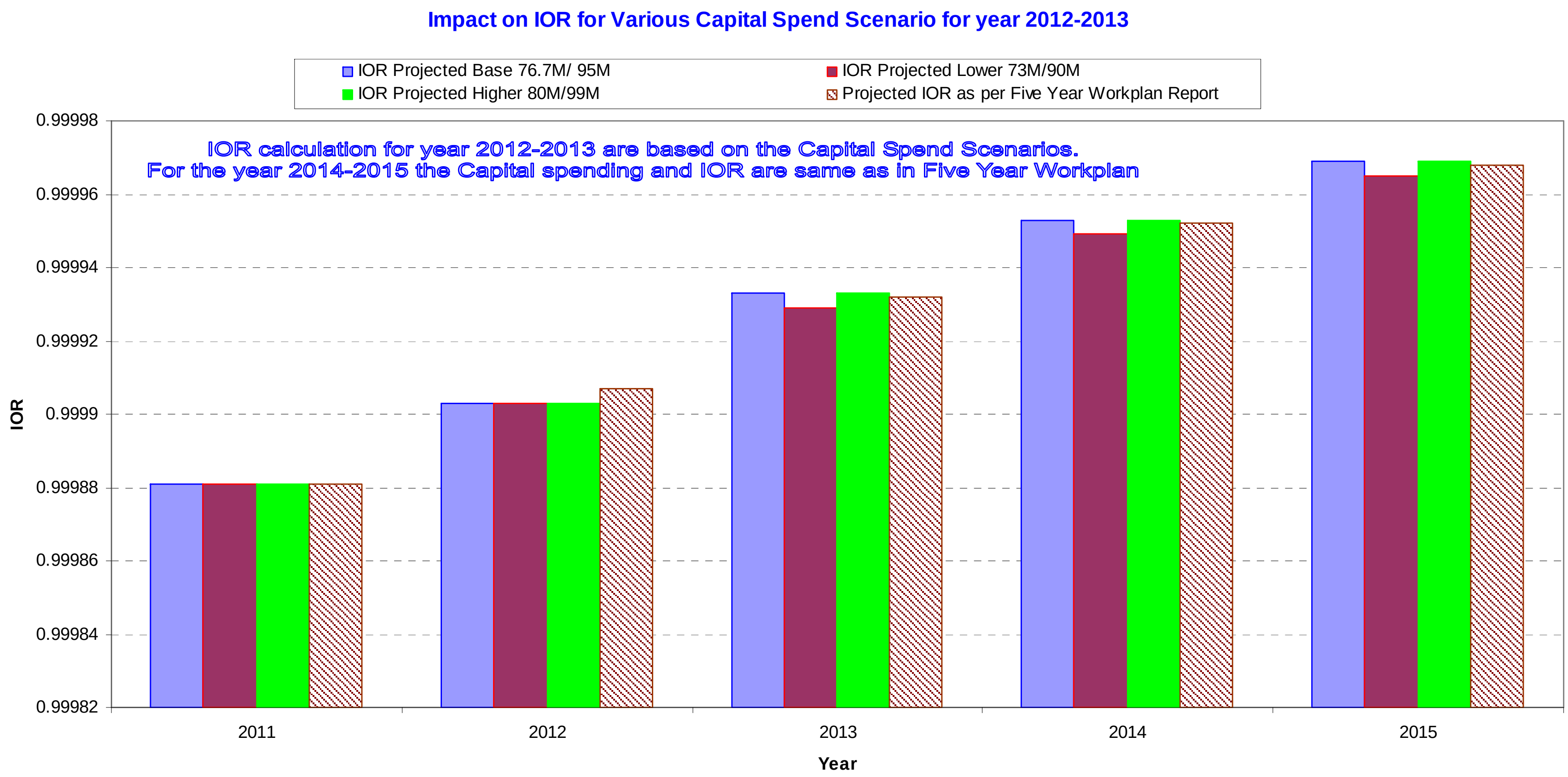
- 29 projects in 2012
  - Oil containment
  - Replacement Crane Truck
  - Automatic Feeder Restoration VTS #1
  - Upgrade 2.5 Element Meters
- 19 projects in 2013
  - Extend 27.6 kV Circuits 14th Ave.
  - Amber MS Feeder Conversion
  - Designer for Service Layouts
  - Feeder Protection Upgrade MTS#2 & MTS#3

Comparison possible scenarios

Scenario 3 – Major Projects Included

- 29 projects in 2012
  - Oil containment
  - Replacement Crane Truck
  - Automatic Feeder Restoration VTS #1
  - Upgrade 2.5 Element Meters
- 19 projects in 2013
  - Extend 27.6 kV Circuits 14^{th} Ave.
  - Amber MS Feeder Conversion
  - Designer for Service Layouts
  - Feeder Protection Upgrade MTS#2 & MTS#3

Reliability



Go Green with PowerStream

Smart Grid

Smart Grid - using new technologies to optimize electricity grid performance and maximize customer benefit

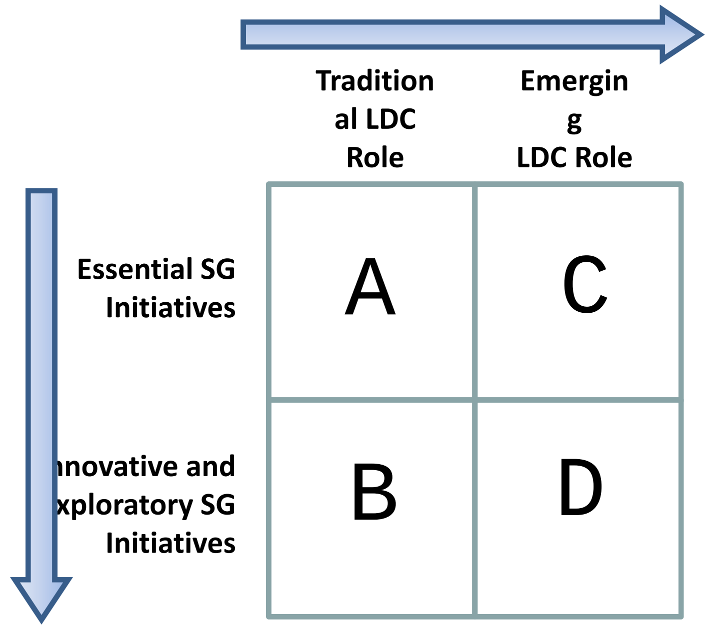
Four Types of SG Initiatives:

Type A = 100% of project considered SG

Type B = part the of project considered SG

Type C = CDM projects (funded by others)

Type D = Pilot and demonstration projects



Go Green with PowerStream

Smart Grid cont'd

Smart Grid Capital Projects Net Budget

	2012				2013			
	Optimized		Deferred		Optimized		Deferred	
	# of Proj.	$000	# of Proj.	$000	# of Proj.	$000	# of Proj.	$000
Type A Projects	27	3,928	20	2,244	37	5,242	21	2,487
Type B Projects	21	1,737	18	380	40	2,782	8	614
Totals	48	5,665	38	2,624	77	8,024	29	3,101

Other Smart Grid Initiatives

	2012		2013	
	# of Proj.	$000	# of Proj.	$000
Deferral Accounts	6	1,250	4	650
OPA & Others	TBD	TBD	TBD	TBD

Recommended Capital Spend 2012 & 2013 (NET $K) - RECAP

Recommended Capital Spend 2012 & 2013 ($K)		2012	2013
SUSTAINMENT CAPITAL			
Non-Controllable		10,830	9,883
Controllable		17,083	35,919
DEVELOPMENT CAPITAL			
Non-Controllable		19,317	19,126
Controllable		3,468	11,350
OPERATIONS CAPITAL			
Non-Controllable		2,641	1,354
Controllable		23,360	17,113
TOTAL CAPITAL		76,699	94,645
OTHER			
Smart Grid – deferral		1,250	650
Distributed Generation Customer Initiated - deferral		756	0
Historical Rebates (Economic Model) – cash flow		2,063	1,500

POWERSTREAM INC.

2012/2013 Budget Guidelines & Financial Outlook

Core Business

EOC

October 20, 2011

Private and Confidential

2012/2013 Preliminary Budget Scenario #3– OM&A reduced to achieve 8% ROE – per EOC Oct. 13'2011

Prelim Summarized Statement of Operations

(in Millions of Dollars)	Actual Core 2010	Budget Core 2011	Q3 Frcst Core 2011	Mock Core 2011	Budget Core 2012	Outlook Core 2013	Outlook Core 2014	Outlook Core 2015	Outlook Core 2016
Cost of Power	691.3	747.3	747.3	747.3	748.4	761.2	784.0	807.5	831.7
Distribution Revenue	155.8	165.7	162.1	162.1	159.3	171.0	176.1	181.4	186.9
Other Revenue	9.2	7.4	7.9	10.2	11.0	11.3	11.4	11.6	11.8
OM&A	58.0	64.5	63.4	79.7	84.6	88.0	91.2	93.9	96.3
Depreciation Expense	46.3	47.6	46.4	36.0	33.2	35.5	38.1	41.2	45.3
Interest Expense	21.9	24.5	23.7	24.0	24.5	25.2	27.4	29.3	31.7
Budget Gap									
EBT	38.9	36.5	36.5	32.7	28.0	33.6	30.8	28.7	25.4
Provision for Income Taxes	11.2	8.6	8.6	4.0	2.0	0.9	0.2	1.7	0.9
Net Income	**27.7**	**27.9**	**27.9**	**28.7**	**26.0**	**32.7**	**30.7**	**27.0**	**24.5**
Deemed ROE - Approved Rate Base	10.0%	9.8%	9.8%	10.1%	9.1%	9.5%	8.9%	7.8%	7.1%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.0%	9.2%	8.0%	9.5%	8.4%	6.9%	5.9%
Net Capital	55.4	75.0	68.8	68.8	76.7	95.0	94.4	113.4	106.3
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	711	711	711	711	860	860	860	860
Rate Base - Real Time	701	784	771	779	815	860	916	978	1,043

2012/2013 Preliminary Budget – Scenario#3 with add'l updates

Prelim Summarized Statement of Operations									
	Actual	Budget	Q3 Frcst	Mock	Budget	Outlook	Outlook	Outlook	Outlook
	Core	Core	Core	Core	Core	Core	Core	Core	Core
(in Millions of Dollars)	2010	2011	2011	2011	2012	2013	2014	2015	2016
Cost of Power	691.3	747.3	771.7	771.7	774.4	822.8	847.5	872.9	899.1
Distribution Revenue	155.8	165.7	162.1	162.1	159.6	171.5	176.6	181.9	187.4
Other Revenue	9.2	7.4	7.9	10.2	10.9	11.3	11.4	11.6	11.8
OM&A	58.0	64.5	63.4	79.7	84.8	89.0	91.7	94.4	97.3
Depreciation Expense	46.3	47.6	46.4	36.0	33.1	35.2	37.7	40.8	44.9
Interest Expense	21.9	24.5	23.7	24.0	24.5	25.0	27.3	29.9	32.8
Budget Gap									
EBT	38.9	36.5	36.5	32.7	28.2	33.5	31.3	28.4	24.3
Provision for Income Taxes	11.2	8.6	8.6	4.0	2.1	0.8	0.2	1.5	0.5
Net Income	**27.7**	**27.9**	**27.9**	**28.7**	**26.1**	**32.7**	**31.2**	**26.9**	**23.7**
Deemed ROE - Approved Rate Base	10.0%	9.8%	9.8%	10.1%	9.2%	9.5%	9.1%	7.8%	6.9%
Deemed ROE - Real Time Rate Base	9.9%	8.9%	9.0%	9.2%	8.0%	9.5%	8.6%	6.9%	5.7%
Net Capital	55.4	75.0	61.7	61.7	76.7	94.7	94.4	113.4	106.3
Statutory Tax Rate	31.0%	28.3%	28.3%	28.3%	26.3%	25.5%	25.0%	25.0%	25.0%
Rate Base - Approved	695	711	711	711	711	858	858	858	858
Rate Base - Real Time	701	784	771	779	812	858	910	974	1,041

2012/2013 Cash Flow – Scenario#3 with add'l updates

Cash Flow Forecast

Linked to FS tab

(in millions of dollars)	2010	2011	2012	2013	2014	2015	2016	Rqr'd
Cash from Operation:								
Funds from Operations	80.1	77.8	61.4	69.6	70.8	69.8	71.0	
Change in reg liabilities	(21.9)	5.2	4.9	(2.6)	(5.3)	(1.6)	0.6	
Change in working cap	(13.8)	(13.5)	(12.5)	(8.1)	(2.2)	(2.3)	(2.4)	
Cash from Financing:								
Borrowing needed	-	-	**50.0**	**45.0**	**50.0**	**60.0**	**50.0**	
Overdraft Protection								
Dividends	(10.5)	(13.9)	(14.4)	(13.0)	(16.3)	(15.6)	(13.4)	
Cash from Investing:								
Capital Expenditure	(70.3)	(61.7)	(76.7)	(94.7)	(94.4)	(113.4)	(106.3)	
Total Change of Cash:	**(36.4)**	**(6.0)**	**12.8**	**(3.8)**	**2.6**	**(3.1)**	**(0.6)**	
Cash beginning balance:	**42.6**	**6.2**	**0.1**	**12.9**	**9.1**	**11.6**	**8.5**	
Cash ending balance:	**6.2**	**0.1**	**12.9**	**9.1**	**11.6**	**8.5**	**8.0**	
S&P debt/equity ratio	60.5%	59.3%	60.4%	61.1%	62.3%	64.0%	65.2%	60.0%
Debt to rate base	58.7%	53.8%	55.4%	57.7%	59.8%	62.0%	62.8%	60.0%
WC/(COP + OMA)	**2.5%**	**1.4%**	**7.2%**	**7.2%**	**7.5%**	**7.2%**	**7.2%**	15.0%

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.2 Is service quality, based on the Board specified performance indicators acceptable?

BOARD STAFF INTERROGATORY #8

Reference(s): E B4/ T1/ S1, p.1

Table 1 presents service quality and reliability measures. The notes to this table state in part that:

"PowerStream does not distinguish between low voltage and high voltage connectors. 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."

a) Please explain why PowerStream does what is described in the above quotation and what impact this treatment has on the service quality and reliability measures.
b) Please explain what, if any adjustments have been made to the statistics in this table for days with unusual events (e.g. a major storm).

RESPONSE:

a) Until recently, PowerStream has interpreted the low voltage and high voltage connection to be at the customer metering point and as such there has been no differentiation between the two categories. Starting on January 1, 2012, PowerStream began tracking connections by voltage and at the point of customer ownership demarcation which provides a differentiation of the low voltage and high voltage connections. PowerStream does not expect the change will demonstrate a difference in service levels.

PowerStream included the category Cable Locates in Table 1 in error. When the DSC Electricity Service Quality Indicators (Chapter 7) was amended in 2008 for reporting January

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.2 Is service quality, based on the Board specified performance indicators acceptable?

1st, 2009, the individual category of underground cable locates was removed. Reporting on underground cable locates is now part of the Appointment Scheduling (s. 7.3), Appointments Met (7.4) and Rescheduling a Missed Appointment (s. 7.5). This change has no impact on service quality as appointments for underground cable locates continue to be tracked and reported above the minimum service quality level required.

b) No adjustments have been made to the statistics in Table 1 for days with unusual events (e.g. a major storm).

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.2 Is service quality, based on the Board specified performance indicators acceptable?

ENERGY PROBE INTERROGATORY #1

Reference(s): Exhibit B4, Tab 1, Schedule 1

The Connection of New Services metric decreased from 97.60% in both 2009 and 2010 to 93.10% in 2011, a reduction of 4.5 percentage points. Please explain what was behind this reduction and whether or not the reduction appears to be continuing into 2012..

RESPONSE:

There will be a natural fluctuation in service levels from year to year based on the dynamic nature of internal resources applied to this activity, the total number of new services requests within the year, the potential for an abnormal number of requests in any given month, as well as other external factors which may influence or delay our ability to connect customers, such as weather. It is expected that the Connection of New Services metric will surpass the minimum required 90% in 2012.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.2 Is service quality, based on the Board specified performance indicators acceptable?

VECC INTERROGATORY #1

Reference(s): Exhibit B4, Tab1, Schedule 1

a) Please provide a breakdown of the reasons for power interruption for the period 2009 through 2011 (e.g. tree contact, pole failure, accidental contact etc.).

b) Please provide the number of unplanned and interruptions due to poles for each of 2009 through 2011 and the sustained outages for each year as a result of pole failure.

c) Please provide the number of unplanned interruptions due to underground cable/conduit for each of 2009 through 2011 and the sustained outages for each year as a result of cable/conduit failure.

RESPONSE:

a) Please see the attached Table VECC # 1a for the reasons for power interruptions for the period 2009 through 2011. Data has been provided using accepted CEA causes with additional sub-codes for major categories.

b) There is no individual cause of outages identified as pole failures. When a pole fails it is categorized under the triggering events, such as adverse weather or foreign interference (vehicle).

The number of sustained outages due to pole failures is as follows:
2009 – 5
2010 – 3
2011 – 3

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.2 Is service quality, based on the Board specified performance indicators acceptable?

c) PowerStream has interpreted "sustained outages" as meaning "sustained interruptions" meaning an interruption of one minute or more, per our standard reporting practice to the OEB.

The number of unplanned interruption/sustained outages due to an underground cable related issue is as follows:
2009 – 87
2010 – 96
2011 – 103

Causes of Power Interruptions – 2009-2011

PowerStream Outage Causes (Reasons) 2009 to 2011 - Categorized by CEA Cause (Reasons) Codes and Sub-Codes								
2009			**2010**			**2011**		
Cause	**# Outages**	**%**	**Cause**	**# Outages**	**%**	**Cause**	**# Outages**	**%**
000 - UK Unknown	64	6.6%	**000 - UK Unknown**	30	3.0%	**000 - UK Unknown**	31	2.7%
100 - SO Scheduled Outage	289	29.6%	**100 - SO Scheduled Outage**	443	44.6%	**100 - SO Scheduled Outage**	558	47.8%
200 - LS Loss of Supply	18	1.8%	**200 - LS Loss of Supply**	17	1.7%	**200 - LS Loss of Supply**	17	1.5%
300 - TC Tree Growth/Untrimmed Tree	45	4.6%	**300 - TC Tree Growth/Untrimmed Tree**	37	3.7%	**300 - TC Tree Growth/Untrimmed Tree**	26	2.2%
301 - TC Tree Failed Tree/Branch into Lines	0	0.0%	301 - TC Tree Failed Tree/Branch into Lines	0	0.0%	301 - TC Tree Failed Tree/Branch into Lines	10	0.9%
400 - LT Lightning	18	1.8%	**400 - LT Lightning**	17	1.7%	**400 - LT Lightning**	22	1.9%
500 - DE Defective Equipment	76	7.8%	**500 - DE Defective Equipment**		0.0%	**500 - DE Defective Equipment**		0.0%
501 - DE Overhead Transformer	14	1.4%	501 - DE Overhead Transformer	18	1.8%	501 - DE Overhead Transformer	20	1.7%
502 - DE Underground Transformer	45	4.6%	502 - DE Underground Transformer	42	4.2%	502 - DE Underground Transformer	49	4.2%
503 - DE Arrestor	2	0.2%	503 - DE Arrestor	16	1.6%	503 - DE Arrestor	15	1.3%
504 - DE Primary Cable	16	1.6%	504 - DE Primary Cable	12	1.2%	504 - DE Primary Cable	30	2.6%
505 - DE Secondary	7	0.7%	505 - DE Secondary	11	1.1%	505 - DE Secondary	7	0.6%
506 - DE Line Hardware	19	1.9%	506 - DE Line Hardware	9	0.9%	506 - DE Line Hardware	15	1.3%
507 - DE Station Equipment	7	0.7%	507 - DE Station Equipment	1	0.1%	507 - DE Station Equipment	2	0.2%
508 - DE Switch	18	1.8%	508 - DE Switch	25	2.5%	508 - DE Switch	24	2.1%
509 - DE Termination	9	0.9%	509 - DE Termination	7	0.7%	509 - DE Termination	7	0.6%
510 - DE Elbow	12	1.2%	510 - DE Elbow	20	2.0%	510 - DE Elbow	20	1.7%

511 - DE Insulator	5	0.5%		511 - DE Insulator	7	0.7%	511 - DE Insulator	6	0.5%
512 - DE Splice	71	7.3%		512 - DE Splice	84	8.5%	512 - DE Splice	73	6.3%
513 - DE Switching Unit	21	2.2%		513 - DE Switching Unit	21	2.1%	513 - DE Switching Unit	26	2.2%
514 - DE Underground Transformer Vault	0	0.0%		514 - DE Underground Transformer Vault	0	0.0%	514 - DE Underground Transformer Vault	1	0.1%
515 - DE Underground Transformer Submersible	0	0.0%		515 - DE Underground Transformer Submersible	0	0.0%	515 - DE Underground Transformer Submersible	1	0.1%
599 - DE Other	1	0.1%		599 - DE Other	6	0.6%	599 - DE Other	2	0.2%
600 - AW Adverse Weather	14	1.4%		**600 - AW Adverse Weather**		0.0%	**600 - AW Adverse Weather**		0.0%
601 - AW Rain	1	0.1%		601 - AW Rain	0	0.0%	601 - AW Rain	1	0.1%
602 - AW Ice Storm	0	0.0%		602 - AW Ice Storm	0	0.0%	602 - AW Ice Storm	2	0.2%
603 - AW Snow	2	0.2%		603 - AW Snow	2	0.2%	603 - AW Snow	2	0.2%
604 - AW Wind	13	1.3%		604 - AW Wind	6	0.6%	604 - AW Wind	26	2.2%
605 - AW Extreme Temperature	1	0.1%		605 - AW Extreme Temperature	1	0.1%	605 - AW Extreme Temperature	0	0.0%
606 - AW Fog	3	0.3%		606 - AW Fog	0	0.0%	606 - AW Fog	0	0.0%
608 - AW Thunder Storm	9	0.9%		608 - AW Thunder Storm	3	0.3%	608 - AW Thunder Storm	13	1.1%
700 - AE Adverse Environment	0	0.0%		**700 - AE Adverse Environment**	0	0.0%	**700 - AE Adverse Environment**	0	0.0%
701 - AE Salt	0	0.0%		701 - AE Salt	0	0.0%	701 - AE Salt	1	0.1%
702 - AE Contamination	4	0.4%		702 - AE Contamination	9	0.9%	702 - AE Contamination	11	0.9%
704 - AE Corrosion	0	0.0%		704 - AE Corrosion	0	0.0%	704 - AE Corrosion	2	0.2%
705 - AE Vibration	1	0.1%		705 - AE Vibration	0	0.0%	705 - AE Vibration	0	0.0%
706 - AE Fire	0	0.0%		706 - AE Fire	1	0.1%	706 - AE Fire	1	0.1%
800 - HE Human Element	20	2.1%		**800 - HE Human Element**		0.0%	**800 - HE Human Element**		0.0%
801 - HE Incorrect Records	2	0.2%		801 - HE Incorrect Records	1	0.1%	801 - HE Incorrect Records	5	0.4%
802 - HE Incorrect Use of Equipment	0	0.0%		802 - HE Incorrect Use of Equipment	9	0.9%	802 - HE Incorrect Use of Equipment	4	0.3%
803 - HE Incorrect Construction or Installation	1	0.1%		803 - HE Incorrect Construction or Installation	0	0.0%	803 - HE Incorrect Construction or Installation	1	0.1%
805 - HE Switching Error	1	0.1%		805 - HE Switching Error	6	0.6%	805 - HE Switching Error	7	0.6%

807 - HE Inadequate Plant Design	0	0.0%	807 - HE Inadequate Plant Design	1	0.1%	807 - HE Inadequate Plant Design	0	0.0%
900 - FI Foreign Interference	52	5.3%	**900 - FI Foreign Interference**		0.0%	**900 - FI Foreign Interference**		0.0%
901 - FI Birds	7	0.7%	901 - FI Birds	7	0.7%	901 - FI Birds	11	0.9%
902 - FI Animals	49	5.0%	902 - FI Animals	56	5.6%	902 - FI Animals	68	5.8%
903 - FI Vehicles	34	3.5%	903 - FI Vehicles	55	5.5%	903 - FI Vehicles	40	3.4%
904 - FI Dig Ins	3	0.3%	904 - FI Dig Ins	10	1.0%	904 - FI Dig Ins	9	0.8%
907 - FI Foreign Objects	1	0.1%	907 - FI Foreign Objects	1	0.1%	907 - FI Foreign Objects	0	0.0%
908 - FI Felled Tree into Line	0	0.0%	908 - FI Felled Tree into Line	0	0.0%	908 - FI Felled Tree into Line	1	0.1%
999 - FI Other	0	0.0%	999 - FI Other	2	0.2%	999 - FI Other	1	0.1%
Total	**975**	**100.0%**	**Total**	**993**	**100.0%**	**Total**	**1,168**	**100.0%**

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.3 Are the proposals to align the rate year with PowerStream's fiscal year, and for rates effective January 1, 2013 appropriate?

CCC INTERROGATORY #5:

Reference(s): (A3/T1/S8)

What is the cost to ratepayers of advancing the rate increase from May 1, 2013 to January 1, 2013.

RESPONSE:

The alignment of rate year to fiscal year has no cost impact for ratepayers since only the timing of the rate increase is affected. The 4.6% average rate increase will be effective from January 1, 2013 until January 1, 2014 instead of from May 1, 2013 until May 1, 2014.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

BOARD STAFF INTERROGATORY #9:

Reference(s): <u>E B2/T1/S1/p.3, 5, 6</u>

On pages 5 and 6 of the above references, PowerStream requested a funding adder for its Green Energy (GEA) Plan, stating as follows:

"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…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."

a) The Board's EB-2009-0397 *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* Revised May 17, 2012 outlines in Section 5.2, the conditions under which additional funding is available for proposed expenditures. Please discuss whether or not in PowerStream's view, its requested funding adder meets these conditions and if so why and, if not, why PowerStream's circumstances would justify a departure.
b) The Board's requirements state that when a funding adder is requested "The costs will be subject to a prudence review in the first cost of service application following the

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

implementation of the adder." However, PowerStream states that "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." Please state whether the implication of this statement is that PowerStream wishes the Board to make a determination in this proceeding as to the prudence of all GEA costs forecasted to be incurred by PowerStream up to 2016.

RESPONSE:

a) The Board's EB-2009-0397 *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* Revised May 17, 2012 states in Section 5.2 that "The Board recognizes that distributors may need additional funding for expenditures proposed in a GEA plan between cost of service applications, and will consider applications for suitable finding mechanisms." In other words, section 5.2 differentiates between two available funding mechanisms, but does not specify the conditions for this funding. To fund the GEA spending between cost of service applications, PowerStream asked for the funding adder mechanism, with costs subject to prudence review in the next cost of service application, as per Section 5.2 of the aforementioned Filing Requirements. PowerStream does not propose any departure from the existing Board policy in respect to the additional GEA funding.

b) No, PowerStream does not ask the Board to make a determination in this proceeding regarding prudency of all GEA costs forecasted to be incurred. PowerStream will record the actual spending in appropriate GEA deferral accounts and these costs will be subject to a prudence review in PowerStream's next cost of service application. The variance between the actual amount spent and the amount received from the funding adder will be disposed of at that time, subject to the demonstration of prudence.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

BOARD STAFF INTERROGATORY #10:

Reference(s): **<u>E B2/T1/S1/p. 5, Table 3, E B2/T1/S2/pp. 33-34 and E I</u>**

The table at the first reference summarizes the amounts for disposition relating to renewable generation connection and smart grid expenditures recorded in deferral accounts 1531, 1532, 1534 and 1535 over the 2010-2011 period.

At the second reference on page 34 PowerStream outlines some of the activities related to the Smart Grid OM&A Deferral Account. The table at this reference also indicates that management of the smart grid strategy for 2010-2011 has resulted in $395,000 in OM&A expenses, and will continue to impose a somewhat steady annual cost of about $200,000/year until 2016. At the same time PowerStream indicates in various instances that if the adoption of some technologies currently tested occurs, expenditures beyond 2013 will be included in the regular capital plan.

With respect to Smart Grid, at page 33 of the second reference PowerStream states that “any reports or findings from these activities are openly shared amongst other LDCs or other interested parties”.

a) Please expand on the second reference by providing a summary of the activities, cost and benefits corresponding to the item on the table “Manage the Smart Grid Strategy” for 2010 and 2011.
b) For 2010 and 2011, have any Smart Grid activities resulted in particular findings or reports? If so, please indicate how to access them.
c) Have the REI activities undertaken in 2010 and 2012 resulted in any premature asset retirements? Where applicable please give an estimate of the remaining useful life of the “replaced” asset and indicate in each case whether there is a residual value.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

d) Based on the response to part c, if applicable adjust account 1531 (REI Capital) at the first reference accordingly.

RESPONSE:

a) The 2011 and 2012 costs associated with managing the smart grid strategy are for ensuring that smart grid technologies are utilized by PowerStream in a prudent manner. Some specific activities performed in this expense category are as follows:

- Leading PowerStream's Smart Grid Task Force, which is a cross functional team, that meets regularly to ensure that the focus on smart grid initiatives continues to be aligned with the regulatory framework and emerging industry initiatives.
- PowerStream regularly reviews industry smart grid developments to assess their applicability.
- Annually review and update PowerStream's Smart Grid strategy and plan.
- PowerStream participates on a number of government and industry forums and committees to assist in shaping the smart grid direction for both the industry and province.
- PowerStream provides recommendations regarding standards and best practices for Ontario smart grid advancement.
- PowerStream participates in and makes presentations at Smart Grid summits, conferences and expositions to exchange knowledge about smart grid development around the world in order to ensure that the best technologies are adopted locally.
- Identify and manage smart grid pilot and demonstration initiatives, ensuring that PowerStream develops statistics and reports on their suitability for integration into PowerStream's standards and capital plan.
- Manage PowerStream Smart Grid Capital and O&M annual budgets.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

Smart Grid is a commitment by the Province of Ontario to modernize the electricity system using sensors, communications, automation and computers to provide improved reliability, flexibility, security and efficiency of the system. The Smart Grid will allow consumers to better control their electricity use in response to prices and other parameters. Smart Grid technology also accommodates diverse and distributed energy resources (e.g. renewable energy sources) while facilitating and optimizing new technologies such as electric vehicle charging. In short, Smart Grid optimizes production, delivery and consumption of electricity for the benefit of consumers and the environment.

PowerStream has calculated benefit to cost ratios for key projects in order to establish priorities. Initiatives that yield a benefit to cost ratio of less than one are not pursued as part of the Smart Grid Plan. This important cost – benefit work was done under "Manage the Smart Grid Strategy" in order to ensure prudence as PowerStream advances smart grid technology.

b) Reports that have been shared with LDCs and other interested parties are as follows. The recipients of the reports have not been tracked:

- Queen's University 2010-11 report on EV Charging Impact on Assets (attached as Appendix A);
- Queen's University 2011-2012 report on Vehicle-to-Home Technology and Better Place (attached as Appendix B); and
- 2010-2012 Smart Charger Trial Report (attached as Appendix C).

b) REI investments in 2010 and 2012 have not resulted in premature asset retirements.

d) Not applicable.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

BOARD STAFF INTERROGATORY #11:

Reference(s): E B2/T1/S1/p. 4, Table 2, E B2/T1/S2/pp. 63-64 and *Report of the Board, Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09*, Paragraph 1.1, Regulation 330/09 (EB-2009-0349) June 10. 2010

With respect to the first reference, the direct benefits calculation has only taken into account capital expenditures related to the connection of renewable generation.

With respect to the second reference, on OM&A costs, the *Framework for Determining Direct Benefits* clarifies that:

> "Eligible investment" costs, as set out in O. Reg. 330/09 and section 79.1 (5) of the Act, are not limited to only the initial capital investment costs but also include the *up-front* OM&A costs necessary for the purpose of "enabling the connection of a qualifying generation facility". However, given that section 79.1 focuses solely on the initial investment, ***ongoing OM&A costs that are incurred by the distributor after the investment has been made will not be eligible for provincial recovery."*** (emphasis added)

a) Please clarify whether any of the labour costs identified at the second reference are fully or partially, initial costs.
b) If initial OM&A costs exist, please revise the direct benefits calculation and funding adder amount accordingly.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

RESPONSE:

a) Out of the labour costs identified in Exhibit B2, Tab 1,Schedule 2, pp. 63-64, $72,949 for “Coordination MicroFit” could be classified as “initial” OM&A costs. The balance of the OM&A costs are ongoing administration costs.

b) The impact of the revision to the direct benefits calculation is immaterial. The direct benefits recalculated to include “initial” OM&A costs are $4,377 higher than in the original application:

Table BS #11-1 Direct Benefits Recalculated to Include "Initial" OM&A (‘000)

		Actual 2010 - 2011	2012	2013	2014-2016	Total 2010-2016
Capital spending - REI Investments		525	756	77	155	1,513
Initial OM&A Costs		73				73
Total Eligible Investments		598	756	77	155	1,586
Less Direct benefits to PowerStream's customers:	6%	(36)	(45)	(5)	(9)	(95)
To be recovered from Provincial rate payers	94%	**489**	**711**	**73**	**145**	**1,418**

Correspondingly, the balance for disposal in deferral accounts would decrease by $4,377 and is equal to $1,108,495.

The 2010-2011 costs are not included in the calculation of the funding adder; therefore, there is no impact of this revision on the funding adder.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

BOARD STAFF INTERROGATORY #12:

Reference(s): *Filing Requirements: Distribution System Plans – Filing under Deemed Condition of Licence*, revised May 17, 2012 [EB-2009-0397], Paragraph 3.2.2, p.11-12.

a) In accordance with the Filing Requirements, and if any such facilities exist, do present plans to connect renewable energy projects have any impacts on embedded distributors?
b) If so please indicate whether appropriate discussions with embedded distributors have taken place.

RESPONSE:

a) There are no embedded distributors attached to PowerStream's distribution system.

b) See a).

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

CCC INTERROGATORY #6:

Reference(s): (B2/T1/S1/p. 5)

Please explain how the $1.422 million was calculated.

RESPONSE:

As per PowerStream's Basic GEA plan, the total forecasted capital spending needed to enable the connection of FIT generators amounts to $1,513,000. All these investments comprise "renewable enabling improvements". Since filing of its Basic GEA Plan, PowerStream has been able to use the default direct benefit percentage as determined by the Board in the relevant Hydro One proceeding, where the Renewable Energy Improvement (REI) investment, the direct benefits for utility customers, are 6%. The $1.422 million represents the total eligible investments less 6% for "direct benefits", as shown in table below.

Table CCC #6-1: Provincial Rate Recovery (000)

		Actual 2010 - 2011	2012	2013	2014-2016	Total 2010-2016
Capital spending - REI Investments		525	756	77	155	1,513
Less Direct benefits to PowerStream's customers:	6%	(31.49)	(45.38)	(4.64)	(9.27)	(91)
To be recovered from Provincial rate payers	94%	**493**	**711**	**73**	**145**	**1,422**

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

ENERGY PROBE INTERROGATORY #2:

Reference(s): Exhibit B2, Tab 1, Schedule 1

a) Has PowerStream included the $5,000 shown in Table 2 as the capital spending amount in the test year as a direct benefit to PowerStream customers in the test year rate base?

b) Has PowerStream included the $650 shown in Table 1 in capital spending in the 2013 rate base calculation?

c) Has PowerStream included the $388 shown in Table 1 of OM&A in the 2013 revenue requirement?

RESPONSE:

a) No, this amount has not been included in the Test Year rate base. An amount of $462,800 was added to the Test Year rate base. This amount represents the capital additions for REI and Smart grid (accounts 1531 and 1534) up to December 31, 2011, net of the provincial recovery portion for account 1531 net of accumulated amortization to December 31, 2012 (as discussed in the Exhibit B1, Tab 1, Schedule 1).

b) No, PowerStream has not included $650,000 for Smart Grid capital investment the 2013 rate base calculation. Please see response to part (a).

c) No, the $388,000 of 2013 OM&A expenses are not included in the 2013 revenue requirement. PowerStream has proposed to continue recording the actual OM&A spending in deferral accounts 1532 and 1534 and to track the difference between the actual spending and the funding collected through the funding adder.

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

VECC INTERROGATORY #2:

Reference(s): Exhibit B2, Tab 1, Schedule 2

a) What alternatives to the WiMAX communication system did PowerStream consider (e.g. leasing communications)? Please provide the analysis of the options considered.

RESPONSE:

a) PowerStream considered the following communication alternatives in order to provide communications for the remote trip signaling and monitoring of Feed-In-Tariff (FIT) generators 250kW and larger in the PowerStream service area:

1. Audio Leased Circuit
2. Cellular Communications
3. Narrow Band Point-to-Point Radio
4. Narrow Band Point-to-Multipoint Radio
5. Broadband Point-to-Multipoint Radio(WiMax)

The communication alternatives were analyzed using the following criteria:

1. Communication capability
2. Security of communication
3. Spectrum Interference
4. Message Latency
5. Signal Range
6. Cost

RESPONSES TO INTERROGATORIES BY ISSUE

1. GENERAL

1.4 Is the proposed Green Energy Act Plan appropriate?

The following is a high-level summary of key issue(s) with respect to each communication alternative:

1. Audio Leased Circuit – monthly cost too high, too many communication circuits coming back to each station.
2. Cellular Communications – not fast enough for remote trip signaling, relatively high monthly cost.
3. Narrow Band Point-to-Point Radio – can only communicate with a single FIT generator, unused licensed frequencies not available.
4. Narrow Band Point-to-Multipoint Radio – Supports multiple remote trip signaling, but can not transmit monitoring data as well.

Broadband Point-to-Multipoint Radio – WiMax technology meets all requirements.

Plug-in Electric Vehicle Grid Loading

Impacts and Strategies for an Emerging Industry

Queen's University

Faculty of Engineering and Applied Science

Jeff English
Adam Kubacki
Geoff Leslie
Jason Wong

4/11/2011

This report examines the potential impact plug-in electric vehicles will have on the electric grid, and more specifically, PowerStream. It analyses potential strategies for PowerStream to encourage off-peak charging among electric vehicle owners, and it also considers new or emerging technologies that can help mitigate the peak loading issues that PowerStream will encounter. The effect of PEVs on transformers is modeled under a variety of scenarios. The financial cost of upgrading the grid to handle PEV loads is estimated. Several strategies for preventing infrastructure failure are suggested for PowerStream to pursue.

Executive Summary

Plug-in electric vehicles (PEVs) will be released in Ontario in early 2012. Charging electric vehicles requires high power levels, which could overload the grid. The most likely point of failure is residential transformers because of their low excess capacity. This report looks at the effect PEVs will have on these transformers, strategies for reducing the rate of transformer failures, partnerships for implementing strategies, and the financial value of equipment at risk.

It is expected that 5% of passenger vehicles in Ontario will be electric by 2020. Assuming an even distribution of vehicles, this will result in 40-50% of transformers being affected by PEV charging. Level 2 chargers, expected to be the most common type of charger, draw 9.8kW of power. This will use a large portion of the extra capacity in residential transformers.

A model was created which simulates the effects of PEV charging on the peak load curve from a sample neighbourhood. Estimates were made for rate of PEV penetration, level 2 charging, controlled charging, and non-residential charging. Controlled charging was found to be very effective in preventing transformer failures. Non-residential charging was found to be somewhat less effective. PowerStream should work to ensure that charge control is implemented as soon as PEVs are on the market. This can be done by arranging to purchase and install charging stations for new PEV owners. This will ensure all PEV chargers in the area will be high quality and capable of meeting PowerStream's needs for controlling charge. This strategy should be supplemented by encouraging non-residential charging to further reduce the chance that transformers will overload.

Contents

Figures

Tables

1. Introduction

There are two primary objectives of this project. First, estimate the effect of plug-in electric vehicle charging on PowerStream's current infrastructure. Second, identify PowerStream's opportunities to benefit from PEV charging.

The analysis of PEV charging is primarily focused on residential neighbourhoods. This is the area in which there is the least spare capacity to accommodate new loading. Successfully predicting the increase in the load caused by PEV charging will allow PowerStream to upgrade its infrastructure before it fails, preventing loss of service. It will also help provide an estimate of the effect new charge control strategies will have before they are implemented. The estimated increase in residential transformer loading is described in Section 9.

The opportunities for PowerStream fall into two broad categories: charge control and partnerships. Charge control is the act of attempting to regulate the timing and/or magnitude of the load caused by PEVs. This can be done through soft means, such as pricing incentives, or hard means, such as remote controlled charging. The goal of charge control is to "flatten" the daily load curve of a residential transformer, preventing equipment failure and maximizing capital usage. Several methods of charge control are described in detail in Section 7.

PowerStream can create partnerships with companies that will be affected by PEVs. Because PEVs have no precedent for widespread adoption, the roles of the many stakeholders are not defined. This affords local distribution companies like PowerStream the opportunity to partner with car manufacturers and dealerships, charging station makers and installers, and PEV drivers to ensure a successful and sustainable rollout of PEVs. Partnership options available to PowerStream are discussed in Section 7.1.

2. Background Research

Plug-In Electric Vehicles (PEVs) could have potentially disastrous effects on PowerStream's electricity infrastructure. However, they simultaneously have the potential to revolutionize and greatly improve electricity distribution technology. It is important to correctly predict how PEVs will be used and how this use will influence the grid in order to upgrade infrastructure in a useful way.

A PEV is a wholly-electric vehicle with an internal battery, charged from grid current through wall outlets or charging stations. The technology dramatically reduces lifecycle greenhouse emissions and vehicle running costs, though with larger initial investment. This will be partially offset by government rebates and incentives. Government programs give some idea as to the penetration of PEVs in the market, and will be used as a benchmark for this project.

The charging of PEVs is the largest concern to PowerStream and other local distribution companies (LDCs). Distribution infrastructure is built to match peak requirements very closely. This allows the LDC to deliver power at the lowest cost to the consumer. PEVs, if unmanaged, will raise peak use significantly. If well-implemented, the use of “Smart Grid” and PEV charge management technology can have a beneficial effect and improve LDC services.

PHEVs, or Plug-In Hybrid Electric Vehicles, have smaller batteries but similar power requirements with shorter charging times. It is assumed that the effects of PHEVs will be similar to those of PEVs.

2.1 General Information

Most auto manufacturers are either developing a PEV or PHEV, or releasing one in the near future. In Canada, the first-to-market have been low-speed electric vehicles such as the ZENN, though these cars have legal restrictions on road use. The Nissan Leaf will be the first PEV to be widely released; it is expected to be released in January 2012 (initial plans were for late 2011). However, Chevrolet, Tesla, and Ford all have plans to release some form of plug-in vehicle by 2015. Official prices for these vehicles in Canada have not yet been released. In the USA the Leaf will retail for $32,780 and the Volt for $41,000. It is likely that the Canadian retail price will be slightly higher than these figures.

The government of Ontario has started and maintained an Electric Vehicle Incentive Program, where each vehicle will qualify for an $8,500 tax credit under Ontario’s “1 in 20 by 2020” plan which seeks to ensure 5% of Ontario passenger vehicles are electric by the year 2020. There is currently no federal tax credit towards the purchase of electric vehicles. Further incentives by the Ontario program include access to High Occupancy Vehicle lanes (HOVs) and access to government charging stations at GO train parking lots and government buildings (Ontario Ministry of Transportation, 2010).

The primary motivation behind government incentives is the reduction in greenhouse gasses in PEV or PHEV lifecycles compared to that of an internal combustion engine vehicle. Currently the transportation sector emits 37% of the total national greenhouse gas emissions, with passenger vehicles account for

57% of the sector, or 20.7% of the national total (Energy-Use and Climate Change - Energy Use in Canada, 2010). In Ontario, 77% of grid electricity is sourced from GHG free plants, 8% from coal, and 15% from oil and natural gas (Ontario Ministry of Energy, 2010). The average emissions per kilowatt hour of coal power plants are 0.95kg, and for natural gas 0.66kg (Environmental Protection Agency, 2000). This means that charging the 24kWh battery if the Nissan Leaf will emit 4.2kg of CO_2 while giving you an estimated range of 160km. Driving a Nissan Versa, which shares the same platform as the Leaf, will burn 10.75L of gasoline and emit 25.2kg of CO_2. Given the Canadian average of 17,000km per year per vehicle a Leaf will reduce CO_2 emissions by 222 tonnes or 84%.

2.2 Electric Vehicle Charging

The charging of electric vehicles follows the standard SAE J1772, a high-speed charging method. There are currently three methods of charging with different time and power requirements, known as level 1, 2 and 3 charging. Data regarding each charging level can be found below in Table 1. Of the types of charging available, the most used will be level 2 (L2) charging; Nissan is bundling the Leaf with the installation of a level 2 charger in the garage (for private non-fleet consumers). There are several producers of PEV chargers such as General Electric and Better Place. The charging methods, associated charging time and electrical characteristics, are summarized below (Canizares, 2010):

Table 1: Characteristics of PEV chargers

Level	1	2	3
Charge Time (hours)	8-30	2-6	30 minutes
Voltage (V)	120	240	480, 3-Phase
Current (A)	12-16	32-70	160 A

It should be noted that level 3 charging will require significant infrastructure changes to become viable, and the technology itself is still under development. The costs of such changes place it beyond the capabilities of most households but it may see use in high-speed charging stations by highways, in parking lots of grocery stores, office buildings or other commercial customers.

2.3 Power Distribution Infrastructure and the Smart Grid

PowerStream is a local distribution company, taking power off of transmission lines at high voltage and stepping down through a series of transformers until it reaches a customer. Supply voltages vary by customer, but residential houses are fed 120/240 volts, and commercial 120/208 or 347/600. The costs of transformers vary greatly, due the range of capacity requirements. Neighbourhood padmount transformers, which only have a capacity of 50kVA, cost approximately $2500. Large step-down transformers, conversely, have a service area of several hundred square kilometres and can cost $20 million to build. The primary concern of this project is the charging of PEVs in a residential setting.

There are between 8 and 10 houses on a particular residential transformer. Each house draws around 3 kW, and the transformer provides a maximum of 50 kW before overloading. In Figure 1, one may see the peak use by hour of power over PowerStream's distribution network. The red line is the peak capacity of the network before transformers begin to fail. It is clear that there is little room for an increase in peak demand before replacements in infrastructure are required.

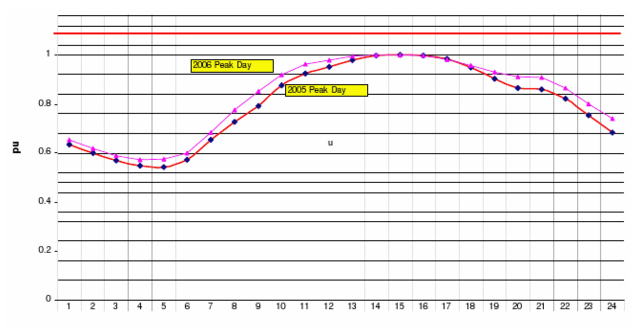


Figure 1: PowerStream's load curve as of 2009

2.4 Effects of PEVs on the Grid

PEVs provide convenience for consumers, as they can recharge their cars while at work or at home, without having to spend time at a gas station. However, electricity distributors (such as PowerStream) must be aware of the effect that PEVs have on their power distribution networks. One study showed that if no system were implemented to control domestic car-charging, peak electricity demand would increase by 18% for every 10% of households that owned a PEV (Putrus, 2009). This increase in peak demand may eventually exceed the supply, which would cause severe problems for the entire network.

One method to reduce peak consumption is by encouraging consumers to recharge their PEVs during low-demand hours – typically between midnight and 6AM. Reduced rates can be offered to PEV owners as an incentive to recharge their cars right at night. In addition, smart-charging systems can be installed into PEVs or charging stations, such that the car does not start recharging until a set time, even if it is plugged in.

Another method is by constructing battery-switching stations. Similar to conventional gas stations, battery-switching stations would allow consumers to switch a nearly-depleted battery with a new, fully-charged one. This could prevent peak hour charging, as consumers would not need to recharge at home. The depleted batteries could then be recharged at appropriate times, without inconveniencing the consumer. PowerStream is currently working with Better Place, who is developing battery swap technology, an example of a relationship already pursued.

PEVs can also help alleviate peak electrical demand from other sources through a Vehicle-to-Grid (V2G) system. V2G systems provide communication between the power grid and the vehicles, and they can prompt the vehicles to send electricity back to the power grid during peak hours. Then, the vehicle could be recharged at night, when rates are lower. Consumers would save money, since distributors would be required to compensate owners at high-demand rates. V2G technology is relatively new, and is currently being studied in-depth, notably at the University of Delaware, as well as the Pacific Gas and Electric Company, and Xcel Energy, all of which are based in the United States. A pilot project is currently underway in Denmark to evaluate the effectiveness of electric vehicles in storing electricity from wind turbines (Graham-Rowe, 2009).This capability can allow an electricity generating utility to avoid being forced to utilize additional more costly energy sources with greater GHG emissions, such as spinning reserves and low-efficiency generators.

2.5 Effects on Total Consumption

Although smart-charging systems and battery-switching stations can help distribute demand more evenly across a day, total daily energy consumption will increase with the introduction of PEVs into the public market. The Government of Ontario forecasts an increase of 3.5% in provincial electricity demand by 2020 (Ontario Ministry of Energy, 2010). This may influence future decisions, such as upgrading production capabilities, or increasing energy purchases.

2.6 Summary of Reports

Several reports describing key factors regarding PEVs in Ontario were used as a basis for predicting future loads. The methods and findings of each of these reports are summarized in this Section.

2.6.1 Transportation Tomorrow Survey

The Transportation Tomorrow Survey (TTS) compiled data on the travel habits of households around the GTA. The report includes the number of trips per day, distance travelled in each trip, and number of cars per household. This information is used to estimate the distance an average PEV driver will travel per day, which is then used to determine the amount of energy required to fully charge their vehicle.

2.6.2 Manitoba Hydro

A report by Manitoba Hydro outlining the timing of PEV charging was used to inform the model of expected load times. The study looked at drivers in Winnipeg to analyze the driving habits of potential PEV owners. It was assumed that each driver will not significantly change their driving habits after purchasing a PEV, and that every driver charges entirely at home. The home departure and arrival times, as well as the daily distance travelled, was analyzed and used to estimate PEV charging characteristics.

The report looks at L1 and L2 charging in uncontrolled and delayed start scenarios. For the purposes of this project it is the estimates of charging start time that are useful. The uncontrolled start times were placed directly into the model while the controlled times were used as a basis for determining ideal start times to minimize failures.

The accuracy of the charge start time distribution with respect to York Region is limited by the similarity to the home arrival times in Winnipeg. Although this information is not yet available for York Region, it is assumed that no major discrepancies exist.

2.6.3 Quanta Technology

Quanta Technology performed a simulation of the effect of PEVs on a sample electricity network using CYMDIST. Failure modes included in the study were transformer overloads, undervoltages, and conductor overloads. The report found that in an uncontrolled scenario transformer overloads occurred at any penetration level. Undervoltages and conductor overloads were not significant at low penetration levels. Controlled charging was found to completely eliminate undervoltages and conductor overloads at penetration rates below 20%, while transformer failures were eliminated completely (Quanta Technology, 2010).

The model discussed in Section 9 is based off Quanta’s methodology. Only transformer failures are considered because they were found to be the most significant source of failure. Each scenario was also run many more times – 500 instead of 10 – in order to reduce the uncertainty in the final result.

2.7 Demographic Information

PEVs are marketed to high-income commuters, and it is thought that higher income households will have a higher chance of PEV ownership. A study of the 2006 census was undertaken to find the income distribution of PowerStream's customer base (studying Vaughan, Richmond Hill, Aurora, and Markham) that also have an average commute within the range of a PEV. It was found that at a resolution of 2 km blocks, PowerStream's customer base has a fairly differentiated average household income – varying from $80k/year to $230k/year. It is likely that PEV ownership will be equally fragmented.

Demographic research to relate income to PEV ownership is available, but is priced beyond the budget of this project. Raw census data has been included in the appendices of this report, and may be used to determine a probability map for planning purposes.

3. Scope and Problem Definition

In order to properly manage the introduction of PEVs to the Ontario market, PowerStream must develop strategies to target and address the potential problems that PEVs may create. This project aims to provide solutions to the most time-sensitive problem, which is the possible grid-overloading effect that PEVs may have on local transformer units.

Currently, for most residential locations, electricity transformers have a capacity of approximately 50kW. Most transformers provide service to between 8 and 10 houses, and one house usually uses less than 4kW of power during peak hours. That means, even during the busiest times of the day, there is a 10kW "cushion" to account for fluctuations in consumption and extenuating circumstances. However, once consumers start charging their PEVs, this cushion is reduced drastically, and in some cases it may not be enough to prevent transformer failure.

The charging method that is available to all homeowners is "Level 1" charging, where consumers can simply plug their vehicle into an electrical outlet in their home after a few minor modifications. This method would consume only 1.5kW, which would have a small impact on the grid. However, level 1 charging is slow, requiring at least 8 hours (and in many cases, around 15) to fully recharge a battery. To many consumers, this may be too long. They may choose to upgrade to Level 2 charging, which can fully recharge a battery in 6 hours. However, Level 2 charging for the Nissan Leaf consumes 9.6kW, and having two or more PEVs charging at Level 2 at the same time could overload transformers.

This study will list several strategies that PowerStream could use to encourage users to charge their PEVs during off-peak hours. However, assuming that user cooperation will not be 100%, this study will also list technologies that PowerStream could implement, and business strategies that PowerStream could pursue, to help mitigate the expected increase in peak-time loading. Most importantly, it will provide financial analysis regarding the merits and drawbacks of each opportunity, and give a concrete reason for why each option should or should not be considered.

Finally, extensive consideration will be given to the fact that PowerStream is committed to being a leader in energy conservation and environmental sustainability. Each option that is considered within this study will be closely analyzed to ensure that it meets or exceed PowerStream's "green" values.

4. Potential Market for Plug-in Electric Vehicles

The Ontario government has developed a plan to reduce greenhouse gas emissions, and one of its targets is to have 1 in 20 passenger vehicles be electric by 2020. It has been projected that in 2020, there will be approximately 8.1 million passenger vehicles on the road in Ontario. Approximately 47% of the passenger vehicles in Ontario will be located in the GTA and its surrounding cities. This means that there will be roughly 150 thousand PEVs on the road in the GTA (WISE, 2010).

On average, the distance of a return trip to work for a Torontonian is 25.9km. In addition, 80% of Toronto commuters travel less than 40km for a round-trip to work(Electric Mobility Canada, 2010). If that number were doubled to include non-work-related travelling, the daily distance travelled would still fall well below current PEV limits, which are between 100 and 150km. Since many businesses may consider implementing charging stations for their employees, we could also consider one-way travelling only. If this were the case, PEVs could service more than 95% of Ontarians' daily travel requirements.

One area of concern for potential PEV customers is that PEVs do not have enough capacity for long-distance travelling during non-work days. This concern can be addressed by the fact that while there are 13 million households in Canada, there are more than 20 million passenger vehicles. On average, there are 1.5 vehicles per household, meaning that approximately 50% of houses have at least two vehicles. One of them could be a PEV and be used for work travelling only, and the other could be used for weekend or vacation travels. As long as PEVs can satisfy the work travel needs, it should be sufficient for a large percentage of travelers.

Although it is not completely reflective of Canadian values, a survey conducted by the Electrification Coalition in the USA can act as a guideline for public acceptance of PEVs. Its results show that if a "high quality electric car" were produced, 65% of the surveyed participants would be likely to purchase a PEV. In addition, 60% feel that auto companies should move away from developing traditional internal combustion engine vehicles, and move towards developed electric and hybrid electric vehicles. This shows that a growing percentage of the public is supportive of the development of electric vehicles (Electrification Coalition, 2010).

From previous market analysis, it has been determined that the majority of PEV sales will be in urban areas. It is expected that many of these PEV owners will commute to and from a job with average work hours of 9am to 5pm. To complete this route, the PEV batteries would generally be fully charged at the beginning of the work day, and below 50% at the end of the day. Typical owners will not want to risk running out of batteries on their next trip, therefore owners will recharge the vehicles between work days. This will result in grid loading either at the end of the work-day, or once the day is complete at night-time. Since the PEV owner is expected to be using this vehicle for daily commutes, fluctuations on grid loading throughout the year is expected to be fairly consistent.

It is possible to speculate that in the future there may be charging stations along the major commuting routes in the GTA or within employment district parking lots. This would result in grid loading between the hours of 9am and 5 pm. However, since the implementation of these charging stations are electrical distribution companies' responsibility (such as PowerStream), and these distribution companies would prefer evening and night-time charging (to reduce peak loading), it is not expected that these chargers will be implemented in the near future. If stage 3 charging stations emerge along the commuter routes, an amount of charging during the day could potentially occur. The implementation of battery-swapping stations, however, will once again evade the loading of the grid during peak hours.

4.1 Commercial Users of PEVs

In additional to residential consumers, to which most PEVs are currently being marketed, some members of the service industry may be interested in participating as well. Compared to normal internal combustion engine vehicles, PEVs have lower fuel costs, more efficient stop/start systems, and less fuel consumption while idling. At a range of 120 km city driving, a Nissan Leaf would have fuel costs of about 4 cents per kilometre (assuming charging costs 20 cents/kWh and one full charge provides a range of 120km). Contrast this with the Cobalt LT, which has fuel costs of 8.14 cents/km (CAA, 2010).

These savings in fuel charges should appear attractive to taxi companies and delivery services, provided fast charging could be provided at reasonable costs. In fact, precedent has already been set – some companies have already adopted hybrid vehicles such as the Toyota Prius to take advantage of similar (if smaller) savings. The exact per-kilometre costs of electric vehicles are hard to determine, as maintenance, tax and insurance information is not yet available or reliable; however, given that fuel costs appear to be half that of current vehicles, even under conservative estimates, it is likely that the service industry would be very interested in running such vehicles.

4.2 Need for Charging Stations

If commuters are to use PEVs, longer-range commuters will require fast-charging stations to some extent. A Barrie-Toronto commute is on the order of 90 km and approximately 5000 people made this commute five times per week in 2006(TTS, 2006); given the optimum range of the Nissan Leaf, recharging at some point during the day would be required to entice users of such a driving range in order to use PEVs. Much more moderate commutes – such as Mississauga/Vaughan or Vaughan/Pickering – are around 80 km round trip, or at least half a charge. Some fast charging system would be required for evening and recreational use of the vehicle during the week.

Further, if PEVs are to become attractive to commercial owners such as taxi or delivery services, fast charging would be required in order to minimize vehicle downtime. Further, such companies would be willing to pay a fairly high price for energy in such a system, as long as running costs stayed below a certain threshold. Taxi charging stations could be provided at idling points near bus stations, popular bars and the like, but the bulk of charging during busy times would have to be completed within a matter of minutes (on the order of filling a gas tank) especially since PEVs have a reduced range compared to gas or hybrid cars.

5. Idea Generation

To prepare PowerStream for the introduction of PEVs, as many feasible solutions should be proposed as possible. This will provide PowerStream with a variety of options that they may not have otherwise been aware of. In order to create this list of solutions, the potential stakeholders were brainstormed, factors affecting the loading of the grid specific to the electric vehicle situation were discussed, and possible strategies were developed that PowerStream could implement to reduce the damage to PowerStream’s grid.

For an example of how the process worked, consider the consumption model that has been developed: In order to determine impact of a particular strategy, consumption patterns of electric vehicles users are required. Consumption is dependent on several factors, such as number of vehicles, charging patterns and distribution losses, and researched each of those concepts; in some cases it was found that the variable was dependent on a new factor, or several factors, or could be used as a constant.

5.1 Stakeholders

Initially, potential stakeholders were identified and a list was created. The list was initially the same as the parties mentioned in the market analysis Section, however as each idea is developed, the potential stakeholders change. For example, it has been determined that Nissan is not interested in initiating the "Including Electricity with Car Purchase" option discussed below in the Business Ideas Section, but may be interested if another company decides to offer the plan. Their role as a stakeholder has thus been changed, and must be considered in the development of that idea.

Stakeholder brainstorming has yielded parties such as electrical distribution companies in Ontario, citizens of PowerStream's districts, auto-manufacturers, charging technology innovators, transformer manufacturers, as well as electrical distribution companies in Quebec, oil companies and others. Relationships with stakeholders are further discussed in Section 7.

5.2 Factors Affecting Power Consumption

Once the stakeholders have been identified, potential factors that could affect peak consumption were brainstormed. To develop an understanding of the magnitude to which each factor affects grid loading, a "factor flow-chart" was created, see Figure 2.

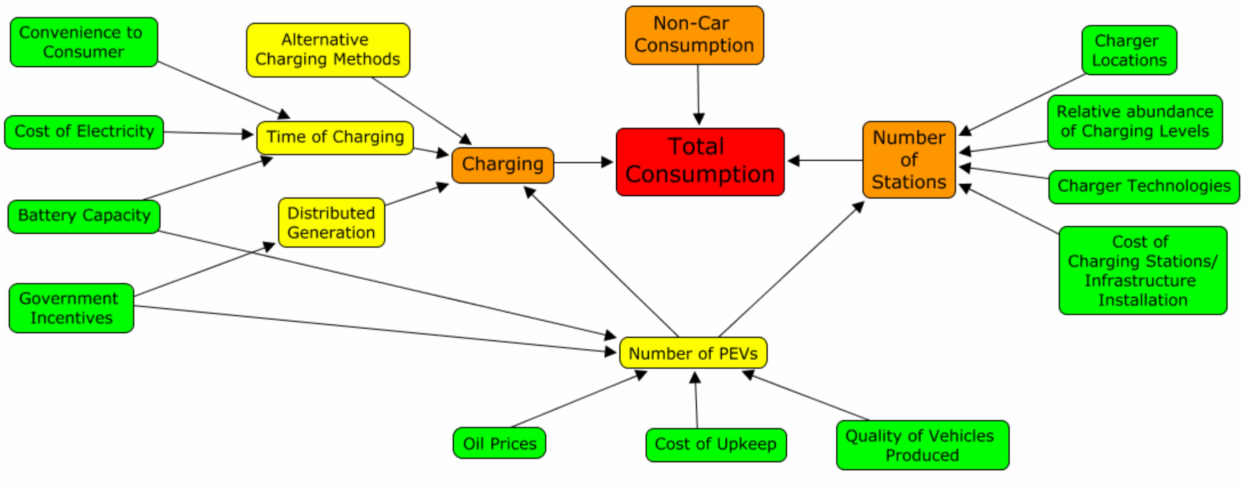


Figure 2: Factors affecting PowerStream's total demand

The factor flow chart provides a visual representation of the relationship between each of the factors that affect grid loading due to electric vehicles. In order to identify each of the factors, the major influences such as number of electric vehicles and number of stations were discussed amongst the team to develop an understanding of what contributes to them. For example, the number of electric vehicles will depend on how the purchase will affect the consumer economically. This can be broken down into the market price of the PEVs at the time, how much it will cost to maintain the vehicles, and how much they are saving versus a gas vehicle. These could then be broken down into cost of oil, cost of electricity, government incentives for PEVs, and the quality of vehicles produced.

This discussion process was followed for factors relating to social and environmental considerations. In discussing the social driving factors behind the number of PEV sales, it was determined that there must be an increase in market demand by the consumers that would like to indicate that they are "green-friendly" and drive an emission-free electric vehicle. This theory is supported by research completed at Harvard University regarding the adoption of Hybrid-electric vehicles, which indicates that there will be "additional motivation for consumers to purchase hybrids in that they allow one to vividly demonstrate one's commitment to environmental protection or energy security" (Muehlegger, 2008). Each of the factors included in Figure 2 are discussed in detail below.

5.2.1 Non-Car Consumption

Non-Car Consumption represents the consumption that exists outside of the Electric Vehicle. This will represent the base load the grid will experience, and will change as the PEV is introduced over the next twenty years. Projections for non-car consumption will affect the economic analysis performed on each of the ideas selected.

5.2.2 Charging

Charging represents the load experienced by the grid due to the recharging of PEV batteries. It's effect on grid loading depends on several factors:

- *Time of Charging* – The time of day and length of time it takes to fully charge a battery will influence when the load appears on the grid.
- *Distributed Generation* – Distributed generation has the ability to reduce grid loading and the cost of electricity to the consumer. Small power generation applications such as solar panels can also be used to power charging stations in the daytime, which will change charging patterns.
- *Alternative Charging Methods* – Different technologies for charging PEVs can change the charging profile of a car significantly. By implementing battery swap stations users could replace their drained battery with a charged battery, enabling the charging of the spent battery to occur during idea off-peak hours.
- *Convenience to Consumer* – How convenient it is for the consumer to charge their PEV will affect when they choose to do so. While various forms of incentives may put be in place that encourage the consumer to charge during off-peak hours, the consumer will often do what is most convenient.
- *Cost of Electricity* – Since electric vehicles rely on electricity for their function, the cost of electricity is expected to directly affect the time at which the consumer will chose to charge their PEV. Time-of-use billing also has the potential to influence the time of day when drivers will charge their cars.
- *Battery Capacity* – "Range anxiety is the fear that a vehicle has insufficient range to reach its destination and would thus strand the vehicle's occupants (Eberle, 2010)." Range anxiety is a currently a deterrent for potential PEV consumers, and thus increasing battery capacity will

make electric vehicles more attractive to the consumer and increase sales. It will also influence the length of time it takes to fully charge a vehicle. Greatly increased battery capacity could also lead to less frequent charging, affecting the PEV load.

- *Government Incentives* – The incentives from the Government of Ontario for electric cars reduce the cost to the consumer of owning an electric vehicle. This eliminates one of the main barriers to purchasing a PEV and expands the potential market. Similarly, Ontario's feed-in tariff (FIT) program has been highly successful having received 23,000 applications in its first year (Hamilton, 2010). This program has made Ontario one of the world's largest markets for photovoltaics, clearly indicating the effectiveness of government incentives at influencing consumer behaviour.

5.2.3 Number of PEVs

The number of PEVs on the road will greatly affect the amount of load experienced by the grid, as there will be more batteries that require power for charging.

- *Oil Prices* – As oil prices increase the cost of operation for combustion vehicles will also increase. Since electricity generation in Ontario is not dependent on oil it is not likely the cost of electricity will increase as well. As consumers tend to be very sensitive to price increases in gasoline this will lead to more people considering electric vehicles.

- *Cost of Upkeep* – One factor that is currently unknown is the cost of maintenance in an electric vehicle. In theory the simple design of electric motors relative to internal combustion engines and the lack of a gearbox on PEVs will mean electric vehicles will be less expensive to maintain. However, this will remain a concern for many drivers until the true cost of upkeep is determined.

- *Quality of Vehicles Produced* – The quality or marketability of the PEVs put forth will greatly affect the sales of the products, and greatly affect the future of the electric vehicle. If this upcoming generation of PEV is poorly made and has dependability issues, the future of the PEV will be compromised and loading will be affected.

5.2.4 Number of Stations

The number and location of charging stations will affect the loading characteristic of the PEV for reasons explained in the following subcategories.

- *Charging Locations* – The location of charging stations – at home, at the workplace and in public places – will determine when users will be charging their cars. With more charging locations available in public more users will charge during the day. Alternatively, if the location of charging stations is predominantly in the home of the consumer, there will be an opportunity to increase the amount of charging during off-peak hours, while the PEV owners are sleeping.

- *Charging Technology* – Improving charging technology can reduce the length of time it takes to charge a battery. It may also influence the number of public chargers if batteries could be charged while drivers are away from home, such as buying groceries.

- *Relative Abundance of Charger Levels* – The ratio of level 1, level 2, and level 3 chargers will influence how large and how long lasting the load from charging each electric vehicle is. A higher proportion of level 1 chargers will mean more users are charging over long periods of time, when they are not using their vehicles, likely at night and on weekends.

- *Cost of Charging Stations/Infrastructure Installation* – The cost of each charging station and the required infrastructure to support it will greatly affect the number of stations that are available to the public.

5.3 Strategies for Grid Demand Reduction

The third part of the idea generation process involved developing strategies to reduce the grid consumption, based on the stakeholders and consumptions factors previously identified. One of the main objectives behind the PowerStream project is the reduction of grid loading, as this will decrease the amount PowerStream will have to spend in repairs. The following two Sections, total and peak grid load reduction, outline various areas that could act on to reduce the load on the grid.

5.3.1 Total Grid Load Reduction

As the category suggests, programs that fall under this category attempt to reduce the total consumption of the grid from PowerStream's clients. In light of the recent awareness of climate change, there have been attempts by both private and government bodies to reduce the overall consumption of the general population. This awareness may enable PowerStream to encourage clients in their districts to reduce their consumption. Some ideas generated in this category include:

- *Reductions of General Usage in PowerStream Regions* – As a result of the efforts made to educate the general public regarding electricity consumption, there has been a recent push to

- *Distributed Generation* – Due to government incentives, consumers have started generating their own energy to reduce electricity costs. Distributed generation can help reduce the demand on the grid by either taking homes off the grid entirely, or producing energy back into the grid throughout the day. Since the majority of the distributed generation systems will be photovoltaic (Tatsumi Ichikawa, 2002), it is likely that much of the power generated from these individuals will occur during peak hours.

5.3.2 Peak Load Reduction

The charging of PEVs will extend peak hours and increase total amount of consumption during it, providing the main reason for infrastructure failure. Strategies that focus on reducing consumption during these times will result in reduced infrastructure damage.

As it has been explained, the reduction of grid loading will result in fewer expenses for PowerStream, allowing them to continue to remain profitable. However, electricity sales are the source of revenue for PowerStream, and PEVs will provide them with more energy sales. Regarding strategies for peak reduction, it should be indicated that there is a large incentive to not just reduce the amount of consumption, as this will decrease total sales, if possible, the consumption should be deferred to off-peak hours: Since power is produced at a near-constant level and currently cannot be feasibly stored, there is a significant amount of wasted power produced during off-peak. By shifting the demand to those hours, PowerStream can take advantage of the excess capacity and generate more revenue. Many potential programs include:

- *Financial Incentives* – Current time-of-use billing encourages consumers to complete activities such as cleaning, laundry, and heating or cooling the house during off-peak times. PowerStream could implement a similar pricing schedule for electricity used to charge electric vehicles.

- *Transportation Service Companies* – Since the PEV will reduce operation expenses for the owners, it is expected that there will be an interest generated from transportation service

- *Programmed Charging* – Introduction of smart-meters provides the possibility of in-home technologies communicating with distribution companies instantaneously. This provides the opportunity for charging units to communicate with the meter, and in turn communicate with the distributor to determine the cost of electricity at any given time. This could provide the consumer with the opportunity to schedule charging using cheap power. More specifically, this program would require the owner to plug in the PEV and input the time at which the EV should be charged. The charger would then automatically turn on when electricity is cheapest, or at lowest grid loading.

- *Charging "Blackout" Times* – A charging "ban" could be placed, where residential charging units would simply not be able to operate during peak hours. Users are forced to charge during off-peak hours. This is similar to arrangements commonly made between large industrial users and electricity distribution companies where power can be cut with little advance notice.

- *Battery to Grid*– The batteries used in PEVs are storage devices, thus having the capability of returning energy back into the grid. This provides the unique opportunity of having PEV owners plug their vehicles into their charger, changing the mode from charge, and selling energy back into the grid. This option could involve the use of old batteries that are deemed no longer useful for PEVs, or for batteries not currently in use at battery swap stations, or even parked in lots outside of office complexes. This technology required charging stations that are capable of moving current in two directions, which is not yet commercially available (British Columbia Hydro and Power Authority, 2009).

5.4 Design Considerations

5.4.1 Modes of Failure

One aspect of our project scope is to investigate the possible failure of current infrastructure as a result of PEVs. A failure modes effect analysis quickly showed that there is a multitude of ways that a transformer can fail. It quickly became apparent that there are many points of possible failure. Finding the loading limits of each component is a simple method of determining failure from overloading (overvolting and overamping). These limits are summarized in Table 2. It is clear that PEVs may exceed these limits.

The other method of failure is harmonic generation, but analysis of that mechanism requires an in-depth examination of the grid. Loading failure can be determined using a comparatively simple spreadsheet analysis.

Table 2: Loading limits of PowerStream's equipment

PowerStream North/Aurora		
Point of Failure	**Failure Method**	**Loading Limit**
Padmount Transformer	Overloading	50 kVA
1/0 Aluminum Cable	Overamping	200 A/~1 600 kVA
13.8 kV Feeder	Overamping	300 A/~7 000 kVA
Transformer Station	Overloading	170 000/115 000 kVA
PowerStream South		
Point of Failure	**Failure Method**	**Loading Limit**
Padmount Transformer	Overloading	50 kVA
1/0 Aluminum Cable	Overamping	200 A/~3 200 kVA
27.6 kV Feeder	Overamping	400 A/~20 000 kVA
Transformer Station	Overloading	170 000/115 000 kVA

5.4.2 Geographic Distribution of PEVs

It seems acceptable to correlate PEV ownership with income. While the exact demographics of PEV owners are beyond the scope of this report, examining the income distribution of PowerStream's customer base and showing areas that will have a slightly higher/lower distribution of PEVs will be useful in planning upgrades or replacements. The income information can be retrieved on a neighbourhood basis from statistical databases. Direct ties of income to ownership are available through market reports, but they are priced beyond the budget of this project. For the purposes of this study, geographical effects will not be considered.

5.4.3 Computational Methods/Constraints

Network analysis is a computationally intense exercise, especially for dynamic modeling and replacement analysis. There are commercial programs available that are better able to perform this analysis, but they were not pursued due to their high cost and complexity. However, some computational methods were used that can simulate a padmount transformer, with randomness associated with a small PEV penetration rate and a low number of houses. Thus one can determine how the load curve will change given PEVs. This information can be scaled up to determine loading at all stages of the grid through the use of Monte Carlo simulations, as well as showing maxima that emerge that will determine whether smaller Sections of the grid will need to be replaced even if larger ones will not.

6. Idea Selection

Once ideas were generated that were relevant to the areas of possible grid reduction, a weighted Pugh chart was used to evaluate how well each would work for PowerStream. This required identifying the criteria upon which each would be evaluated. The criteria included:

- Implementation cost
- Leadership
- Consumer satisfaction
- Chance of infrastructure failure

- Environmental benefit
- Income potential
- Risk

Each of these criterion were assigned a weight as decided be each of the members of the group to be appropriate for PowerStream's objectives both as a company and regarding the project itself. Items such as Leadership do not pertain so much to the preparation of the grid for the introduction of the PEVs however it was made very clear that PowerStream cares strongly about their image as a company, and their status as a "Leader of Energy and Environmental Design." See Table 3 for an example of the ideas included in the chart, and the assigned weighting of each of the criterion.

Table 3: Portion of the Pugh chart used in idea evaluation

Factor	Weight	Time of Use Billing	Different Billing for PEV Charging	Charging Plan	Include Electricity in Sale of Car	Destination Charging
Implementation Cost	4	0	1	0	0	-1
Leadership	4	0	0	1	1	1
Consumer Satisfaction	3	0	-1	1	1	2
Chance of Infrastructure Failure	3	0	1	1	1	2
Environmental Benefit	3	0	2	2	2	1
Income Potential	4	0	1	1	1	1
Risk	4	0	1	1	1	1
TOTAL		**0**	**18**	**24**	**21**	**23**

Each team member completed a Pugh chart individually. The results of these charts were then compared and eight final ideas were selected. These ideas are explained in detail in the following Section.

7. Selected Ideas

Eight ideas were presented to PowerStream in January 2011 at a design review meeting, of which five were selected for further inquiry. These ideas can be roughly divided into two main groups: business ideas and technical ideas. Business ideas deal with policies and programs PowerStream could implement which technical ideas are ways of using new technologies to PowerStream's advantage. This benefits and drawbacks of each idea area presented in Table 4:

Table 4: Summary of the benefits and drawbacks of each of the options currently being discussed

Option	Benefits	Drawbacks
Selective Transformer Replacement	• Low chance of infrastructure failure • Prepares for the future	• Expensive • No demonstration of leadership
Encourage In-Town Charging	• Shifts load away from residential transformers • Demonstrates industry leadership	• Negative environmental impact • High implementation cost
Dedicated Charging Centres	• Shifts load away from residential transformers • Demonstrates industry leadership • Low chance of infrastructure failure	• Negative environmental impact • High implementation cost
Destination Charging	• Increased user satisfaction • Low chance of infrastructure failure	• High implementation cost • Cannot be implemented in the near-term
Charger – Transformer	• Low chance of infrastructure	• High implementation

Communication	failure	cost

7.1 Potential Relationships

Many of the solutions proposed can be more effectively leveraged by independent specialists or equivalent subsidiaries under PowerStream. There are other business ideas that require partnerships with established businesses in different areas.

7.1.1 Relationships with Corporate Fleets

It has been found that the costs of electric vehicles in corporate fleets are attractive in the short term due to decreased running fuel costs of electricity compared to gasoline. There are further secondary benefits such as marketing opportunities. Some fleets are already making a change-over to hybrid electric vehicles. The change to PEVs is more problematic because of the comparatively longer charging time and lower ranges of the vehicles. It may be beneficial to approach delivery and taxi services once Level 3 charging becomes a more viable technology.

7.1.2 Relationships with Innovators

The Pecan Street Project in Austin, Texas is an example of one of the more effective relationships possible in terms of innovation and leadership. Recruit a number of volunteers from your customer base and licence an innovation firm – or start a subsidiary – that tests and develops peak levelling and smart grid technology. There are fewer more effective ways of making an impact on consumers than including them in the design process. Further, trial runs of technology will greatly accelerate the validation and design of beneficial technologies, and a special relationship with a development company would allow PowerStream better access to new strategies.

7.1.3 Relationships with Auto Companies

Many of the ideas listed – particularly those involving charger technologies – could be more effectively accomplished in partnership with auto makers. For example, PowerStream may wish to provide charger installation for new PEV owners. This would ensure that every PEV owner has a high quality charging station which is capable of working with any charge control strategy PowerStream wishes to implement. In the scenario the auto dealer will and consumer will both be relieved of having to install charging stations, and PowerStream can control the new equipment being added to the grid.

7.1.4 Relationships with Consumers

An awareness campaign showing how smart PEV charging can both extend the life of the vehicle and reduce the infrastructure and cost impacts of the same would have a marked effect on consumption patterns. It has been suggested that consumers will have to be taught how to charge electric vehicles without damaging the battery – i.e. allow the battery to discharge periodically, etc. This education could be extended to charging without damaging electricity grid infrastructure.

Use of peak levelling technologies such as Vehicle-to-Vehicle (V2V) and Vehicle-to-Grid (V2G) will have to be picked up by the consumer before they will be widespread enough for use. It is highly likely that an electric vehicle and charging station equipped with V2G or V2V technology would be significantly more complex and thus costly than a simpler charger. Subsidizing the adoption of the technology with cheap power plans or partial rebates would increase the attractiveness of these technologies and bring about a greater impact, if they become commercially and technologically viable.

7.1.5 Relationships with Commercial Customers and Office Buildings

Once level 3 charging becomes technically viable, dedicated charging in parking lots may become attractive depending on the cost of the system. It has been noted that level 3 charging will require dedicated infrastructure to fulfill power and voltage requirements of such systems. If multiple level 2 charging systems are put in use, a similar problem occurs. Approaching businesses with such plans to sell power is a beneficial strategy.

7.2 Business Ideas

7.2.1 Public Awareness Campaign

This option seeks to educate PEV drivers on good charging habits at the time of vehicle purchase. This would be supported by public education initiatives. This campaign would inform customers of the cost benefits of off-peak charging as well as indicating how off-peak charging can reduce their overall carbon footprint. Additionally, this campaign could include instructions for safe charging and battery maintenance of PEVs.

This awareness campaign would be highly visible and promote PowerStream as a leader in environmental sustainability. It is also low cost, requiring little capital investment. However, the ability of this option to shape load curves is questionable as it relies on the user to adopt and maintain good charging habits over the course of their PEV ownership.

7.2.2 Encourage In-Town Charging

This option seeks to divert some of the load in residential areas to commercial locations which are better prepared to handle the additional load. Level 2 and 3 charging stations would be provided in areas drivers tend to remain for a significant time such as grocery stores, movie theatres, and office parks. These charging stations would be connected to the existing transformer at the location.

The charging stations involved in this plan could be owned by local businesses or a third party, potentially PowerStream. Local businesses would benefit from the boost in image from supporting green technology and additional revenue from PEV drivers making an effort to patronize their locations. Offices would also increase their green image as well as potentially profiting from charging revenues. Alternately, a third may own and operate the charging stations and lease them to interested businesses.

The cost of implementing and running these stations could be paid for by PowerStream, the provincial or federal government, local businesses, or a combination of the three. The cost of the centres could be absorbed by the parties to build goodwill. Alternately, PEV drivers could be billed for the electricity they consume at these centres. The specifics of this option are discussed more in the following Section.

These locations would play into a driver's existing travel patterns and allow them to recharge at their leisure. Its high visibility will also help to encourage the acceptance of PEVs in the consumer consciousness. One concern is that by transferring the load to commercial locations it will simply relocate the issue and transformers will still need to be replaced. This option will also encourage on-peak charging which, if it is billed normally, will increase PowerStream's revenue. However, on a provincial level it will increase peak load, perhaps significantly, and require additional expensive fossil fuel based electricity to be generated. Although this is still a cleaner energy source than internal combustion automobiles, it is less ideal than night charging.

7.2.3 Install Home Charging Stations

As mention in Section 7.1.3, this plan would have PowerStream take over the responsibility for purchasing and installing home charging stations for PEV owners. This would allow PowerStream to ensure that every charging station is capable of working with charge control strategies. For example, at installation a charging time slot could be suggested for the user which does not overlap with others in the neighbourhood.

This strategy benefits the consumer and auto dealers who will not have to coordinate charger installation. While it does not directly prevent infrastructure failure, this strategy does allow

PowerStream to better implement other charge control methods described in Section 7.3. This is a very visible method by which PowerStream can demonstrate their leadership in adapting to PEVs.

The cost of installing these chargers could either be absorbed by PowerStream or passed on to the user in the form of a direct payment or charger lease. A lease would allow PowerStream to upgrade the charger should a newer and better model become available. However, it also means that PowerStream will be required to maintain the unit. The cost of implementing this strategy is discussed in Section 10.2.

7.3 Technical Ideas

7.3.1 Dedicated Charging Centres

This option is an extension of the In-Town Charging solution. Instead of simply encouraging commercial area charging, create charging stations, which would be comparable to gas stations, in high traffic locations in PowerStream's service area at which PEV drivers can recharge their vehicles. These stations would provide level 3 charging capabilities at a premium price to the driver. These charging stations could have dedicated transformers for PEV charging which are capable of withstanding the loads associated with level 3 charging. Charging stations could be placed at locations such as grocery stores and shopping centres to provide convenience for PEV owners. This would allow much of the PEV charging load to be transferred to these dedicated centres.

Ownership and financing of the equipment at these centres could be done in several ways. Local businesses could pay for PowerStream to provide the infrastructure for these stations in exchange for a portion of the electricity sales at the location. Alternately, PowerStream could own and operate the centres either directly or through a subsidiary company.

Unlike the in-town charging, dedicated charging centres are only economically viable if the user pays for the electricity. One possibility is for users to pay the charging unit directly – similar to parking meters. Another would be for the charging station to identify the car it is charging either automatically or through user input. The station could then bill the user either directly via credit card or indirectly via their account with PowerStream or a third party operator.

Charging centres are highly visible and will provide a green image for the operating company and the community in which they are located. They will also increase public awareness of PEVs and help reduce concerns regarding their range and practicality. PowerStream could then advertise their input into electric vehicles to enhance their reputation as an environmental leader. This image could be further improved by integrating sustainable generation, solar PV or wind, into the design. However, the environmental impact of charging PEVs during the day would negate some of the benefit of electric vehicles.

7.3.2 Destination Charging

Under a destination charging scheme PEV drivers will specify a time for charge completion rather than for charge initiation. Automated software in home charging stations will then communicate to determine the optimal charging rate and times for each car.

Destination charging will reduce the load occurring at peak times, particularly when commuters arrive home from work. This will in turn reduce the risk of overloading padmount transformers while simultaneously increasing the capacity factor of each transformer. It also simplifies charging for the user by handling charging timing automatically.

This option will require the cooperation of charging station manufacturers, PowerStream, and PEV drivers to be successful. The primary benefit of destination charging, reducing load spikes, is negated if a significant portion of consumers do not participate. PEV owners must also be willing to relinquish control over charging their vehicle which may be off-putting for some. This option also has a relatively narrow scope of effectiveness: if only one car is using a transformer the system will have little to no effect on the load curve; if too many cars are using a transformer it will not be possible to charge each by the desired time without stressing the transformer.

7.3.3 Transformer – Charger Communication

With this scheme each charger will be equipped with a means of communicating with the transformer. If the load on the transformer gets too high the charger will shut off or, if possible, drop to a lower charging level. This will allow the charging network to self-adjust in order to prevent brownouts.

The capacity for preventing infrastructure failure in the system is quite high. To prevent excessive consumer backlash an option to override the shutdown should be included. However, use of this option should be discouraged by regularly informing the user that overriding the shutdown system may cause loss of power.

The installation cost of this option is very high. Each transformer which will be servicing aPEV owner will need to be retrofitted with a system that can detect load and communicate with external chargers.

Similarly, each home charger will need to be equipped with a communications system. These two systems will need to be connected which will likely require special setup.

Effective implementation of transformer – charger communication will require the cooperation of local distribution companies, charging station manufacturers, and PEV owners. It is not likely that this could be implemented for the current generation of PEVs and PEVchargers; however, it is a possible long-term remedy. In the future the system could be expanded to include other large electrical appliances such as air conditioners and water heaters, further reducing the chance of padmount transformer failure.

7.3.4 Selective Transformer Replacement

In this scenario PowerStream will perform a phased upgrade of padmount transformers, with transformers being used by electric vehicles being the first to be upgraded. This will prevent PEV charging from overloading transformers with a lower capital investment than replacing every transformer in the service area. This plan is sustainable over a long time period. Residential areas will tend to increase their power consumption over time necessitating the upgrading of electrical infrastructure – this option will spread that cost over a longer time period.

Information on PEV location can be obtained in a number of ways. One would be to adopt the strategy mentioned in Section 7.2.3 where PowerStream would install the PEV chargers themselves. Alternately, users could be told to inform PowerStream of their purchase shortly after they buy the car. This information could also be provided by the Ontario Ministry of Transportation at the time of vehicle registration.

One concern with this plan is the size of transformer to be installed. If the transformer is too small it may need to be upgraded once again after a short time – if it is too large it will not be used effectively. A 100kVA transformer will be able to handle several PEVs charging simultaneously in addition to the normal base load. The economic details of this plan are further discussed in Section 10.

8. Rejected Ideas

Ideas listed in this Section were considered poor options in the preliminary stages of the project. However, they are included because some of the ideas may still have potential, and could be considered if the drawbacks were overcome.

8.1 PEV Specific Time of Use Billing

By increasing the price difference between on-peak and off-peak charging users could be more strongly persuaded to charge off-peak. This solution would involve a second power meter being installed specifically for the PEV charger. Users would then be billed at one rate for general electricity use and another for car charging.

This option is likely to be very unpopular with customers. It would also increase consumer hesitance to purchase an electric vehicle. The installation cost of this plan would be high as it requires PowerStream set up and operate a second billing system partially integrated with what is already in place. Finally, the Ontario Energy Board may not allow PowerStream to bill users different rates for electricity depending on its end use.

8.2 Discounted Rate for Controlled Charging

Similar to the destination charging scheme discussed below, this option would switch control over when a PEV is charged to centrally located controller. If users allow this system to select when they wish to charge their cars they would be billed at a low rate. However, if they select to manually charge their car, the electricity would be billed at a higher rate and/or a one-time flat fee would be applied.

PEV owners are likely to be unhappy with the idea of not being able to charge their car when they want. Additionally, this idea will be expensive to implement due to the increased monitoring PowerStream must perform on users' charging habits. Similar to the previous idea there are legal concerns about this billing plan.

8.3 Charging Cut-Off

This plan is an extension of charger-transformer communication. The difference is that in this situation the user would not have the option to prevent their charging station from turning off. This would make the system more effective at preventing failures. This comes at the expense of user satisfaction. It may also face resistance from the Ontario Energy Board.

8.4 Power Level Billing

This option would change the billing system for residential customers from the current time-of-use model to one based on the power consumption of the house. For example, the first 2kW of power a house uses would be billed at a base rate, an additional kW would be billed at a medium rate, and any power above that level would be charged at a premium. This is more similar to the true cost structure of electricity generation and distribution.

The environmental benefit of this idea is substantial as it encourages users not only to conserve electricity but to uniformly distribute their electricity use over the course of the day. This reduces the need for peak production on a provincial level. However, customers are likely to be unhappy with this billing system being introduced so soon after time of use billing. There is also some concern about getting this billing system approved by the Ontario Energy Board.

8.5 Taxi Company

As a method of promoting electric vehicles PowerStream could, through a subsidiary company or partnership, operate a taxi service using electric vehicles in the greater Toronto area. This would be a highly visible means of demonstrating the capabilities of electric vehicles. PowerStream would then benefit from being associated with this technology.

PowerStream would additionally benefit from the opportunity to collect data on PEV power consumption, charging, and maintenance. This could be used to support future policies.

For obvious reasons this would be a very expensive course of action. It also does little to reduce the strain on the distribution network.

8.6 Service Vehicle Partnership

This is similar to the previous idea in that it seeks to increase awareness of electric vehicles through a demonstration project. In this case PowerStream would partner with a third party to demonstrate electric vehicles in service roles such as delivery and light transport. This would increase consumer awareness of electric vehicles and PowerStream's association with them. Like the previous idea, the benefits from this option are primarily goodwill and knowledge. It will have little effect on infrastructure failure.

8.7 Charging Plans

In order to encourage PEV owners to charge during off-peak hours PowerStream could offer charging plans – similar to what currently exists for cellular phones. In its most basic form a user would pay a flat rate to PowerStream in exchange for a set amount of electricity to be delivered during set hours, for example between midnight and 6am on weekdays and all day on weekends. By choosing to charge outside these hours users would be required to pay more per kilowatt hour to charge their car. This difference would be greater than the existing difference between on- and off-peak rates.

The effectiveness of this plan depends on a high discrepancy between on-peak and service plan rates. Since charging rates are capped by the Ontario Energy Board it is possible that this option will not provide enough incentive to users to justify its implementation. The additional cost of implementing and maintaining the billing system coupled with the decreased revenue from electricity being used for PEV charging may result in an ultimately unprofitable situation for PowerStream.

8.8 Include Electricity with Car Purchase

This idea would involve PowerStream partnering with dealerships so that electricity can be sold as part of the PEV package. At the time of purchase users can opt to purchase unlimited overnight charging for a year or more.

The implementation of this plan would require PowerStream to monitor PEV charging separately from normal household use. The costs associated with this could be avoided by giving each customer a designated charging time in which all household electricity is discounted and adjusting the cost of the one-time sale accordingly. This could potentially result in abuse by users who run many household appliances during this time; however, it is not likely a significant portion of PEV drivers will choose to do this.

PEV manufacturers could use unlimited charging as a marketing point when introducing their vehicles. Customers would not have to worry about the increase to their electricity bill after buying a PEV. Their regular electricity bill could then include a Section with how much money they've saved so far compared to paying for electricity normally and compared to running a conventional automobile. This information could be used after the plan expired to predict consumers' charging habits.

9. Modeling PEV effects

In order to evaluate the effect of PEV charging on a transformer level, a model was created using Microsoft Excel to simulate the load changes on a sample transformer. Different charging scenarios were entered into the model to determine the effect of strategies on reducing transformer failures.

9.1 Model Description

In this model, a fixed percentage value is entered for PEV penetration, L2 charging prevalence, number of households per transformer, percentage of users using controlled charging, and percentage of users who charge non-residentially. The effects of each input on the model are explained in the appendix. Given these inputs, the spreadsheet simulates 500 transformers and returns the average load by hour, the maximum load each hour, and the number of transformer failures.

In this model the average PEV was assumed to require 10kWh of energy every day. This number is based on the average distance driven by a York Region resident (Transportation Tomorrow Survey, 2006). This is well below a full charge, meaning that the full 4-6 hours of charge time will not be needed on a regular basis. Instead, a L2 charger can fully charge a vehicle in just over one hour. Because the model is divided into one hour time steps, a single PEV is assumed to require two hours to charge with a L2 charger, 5 hours with a L1 charger.

The number of households per transformer was kept constant at 10. This corresponds with the maximum found in the Village in the Valley sample community. The maximum consumption from 2010 was used as the base load. Reducing the number of houses per transformer would linearly decrease both the base load and chance of a PEV being present, with the net effect of a lower estimate of the impact of PEVs. Since the purpose is to detect and predict transformer failure, the upper limit was studied.

In town charging was assumed to be constant at 10% in the simulation measuring charge control. This was considered to be the upper limit, as there will be a limited number of businesses providing these services. Separate simulations evaluating the effect of non-commercial charging were run with levels of 0%, 10%, 25%, and 50%.

The percentage of users using L2 charging was assumed to be between 50% and 100%. The exact value over the next few years will depend on the success of Nissan in selling L2 chargers alongside vehicles, and the desire of users to charge their car quickly. Simulations were run at L2 penetration levels of 50%, 75%, and 100%.

9.2 Model Limitations

While providing a strong estimate of failure rates, the model makes several assumptions which limit its accuracy.

The average PEV driver will not fully discharge their battery, instead using 10kWh per work day. The model assumes average charge behaviour for all users. This is unlikely to cause issues at low penetration levels where there is little chance of charging overlap. However, at higher penetration levels overlap becomes more probable and a more robust charge time estimate would be desirable. Likewise, the model cannot account for users who do not charge every day. This would lead to a longer charge time on days charging does occur.

Similarly, the model cannot account for users who sometimes charge non-residentially, and sometimes charge at home. Should a driver charge entirely at home or in town for the day, the model will not be affected, since there will be no residential load change. However, drivers who charge partially away from home will require a different charging time, which, as previously mentioned, is outside the capabilities of the model.

Smart charging is also problematic for the model. While the controlled charging curve is shaped such that it is unlikely that there will be charging overlap, there is no mechanism which will directly prevent it from happening. This will occasionally lead to loads above 50kW during the early morning at high penetration rates, leading to slightly inflated transformer failure numbers. This is accurate should the chargers be unable to communicate and simply set to begin at a pre-determined time, such as the scenarios described in Section 7.3.2. However, there is no function in the model to account for the charge control outlined in Section 7.3.3

9.3 Results

9.3.1 Effect of Controlled Charging

Simulations were run at a 5% adoption rate with controlled charging levels of 0, 10%, 25%, 50%, 75%, 90%, and 100% assuming 50%, 75%, and 100% adoption of level 2 charging and a 10% commercial charging rate. Figure 3 shows the number of transformer overloads for each scenario:

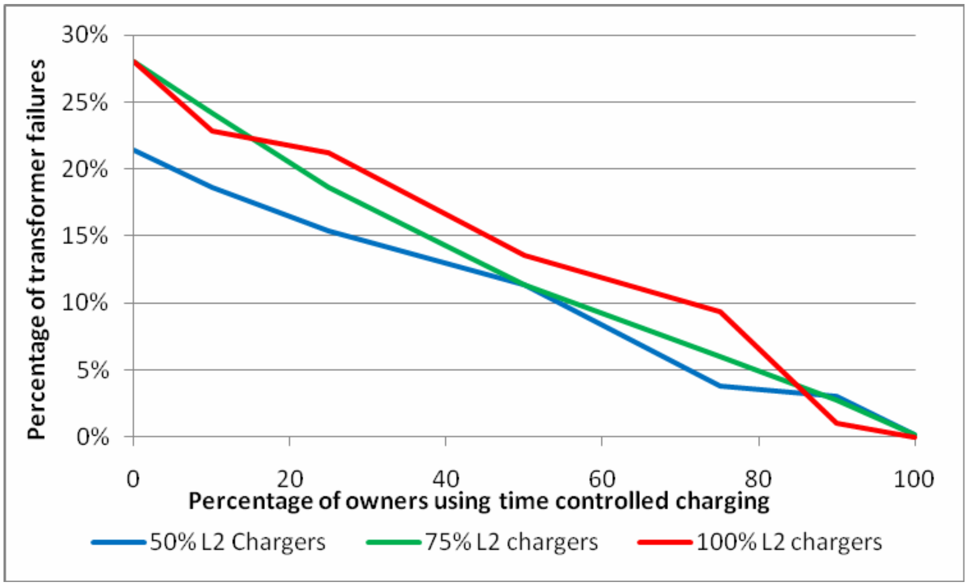


Figure 3: Effect of controlled charging on transformer failures

Figure 3 illustrates the roughly linear relationship between controlled charging and transformer failures. It is also clear that more users adopting L2 chargers will increase the number of transformer failures for an equal controlled charging rate. Furthermore, it can be seen that controlled charging has a much greater impact on failure rates than charging level. At very high controlled charging levels (>95%) the chance of transformer failure is less than 5% regardless of charger type.

9.3.2 Effect of Charge per Day

Increasing the daily charge to 20kWh yields the results shown in Figure 4:

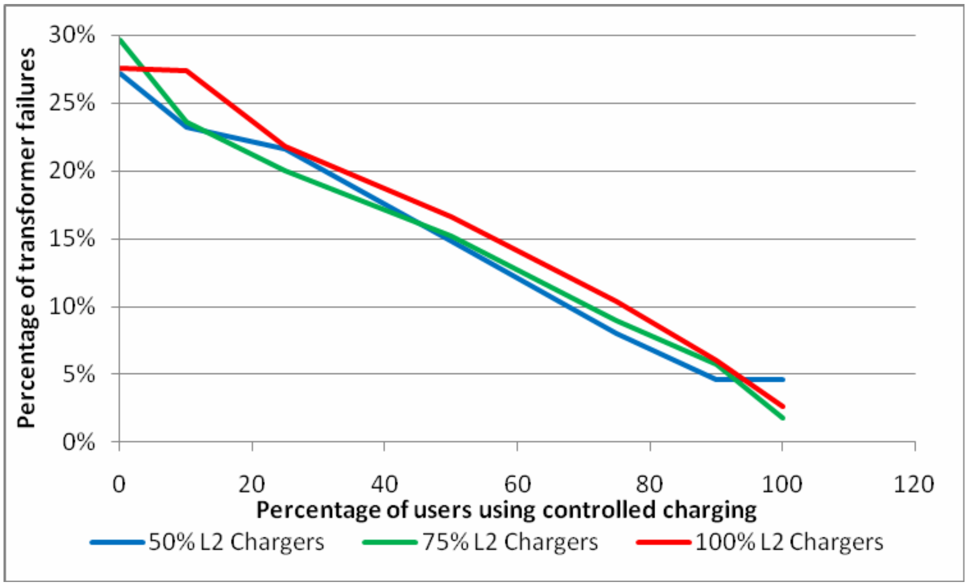


Figure 4: Effect of controlled charging on transformer failure rate assuming higher energy requirement

The same downward trend present in Figure 3 is maintained in this scenario. It is also notable that the failure rate does not reach zero under any time control scenario. The failure rate is nearly universally higher than at a lower charge requirement, however, the average increase in failure rate (25%) is much less than the increase in energy delivered (100%). From these results it can be assumed that the overall failure rate at low penetration levels is independent of the amount of energy needed to recharge.

9.3.3 Effect of Non-Residential Charging

Further tests were run at 50%, 75%, and 10%% L2 charging and 50% and 75% controlled charging with 10%, 25%, 50%, 75%, and 90% non-residential charging. The results of these tests are summarized in Figures 5 and 6:

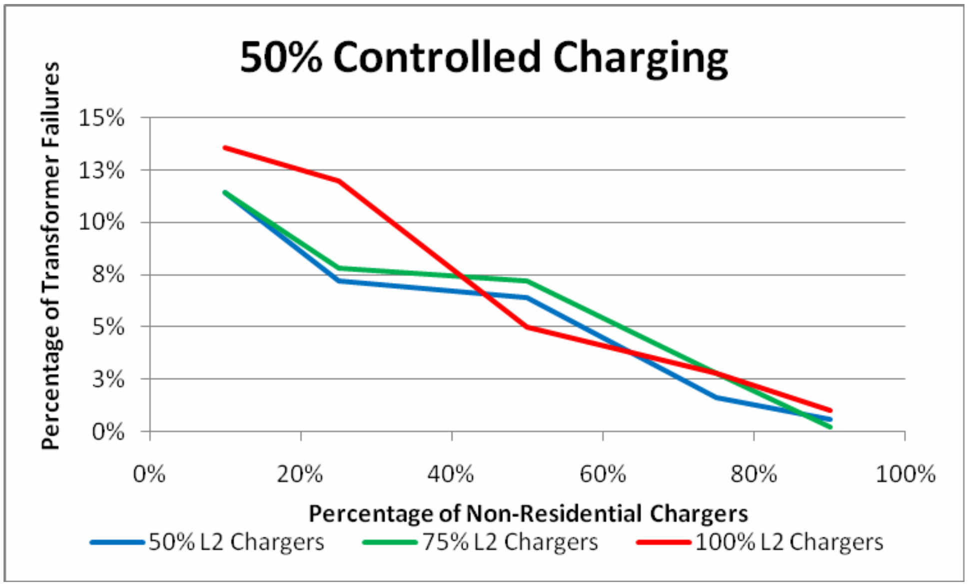


Figure 5: Effect of non-residential charging on transformer failures at 50% controlled charging

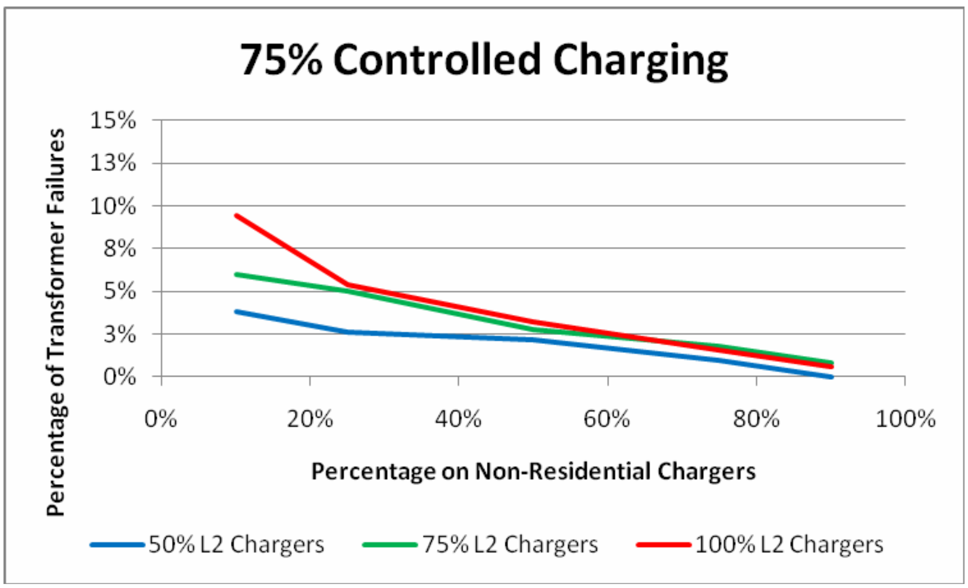


Figure 6: Effect of non-residential charging on transformer failures at 75% controlled charging

Non-residential charging also decreases transformer failure rates linearly. However, the decrease in failure rate per increase in adoption is not as large as that for controlled charging.

When comparing these results it should be noted that adoption rates for any single strategy will most likely not reach 100%. By providing multiple charging options PowerStream can provide an option for more users without incurring the costs of enforcing a single charging scheme. For example, it may be ideal to target a controlled charging rate of 60% with 25% of PEV drivers charging non-residentially. This will result in a failure rate near 6% assuming 100% L2 charging, much lower than either option individually.

9.4 Comparison to Quanta Technology Report

Compared to the Quanta report, which modeled the effect of PEVs on a sample electricity network using CYMDIST, the model predicted a much higher transformer failure rate This is likely because of the base load considered – the Quanta report used an average load while this report assumes the worst case scenario. Both models show a large decrease in failure rates as controlled charging is implemented.

9.5 Proof of Concept

Without having PEVs on the market, it is impossible to guarantee the accuracy of the results. Therefore, the relative accuracy of the model will be determined by comparing it to theoretical consumption curves, as forecast by various reports.

The consumption model was developed using simulation data found from the Manitoba Hydro report, using the methods discussed in Section 2.6.2. To determine the time at which a PEV started charging, a random number was generated between 0 and 100. Each hour corresponded to a range of numbers, and if the number generated lay within that range, then that hour was designated to be the starting time. In order to ensure that this method accurately reflected the charging distribution provided by the Manitoba Hydro report, 500 random numbers were generated, and the start times that corresponded to those numbers were recorded. The probability distribution curve of charge starting time was then compared to the Manitoba Hydro values, and all starting times were accurate within two percentage points. This shows that the Manitoba Hydro data was accurately imported into the model file.

The consumption curve produced by the model for controlled and uncontrolled charging was compared to the simulations published in the Quanta report. There was no specific penetration information, so the differences between PEV and non-PEV consumption cannot be compared. However, general comments of the differences between the two curves can be made. The difference between PEV and non-PEV consumption is larger during peak hours than during non-peak hours in both the model and the Quanta report. In the model, peak consumption without PEVs occurs at approximately 5:00pm, and this is also true for the Quanta report. Peak consumption with PEVs occurs at approximately 9:00pm for the Quanta report, while the model predicts to occur at 5:00pm. The difference here may be due to the amount of L1 and L2 charging assumed in the Quanta report. Overall, the model follows the same trend as the Quanta report, so the model is reasonably accurate.

10. Economic Analysis

A financial assessment of the costs of an uncontrolled scenario and controlled scenario is investigated to indicate the cost of PEVs on PowerStream. Additionally, the effects of the higher demand for electricity on PowerStream's purchase price of power from power generation companies are investigated.

10.1 Uncontrolled Scenario

To contrast any strategy that PowerStream implements, the financial repercussion of taking no action must be evaluated. In the "uncontrolled" scenario, PowerStream chooses to take no action by allowing each 50kVa transformer to fail, and replaces it with a 100kVA unit. The loading characteristics can vary, as each of the chargers that the EV owners could be level one or level two chargers. Additionally, not all of these owners choose to use time-controlled charging as a financial incentive does exist to charge at off-peak times. In this analysis, however, a "worst-case" approach is used where all chargers are level two and the time at which EV owners choose to charge is completely random.

In estimating the cost of this "no action," the cost of paying each electrician for removal and installation of each transformer is ignored, and only the raw costs of the transformers is used. The 50kVA transformers PowerStream uses in our sample neighbourhood have a value of $2,500, and the 100kVa transformers cost $7500.

For the 5% penetration loading scenario, where all chargers are level 2, each charge requires 10kW, there are 10 houses to a transformer and 10% of EV owners charge non-residentially, a failure rate of 28% is projected. Estimating that there are 39,375 residential transformers, this failure rate would result in $27.5 million in failed 50kVA transformers and $82.7 million in replacement costs.

10.2 Ownership of Residential Chargers

One technical scenario has PowerStream purchasing each of the residential chargers capable of time-charging in their regions, on the condition that PowerStream is permitted to schedule the charging during off-peak hours. Financially, this scenario will reduce or completely mitigate transformer replacement costs at the price of paying for and installing each of the residential chargers.

The Nissan Leaf is currently designed to be charged by the AeroVironment EVSE-RS+ level 2 charging dock. This dock is capable of communicating with the grid and can be scheduled by the user or by the utility company. At the time of purchase, the consumer would have to pay $1500 for the charger and anywhere between $2200 and $4500 for installation, as each residence could have varying electrical capabilities. On average, an EV owner may expect to spend $3900 to $6000 for installation of level two smart-chargers (AeroVironment, 2010). PowerStream would likely be able to obtain a deal with AeroVironment for the bulk purchasing of the chargers. Additionally, PowerStream employs their own electricians which would decrease installation costs. It has therefore been estimated that PowerStream would pay 60% what consumers would for charger purchase and installation, a total of $3000 per charger.

With the government projection that 5% of cars will be EVs by 2020 (Ontario Ministry of Transportation, 2010), this analysis assumes that EV penetration will be linear from 1% in 2012 to 7.5% in 2023, resulting in approximately 1500 chargers requiring installation annually.

The commercial success of EVs will result in an increase in electricity sales. Since, in this scenario, the majority of EVs will charge during off-peak hours, the sale price for all EV power is 5.1 cent per kilowatt hour (Ontario Energy Board, 2010). As previously determined, the amount of power required per charge is estimated at 10 kilowatts per EV in the Vaughan region. The projected costs and revenues associated with this scenario are included in Figure 7 (Ontario Energy Board, 2010)

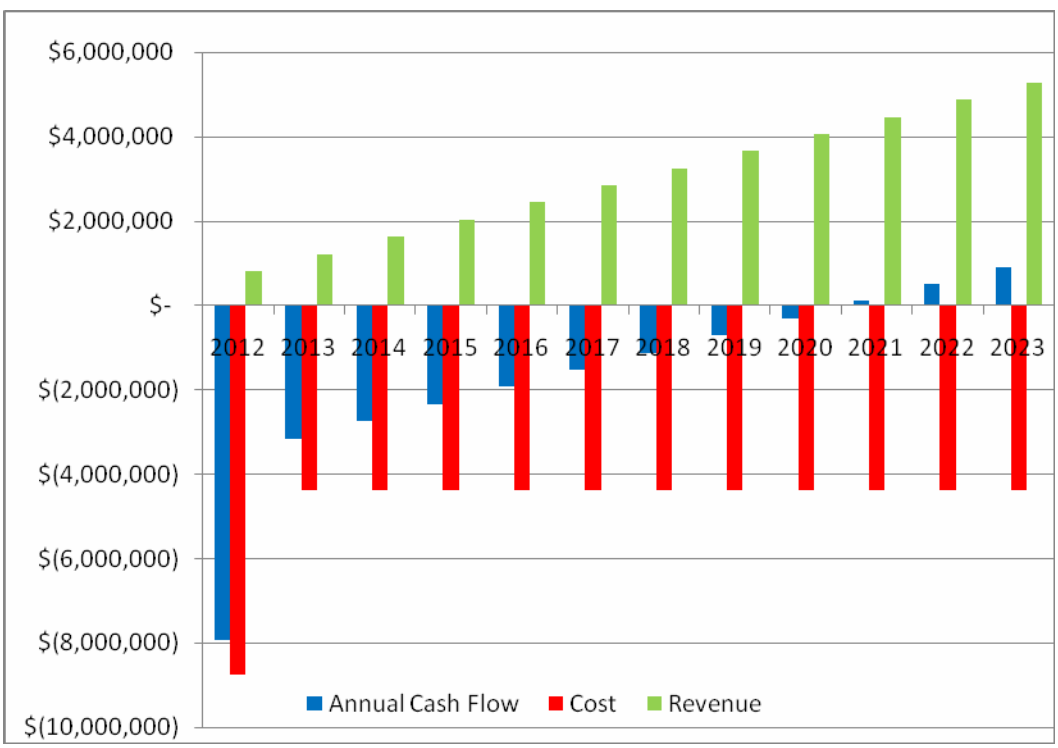


Figure 7: Projected annual cash flow for charger installation

With the government projection that 5% of cars will be EVs by 2020 (Ontario Ministry of Transportation, 2010), it is assumed that EV penetration will be linear from 1% in 2012 to 7.5% in 2023, resulting in approximately 1500 chargers requiring installation annually, costing $4.4 million. In 2020, the revenue from EV electricity sales is projected to reach $4 million. Cumulatively, by 2025, this plan will result in a $17 million deficit. This results in a 79.3% reduction in cost from the uncontrolled estimate of $82 million for transformer upgrades. A financial summary of costs, revenues, and cash flows for each year is included in the appendix, Table A1.

In implementing this strategy PowerStream could charge EV owners a small annual fee for their charger. A rent of $57 per year would result in PowerStream breaking even each year. Allowing PowerStream to own the charger and control timing would still be an attractive option for the consumers, as the charger would cost only 13% of what purchasing and installation could be, totalling $648 in 12 years.

10.2.1 Limitations of Analysis

For the sake of this economic analysis, it has been assumed that PowerStream will be able to purchase level 2 chargers for all residents and schedule charging for off-peak hours. In reality, some consumers that will not be able to participate in late-night charging, as they may have irregular or night-shift work schedules. Additionally, the costs associated with purchasing chargers would not be limited to purchase and installation, as PowerStream would be required to train their electricians on installation and servicing, and may need to pay for charger maintenance throughout the EV lifetime. There may also be costs for charger un-installation and disposal.

10.3 Changes in Purchase Price of Power due to Increased Demand

The increase in power consumption caused by the introduction of PEVs, will affect the fixed and variable costs comprising the total cost of power. Understanding how the cost of power could change will prepare PowerStream for the changes in revenue they will experience.

The source of changes in fixed cost will mainly stem from the possible upgrading of the grid. If it is determined that business strategies could not be implemented to deflect loading to off-peak hours, investments must be made to upgrade infrastructure to meet the demand. The change in variable cost is caused largely by the increased volume PowerStream will need to purchase from generation companies to sell to their clients. This purchase price could increase due to a limited supply of available energy or because higher generation assets are required to be brought on-line (Scott, 2007).

The Pacific Northwest National Laboratory, one of ten laboratories owned by the U.S. Department of Energy, completed an Impacts Assessment to investigate how increased volume would affect purchase price. The study focused on two utilities companies, one of which being dependant on imported power; a "wires-only" utilities company. This company, San Diego Gas and Electric Company (SDG&E), purchased electricity from one nuclear power plant (Scott, 2007).

Results of the study concluded that the effect from the increased load from EVs can be a net positive, as charge control would result in distributed loading and optimization of current assets. It was determined that while the cost of power to the wires-only company is likely to increase due to either limited supply or increase in price due to higher demand, the optimization of infrastructure results in an increase in revenue greater than rise in costs.

11. Project Management

In order to plan the work associated with each of the ideas proposed at the end of the fall semester, a work breakdown structure was used. This project management tool ensured that each member of the team was aware of the status of the development of each proposed idea. As the project continued and work was completed, each of the tasks was colour-coded to green, indicating they were completed. This provided a quick and easy to interpret means of understanding the progress of the project. The work breakdown is attached in the appendix (Figure A-1) for review. This structure included a brief summary of the work included on background research and market analysis. The focus of the structure was on the uncontrolled scenario: the tasks required to model the demand experienced by the grid without any intervention, as well as the various strategies for the controlled scenario. The tasks associated with the ladder scenarios involved mainly further developing the idea, modeling its ability to reduce loading, and the cost model. To further develop the idea, tasks included further research, surveying, and brainstorming. To model each strategy’s ability to reduce the load, tasks included estimating technology penetration rates, and performance. Estimating penetration of technologies may depend on the potential partnerships PowerStream creates. This could require more tasks to be required to further develop the scenario.

The tasks included in the work breakdown structure were included in the Gantt chart which is included in the appendix (Figure A-2). This project management tool assisted the group in assessing the amount of time required for the work laid out in the work breakdown structure. This tool was updated at each team meeting and uploaded to the cloud folder online.

Reports and modelling was done with the use of the cloud storage system Dropbox. This allowed the team to instantly access information from other members without relying on e-mails and USB transfers. This was particularly useful in writing the final report, where individual Sections could be completed and stored online where they could be easily accessed and edited by other team members.

11.1 Group Statement

This group worked well together, with each of us willing to take responsibilities and complete the work as necessary. Due to commitments to other classes, the group was not always able to commit fully to this project, thought it was always a priority. On the whole, we used a 'group/individual' method to work. We would meet once or twice a week to decide what needed to be done, and then separate into smaller groups to complete specific tasks. For instance, Jeff and Jason worked on implementing the excel models after we figured out the algorithms and approach as a group.

We did not use techniques to identify each group member's personality type or use the thinking-hat method, preferring to let things develop organically. In retrospect this may have been a mistake. Considering personality type may have solved some of the dynamic problems associated with stress that popped up towards the end of the year.

In general, we could identify trends in each group member's behaviour and work to the strengths present. Geoff was very passionate, Jeff had great stamina, Jason was an excellent individual worker, and Adam provided good constructive criticism. In recognizing how we worked, when things were going well, we could specialize and work to our personal strengths.

The last group dynamic method we used was an 'expert' technique. While some individual work did not require specialized skills, some, such as macro programming or economic analysis, did. And since the project was very multidisciplinary – there are aspects of business, programming, engineering, and planning involved – there was a great deal of material to cover. So Geoff studied failure conditions of the grid; Adam studied business and economics; Jeff studied macros and presentation methods; and Jason primarily studied charge control and grid loading curves. We would all double-check each other's work and tell each other about what we had learned. In this way we could more effectively utilize our particular thinking styles and skills.

12. Recommendations

12.1 Strategies to Implement

The results of the model tests indicate a strong need to implement some manner of charge control in the near future. Adopting a time controlled charging scheme, where users specify a time to begin charging, would decrease the transformer failure rate by approximately 90%. When coupled with encouraging users to charge away from home this failure rate can be decreased to near zero.

PowerStream should consider the option of purchasing chargers and renting or leasing them to PEV owners. This would allow PowerStream to ensure that all the chargers in the region are of high quality and are capable of working with time controlled charging. PEV drivers would also benefit from savings compared to buying and installing the charger themselves. Likewise, car manufacturers would benefit from a reliable and well established partner in creating a charging network.

12.2 Model Improvements

While our model provides useful information and is an important first step, the results are inherently limited in two ways:

1. Model based on bulk terms – charger type, penetration rate, average charge start time, etc.
2. Simplistic additive power consumption model
3. Unable to use Better Place charging data

Using our model, we were able to determine an average consumption curve at various consumption rates, corresponding to various charging strategies. This is useful information and fairly robust, and about the limit of information that can be gathered using Excel.

Chronological Dispatch modeling software would provide more information and a more robust examination of the problem, based on

1. Individual tracking of PEVs, based on consumer GPS data from Better Place or similar analysts
2. Evolution of base load curves and implementation at specific customer addresses
3. More sophisticated grid modeling strategies yielding real-time results

PowerStream has access to CYMDIST, which would be the ideal platform for running such a study. In our model, we ran trials according to market penetration, usage of level 2 vs. level 1 charging, and subscription to charge control strategies. CYMDIST could do much the same, but include consumption of commercial/office charging, implement much more dynamic charging system tests (such as controlling chargers according to padmount charging levels) which our simplified model is simply incapable of reflecting.

It is important that the impact of charging at commercial locations be investigated; a brief look at Vaughan Mills explains why. There are in excess of 6000 parking spaces at that particular mall. At a 5% market penetration of PEVs, one would expect 300 PEVs to be parked at that mall. If all were charging using a charge system in the parking lot, one would expect a load of nearly 3MW. While this is an extreme case, it does establish the magnitude of the problem.

There is finally the issue of load spiking. While a controlled charger could turn on slowly, our model shows level 2 chargers turning on instantaneously. Our model looked exclusively at the power consumption; analysis of load spiking is not within the bounds of our study. While the behaviour will average out in the scale of the system as a whole, there is no simple equivalent system turning on so quickly in a residential area.

13. Conclusions

It has been previously demonstrated that electric vehicle charging, left uncontrolled, would dramatically increase loading at peak usage conditions. This report in particular assumed that the Ontario government's goal of 5% market penetration would be met, and in simulating that case found that a significant number of transformers would overload. The case exists for charge control, and significant investment for incentivising charge control.

Some further work needs to be done in confirming the accuracy of the simulation, and but this project outlines the magnitude of investments (tens of millions). That is felt to be adequate justification to further study the case. There are descriptions of the assumptions and method of the model we developed that should make a second simulation study easier to pursue.

There are a number of different strategies we have developed and examined for this report, but in terms of demonstrating leadership and effectiveness, buying and renting controlled chargers was the highest-scoring category. PEV owners save on installation and running costs of the device, PowerStream will be able to lever bulk-rate discounts and use in-house electricians for installation, and charger vendors will be able to deal in bulk rather than on a house-by-house basis. And the customer has a constant reminder of PowerStream's commitment to the environment.

14. Works Cited

Energy-Use and Climate Change - Energy Use in Canada. (2010). *MECH 430 Course Notes*. Queen's University.

British Columbia Hydro and Power Authority. (2009). *Electric Vehicle Charging Infrastructure Deployment Guidelines British Columbia.*

Canizares, e. a. (2010). *Towards an Ontario Action Plan for Plug-In Electric Vehicles (PEVs).* Waterloo: Waterloo Institute for Sustainable Energy.

Eberle, U. (2010). Sustainable transportation based on electric vehicle concepts: a brief overview. *Royal Society of Chemistry*.

Electric Mobility Canada. (2010). *Demonstrating Electric Vehicles in Canada.* Toronto: Electric Mobility Canada.

Electrification Coalition. (2010). *Presentation of Findings From a National Survey.* Washington: The Mellman Group.

Environmental Protection Agency. (2000, July). Carbon Dioxide Emissions from the Generation of Electric Power in the United States.

Government of Canada. (2010, March 31). *ecoENERGY Retrofit Homes*. Retrieved 2010, from ecoACTION Using less, living better: http://www.ecoaction.gc.ca/ecoenergy-ecoenergie/retrofithomes-renovationmaisons-eng.cfm

Hamilton, T. (2010, Septemner 27). Hamilton: Ontarios FIT program a success after one year. *The Toronto Star*.

Ministry of Transportation. (2005). *Provincial Highways Traffic Volumes (AADT Only).* Ministry of Transportation.

Muehlegger, E. (2008). Giving Greed to Get Green: Incentives and Consumer Adoption of Hybrid Vehicle Technology. *Harvard University, John F. KEnnedy School of Government, Faculty Reserach Working Papers Series*, 6.

Nissan. (n.d.). *Nissan Canada*. Retrieved October 13, 2010, from Nissan Canada - Vehicles: www.nissan.ca/vehicles/cars/versa/hatchback/en/

Nissan. (n.d.). *Nissan LEAF Electric Car*. Retrieved October 13, 2010, from Nissan Canada: www.nissan.ca/vehicles/ms/leaf/en/

Ontario Ministry of Transportation. (2010, September 10). *Electric Vehicle Incentive Program*. Retrieved December 02, 2010, from Ontario Ministry of Transportation: http://www.mto.gov.on.ca/english/dandv/vehicle/electric/electric-vehicles.shtml

Ontario Ministry of Transportation. (2010, June 18). *Ontario Paves the Way for Electric Cars.* Retrieved December 02, 2010, from Ontario Ministry of Transportation: http://www.mto.gov.on.ca/english/dandv/vehicle/electric/

Parker, M. (2010, July 13). *GE Introduces Smart Grid-Compatible Electric Vehicle Charger*. Retrieved October 21, 2010, from General Electric : http://www.genewscenter.com/Content/Detail.aspx?ReleaseID=10582&NewsAreaID=2&ClientID=1

Putrus, e. a. (2009). *Impact of Electric Vehicles on Power Distribution.* Newcastle upon Tyne: Northumbria University.

Tatsumi Ichikawa, C. R. (2002). Recent trends in distributed generation - technology, grid integration, system operation. 4.

Transportation Tomorrow Survey. (2006). *Transportation Tomorrow Survey.* Retrieved October 13, 2010, from Urban Transportation Research and Advancement Centre: http://www.jpint.utoronto.ca/ttshome/publications.html

Tsvetkova, A. A., & Hadley, S. (2009). Potential Impacts of Plug-In Hybrid Vehicles on Regional Power Generation. *The Electricity Journal, 22*(10), 56-57.

Waterloo Institute for Sustainable Energy. (2010). *Towards an Ontario Action Plan For Plug-In-Electric Vehicles.* Waterloo: University of Waterloo.

15. Appendices

Economic Estimates

Table A1 – Summary of costs and revenues associated with purchasing all residential level 2 chargers

	Percent Penetration	# Of EVs	Cost	Revenue from Power Sales	Annual Cash Flow	Revenue from Rent (To Break-Even)
2012	1.0%	2,915	$ (8,743,530)	$ 813,804	$ (7,929,726)	$ 157,699
2013	1.5%	4,372	$ (4,371,765)	$ 1,220,706	$ (3,151,059)	$ 236,549
2014	2.0%	5,829	$ (4,371,765)	$ 1,627,608	$ (2,744,157)	$ 315,399
2015	2.5%	7,286	$ (4,371,765)	$ 2,034,510	$ (2,337,255)	$ 394,248
2016	3.0%	8,744	$ (4,371,765)	$ 2,441,412	$ (1,930,353)	$ 473,098
2017	3.5%	10,201	$ (4,371,765)	$ 2,848,314	$ (1,523,451)	$ 551,947
2018	4.0%	11,658	$ (4,371,765)	$ 3,255,216	$ (1,116,549)	$ 630,797
2019	4.5%	13,115	$ (4,371,765)	$ 3,662,118	$ (709,647)	$ 709,647
2020	5.0%	14,573	$ (4,371,765)	$ 4,069,020	$ (302,745)	$ 788,496
2021	5.5%	16,030	$ (4,371,765)	$ 4,475,922	$ 104,157	$ 867,346
2022	6.0%	17,487	$ (4,371,765)	$ 4,882,824	$ 511,059	$ 946,196
2023	6.5%	18,944	$ (4,371,765)	$ 5,289,726	$ 917,961	$ 1,025,045
2024	7.0%	20,402	$ (4,371,765)	$ 5,696,628	$ 1,324,863	$ 1,103,895
2025	7.5%	21,859	$ (4,371,765)	$ 6,103,530	$ 1,731,765	$ 1,182,745

Demographic Data

Markham		Richmond Hill	
InterSection	Average Household Income	**InterSection**	Average Household Income
Personna and Chachet	$127,037.00	**Humberland and Coon's**	$101,448.00
Holbrook and Graystone	$121,461.00	**Worthington and Wood Rim**	$105,777.00
Rodick and 7	$77,991.00	**Tiger Lily and Old Colony**	$105,135.00
End of Angus Glen	$259,225.00	**Tower Hill and Rollinghill**	$109,642.00
Gainsville and Callahan	$124,086.00	**Brookeside and Alamo Heights**	$102,029.00
Weatherill and The Birdle Walk	$93,191.00	**19th Ave and Linda Margaret Crescent**	$109,569.00
Atlantic and Brooklyn Crescent	$114,031.00	**Rumble and Wood**	$117,902.00
Raymond Bartlett and Isabella	$82,396.00	**Crosby and Newkirk**	$62,385.00
Bur Oak and Dogwood	$83,783.00	**Redstone and Princeton**	$93,118.00
Beck and Feltham	$95,555.00	**Marsi and Wainwright**	$88,445.00
Bur Oak and Swan Park	$85,447.00	**Hillsview and Kirsten**	$85,708.00
Ramona and Wootten Way	$122,710.00	**Frank and Boake**	$141,915.00
Shady Oaks and Old Markham	$97,728.00	**Westwood and Pearson**	$102,257.00
		Briggs and Bayview	$98,377.00

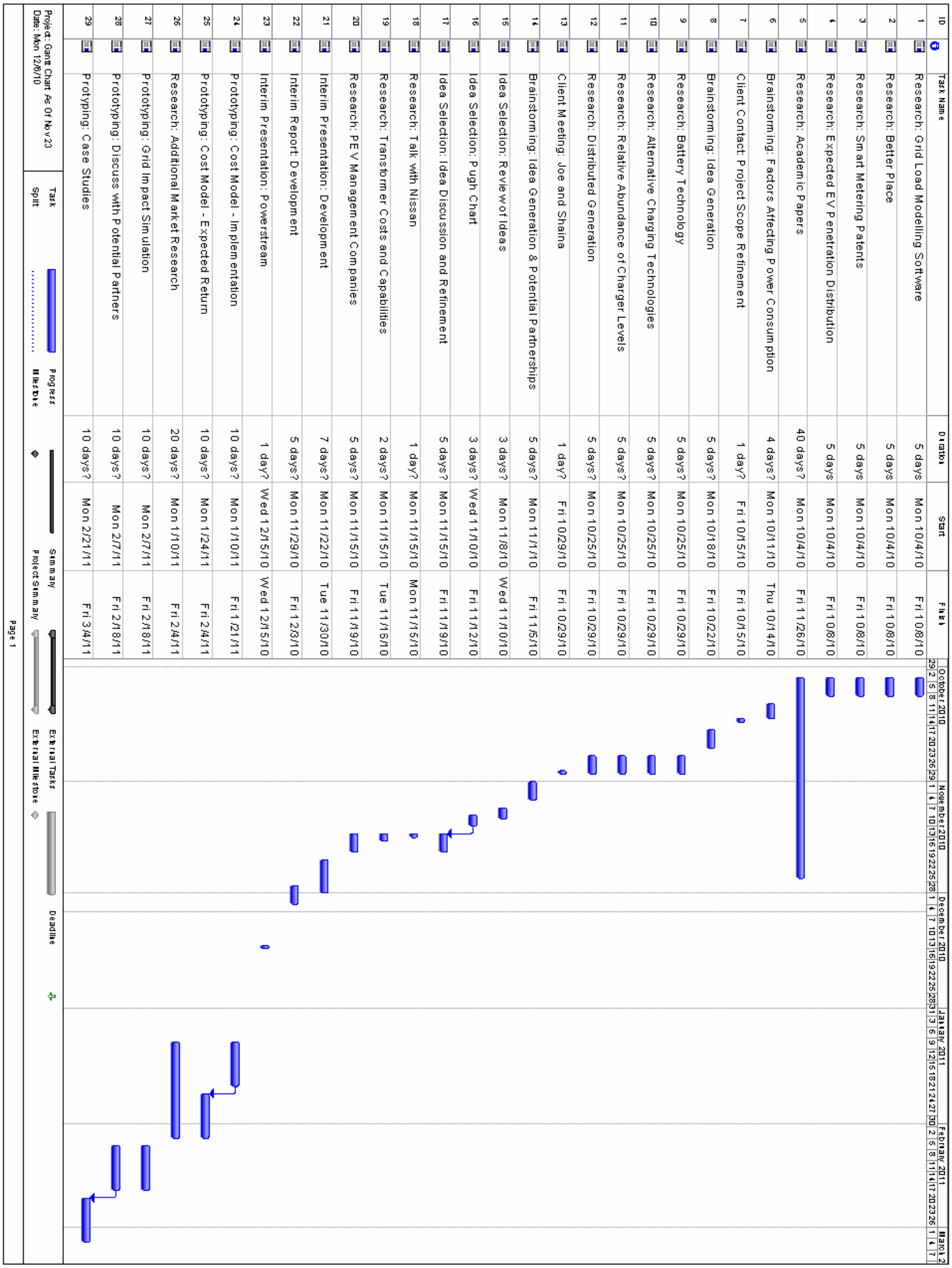
Aurora		Vaughan	
InterSection	Average Household Income	InterSection	Average Household Income
Loraview and Beechbrooke	$126,112.00	**Forest and Martin Grove**	$90,023.00
Beacon Hall and Tree Tops	$241,425.00	**Pine Valley and Road 7**	$96,501.00
Kennedy and Murray	$118,542.00	**Forest Fountain and Colle Melito**	$97,335.00
Cousins Dr E	$115,765.00	**Wycliffe and Kiloran**	$212,359.00
Orchard Heights and Lanewood	$140,099.00	**Langstaff and Weston**	$122,029.00
Steckly and Hollandview Trail	$96,958.00	**Fossil Hill and Rutherford**	$112,932.00
		400 and Major Mackenzie	$84,471.00
		Keele and Major Mackenzie	$92,704.00
		Teston and Jane	$97,692.00
		Barrhill and Rutherford	$107,059.00
		Langstaff and Spinnaker Way	$92,413.00

Work Breakdown Structure

Figure A-1. Work breakdown structure, as of December 6, 2010

Gantt

Chart



ID
Task Name
Duration
Start
Finish
October 2010
November 2010
December 2010
January 2011
February 2011
March 2
1 Research: Grid Load Modelling Software 5 days Mon 10/4/10 Fri 10/8/10
2 Research: Better Place 5 days Mon 10/4/10 Fri 10/8/10
3 Research: Smart Metering Patents 5 days Mon 10/4/10 Fri 10/8/10
4 Research: Expected EV Penetration Distribution 5 days Mon 10/4/10 Fri 10/8/10
5 Research: Academic Papers 40 days? Mon 10/4/10 Fri 11/26/10
6 Brainstorming: Factors Affecting Power Consumption 4 days? Mon 10/11/10 Thu 10/14/10
7 Client Contact: Project Scope Refinement 1 day? Fri 10/15/10 Fri 10/15/10
8 Brainstorming: Idea Generation 5 days? Mon 10/18/10 Fri 10/22/10
9 Research: Battery Technology 5 days? Mon 10/25/10 Fri 10/29/10
10 Research: Alternative Charging Technologies 5 days? Mon 10/25/10 Fri 10/29/10
11 Research: Relative Abundance of Charger Levels 5 days? Mon 10/25/10 Fri 10/29/10
12 Research: Distributed Generation 5 days? Mon 10/25/10 Fri 10/29/10
13 Client Meeting: Joe and Shaina 1 day? Fri 10/29/10 Fri 10/29/10
14 Brainstorming: Idea Generation & Potential Partnerships 5 days? Mon 11/1/10 Fri 11/5/10
15 Idea Selection: Review of Ideas 3 days? Mon 11/8/10 Wed 11/10/10
16 Idea Selection: Pugh Chart 3 days? Wed 11/10/10 Fri 11/12/10
17 Idea Selection: Idea Discussion and Refinement 5 days? Mon 11/15/10 Fri 11/19/10
18 Research: Talk with Nissan 1 day? Mon 11/15/10 Mon 11/15/10
19 Research: Transformer Costs and Capabilities 2 days? Mon 11/15/10 Tue 11/16/10
20 Research: PEV Management Companies 5 days? Mon 11/15/10 Fri 11/19/10
21 Interim Presentation: Development 7 days? Mon 11/22/10 Tue 11/30/10
22 Interim Report Development 5 days? Mon 11/29/10 Fri 12/3/10
23 Interim Presentation: Powerstream 1 day? Wed 12/15/10 Wed 12/15/10
24 Prototyping: Cost Model - Implementation 10 days? Mon 1/10/11 Fri 1/21/11
25 Prototyping: Cost Model - Expected Return 10 days? Mon 1/24/11 Fri 2/4/11
26 Research: Additional Market Research 20 days? Mon 1/10/11 Fri 2/4/11
27 Prototyping: Grid Impact Simulation 10 days? Mon 2/7/11 Fri 2/18/11
28 Prototyping: Discuss with Potential Partners 10 days? Mon 2/7/11 Fri 2/18/11
29 Protyping: Case Studies 10 days? Mon 2/21/11 Fri 3/4/11
Project: Gantt Chart As Of Nov 23
Date: Mon 12/6/10
Task
Split
Progress
Milestone
Summary
Project Summary
External Tasks
External Milestone
Deadline
Page 1

Figure A-2: Gantt chart, as of December 6, 2010

Model Operation Manual

Inputs

Expected penetration rate – This is the projected number of houses which will have a PEV. It is expected that 5% of passenger vehicles will be electric by 2020.

Percentage of PEV owners using L2 charging – This is the percentage of houses which will use level 2 charging (9.8kW). It is assumed that every user not using L2 charging will be using level 1 (1.9kW). The model currently assumes 2 hours to charge on a L2 charger or 5 hours on a L1 charger.

Number of households per transformer – Default is 10 for a worst-case scenario. This does not need to be an integer.

Percentage of users using controlled charging – Separate for L1 and L2 chargers, represents the proportion of PEVs following the controlled charging pattern.

Percentage of users who charge non-residentially – The proportion of users who do not charge at home. Currently these cars are simply removed from the model. There is no distinction between L1 and L2 users in determining which cars to remove.

Methodology

First, the percentage chance of a car being present at both the L1 and L2 charging levels is determined. A random number is generated for 10 houses to represent the chance that a PEV is present. The number of houses per transformer can limit this trial to fewer than 10 houses if desired.

Once the PEVs are "placed" onto the model, another random number determines if they will be controlled or uncontrolled charging based on the input data. A third random number is then compared to a distribution of start times for each of the four possible charging routines (L1 vs L2, controlled vs uncontrolled). The percentage chances of charge start times are found by hour on pages "Level 1 Residential" and "Level 2 Residential" in columns B and E. These can be changed as desired.

With the charge start time and charging level determined, the power consumption by the PEV charger is added to the base load, entered in column D of the sheet "Single Trial". This outputs a new load curve representing the total load on the transformer every hour.

Pressing Ctrl+R will generate a new set of random numbers and copy the output onto a new sheet ("Monte Carlo Data"). By default this is done 500 times, which can be changed by editing the 21st line of the "repeat" macro. This data is then used to output relevant information in the "Results" tab. This shows a graph of the base load, average PEV-specific load, maximum load across all trials, and average total load. The average load curves are represented by the upper 95% confidence limit across all trials. This page also shows the number of transformers exceeding a 50kW load as both a number and a percentage of the number of trials. This is then extrapolated across the total number of transformers (36,875) to determine the total number of transformers at risk of failure and the cost required to upgrade them.

Outputs

Graphical Information

Base Load – The base load on the transformer without PEV loading. Taken from the data input on the "Single Trial" tab.

PEV Load – The upper 95% confidence limit of the transformer load caused by PEV charging each hour.

Average Load – The sum of the base and PEV loads. Represents the upper 95% confidence limit of the load on a transformer.

Maximum Load – The highest load on a transformer across all trials at each hour.

Numerical Information

Percentage chance of failure – The percentage of simulations where the load on a transformer exceeds 50kW.

Number of transformers failing – The percentage chance of transformer failure multiplied by the number of transformers expecting this load scenario. By default this is 36,875 (the total number of residential transformers)

Value of failed 50kW transformers – The number of transformers failing multiplied by the cost of each transformer.

Cost of replacement with 100kW transformer – The cost of replacing each failed transformer with a larger unit. Includes the cost of the transformer and installation.

PowerStream YOUR CURRENT CONNECTION

Queen's UNIVERSITY

Vehicle-to-Grid Strategic Assessment

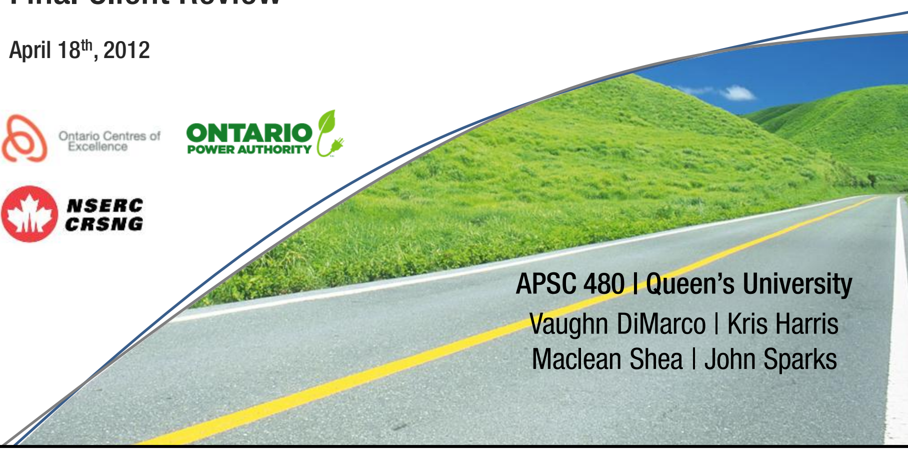
Final Client Review

April 18th, 2012

Ontario Centres of Excellence

ONTARIO POWER AUTHORITY

NSERC CRSNG



APSC 480 | Queen's University
Vaughn DiMarco | Kris Harris
Maclean Shea | John Sparks

Where we left off on February 17th …

Power aggregation found to be highly unprofitable …

Participant Suggestions

- Refine economic model with data from Nissan Canada and Better Place
- Conduct variable sensitivity analysis
- Analyze the operating reserves power market
- Determine the impact of a Power Stream / Veridian Connections collaboration

V2G power found to have a detrimental effect on transformer ageing …

Participant Suggestions

- Explore in greater detail the potential positive and negative effects V2G power may have on the grid

Today's Agenda

1) Overview of project

2) Profitability projections and sensitivity analysis

3) Technical implications

4) Review of mobile applications

5) Conclusions and future projects

6) Hands-on economic model walkthrough

A broad research scope was required to understand V2G's impact on PowerStream

Key Areas of Research

Economics of Power Aggregation	Key Players & Partnerships	Impact on Grid Management
Peak Power Offset	LDC Collaborations	Power Supply Curve Redistribution
Operating Reserves	EV Service Providers	Transformer Harmonics
Regulation Services	Electric Vehicle OEMs	

\+ technology & market growth projections, mobile application development guide

Note: Local Distribution Company (LDC), Electric Vehicle (EV)

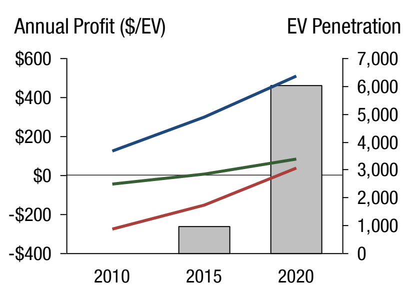
Various markets are available for V2G power aggregation

	Attractiveness	Description
Peak Power Offset		Provide energy to the grid at high demand and draw energy at low demand. **Weakness**: limited storage, high $/kWh
Operating Reserves		Contract to provide energy if unexpected demand spike occurs in real-time market.
Regulation Services		Contract to provide/draw energy to match system generation with load. **Strengths**: quick response, low $/kW

Source: Willett Kempton "Vehicle-to-grid power fundamentals", IESO

Regulation services the only consistently profitable market

Operating Profitability of an Established System



	2010	2015	2020	
RS	$124	$292,065	$3,060,047	Total Profit
PO	-$44	$5,877	$490,477	
OR	-$277	-$150,509	$211,228	

Sensitivity Analysis Markets in 2020

	+10%	%Δ Profit
RS	$p_{contract}$	+12%
	$t_{plug/day}$	+10%
	$R_{d\text{-}c}$	-9%
PO	$p_{elec\text{-}diff,avg}$	+24%
	L_{energy}	+14%
	$C_{bat,kWh}$	-13%
OR	$t_{plug/day}$	+84%
	$p_{contract}$	+82%
	N_{disp}	-74%

Source: Numerous (see V2G Power Aggregation – Economic Feasibility Model.xlsx)

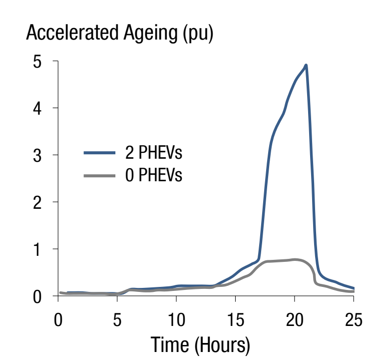
PowerStream is not well positioned to take advantage of power aggregation alone

	Partner with Adjacent LDC	Partner with Service Provider
	e.g. Veridian Connections	e.g. Better Place
Positive	• Incremental increase to available EV battery stored energy • Ideal for consumers who regularly cross LDC jurisdictional boundaries • Shared SmartGrid management experience	• Shared risk with larger company • Combined advantage of existing LDC relationship with residents and service provider control over batteries • Existing charging control system and infrastructure
Negative	• Inadequate leverage over battery owners to ensure participation in V2G initiative • Capital development cost of V2G control and communications system (i.e. middleware) prohibitively high	• Service providers likely to have more control over partnership given their size and existing resources

V2G current harmonics pose a risk to residential transformers

- V2G loads are non-linear & require rapid bi-directional power flow
- Chargers rectify low-voltage AC power & convert to DC, producing harmonic distortion
- Harmonic distortion increases power loss: accelerates ageing due to thermal loading
- 20-31% power loss versus transformer with no harmonics present

Increased harmonics accelerate ageing of transformers



Source:Balathandayuthapani

Vehicle-to-grid power has potential for positive grid impact

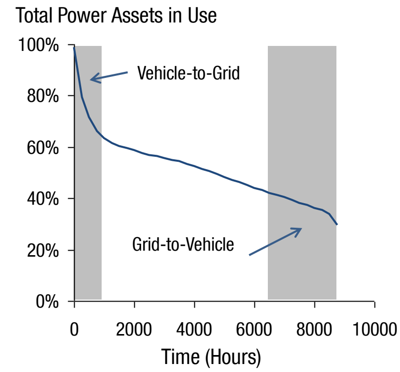
Harmonic loads may potentially cancel out, reducing harmonic distortion

Low nighttime temperatures may offset internal thermal loading

Flatter load profile resulting from off-peak charging could reduce expansion and contraction of the transformer, reducing ageing of transformer bushings.

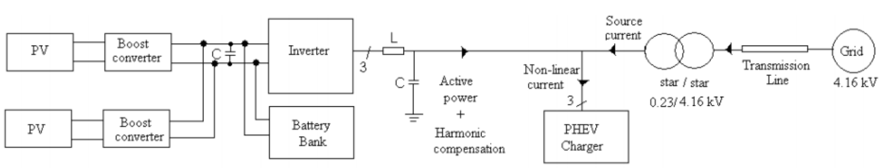
V2G could reduce the total power assets required by as much as 64MW in 2020

V2G has potential to reduce total necessary power assets

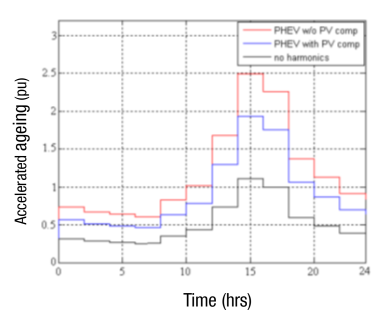


Source: Chris Farmer, et. al. "Modeling the impact of increasing PHEV loads …", PowerStream

Potential for Harmonic Compensation such as Photovoltaic Active Power Filters



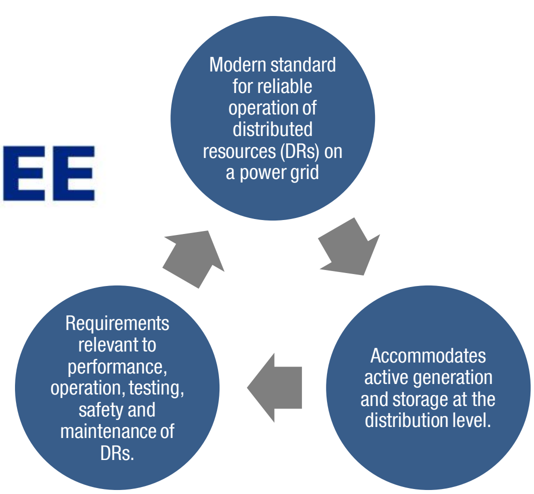
- Integrating a PV inverter with the grid to function as an APF to mitigate harmonic effects using a harmonic-extraction algorithm.
- Results of research show that transformer ageing can be slowed down by mitigating harmonic effects of bidirectional power flow.
- Harmonics are detected using any number of current-detection algorithms



Further potential impacts of V2G on grid infrastructure

- Infrastructure not adequate for rapid bidirectional power flow
- Insufficient communications architecture for IESO power flow control
- Further research into the effect of V2G on grid infrastructure must be carried out.

IEEE 1547 – a standard for connecting distributed resources with power systems



A V2G mobile application could significantly improve the consumer experience

- **Mobile Application Features**
  - Expected
    - Battery details
    - Utility account details
  - Quality
    - Vehicle settings
    - Security
    - GPS
  - Innovative
    - Gamification
    - Social integration

Moving forwards …

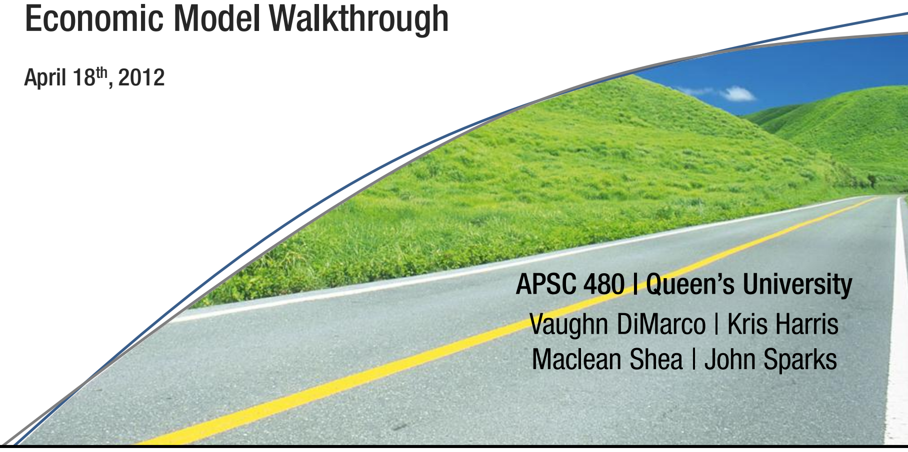
Project Conclusions	• Actively pursue data as it becomes available • Focus on regulation services with regards to power aggregation • Think critically about partnerships and collaboration • Investigate implementation of IEEE 1547
Future Projects	• Establish working relationship with IESO to develop guidelines and methods for V2G participation in power markets • Determine the capital cost of middleware and control systems development • Further refine economic analysis of power aggregation • Continue research into the effects of V2G on transformer harmonics

APSC 480 | Queen's University

Vehicle-to-Grid Strategic Assessment

Economic Model Walkthrough

April 18th, 2012



APSC 480 | Queen's University
Vaughn DiMarco | Kris Harris
Maclean Shea | John Sparks

Economic Model Walkthrough

Please Open Your Laptops Now

V2G Power Aggregation – Economic Feasibility Model (v1.0).xlsx

is available at

http://db.tt/0I4WRYBg

Ontario Electric Car Demonstration Project
Final Project Report

March 2012

Contents

Note: The picture on the front page shows a Nissan Leaf plugging into a Better Place charge spot at the Evergreen Brick Works. The Education and Demo centre was located on the top floor of the Centre for Green Cities in the background.

Executive Summary

Better Place and our Ontario Partners launched the Electric Car Demonstration project in Ontario on February 28, 2011 and operated the project until February 29, 2012. Our local utility partners were PowerStream and Veridian and our local education/site partner was Evergreen. Over the past year the project met the two defined objectives: 1) building knowledge and capacity for building and operating electric vehicle (EV) networks in Ontario and 2) educating the general public and Ontario stakeholders on the opportunity with electric vehicles. The project had two components: a centrally managed charging network and a demonstration and education centre.

The centrally managed charging network was launched and operated with our partners. Six EVs – four Nissan Leafs, one GM Volt and one AMP Chevrolet Equinox – were operated on a network of 14 charge points. Additional EVs that connected to the network at various times include the Ford Transit Connect, the Mitsubishi iMiEV and the Mercedes-Benz Smart Car. The Better Place network centre collected and analyzed data on charge spot usage and, through smart charging capabilities, demonstrated the benefits that a centrally managed charge network can provide to Ontario drivers and utilities.

The Better Place Visitor Centre welcomed 3,298 visitors during the course of the year, including over 200 Ontario industry stakeholders, providing information on the economic and environmental benefits of electric cars. Visitor surveys showed both a strong increase in EV knowledge from the visit to the centre and strong agreement that the government should support the transition to electric cars.

Overall, this project demonstrated the viability of the Better Place solution and the interest of the public in mass adoption of EVs. The strong support of the Ontario government and the active engagement and local expertise of our Ontario partners were key to the success of the project.

Better Place delivers the network and services that make an electric car affordable to buy, easy to use, and amazing to own. This project demonstrated some of the key components of the complete solution that Better Place is introducing in countries and regions around the world. We are excited to continue to work with Ontario on the transition to electric transportation and an oil free future.

Introduction and Overview

Better Place operated an Electric Car Demonstration project in Ontario to build local capabilities for electric vehicle adoption and to educate the public and local businesses on EV technologies and benefits. This project was operated with funding support from the Ontario Ministry of Economic Development and Innovation.

In this project, Better Place partnered with two of Ontario's largest municipal electric utilities – PowerStream Inc. and Veridian Corp. – as well as Evergreen, a national charity. The project had two components: an intelligent EV charging network and a demonstration and education centre.

Better Place, in coordination with its partners, deployed and operated an intelligent EV charging network. The infrastructure and systems (charge spots, communication system, remote network operating centre, customer service) were installed and the local partners operated electric vehicles as part of their fleets[1]. A total of 7 charge spots (14 sockets) were installed at 6 locations[2]. The electricity usage and driving pattern data was collected and analyzed to inform future decisions on the capability, requirements and placement of EV networks and infrastructure.

Better Place provided training to the local partners on how to use the charge spots and provided ongoing customer support and service. In addition, Better Place had a service agreement with Ainsworth, a Canadian electrical contractor, to install, service, and maintain network operations. Better Place established a local office at the Evergreen Brick Works to manage day-to-day project operations.

In addition to the smart charging network, Better Place opened an education and demonstration centre (the Better Place Visitor Centre) at the Evergreen Brick Works that used interactive material to show consumers and businesses how they could and why they should switch to EVs. The build phase of the project began in Q3 2010 and the centre opened on February 28, 2011. The centre generated its own traffic in addition to partnering with associated events and activities on-site at the Brick Works and around the region. A number of key stakeholders in the Ontario market were brought into the centre for customized tours[3]. Better Place has operated education and demonstration programs around the world, including Denmark, Israel, Japan, China and the United States.

[1] For a list and overview of vehicles operating on the network, please refer to Appendix 1.
[2] For a map of charge spot locations, please refer to Appendix 2.
[3] For a list of stakeholders, please refer to Appendix 5.

Project Objectives

This project had a number of objectives, all related to advancing the adoption of EVs in Ontario through capability building and education. Better Place met all of the objectives set out in the project.

Objective	Project Deliverables
I. Build expertise in Ontario for planning and deploying EV network infrastructure	• Network deployment allowed Better Place and Ontario partners to gain experience on practical aspects such as cost, site requirements and operations
II. Demonstrate tangible progress in Ontario that will drive further transportation electrification projects and commercialization	• Operation of a smart charging network was a step towards broader adoption of EVs in Ontario • Data collected demonstrated the business case and requirements for EVs in Ontario • Better Place partnered with PowerStream and Veridian on two proposed Smart Grid projects • Better Place presented project results, methods, and learnings to other LDCs and stakeholders at events such as the Electricity Distributors Association Conference and the Electric Mobility Canada Conference
III. Pre-commercial testing and validation of the integration of smart EV network infrastructure with Ontario LDCs	• Smart charging – the ability to remotely monitor and control charging – was demonstrated • Better Place and utility partners used the live network to have informed and practical discussions on integration options/requirements
IV. Collect and analyze data of vehicle operation, battery operation, and user behavior (e.g., driving and charging patterns), which will be used to help optimize the EV network infrastructure for future commercial buildout	• The operating centre recorded charging events to allow analysis and control of charging patterns. LDCs can use this capability, coupled with smart meters, as a lower cost / better performance option than increasing transformer sizes in order to accommodate additional loads from EVs • A total of 746 charge events[4] providing over 6,800 kWh of electricity were recorded using the Better Place Network Operating Centre (NOC) • A total of 12,573 km of travel with total energy consumption of 2,292 kWh was recorded by onboard vehicle systems[5]. The average vehicle efficiencies were 5.9 km/kWh (Nissan Leaf) and 3.8 km/kWh (Equinox).

[4] Charge events were required to last more than 10 minutes and deliver more than 0.1 kWh to be counted.

V. Demonstrate to the public and industry stakeholders a complete electric vehicle solution – including the vehicles, charging infrastructure and customer services – allowing people to personally see the ease of adoption	• The Better Place Visitor Centre offered an interactive space for the public to learn about electric vehicles. The Centre also provided an excellent site to meet with stakeholders and demonstrate the business potential of EV industry • The Centre hosted a total of 3,298 visitors, including 203 industry stakeholders
VI. Educate the public on the overwhelming benefits—in terms of climate action, pollution reduction, and economic development—of a transportation system based on EVs	• The Visitor Centre informed and educated the public on the many benefits of EVs • On site survey results showed centre experience moved average EV understanding from between "not very informed" and "fairly informed" to "well informed" • Over 80% of visitors agreed or strongly agreed the government should support the transition to electric cars

Project Milestones

The project milestones are the specific steps Better Place undertook to meet the project objectives. Better Place has completed all the project milestones: a smart charging network was put into operation, data was gathered and analyzed, and the Better Place Visitor Centre was open to the public all year.

Smart Charging Network

Milestone	Progress to date	Details
1. Confirm local operating partner(s)	• Completed	• Local operating partner was Evergreen
2. Confirm local utility partner(s)	• Completed	• Local utility partners were Veridian and PowerStream
3. Install charge spots	• Completed	• Site inspection completed for all sites • Wiring and mounting completed for all sites • Charge spots deployed and activated
4. Install remote network communications system	• Completed	• North American NOC is operational • Local telecomm. service provider established • Charge spots connected to network

[5] Note the onboard vehicle systems recorded significantly less energy than the Better Place NOC since a) not all vehicles had onboard vehicle systems and b) the onboard vehicle systems were not always active.

5. Develop and implement user service program	• Completed	• Customer service line registered and operational (1-866-9-SWITCH) • Users have been fully trained on EV and charge spot use
6. Launch operations	• Completed	• Charging network operational • EVs have been distributed to partners for fleet use
7. Collect and report data	• Completed	• Vehicle data is available for the most of the year; NOC data is available for the last nine months • Charge spot data collection through the NOC began at the beginning of June

Education and Demonstration Centre

Milestone	Progress to date	Details
1. Determine site	• Completed	• Leases signed for Education/Demo Room and Better Place Canada office at Evergreen Brick Works
2. Design and manufacture education and demonstration material and equipment	• Completed	• Room design completed • Education/demo material completed
3. Install education and demonstration material and equipment	• Completed	• Centre completed mid-February, 2011
4. Launch operations	• Completed	• Centre opened February 28, 2011 • Official press launch March 3, 2011
5. Collect and report data	• Completed	• Total of 3,298 visitors, including 203 industry stakeholders • Survey results analyzed • Partnered with local events to increase awareness and attendance

Smart Charging Network Operations and Learnings

Mass adoption of EVs in Ontario will lead to an overall increase in electricity consumption. Unmanaged EV charging could be a source of significant stress on Ontario's existing electrical infrastructure, particularly at the distribution level, due to increased peak demand. Furthermore, large-scale integration of renewable energy sources into Ontario's energy mix creates a need for load management and distributed storage to absorb off-peak electricity. The Better Place EV smart charging network helps Local Distribution Companies remove the electric grid risks and capture the electric grid benefits without requiring investment in additional electricity generation, transmission or communication systems.

The EV smart charging network allows Better Place to monitor, control and aggregate the charging infrastructure in the network. The network systems can communicate this data to utility partners, allowing allocation of energy based on available supply and EV drivers' demand.

For this project, Better Place established a Network Operations Centre (NOC) in Palo Alto, California. Each charge spot site had the local intelligence and communications to connect to the NOC, allowing real time monitoring and control. This included identifying which charge spots were in use and how much electricity was being provided to the vehicles.

Data on charge spot and vehicle operations was collected from two sources: 1) the network operating centre system and 2) on-board vehicle systems. The network operating centre develops a log of charge spot usage as shown in Figure 1. This information allows Better Place and utilities to analyze historical demand patterns and consumption and intelligently manage electricity supply and demand to align with grid capabilities. On-board vehicle systems record energy consumption and additional metrics such as trip time and trip distance. This allows the efficiency of electric vehicles to be analyzed, allowing more accurate predictions of future energy demand.

The onboard vehicle systems recorded less energy usage than the Better Place NOC since a) not all vehicles had onboard vehicle systems and b) the onboard vehicle systems were not always active. There were also some charge events that were not on a Better Place charge spot (e.g. a home 120V outlet) and therefore were not recorded by the Better Place NOC.

Network Operating Centre Data and Performance

The NOC was fully operational beginning in June, collecting real time charge event data and giving Better Place and our utility partners' key insights into charge spot usage and electricity demand. The data collected and organized by the NOC allowed Better Place to (a) monitor charge spot usage and demand in real time and (b) collect historical data to determine demand and consumption patterns that inform future electricity demand expectations.

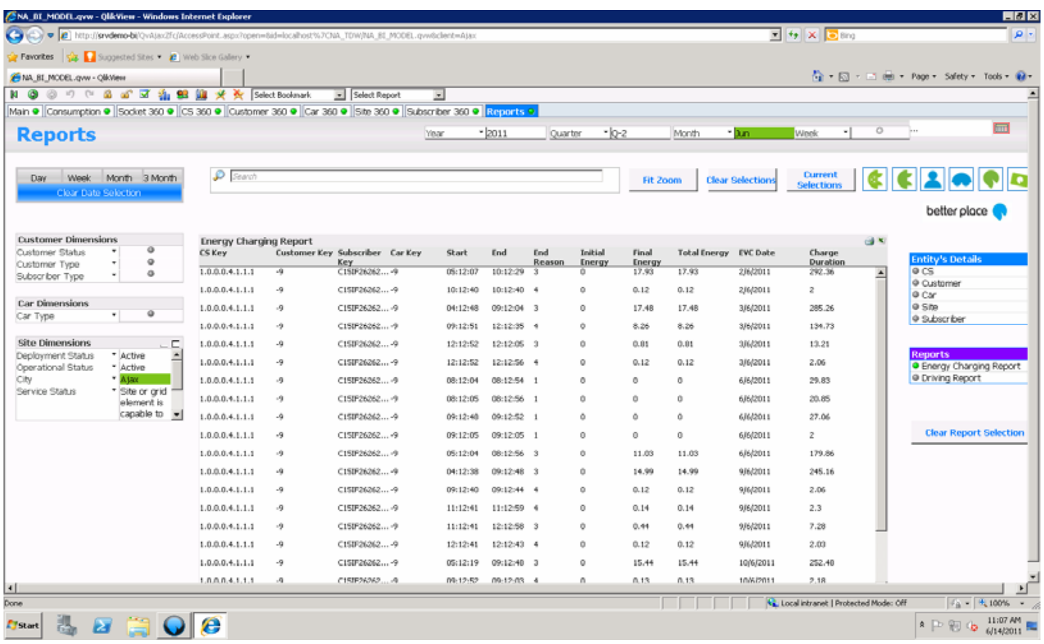
Examples of system views of network operations are shown in Figures 1, 2 and 3.

Over the last nine months of the project, the NOC recorded 746 individual charge events at the six charge spot locations. The average charge event was approximately 2.75 hours in duration and provided 9.1 kWh in electricity and a total of 6803.5 kWh of charging was delivered. Further, the data provided by the NOC allowed more complex analysis, such predicting future demand (load) profiles based on historical network usage. This data is extremely useful for utilities in planning for the electricity demand increase associated with mass adoption of electric cars.

Key components of the data analysis and utility reporting are shown in Appendix 3. The analysis demonstrates that without smart charging, EVs will contribute to peak loads. Shifting this demand to off-peak periods through the use of smart charging will be necessary in order to avoid grid stress and excessive peak demand. Additionally, the analysis shows that the predictability of the daily energy requirements increases substantially as the number of sites and the average energy delivered increases. This provides confirmation to utilities and service providers that the daily energy requirement will be very predictable even with a relatively low adoption level of electric cars.

From a network performance perspective, there were early operational challenges on both configuration of the network operating centre system and network connectivity[6]. The launch of the network operating centre system was delayed, primarily due to the fact that the NOC, though now serving operations across North America, was specifically opened for this project and required new internal processes both within North America and globally. These challenges were addressed and the NOC was been completely operational for the last nine months of the project. Additionally, the network connectivity of one of the charge spot sites was a challenge due to low and fluctuating reception signal strength. This was addressed by establishing a local landline connection. This was a key lesson learned for network deployment, leading to an internal recognition of the need for thorough and comprehensive connectivity testing before charge spot deployment.

Figure 1. Screen shot of a charge spot usage report from the Better Place network system. The top two panels indicate how network usage can be analyzed from any perspective – charge spot, customer, car, site or subscriber – and for any time period.



[6] Although local site intelligence and data storage ensures that charge spots are operational even without network connectivity, real-time communication is required to maximize the grid benefits of an intelligent charging network

Figure 2. Screen shot of individual site from Better Place network system. Left panel shows real-time usage and status of site charge spots. Right panel shows real-time total electricity demand and total supply.

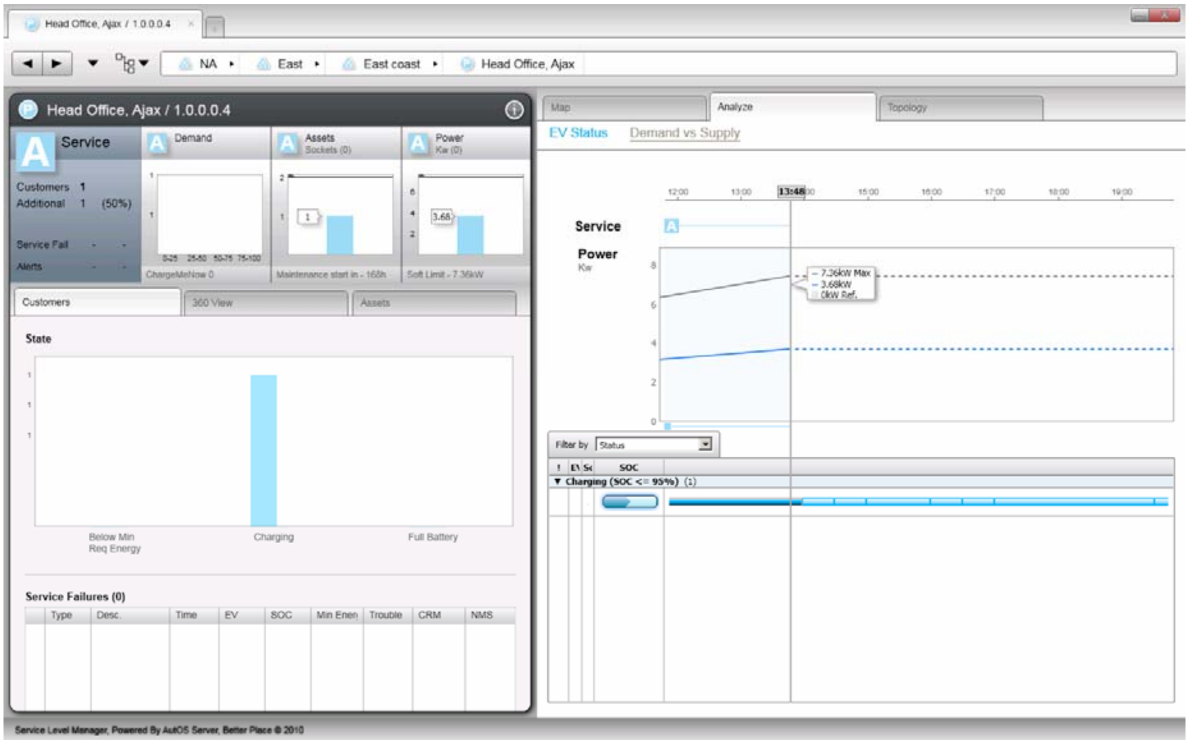
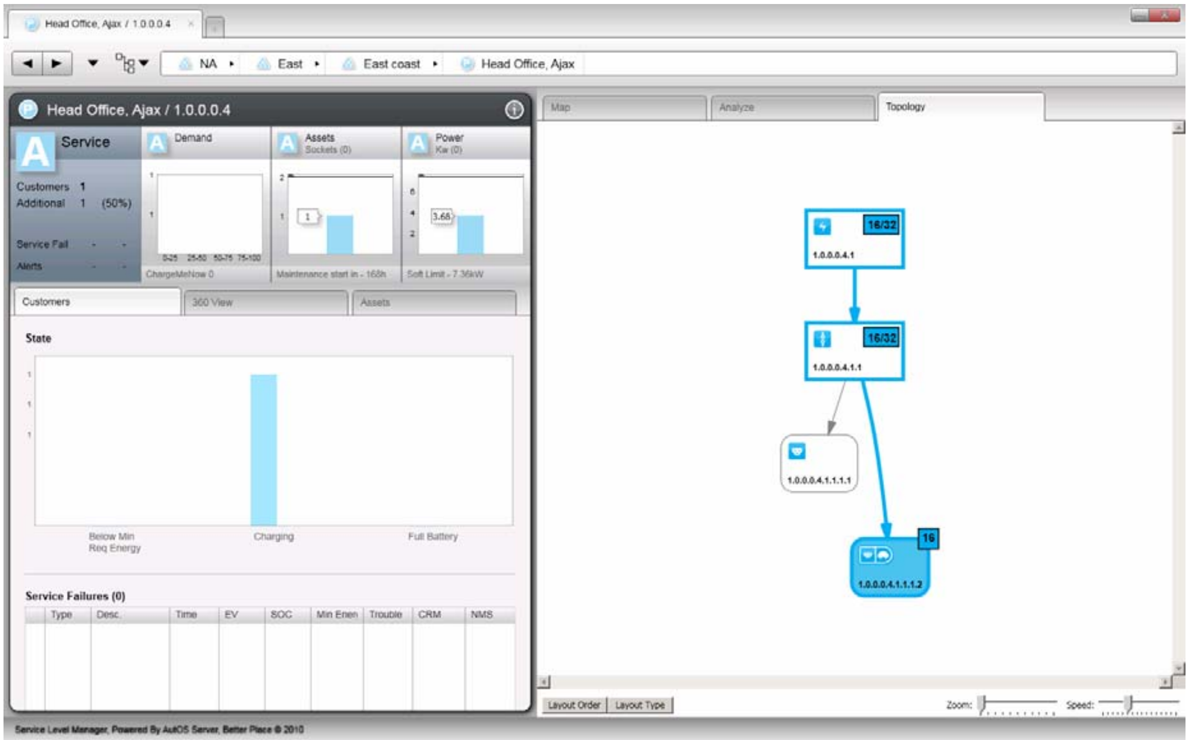


Figure 3. Screen shot of individual site from Better Place network system. Left panel shows real-time usage and status of site charge spots. Right panel shows topology of site panels, circuits and sockets.



Smart Charging Demonstration

As part of the demonstration project, smart charging tests were conducted in coordination with Better Place's utility partners, PowerStream and Veridian. These tests demonstrated Better Place's capability to shed load and modulate power in response to grid capacity constraints. Figure 4 illustrates Better Place's smart charging response for a single charge spot delivering 3.8 kW of electricity. Under this circumstance, the LDC would indicate to Better Place to reduce its power demand due to local capacity constraints, for example at the transformer or substation level. The response would occur instantaneously, and power would gradually as the result of communications between Better Place and the LDC as capacity becomes available. This example of smart charging, or load management, can be provided through fixed, day-ahead, or real-time requests.

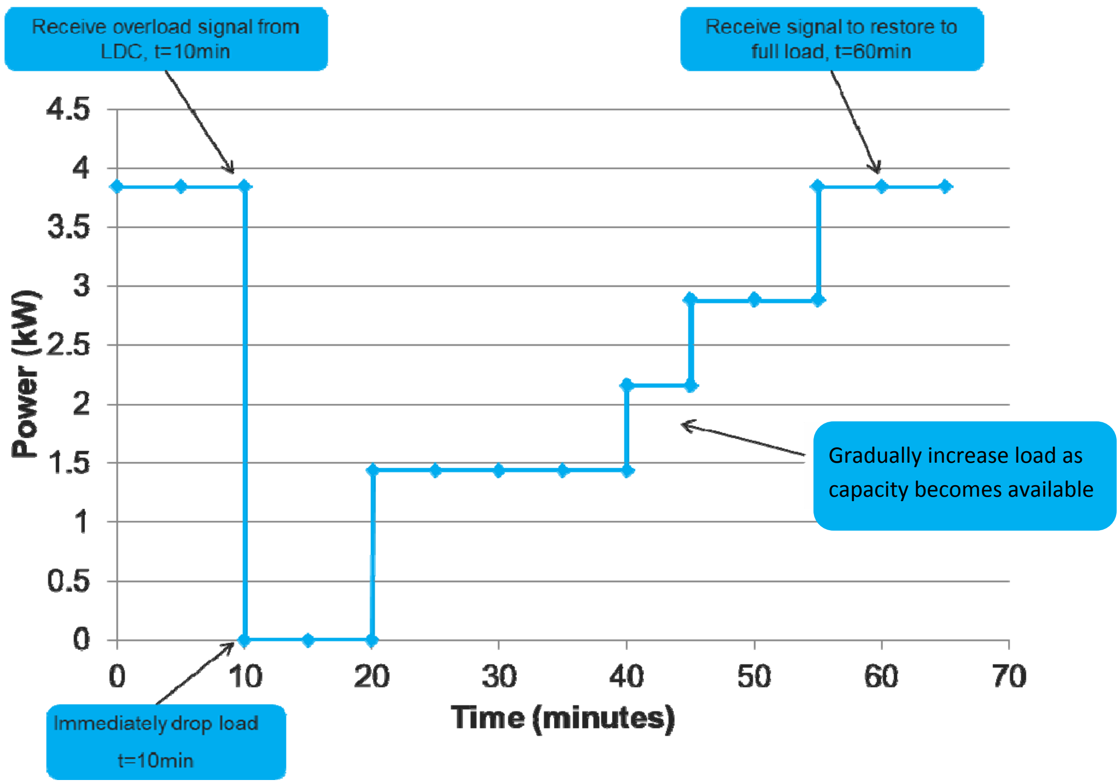


Figure 4. Load management response by Better Place

Vehicle Performance

Better Place arranged for the use of a number of electric vehicles as part of this project. The vehicles were used to provide a load for the charging network and generate data about electric car usage patterns.

There was an initial challenge acquiring the EVs. Originally it was planned for PowerStream and Veridian to each operate a converted Chevrolet AMP Equinox. However, due to production delays the project switched to Nissan Leafs. This resulted in a 4-10 week delay in vehicle delivery to partners. Better Place acquired one Chevrolet AMP Equinox and operated it for the first three months of the project. A list of vehicles operated during the project is in Appendix 1.

For the first three months of this project, data was only recorded using the on-board vehicle systems while the network operating centre system was being tested and localized. In the second quarter of the project the on-board vehicle data was unavailable for two reasons. The first reason was the discontinued use of the AMP Equinox which ended one data stream. At the same time, Nissan changed its network coverage in Canada such that the Nissan Leafs that were in operation were unable to connect to the central server and upload any driving data. Nissan Leaf data for the PowerStream Leafs was available from August 2011 onward.

Data and analysis from vehicle systems is shown in Appendix 4. Vehicle trips totalling 12,573 km and 2,292 kWh of electricity were recorded over the course of the project. This gives an average energy efficiency of 5.5 km/kWh. The Nissan Leaf had an average energy efficiency of 5.9 km/kWh while the larger, converted Equinox had an efficiency of 3.8 km/kWh. The estimated gasoline reduction from EV use was 1,479 L, resulting in an estimated greenhouse gas reduction of 3,484 $kgCO_2$.

Vehicle efficiency was aggregated by day and compared to the mean daily temperature records from Environment Canada for Toronto Pearson Airport. As expected there was a strong correlation between temperature and vehicle efficiency, with efficiency dropping from an average of 7km/kWh at 20^oC to an average of 5km/kWh at -10^oC. This ~30% reduction in efficiency was due to an increase in energy expended on climate control and aligns with system expectations[7]. This is an important result for utilities, as it confirms that overall energy requirements of EVs will increase as temperatures decrease, although the size of this effect is expected to decline as EV thermal management systems improve.

Customer Service

Customer service is also a key component of the Better Place system. To this end, Better Place fully trained all users on EV charging and operation. Furthermore, Better Place established a customer service line (1-866-9-SWITCH) which users could call to resolve technical issues regarding the charge spots or the vehicles. This service successfully resolved the few technical problems that occurred while the project was operational.

Visitor Centre Operations and Learnings

The Better Place Visitor Centre was an interactive, educational facility that promoted EVs and the Better Place model. The Visitor Centre featured videos, interactive touch-screen kiosks, information, and trained guides to inform visitors on the economic and environmental benefits of EVs and the Better Place solution. The centre proved to be an exceptional facility for informing the public and key stakeholders about EVs in Ontario.

The Visitor Centre had a successful launch on February 28, 2011, with media and press attention for the official launch party on March 3, 2011. The centre was open six days a week to the public. Better Place coordinated with Evergreen, the Toronto Renewable Energy Cooperative, and other organizations in planning and hosting public outreach events on the Brick Works site and at other locations around Toronto. On most Sundays in July and August Better Place, in partnership with Autoshare, offered public electric car test drives. Other past events include Earth Day and the Kids World of Energy Festival.

Better Place collected and analyzed visitor data over the year of operations[8]. During this time period, total attendance was been 3,298; an average of 275 people per month. This total included visits by 203 key stakeholders. Better Place conducted a voluntary survey of visitor centre guests with a response rate of 4% of visitors. Data collected included knowledge of EVs and opinions on government involvement with EVs[9]. Responses indicated very high public support for electric cars and the Visitor Centre:

- 80% of respondents agreed or strongly agreed that the government should support EVs
- Average respondent's understanding of EVs increased from between "not very informed" and "fairly informed" to "well informed"

Additional information on the centre visitors and the survey results is in Appendix 5.

[7] See for example, the Department of Energy NERL 2010 report, Analysis of Off-Board Powered Thermal Preconditioning in Electric Drive Vehicles
[8] Please refer to Appendix 5 for more information on Visitor Centre attendance and performance.
[9] Please refer to Appendix 6 for a list of survey questions

Summary

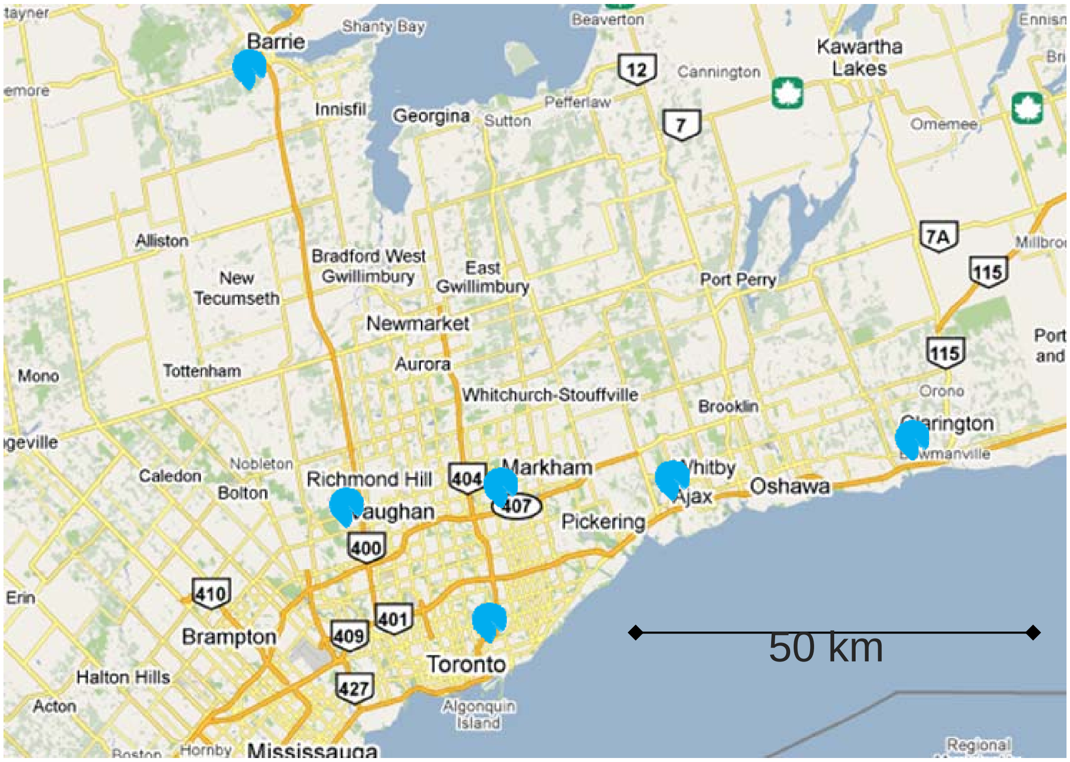
The Better Place Electric Car Demonstration project has demonstrated the technical and consumer solution for EV charging in Ontario and has educated the public about the future of EVs in the province. The experience and challenges faced in introducing the first smart charging network has built the required experience and capabilities. Globally, electric cars and electric car networks are now at the stage of mass adoption and deployment in many countries and regions. The next step towards sustainable transportation in Ontario is the introduction of a comprehensive private electric vehicle service offering and a large public network that uses the lessons learned from this project so that Ontario drivers and utilities can make the switch to electric vehicles.

Appendix 1: Electric Vehicles Operated by Better Place and Partners

Vehicle Make and Model	Battery size	Local Operator
Nissan LEAF	24 kWh	Better Place
Nissan LEAF	24 kWh	PowerStream
Nissan LEAF	24 kWh	PowerStream
Nissan LEAF	24 kWh	Veridian
Chevrolet Volt	16 kWh	Veridian
Chevrolet AMP Equinox	37 kWh	Better Place

Additional EVs that connected to the network at various times include the Ford Transit Connect, the Mitsubishi iMiEV and the Mercedes-Benz Smart Car.

Appendix 2: Map of Charge Spot Locations



Partner	Location	Address	Charge spots
Evergreen	Evergreen Brick Works	550 Bayview Avenue, Toronto	2
PowerStream	Head Office, Vaughan	161 Cityview Boulevard, Vaughan	1
PowerStream	Operations Office, Markham	80 Addiscott Court, Markham	1
PowerStream	Operations Office, Barrie	55 Patterson Road, Barrie	1
Veridian	Head Office, Ajax	55 Taunton Rd. E., Ajax	1
Veridian	Operations Office	Highway 2/ Lambs Rd, Bowmanville	1

Appendix 3: Network Performance Reports

Ontario EV Network Activity Report

June 2011- February 2012

Overall Network Charging

	Charging Events
746 events	Total charge events
2.8 events	Average charge events per day
02:51 (hh:mm)	Average charge event duration
	Energy
6803.5 kWh	Total energy provided (kWh)
9.1 kWh	Average energy provided per charge event (kWh)
Location:	All
Customer:	All

Example of Charging by Site

	Charging Events
245 events	Total charge events
0.9 events	Average charge events per day
02:23 (hh:mm)	Average charge event duration
	Energy
1858.3 kWh	Total energy provided (kWh)
7.6 kWh	Average energy provided per charge event (kWh)
Location:	Ajax Head Office
Customer:	All

Example of Charging by Customer

	Charging Events
278 events	Total charge events
1.0 events	Average charge events per day
03:52 (hh:mm)	Average charge event duration
	Energy
3428.1 kWh	Total energy provided (kWh)
12.3 kWh	Average energy provided per charge event (kWh)
Location:	All
Customer:	Power Stream

Example of Charging by Customer and Site

	Charging Events
30 events	Total charge events
0.1 events	Average charge events per day
01:45 (hh:mm)	Average charge event duration
	Energy
169.1 kWh	Total energy provided (kWh)
5.6 kWh	Average energy provided per charge event (kWh)
Location:	Evergreen Brick Works
Customer:	Better Place Canada

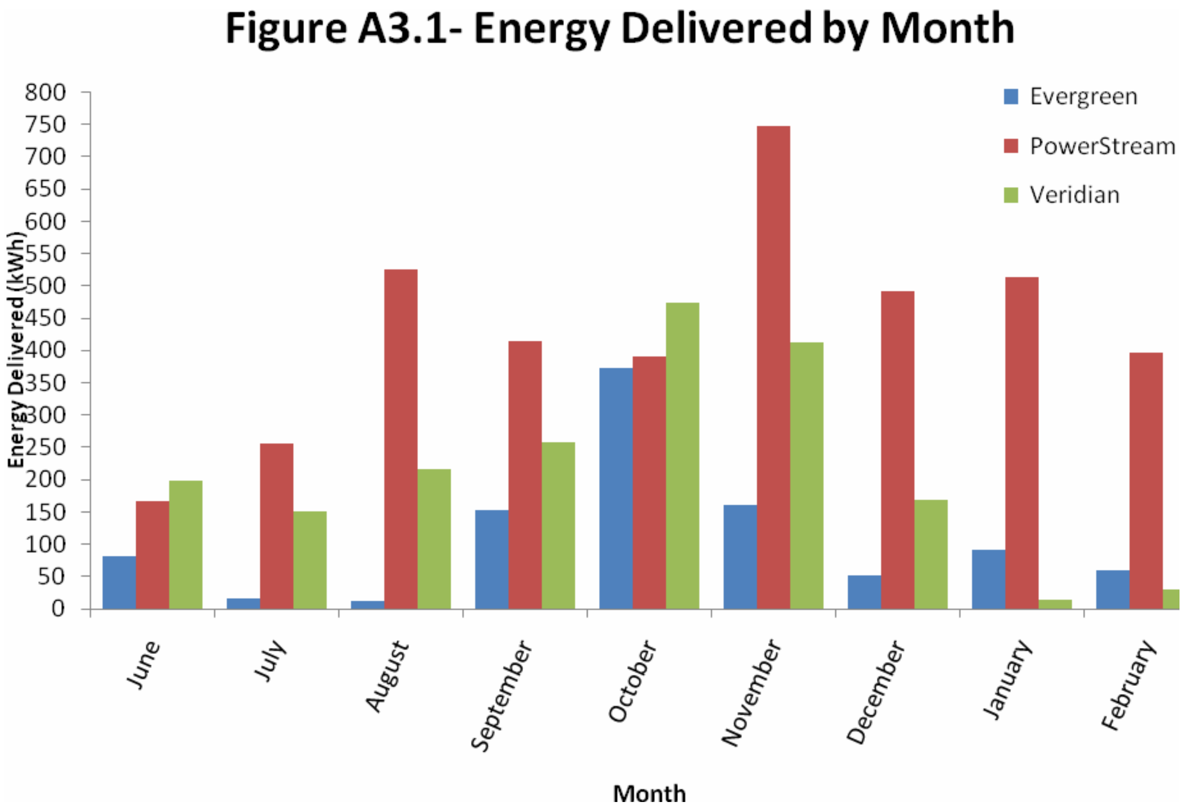


Figure A3.1- Energy Delivered by Month
Evergreen
PowerStream
Veridian
Energy Delivered (kWh)
800
750
700
650
600
550
500
450
400
350
300
250
200
150
100
50
0
June
July
August
September
October
November
December
January
February
Month

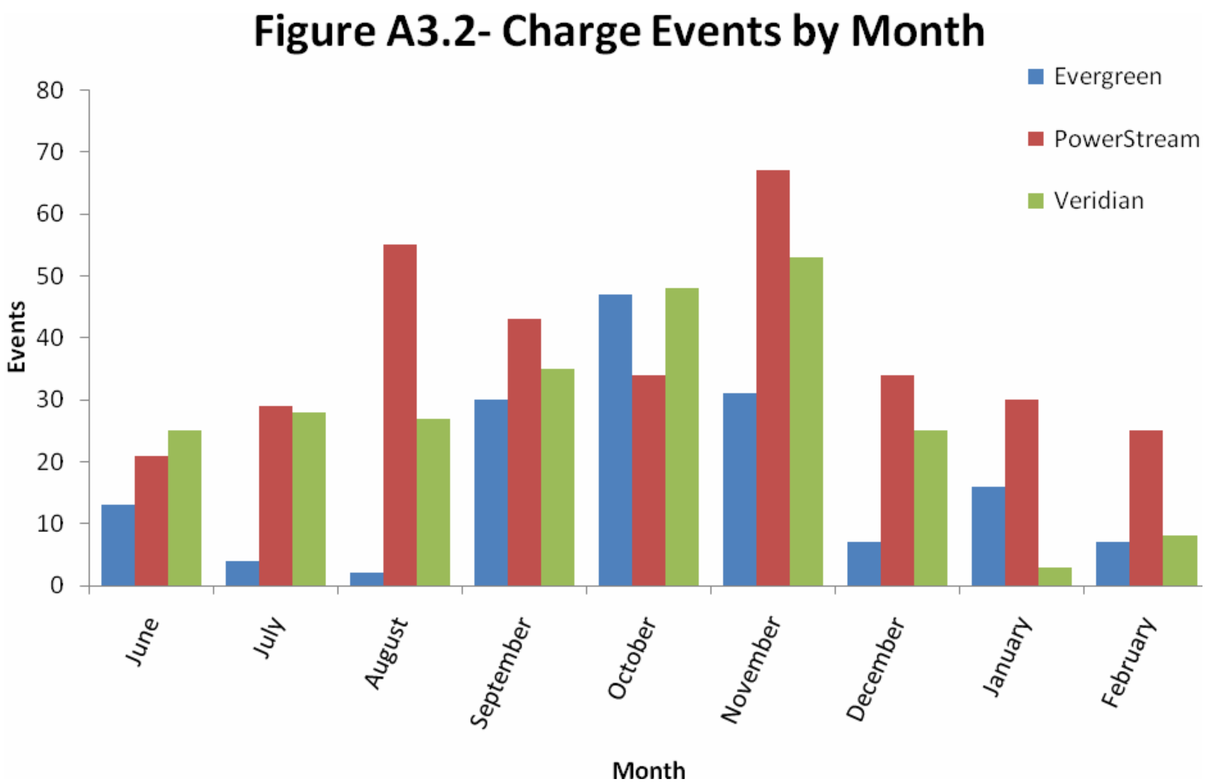


Figure A3.2- Charge Events by Month
Evergreen
PowerStream
Veridian
Events
80
70
60
50
40
30
20
10
0
June
July
August
September
October
November
December
January
February
Month

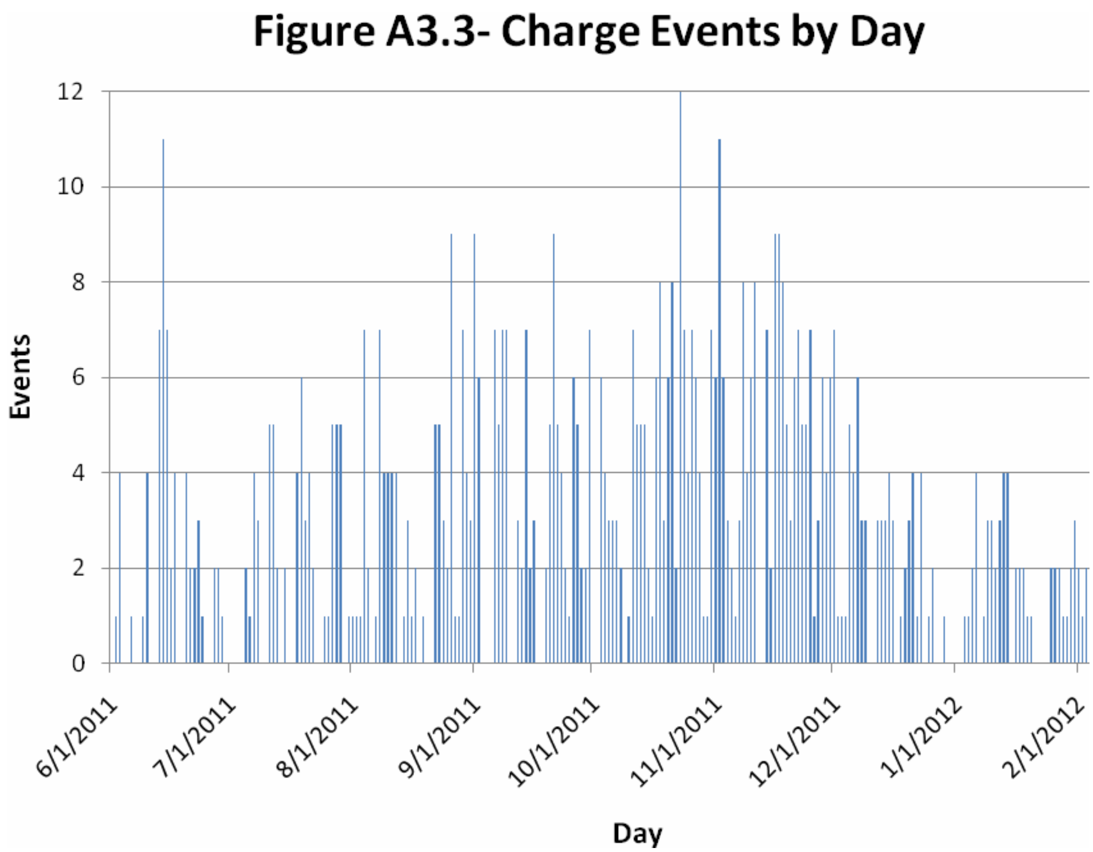


Figure A3.3- Charge Events by Day
Events
0
2
4
6
8
10
12
6/1/2011
7/1/2011
8/1/2011
9/1/2011
10/1/2011
11/1/2011
12/1/2011
1/1/2012
2/1/2012
Day

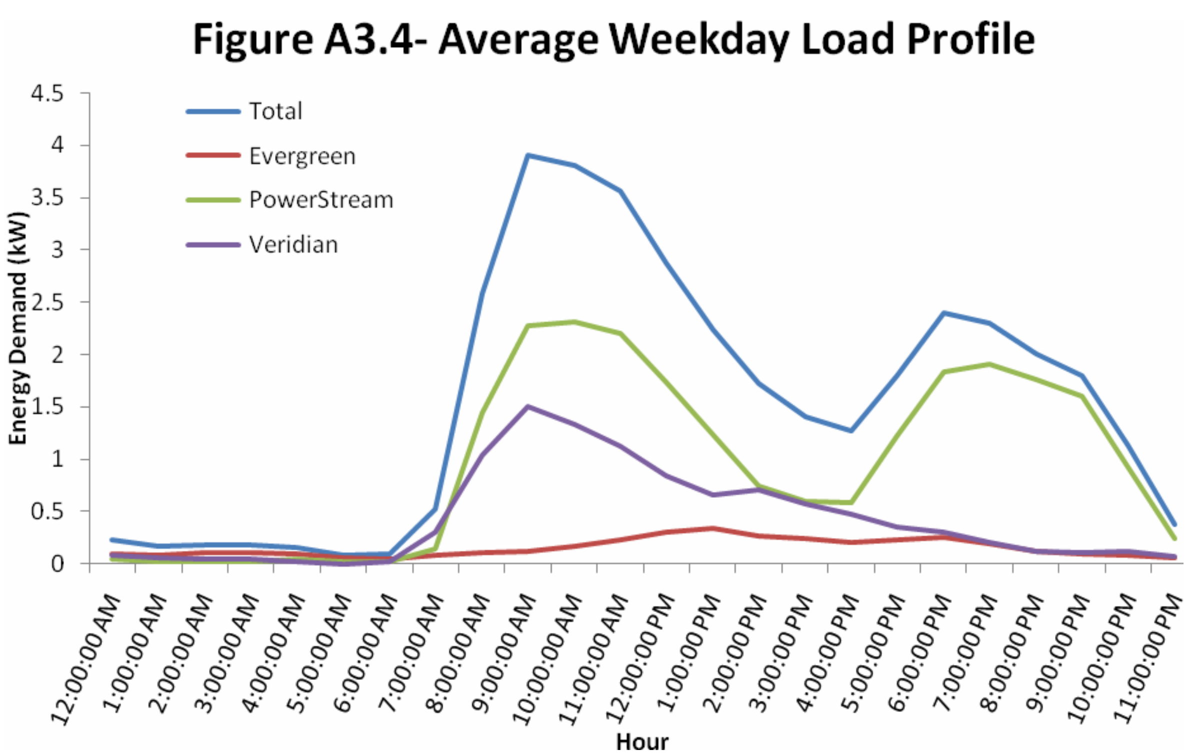


Figure A3.4- Average Weekday Load Profile
Total
Evergreen
PowerStream
Veridian
Energy Demand (kW)
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Hour

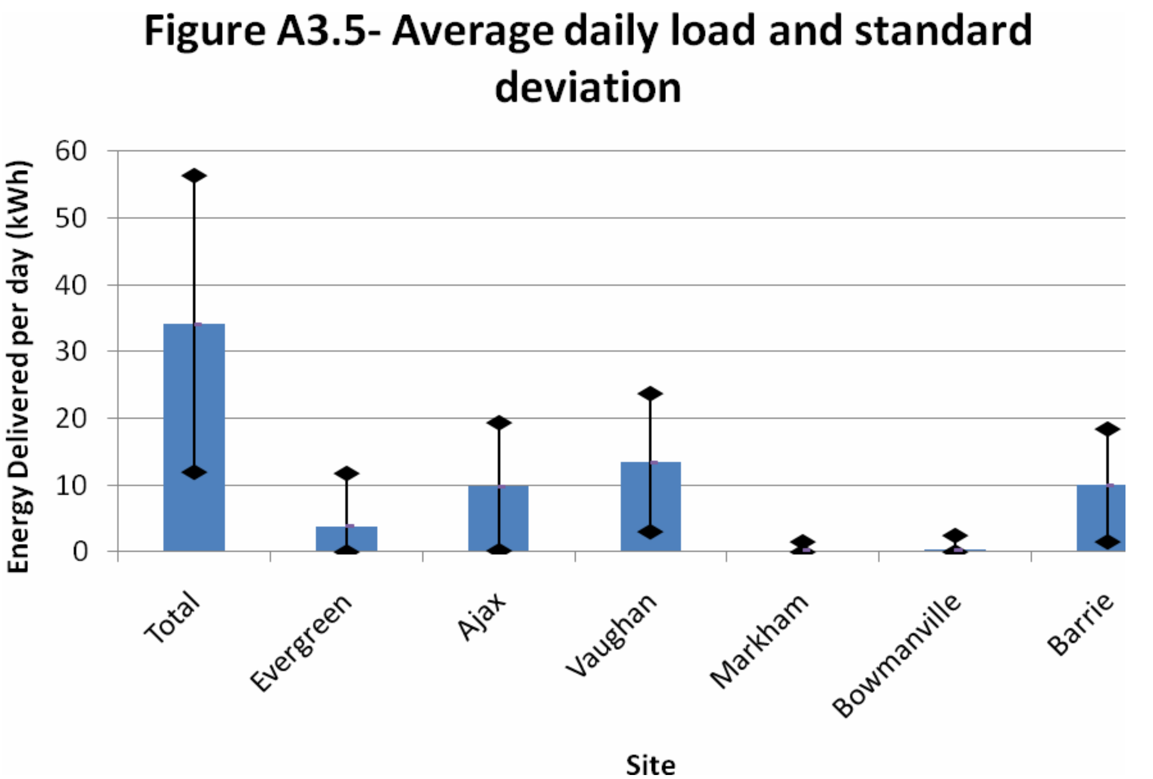


Figure A3.5- Average daily load and standard deviation
Energy Delivered per day (kWh)
60
50
40
30
20
10
0
Total
Evergreen
Ajax
Vaughan
Markham
Bowmanville
Barrie
Site

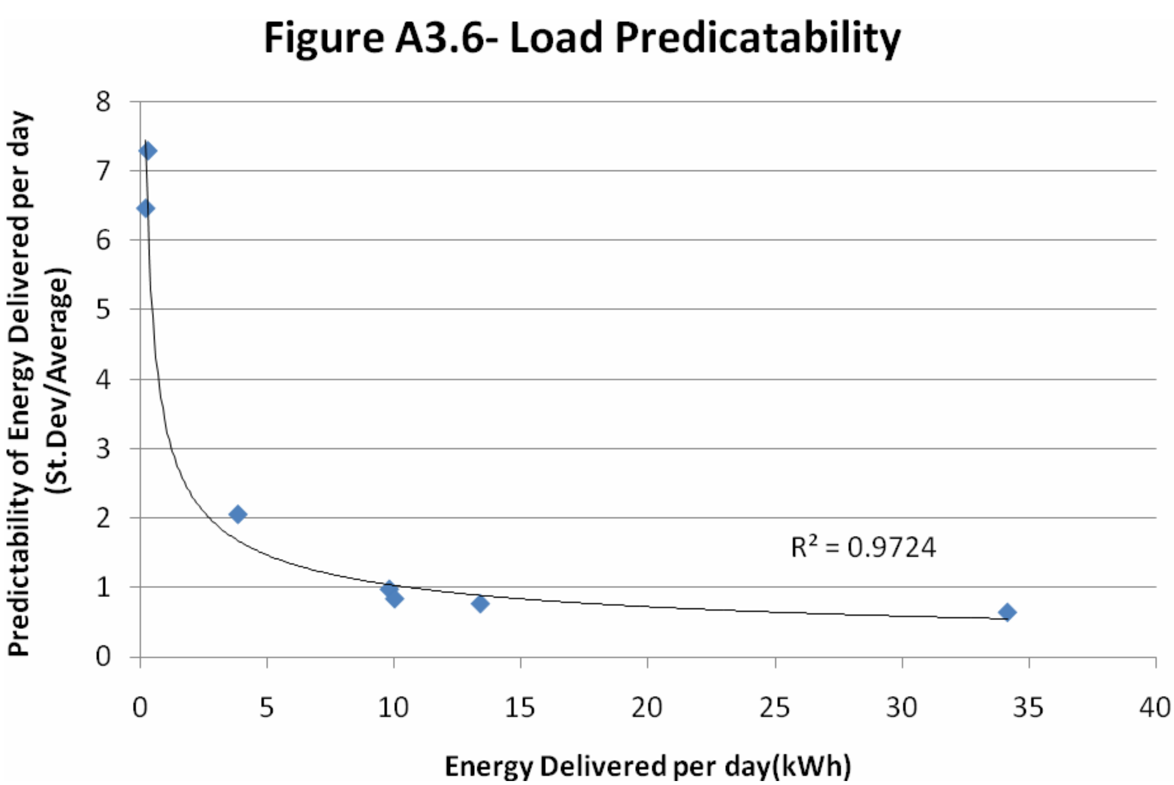


Figure A3.6- Load Predicatability
Predictability of Energy Delivered per day (St.Dev/Average)
8
7
6
5
4
3
2
1
0
$R^2 = 0.9724$
0
5
10
15
20
25
30
35
40
Energy Delivered per day(kWh)

Appendix 4: Vehicle Performance Reports

Nissan Leaf Aggregated Activity Report

	Driving Events
487 events	Total driving events
11635 km	Total distance driven
167.3 hours	Total time driving
23.9 km	Average KM driven per trip
62.1 km/h	Average speed
5.9 km/kWh	Average driving efficiency
	Energy
1966.9 kWh	Total driving energy expended (kWh)
	Environment
1368.3 liters	Gasoline usage reduction (based on 20mpg / 8.5km per litre)
3224.3 kg	Estimated GHG emission reductions (CO_2)[10]

[10] Assumes that the grid is providing clean energy to power the EV.

Chevrolet AMP Equinox Activity Report

	Charging Events
102 events	Total charge events
1.7 events	Average charge events per day
11:53 (hh:mm)	Average charge event time
60%	Average starting SoC percentage
65%	Average final SoC percentage
05%	Average increase in battery SoC percentage
	Driving Events
70 events	Total driving events
17:12:06 (hh:mm:ss)	Total time driving
938 km	Total distance driven
15.4 km	Average KM driven per day
13.4 km	Average KM driven per trip
00:14:45 (hh:mm:ss)	Average trip time (hour:minute)
3.8 km/kWh	Average driving efficiency
54.5 km/h	Average speed
80%	Average starting SoC percentage
69%	Average final SoC percentage
11%	Average decrease in battery SoC percentage
	Energy
352.3 kWh	Total energy provided (kWh)[11]
246.9 kWh	Total driving energy expended (kWh)
3.5 kWh	Average energy provided per charge event (kWh)
	Environment
110.3 liters	Gasoline usage reduction (based on 20mpg / 8.5km per litre)
259.9 kg	Estimated GHG emission reductions (CO_2)[12]

[11] The discrepancies between energy provided and energy expended occur for several reasons. The primary factor is that charge events in the month may not have corresponding driving events. Secondly, efficiency losses during charging and discharging that aren't captured in the data. Additionally lesser factors include other energy consuming events that aren't recorded such as the heater or other accessories and that the battery continues to draw power even when the battery is full in order to balance the cells.

[12] Assumes that the grid is providing clean energy to power the EV.

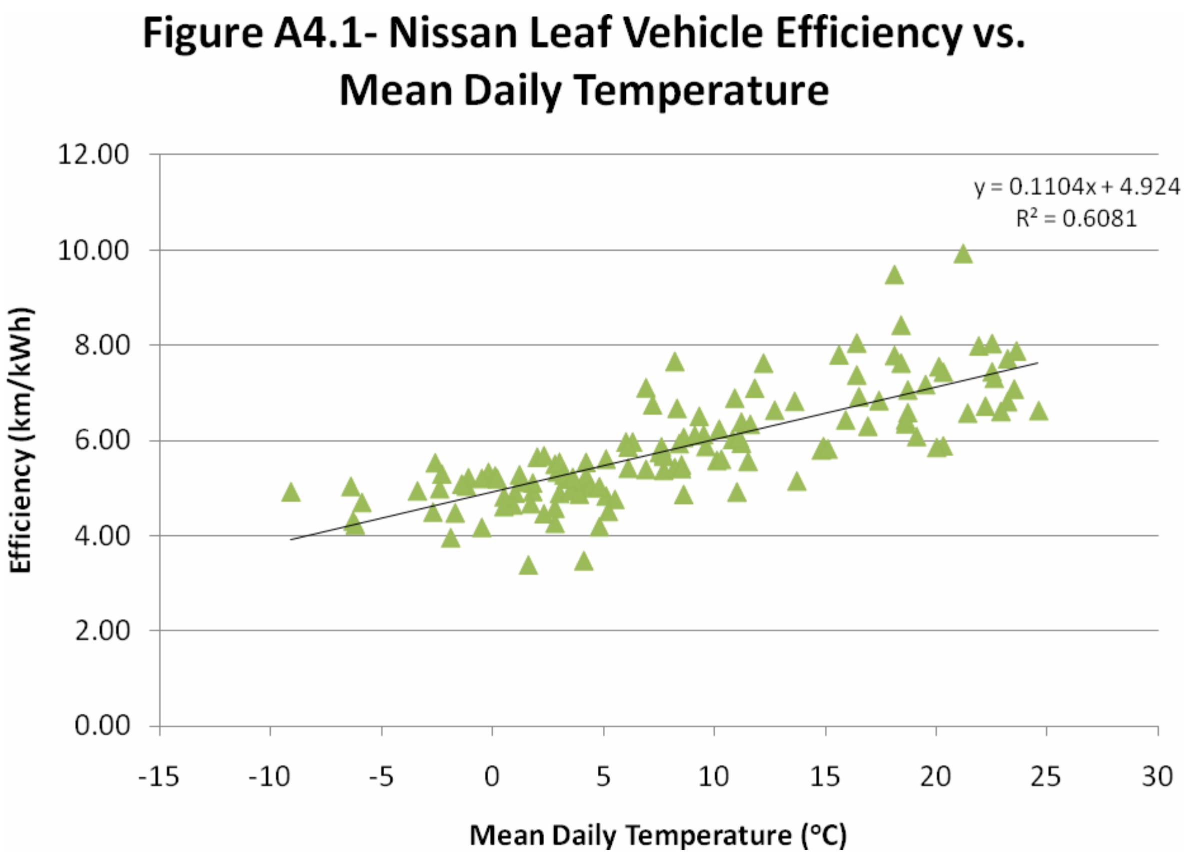


Figure A4.1- Nissan Leaf Vehicle Efficiency vs. Mean Daily Temperature
y = 0.1104x + 4.924
R² = 0.6081
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Efficiency (km/kWh)
-15
-10
-5
0
5
10
15
20
25
30
Mean Daily Temperature (°C)

Appendix 5: Visitor Centre Reports

Community Outreach

Visitors

	Total	Public	Stakeholders
March	274	224	50
April	169	132	37
May	895	883	12
June	366	366	0
July	304	302	2
August	249	249	0
September	249	241	8
October	351	294	57
November	254	224	30
December	55	51	4
January	132	129	3
February	147	87	60
Total to date	3298	3095	203

Community Events

- Evergreen Farmers' Market
- Public skating
- Chinese New Year's – January 21
- Evergreen Earth Day Celebration
- TREC (Toronto Renewable Energy Co-operative) Kids' World of Energy Festival
- Doors Open Toronto
- Evergreen Pollinators Festival
- AutoShare Electric Vehicle Test Drive Days
- Canadian Family Magazine 15th birthday celebration
- Garlic Festival
- Memory in the Mud screening
- 5th Annual Picnic at Brick Works
- EV Fest
- Café Conversations for underserved youth
- MOVE: Transportation Charrette
- Winter Festival

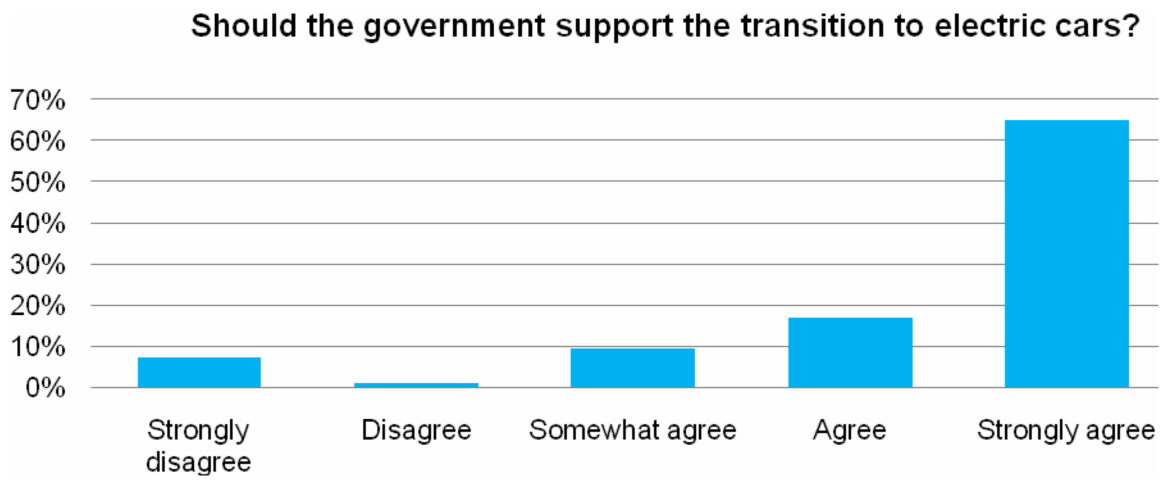
-

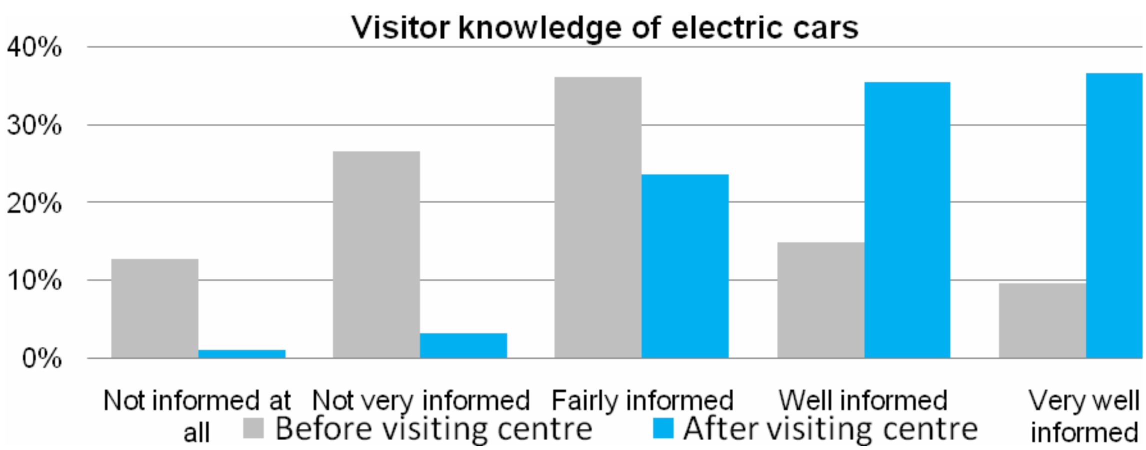
Stakeholder Events

Aecon Construction
Aird & Berlis
Atlantic Canada car magazine
Beit Issie Shapiro
Bendale Business and Tech Institute
Build Toronto
Bullfrog
Cabtricity
Cape Construction
Carleton University
City of Toronto, Economic Development
City of Toronto Environmental Department
City of Toronto, Forestry, NECP
Cushman&Wakefield
Deloitte
Electric Mobility Canada
Electronic Product Stewardship Canada
Enermodal
Evergreen
General Electric
Helios Energy
IESO
Innovative Air Solutions Inc.
Israel Consulate
L'Express Magazine
McMaster
Metrolinx
Miller Thomson
Ontario Ministry of Economic Development and Trade
Ontario Ministry of Transportation
Outward Bound
Panasonic
PB Consulting
Peel Alternative School
Power Corporation of Canada
Queen's University
RBC
Regen
Region of Peel
ReNew Magazine
Rockwell Automation
Rotman Energy Club
Schulich MBA
Sears
St Lawrence College
Storehouse Capital
TDSB newcomers program
Toronto Atmospheric Fund
Toronto Hydro
Town of Caledon
Town of Markham
University of Toronto Environment Students
Universtiy of Toronto Engineering Student Society
University of Toronto Environmental Law Students
UJA Federation
Vantage Point
Veridian
Yonge Street Website
York University

Survey Feedback

162 surveys completed





Appendix 6: Visitor Centre Survey Questions

Question 1: I have a driver's license (Yes/No)

Question 2: I currently own a vehicle (Yes/No)

Question 3: Number of kilometers driven per year:

- under 10,000
- 10,000-15,000
- 15,000-20,000
- 20,000-25,000
- 25,000+

Question 4: Knowledge of EVs before visit to the Centre? (Scale from 1 to 5)

- 1 = not informed at all, 2 = not very informed, 3 = fairly informed, 4 = well informed, 5 = very well informed

Question 5: How informed about EVs do you feel now? (Scale from 1 to 5)

- 1 = not informed at all, 2 = not very informed, 3 = fairly informed, 4 = well informed, 5 = very well informed

Question 6: Government should support EVs (Scale from 1 to 5)

- 1 = I strongly disagree, 2 = I disagree, 3 = I somewhat agree, 4 = I agree, 5 = I strongly agree

Comments:

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #7:

Reference(s): (B1/T1/S3)

What would be the impact on the 2013 revenue requirement if PowerStream's proposal to include a full year of amortization expense is rejected by the Board?

RESPONSE:

PowerStream has included a full year of depreciation for 2013 additions; this has increased depreciation expense by $1,569,000 as compared to the amount determined using the half-year rule. For details, please refer to the Exhibit D1, Tab 4, Schedule 1.

If this proposal is not approved by the Board, the 2013 revenue requirement will be decreased by this amount and the corresponding decrease in PILs. The resulting revenue requirement will decrease by $2,105,000.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

ENERGY PROBE INTERROGATORY #3:

Reference(s): Exhibit B1, Tab 1, Schedule 3

a) What was the impact on the 2009 NBV of the delay in the in-service date of Markham Transformer #4?

b) Please provide more details on the several large purchases that were avoided as a result of the merger and show the impact on the 2009 NBV of those costs.

c) Were the several large purchases noted avoided completely, or delayed to a future year? If the later, please provide details on each of the large purchases as to when they were actual made, or are forecast to be made.

RESPONSE:

a) Markham TS#4 was expected to be in-service during 2009 but was put into service in 2010. The amount of $16,248,000 in NBV included in the 2009 fixed assets for Markham TS#4 increased the 2009 rate base by $8,124,000.

b) The large purchases that were delayed in 2008 due to the merger were:

ERP System for Barrie - $1,500 K
1 Large Truck in Barrie - $400 K
GIS Enhancements (Designer) in Barrie - $330 K

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

SAN/NAS in Barrie - $240 K

The impact on 2009 net book value (NBV) is $1,408 K. Due to averaging only half of the net book value of these 2008 additions was included in rate base.

c) The large purchases listed in b) above were avoided completely.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #8:

Reference(s): [A2/1/1/p.6]

Please explain any material growth in rate base in any year from 2008 – 2014 that exceeds the combination of inflation and customer growth.

RESPONSE:

Table SEC#8-1 below provides a comparison between changes in the actual rate base for the period from 2008 to 2014 (i.e. for the 2009, 2010, 2011, 2012 and 2013 years) and a calculated rate base assuming that the rate base increases by the amount of customer growth and inflation in the year.

Customer growth changes are based on the change in the number of customers from year to year. The inflation rate is based on the year over year change in the annual average Ontario Consumer Price index obtained by averaging the indexes for the 12 months of the calendar year (Source: Statistics Canada, CANSIM, table 326-0021). The customer growth percentage change and the inflation change are then multiplied to arrive at the change factor for the year. As an example if customer growth is 2% and inflation is 3%, the change factor is calculated as 1.02*1.03 for a resulting factor of 1.0506. The change factor for 2009 was applied to the starting point, which is the 2008 actual rate base amounts, to arrive at the "calculated" 2009 rate base amounts. The calculated rate base for 2010 is determined by applying the 2010 change factor to the previous year's (2009) calculated rate base. The same method is used for 2011, 2012 and 2013.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

Table SEC#8-1: Requested Rate Base Analysis 2008 to 2014 ($000)

	CGAAP				MIFRS		
	2008	**2009**	**2010**	**2011**	**2011**	**2012**	**2013**
Customer growth		2.07%	2.41%	2.24%	2.24%	2.17%	2.12%
Inflation (Ontario CPI)	2.30%	0.40%	2.50%	3.10%	3.10%	2.80%	2.80%
"Change" factor		102.48%	104.97%	105.41%	105.41%	105.03%	104.98%
Calculated Rate base:							
WCA Amount	$ 98,803	$ 101,252	$ 106,284	$ 112,033	$ 112,033	$ 117,669	$ 123,529
Average NBV PP&E	$ 532,840	$ 546,045	$ 573,185	$ 604,191	$ 604,191	$ 634,586	$ 666,184
Rate Base	$ 631,642	$ 647,296	$ 679,469	$ 716,224	$ 716,224	$ 752,255	$ 789,713
Actual Rate base:							
WCA Amount	$ 98,803	$ 102,209	$ 112,223	$ 122,032	$ 123,801	$ 117,089	$ 122,653
Average NBV PP&E	$ 532,840	$ 537,272	$ 576,322	$ 632,533	$ 636,527	$ 677,435	$ 717,933
Rate Base	$ 631,642	$ 639,481	$ 688,545	$ 754,565	$ 760,328	$ 794,524	$ 840,586
Difference:							
WCA Amount	$ -	$ (958)	$ (5,939)	$ (9,998)	$ (11,768)	$ 580	$ 876
Average NBV PP&E	$ -	$ 8,773	$ (3,137)	$ (28,342)	$ (32,336)	$ (42,849)	$ (51,749)
Total	$ -	$ 7,815	$ (9,077)	$ (38,341)	$ (44,104)	$ (42,269)	$ (50,873)

Rate base is comprised of the Working Capital Allowance (WCA) and the Average Net Book Value (NBV) of Property Plant and Equipment (PP&E).

Table SEC#8-1 shows that the ending difference between the actual and calculated rate base for 2013 is mainly due to the increase in the average NBV of PP&E compared to the assumed increase based on inflation and customer growth over this period. The differences in the year over year change between calculated and actual average NBV of PP&E are shown in Table SEC#8-2 below.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

Table SEC#8-2: Actual vs. Calculated Average NBV PP&E Year over Year Changes ($000)

	CGAAP			MIFRS			
	2009	2010	2011	2011	2012	2013	Total
Calculated	$ 13,205	$ 27,140	$ 31,006	$ 31,006	$ 30,395	$ 31,598	$ 133,345
Actual	$ 4,433	$ 39,050	$ 56,211	$ 60,205	$ 40,908	$ 40,498	$ 185,094
Difference	$ 8,773	$ (11,910)	$ (25,205)	$ (29,199)	$ (10,513)	$ (8,900)	$ (51,749)

Note: Total includes 2011 MIFRS and excludes 2011 CGAAP

Table SEC#8-2 shows that the rate of increase, in the average NBV of PP&E, exceeded the combined rate of increase, in customers and inflation, in most years with the largest difference occurring in 2011 and the second largest in 2010. Due to the effect of averaging opening and closing PP&E, changes for 2011may be driven by capital additions in both 2010 and 2011 and changes for 2010 may be driven by capital additions in both 2009 and 2010.

The Smart Meter implementation program is responsible for a portion of these differences as this government mandated initiative is not related to customer growth and inflation. Over the period 2009 to 2012, PowerStream added approved smart meter capital assets with a net book value of $46.5 million and removed stranded meters with a NBV of $12.8 million for a net increase in average NBV of PP&E of $33.7 million.

The capital lease on the Addiscott Operations Center in Markham adds $15.4 million to the average NBV of PP&E which would not be reflected in the calculated rate base.
Purchase of a spare power transformer for $3.1 million as back up PowerStream transformer stations to increase reliability is another increase not reflected in the calculated rate base.

Much of the remaining difference can be attributed to spending on underground cable and poles which are at end of life. These are not growth related and the cost of replacing these assets

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

purchased 25 to 40 years ago is being compared to inflation for a few years on the small net book value in the opening 2008 NBV of PP&E.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #9:

Reference(s): [A3/1/3, p. 6]

Please provide a table showing a breakdown of the engineering burden under the old methodology, and for each component of that breakdown how much continues to be allocated to capital projects by direct allocation, how much is now allocated to capital through the Direct Labour Capitalization burden, and how much is now expensed. If it is possible to provide this information for the Test Year, please do. If not, please provide this calculation comparing the old and new methodology for the last CGAAP year.

RESPONSE:

The 2013 budget was developed under MIFRS with no comparatives to CGAAP. To provide the response requested with respect to the 2013 year, it would require a substantial amount of time and effort. Below is a comparison of the results under the old and the new methodology applied to the Engineering Burden Pool for the last CGAAP year, 2011.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

Table SEC #9: Engineering Burden

In Millions of Dollars

Category	CGAAP 2011	MIFRS		
		Direct Allocation to Capital	Direct Labour Capitalization	Expensed
Labour	11.3	0.0	(3.0)	8.3
Consulting: Engineering	0.7	0.0	0.0	0.7
Building Allocation	0.4	0.0	0.0	0.4
Memberships	0.2	0.0	0.0	0.2
Software Maint. Agreement	0.2	0.0	0.0	0.2
Conferences	0.1	0.0	0.0	0.1
Other	0.4	0.0	0.0	0.4
Grand Total	**13.3**	**0.0**	**(3.0)**	**10.3**

Under CGAAP 20% of the Engineering Burden Costs would be allocated to OMA and 80% to Capital

Under the old burden methodology, the total Engineering Burden pool cost was about $13.3M, of which, the majority was labour, $11.3M. Under MIFRS, the costs in this burden pool are now charged directly to OM&A. Under the old methodology, none of the costs in this burden pool could be directly allocated to capital, therefore this has not changed under MIFRS. However, currently a portion of the labour ($3.0M in 2011) is allocated to capital through the Direct Labour Capitalization burden leaving $10.3M in OM&A as expense.

The old methodology of allocating the Engineering burden between OM&A and Capital split the cost approximately 20% / 80% in 2011, $2.7M OM&A and $10.6M Capital.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #10:

Reference(s): [A3/1/4, p. 1]

Please provide the dollar impact of moving from the OEB prescribed interest rate to weighted average cost of capital for interest on funds for construction, including the underlying calculations supporting that impact.

RESPONSE:

The impact of using PowerStream's actual WACC (instead of the OEB prescribed interest rate) is a higher interest capitalization by $77,113 for 2011. Please refer to the table below.

Table SEC #10: Impact on Capitalization of PowerStream WACC

<table>
<tr><th>Quarter by Year</th><th>CWIP Prescribed Rate</th><th>Average CWIP Prescribed Rate for 2011
(a)</th><th>PowerStream WACC Rate
(b)</th><th>Difference in Rates
(c) = (b) - (a)</th><th>MIFRS CWIP Eligible for Interest Capitalization *
(d)</th><th>Difference in Amount of Interest Capitalization
(e) = (d) x (c)</th></tr>
<tr><td>Q4 2011</td><td>3.92%</td><td rowspan="4">4.20%</td><td rowspan="4">5.63%</td><td rowspan="4">1.43%</td><td rowspan="4">$ 5,383,108</td><td rowspan="4">$ 77,113</td></tr>
<tr><td>Q3 2011</td><td>4.29%</td></tr>
<tr><td>Q2 2011</td><td>4.29%</td></tr>
<tr><td>Q1 2011</td><td>4.29%</td></tr>
</table>

* = calculated using actual 2011 MIFRS interest capitalization amount ($303,069) divided by the PowerStream WACC Rate

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #11:

Reference(s): [A3/1/4, p. 7]

Please provide the vintage tables for existing assets prepared with respect to the change from CGAAP to MIFRS.

RESPONSE:

The company has created Appendix 2-CB Depreciation and Amortization Expense which is being filed in Exhibit J1, Tab 1, Schedule 1.0, Attachment Board Staff #5-3. Column i) of this document outlines the average remaining life of the opening net book value for the conversion from CGAAP to MIFRS.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #12:

Reference(s): [A3/1/5, p. 16]

Please provide the full calculations underlying the figure of $939,000 PP&E impact from MIFRS.

RESPONSE:

The amount included on page 16 is based on the financial statements and contains non-distribution items. Please refer to A3/1/5, p. 25, Table 10 for the correct PP&E amount of $920,000.

Table SEC #12-1 below summarizes the differences in PP&E between CGAAP and MIFRS. Attached as Appendix A are the supporting PP&E details in both CGAAP and MIFRS. PowerStream has tracked actual transactions for 2011 in its JD Edwards accounting system under CGAAP, IFRS and MIFRS.

Please note that the account 1575 PP&E Transitional amount has been updated to remove the depreciation on the fair market value increment recorded on the assets acquired in the purchase of Aurora Hydro in 2005, as this is excluded in the calculation of PP&E for rate base.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

Table SEC #12-1: MIFRS Transitional PP&E Differences

Summary of Differences	MIFRS	CGAAP	Difference
2011 Actual			
Derecognition	$ (1,197,533)	$ -	$ (1,197,533)
Depreciation	$ (35,719,827)	$ (48,970,888)	$ 13,251,061
Burdens capitalized	$ 18,089,286	$ 29,717,179	$ (11,627,893)
Damage Claims (contributed capital)	$ -	$ (728,301)	$ 728,301
Interest Capitalized	$ 303,069	$ 536,625	$ (233,556)
Subtotal			**$ 920,380**
2012 Forecasted			
Derecognition	$ (1,400,106)	$ -	$ (1,400,106)
Depreciation	$ (34,296,619)	$ (49,101,931)	$ 14,805,312
Burdens capitalized	$ 18,000,000	$ 30,200,000	$ (12,200,000)
Damage Claims (contributed capital)	$ -	$ (700,000)	$ 700,000
Interest Capitalized	$ 300,000	$ 550,000	$ (250,000)
Subtotal			**$ 1,655,206**
Total as filed			**$ 2,575,586**
Regulatory adjustment[1]			
2011 Depreciation adjustment	$ 150,363	$ 244,728	$ (94,365)
2012 Depreciation adjustment	$ 150,363	$ 244,728	$ (94,365)
Revised Total			**$ 2,386,856**

1. Adjustment to remove the depreciation on the fair market value (FMV) increase recorded on assets acquired in the purchase of Aurora Hydro. The FMV bump has been removed from rate base.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #13:

Reference(s): [B1/1/5/p.1]

Please provide the internal business case for the acquisition of the new distribution operations Centre in Markham.

RESPONSE:

No business case was prepared for this project. The process by which this decision was made is outlined in Exhibit B1, Schedule 1, Tab 5.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.1 Is the proposed Rate Base for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #14:

Reference(s): [D1/4/1, p. 1]

Please restate opening rate base for the Test Year on the assumption that the half year rule had been applied in 2010 and 2011.

RESPONSE:

In response to this IR, the 2013 opening PP&E net book value would be $693,709,000 using the half year rule for 2010 and 2011.

The 2013 opening PP&E net book value is $694,971,000 in the Application. PowerStream does not propose any change to its Application.

Please see response to Energy Probe IR #12 filed at Exhibit J1, Tab 2, Schedule 2.3 for a 2013 fixed asset continuity schedule prepared on the above assumptions.

PowerStream Inc.
Capital Assets Continuity Schedule
as at December 31st, 2011

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 2
Schedule 2.1
Appendix A
2 Pages
Filed: August 31, 2012

Account	Description	CGAAP Total Cost Dec 31, 2011	CGAAP Total Accum Dprn Dec 31, 2011	CGAAP Net Book Value Dec 31, 2011	MIFRS Total Cost Dec 31, 2011	MIFRS Total Accum Dprn Dec 31, 2011	MIFRS Net Book Value Dec 31, 2011	MIFRS-CGAAP Total Cost Dec 31, 2011	MIFRS-CGAAP Total Accum Dprn Dec 31, 2011	MIFRS-CGAAP Net Book Value Dec 31, 2011
1805	Land	11,367,505.81	-	11,367,505.81	11,456,031.75	-	11,456,031.75	88,525.94	-	88,525.94
1808	Building & Fixtures	7,325,201.61	(1,380,660.96)	5,944,540.65	6,120,071.92	(190,633.61)	5,929,438.31	(1,205,129.69)	1,190,027.35	(15,102.34)
1810	Major Spare Parts	9,183,888.92	-	9,183,888.92	9,183,888.92	-	9,183,888.92	-	-	-
1815	Transformer Stn. Equip >50kv	(127.93)	-	(127.93)	(61,884.34)	-	(61,884.34)	(61,756.41)	-	(61,756.41)
1816	Power Transformer & Other- TS	12,659,484.13	(3,468,079.15)	9,191,404.98	9,507,112.84	(303,387.87)	9,203,724.97	(3,152,371.29)	3,164,691.28	12,319.99
1817	Tap Changer - TS	12,659,484.13	(3,468,079.15)	9,191,404.98	9,507,112.84	(877,433.92)	8,629,678.92	(3,152,371.29)	2,590,645.23	(561,726.06)
1818	Winding - TS	51,903,884.97	(14,219,124.88)	37,684,760.09	38,979,162.78	(1,243,889.03)	37,735,273.75	(12,924,722.19)	12,975,235.85	50,513.66
1819	Support Steel Structure - TS	8,861,638.89	(2,427,655.36)	6,433,983.53	6,654,979.02	(212,371.50)	6,442,607.52	(2,206,659.87)	2,215,283.86	8,623.99
1820	Transformer Stn. Equip <50kv	0.04	-	0.04	(22,002.33)	-	(22,002.33)	(22,002.37)	-	(22,002.37)
1821	Grounding Station - TS	6,329,742.07	(1,734,030.41)	4,595,711.66	4,726,648.74	(151,292.60)	4,575,356.14	(1,603,093.33)	1,582,737.81	(20,355.52)
1822	P & C System - TS	6,329,742.07	(1,734,039.51)	4,595,702.56	4,753,556.46	(1,099,354.83)	3,654,201.63	(1,576,185.61)	634,684.68	(941,500.93)
1823	SwitchGear and Relays - TS	22,787,071.50	(6,242,542.43)	16,544,529.07	17,112,803.19	(889,173.59)	16,223,629.60	(5,674,268.31)	5,353,368.84	(320,899.47)
1824	Capacitor Banks - TS	5,063,793.68	(1,387,231.59)	3,676,562.09	3,802,845.22	(197,594.13)	3,605,251.09	(1,260,948.46)	1,189,637.46	(71,311.00)
1826	Power Transformer - MS	16,746,811.83	(7,390,348.62)	9,356,463.21	9,878,053.24	(304,931.31)	9,573,121.93	(6,868,758.59)	7,085,417.31	216,658.72
1827	Protection & Control - MS	16,493,770.17	(7,342,411.80)	9,151,358.37	9,664,513.68	(1,665,831.32)	7,998,682.36	(6,829,256.49)	5,676,580.48	(1,152,676.01)
1828	SwitchGear - MS	3,665,283.08	(1,631,647.12)	2,033,635.96	2,147,670.53	(108,304.36)	2,039,366.17	(1,517,612.55)	1,523,342.76	5,730.21
1830	Poles,Towers & Fixtures	153,665,788.53	(57,056,588.29)	96,609,200.24	100,912,590.41	(2,327,218.25)	98,585,372.16	(52,753,198.12)	54,729,370.04	1,976,171.92
1835	Overhead Conductors & Device	179,002,896.96	(89,139,401.10)	89,863,495.86	95,330,994.62	(2,817,199.91)	92,513,794.71	(83,671,902.34)	86,322,201.19	2,650,298.85
1836	Overhead Conductors & Device	(0.00)	1,276.68	1,276.68	1,276.67	(267.88)	1,008.79	1,276.67	(1,544.56)	(267.89)
1840	Underground Conduits	125,695,622.06	(63,715,131.34)	61,980,490.72	63,373,931.34	(1,080,516.60)	62,293,414.74	(62,321,690.72)	62,634,614.74	312,924.02
1845	Underground Cond. & Devices	348,930,267.59	(177,386,336.75)	171,543,930.84	183,880,995.16	(4,958,822.45)	178,922,172.71	(165,049,272.43)	172,427,514.30	7,378,241.87
1849	O/H Transformers	55,078,948.22	(37,424,662.29)	17,654,285.93	18,982,343.35	(593,632.85)	18,388,710.50	(36,096,604.87)	36,831,029.44	734,424.57
1850	U/G Transformers	220,008,043.13	(112,921,467.05)	107,086,576.08	113,701,541.62	(5,142,891.33)	108,558,650.29	(106,306,501.51)	107,778,575.72	1,472,074.21
1855	Services O/H	15,120,993.03	(6,382,542.50)	8,738,450.53	8,976,989.36	(251,684.21)	8,725,305.15	(6,144,003.67)	6,130,858.29	(13,145.38)
1856	Services U/G	95,088,179.59	(52,811,614.80)	42,276,564.79	44,956,110.92	(4,216,985.87)	40,739,125.05	(50,132,068.67)	48,594,628.93	(1,537,439.74)
1860	Meters	7,370,550.83	2,773,723.56	10,144,274.39	8,615,249.12	1,212,738.42	9,827,987.54	1,244,698.29	(1,560,985.14)	(316,286.85)
1861	Interval Meters	10,844,608.68	(821,791.58)	10,022,817.10	9,454,519.02	(438,479.58)	9,016,039.44	(1,390,089.66)	383,312.00	(1,006,777.66)
1862	Smart Meters	51,031,174.06	(8,499,188.10)	42,531,985.96	46,535,921.27	(3,735,397.30)	42,800,523.97	(4,495,252.79)	4,763,790.80	268,538.01
1870	Leased Property-Customer Prem	575,421.00	(575,421.00)	-	-	-	-	(575,421.00)	575,421.00	-
1908	Building & Fixtures	22,076,668.50	(2,314,175.74)	19,762,492.76	20,314,207.19	(431,550.84)	19,882,656.35	(1,762,461.31)	1,882,624.90	120,163.59
1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1911	Leashold Cochran/JOC	-	-	-	-	-	-	-	-	-
1912	Building & Fixtures - Other	21,337,351.44	(4,863,174.38)	16,474,177.06	16,914,768.81	(391,293.53)	16,523,475.28	(4,422,582.63)	4,471,880.85	49,298.22
1913	Building & Fixtures - Windows	2,791,091.21	(195,856.33)	2,595,234.88	2,655,479.16	(96,107.26)	2,559,371.90	(135,612.05)	99,749.07	(35,862.98)
1915	Office Furniture & Equip.	5,838,569.52	(2,664,608.87)	3,173,960.65	3,679,847.12	(475,193.21)	3,204,653.91	(2,158,722.40)	2,189,415.66	30,693.26
1920	Computer Equip. - Hardware	0.00	-	0.00	0.01	-	0.01	0.01	-	0.01
1921	Desktops Laptops Monitors	5,186,044.13	(4,385,248.01)	800,796.12	1,179,809.70	(519,881.04)	659,928.66	(4,006,234.43)	3,865,366.97	(140,867.46)
1922	Servers	8,932,437.88	(7,102,562.78)	1,829,875.10	2,573,823.55	(742,984.40)	1,830,839.15	(6,358,614.33)	6,359,578.38	964.05
1923	Multi Functional Printers	1,291,697.63	(1,119,016.01)	172,681.62	247,892.27	(75,007.47)	172,884.80	(1,043,805.36)	1,044,008.54	203.18
1924	Switches/Routers	3,973,499.95	(3,194,305.27)	779,194.68	1,098,301.54	(230,045.42)	868,256.12	(2,875,198.41)	2,964,259.85	89,061.44
1930	Transportation Equipment	9,192,355.47	(6,780,166.94)	2,412,188.53	3,811,943.66	(706,957.62)	3,104,986.04	(5,380,411.81)	6,073,209.32	692,797.51
1931	Transportation Equipment	12,866,807.43	(8,319,107.96)	4,547,699.47	5,696,742.14	(555,106.44)	5,141,635.70	(7,170,065.29)	7,764,001.52	593,936.23
1932	Vehicles Trailers	206,725.74	(79,807.64)	126,918.10	165,563.25	(6,006.50)	159,556.75	(41,162.49)	73,801.14	32,638.65
1935	Stores Equipment	190,894.90	(190,899.66)	(4.76)	(4.76)	-	(4.76)	(190,899.66)	190,899.66	0.00
1940	Tools, Shop & Garage Equip.	6,885,305.27	(4,759,759.26)	2,125,546.01	2,512,377.46	(369,845.91)	2,142,531.55	(4,372,927.81)	4,389,913.35	16,985.54
1955	Communication Equipment	2,310,561.42	(934,676.74)	1,375,884.68	1,563,007.69	(373,394.84)	1,189,612.85	(747,553.73)	561,281.90	(186,271.83)
1956	Wireless Hardware	97,191.66	(67,198.66)	29,993.00	55,430.76	(24,994.27)	30,436.49	(41,760.90)	42,204.39	443.49
1961	Process Re-Engineering	0.00	(4,552.79)	(4,552.79)	-	-	-	(0.00)	4,552.79	4,552.79
1980	System Supervisory Equip.	3,785,518.89	(2,424,777.11)	1,360,741.78	1,680,408.31	(256,998.51)	1,423,409.80	(2,105,110.58)	2,167,778.60	62,668.02
1981	Remote Terminal Unit - Scada	14,176,381.86	(9,080,542.64)	5,095,839.22	5,740,350.60	(958,099.38)	4,782,251.22	(8,436,031.26)	8,122,443.26	(313,588.00)
1982	Display Wall - Scada	1,351,971.01	(865,991.72)	485,979.29	548,737.08	(223,806.90)	324,930.18	(803,233.93)	642,184.82	(161,049.11)
1985	Sentinel Light Rental Units	15,238.88	(15,238.88)	-	-	-	-	(15,238.88)	15,238.88	-
1995	Contributions & Grants-CR	(277,009,926.48)	72,726,337.69	(204,283,588.79)	(214,598,218.02)	6,915,089.74	(207,683,128.28)	62,411,708.46	(65,811,247.95)	(3,399,539.49)
1996	Contributions & Grants-CR	(23,862,251.04)	490,163.13	(23,372,087.91)	(23,412,129.26)	291,100.93	(23,121,028.33)	450,121.78	(199,062.20)	251,059.58
2005	Prop. Under Capital Lease	18,280,294.05	(1,462,423.52)	16,817,870.53	17,549,082.29	(730,711.27)	16,818,371.02	(731,211.76)	731,712.25	500.49
2075	Non-Utility Property Owned	0.72	-	0.72	(342.89)	-	(342.89)	(343.61)	-	(343.61)
2055	WIP	30,514,073.05	-	30,514,073.05	23,501,933.61	-	23,501,933.61	(7,012,139.44)	-	(7,012,139.44)
	Total PP&E (Core)	**1,324,218,171.74**	**(643,992,585.63)**	**680,225,586.11**	**711,612,038.59**	**(31,556,350.02)**	**680,055,688.57**	**(612,606,133.15)**	**612,436,235.61**	**(169,897.54)**
1460	Barrie Cont. Capital - Ontario Hydro	-	-	-	-	-	-	-	-	-
1606	Organization - HVDI	1,430,462.56	(1,430,462.56)	-	-	-	-	(1,430,462.56)	1,430,462.56	-
1611	Barrie Cont. Capital - Ontario Hydro	609,442.28	(28,970.46)	580,471.82	609,442.28	(28,970.46)	580,471.82	-	-	-
1806	Land Rights	760,235.13	-	760,235.13	765,751.97	-	765,751.97	5,516.84	-	5,516.84
1925	Computer Software	24,646,043.93	(19,133,570.22)	5,512,473.71	8,733,932.20	(2,136,698.96)	6,597,233.24	(15,912,111.73)	16,996,871.26	1,084,759.53
	Total Intangibles	**27,446,183.90**	**(20,593,003.24)**	**6,853,180.66**	**10,109,126.45**	**(2,165,669.42)**	**7,943,457.03**	**(17,337,057.45)**	**18,427,333.82**	**1,090,276.37**
	GRAND TOTAL	**1,351,664,355.64**	**(664,585,588.87)**	**687,078,766.77**	**721,721,165.04**	**(33,722,019.44)**	**687,999,145.60**	**(629,943,190.60)**	**630,863,569.43**	**920,378.83**

PowerStream Inc.
PP&E Transitional AmountsFC
as at December 31st, 2012

Account	CGAAP Net Book Value	MIFRS Net Book Value	MIFRS-CGAAP Net Book Value
Total Actual 2011	**687,078,766.77**	**687,999,145.60**	**920,378.83**
2012 Additions (net of vehicle disposals)	92,220,195.00	80,020,195.00	(12,200,000.00)
2012 Derecognition	-	(1,400,106.23)	(1,400,106.23)
2012 Depreciation	(49,101,931.00)	(34,296,619.00)	14,805,312.00
2012 Damage Claims	-	700,000.00	700,000.00
2012 Interest Cap	550,000.00	300,000.00	(250,000.00)
Total Forecast 2012	**730,747,030.77**	**733,322,615.37**	**2,575,584.60**

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.2 Is the Working Capital Allowance for Test Year 2013 appropriate? (B3)

ENERGY PROBE INTERROGATORY #4:

Reference(s): Exhibit B3, Tab 1, Schedule 5

a) Please confirm that the Commodity (Spot) figure for November and December shown in Table 4 was calculated by increasing the August through October rate by 7%.

b) Please explain how the 7% average increase over the 2009 to 2011 period as described on page 1 was calculated? In particular, should the 7% increase to calculate the November and December commodity (spot) be applied to the November 2012 through January 2013 price of $0.02464 shown as the HOEP price in the Navigant report noted in the evidence?

RESPONSE:

Preamble: The relevant reference is Exhibit B3, Tab 1, Schedule 2, page 5.

a) Yes. The Commodity (Spot) figure for November and December shown in Table 4 was calculated by increasing the August through October rate by 7%.

b) An average increase of 7%, as based on a three-year (2009-2011) average (source: IESO invoices), is applied to the HOEP effective November 1, 2013 in order to project the commodity cost for the remainder of the test year period. Details of the 7% average increase were calculated as per the following:

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.2 Is the Working Capital Allowance for Test Year 2013 appropriate? (B3)

Table EP#4b: Commodity Price Increase

	2008	2009	2010	2011	AVG
Average HOEP as per IESO Invoice	0.0528	0.0316	0.0380	0.0319	
Average GA as per IESO invoice	0.0062	0.0312	0.0278	0.0403	
HOEP + GA	0.0590	0.0628	0.0658	0.0722	
% rate increase		6.5%	4.8%	9.8%	**7.0%**

The Board's guidance for the 13% Working Capital Allowance approach provides, "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".[1] The most current RPP price forecast developed by Navigant is based on the Ontario Wholesale Electricity Market Price Forecast Report dated 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. PowerStream determined that the spot price estimates outlined in the Report were the best data available to provide a reliable proxy for the November 2012 to October 2013 spot price forecast. In the absence of third party forecast data for November to December, the 2013 spot price increase was based on the 7% increase to these values, as described above.

[1] Page 2, OEB April 12, 2012 letter to All Licensed Electricity Distributors, All Licensed Electricity Transmitters and All Other Interested Parties: *Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications – Allowance for Working Capital*.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.2 Is the Working Capital Allowance for Test Year 2013 appropriate? (B3)

SEC INTERROGATORY #15:

Reference(s): [A2/1/1, p. 7]

Please explain why Powerstream did not carry out a lead/lag study.

RESPONSE:

As part of this application, PowerStream engaged Navigant in 2011to prepare a lead/lag study. In April, 2012, using 2010 data, Navigant's model was indicating a preliminary working capital allowance of 13.2%.

On April 12, 2012, the Board issued a letter, *Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications - Allowance for Working Capital* that established a default allowance of 13%. As result of the letter and given that the filing deadline was quickly approaching, PowerStream decided, for simplicity to adopt the default level. The alternative would to have been to have Navigant update their model with PowerStream's 2011 data and finalize the report. This would have been very challenging given the demands on PowerStream staff to complete the application.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.2 Is the Working Capital Allowance for Test Year 2013 appropriate? (B3)

SEC INTERROGATORY #16:

Reference(s): [B3/1/1/p.2]

Please provide the same comparison to actual WCA for all years to date.

RESPONSE:

Please see the table below.

Table SEC #16: Comparison of Actual WCA to "Total Approved" (2009-2011) ($millions)

	Board Approved			Actual			Difference to total Approved		
	Barrie 2008	South 2009	Total	2009	2010	2011	2009	2010	2011
Cost of Power	$ 119.7	$ 421.6	$ 541.3	621.7	$ 691.3	751.5	$ 80.4	$ 150.0	$ 210.2
Distribution Expense	$ 10.0	$ 43.2	$ 53.2	59.7	$ 56.8	62.1	$ 6.5	$ 3.6	$ 8.9
Total for WCA calculation	$ 129.7	$ 464.8	$ 594.5	681.4	748.1	813.6	$ 86.9	$ 153.6	$ 219.1
WCA %	15%	15%	15%	15%	15%	15%	15%	15%	15%
WCA $	$ 19.5	$ 69.7	$ 89.2	$ 102.2	$ 112.2	$ 122.0	$ 13.0	$ 23.0	$ 32.9

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.2 Is the Working Capital Allowance for Test Year 2013 appropriate? (B3)

VECC INTERROGATORY #3:

Reference(s): Exhibit B3, Tab 1, Schedule 1, page 1

a) Did PowerStream complete a lead-lag study? If so please file this study.

b) If not, did PowerStream do any other type of analysis of the working capital requirement as compared to what would be allowed under the Board's default methodology? If yes, please file that analysis.

RESPONSE:

a) Please see response to SEC IR#15, filed in this Exhibit.

b) Please see response to SEC IR#15, filed in this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

BOARD STAFF INTERROGATORY #13:

Sustaining Capital Expenditures

Reference(s): <u>E B1/ T1/ S4/p. 2 and 4</u>

Table 1 on page 2 of the above referenced schedule includes an expenditure level in the 2013 Test Year on the category "Sustainment Driven Lines Projects" of $23.2 million. Expenditures in this category for the years 2007 to 2012 in Table 1 range from a low of $6.5 million to a high of $10.7 million.

On page 4 of this schedule, PowerStream explains this increase as follows:

"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…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."

a) Given that the need to replace underground cable appears to be an ongoing requirement, please state why a level of expenditure in 2013, which is more than double the highest level spent in prior years, is necessary.
b) Please state whether PowerStream anticipates any difficulties in completing a replacement program in 2013 that is so much larger than that of previous years. Please explain why or why not.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

c) Please state whether there has been any quantitative evidence such as declining service quality or reliability indicators that there is a need to accelerate this replacement program. If yes, please provide details, if not please explain why the stated service deterioration is not showing up in these indicators.

RESPONSE:

a) See Exhibit B1, Tab 2, Schedule 2, Section 6.1.2.1 and Exhibit B1, Tab 2, Schedule 4, page 139 for justification of PowerStream's underground cable replacement program. The 2013 spending reflects the first year of a 20 year capital sustainment program to replace all Group 1 and Group 2 cables.

In 2009, PowerStream engaged Kinetrics Inc. and BIS Consulting, LLC to complete an Asset Condition Assessment (ACA). The ACA technical report by Kinetrics indicated the need to replace end-of-life underground cable. In addition, the report indicated that actual spending programs should be based on more precise information and verification of the cable condition, age, type and installation methods. The verification work was completed in 2010-2011 and subsequent analysis on required spending levels was completed. The increased spending that the analysis demonstrated being required was not budgeted for 2012 to allow time for appropriate planning to ensure stable program initiation in 2013.

If one projects out 20 years the highest annual spending of $10.7M from the 2007-2012 period, PowerStream will replace approximately 50% of the Group 1 and 2 cables as compared to 100% of the Group 1 and 2 cables based on the 2013 spending levels. This would mean, at the 2007-2012 annual spending level that after 20 years at least 50% of Group 1 and 2 cables will be greater than 50 years old, well past their expected useful life. In

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

addition, at the completion of this potential 20 year under funded program, PowerStream projects that approximately 1,755km of Group 3 cables will be greater than 40 years of age and approaching or at the end of useful life and needing to be addressed in a multiyear replacement program.

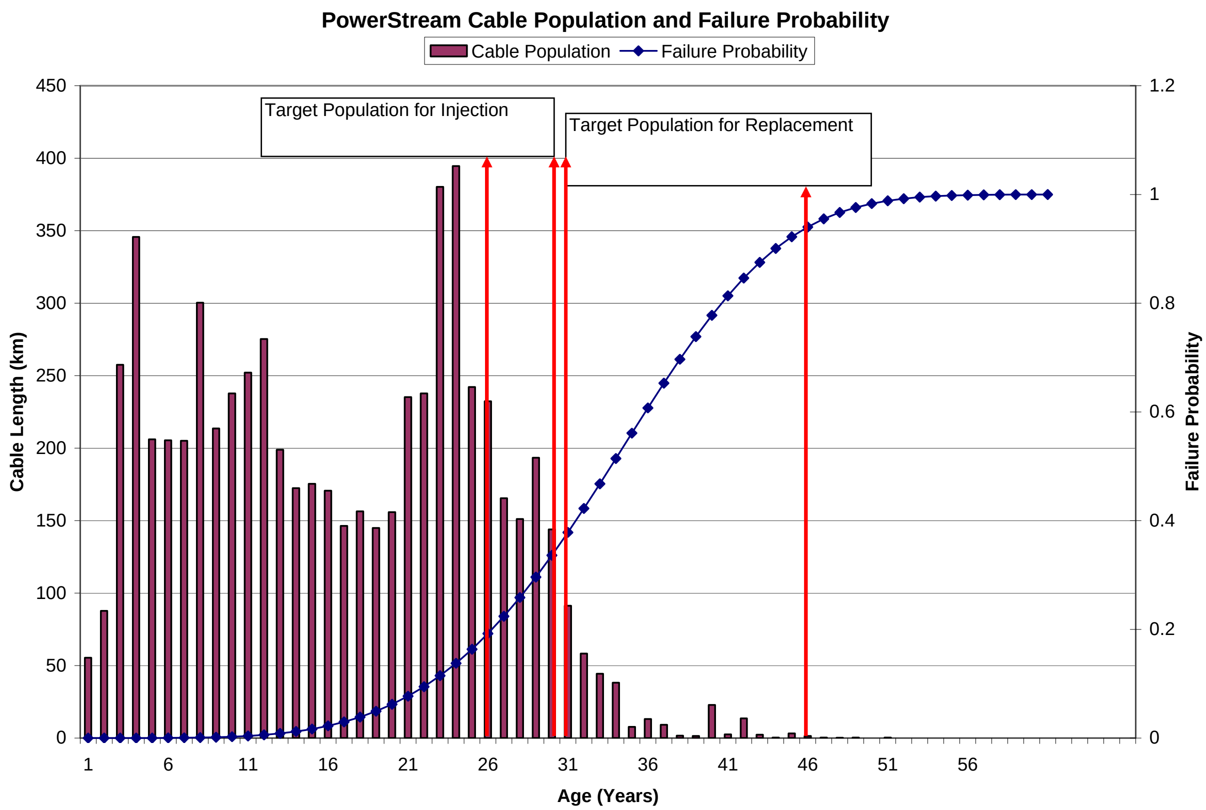
The following diagram overlays the Weibull Failure Probability curve of underground cable on top of the cable population. The Weibull distribution is widely used for lifetime distribution analysis and this curve has been used in PowerStream's cable ACA models, as developed by Kinetrics and BIS Consulting, Inc.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Figure Board Staff #13: Cable Population and Failure Probability



As seen from the above graph for a cable aged **32** years the probability of failure is **0.46** while for a cable which is **35** years the probability of failure is **0.60**. This implies that the failure probability increases by **29%** within 3 years as the cable ages. PowerStream's plan is to address the cable population before the failures become unmanageable both from a customer service and resources perspective.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

b) PowerStream does not anticipate any difficulties in completing the 2013 cable replacement program.

The 2013 Cable Replacement projects will require incremental design, material and installation resources as compared to previous years' spending. The incremental work, for the most part, will be completed utilizing Engineering/Procurement/Construction (EPC) contracts. In 2012, PowerStream is using the EPC contract process to complete 2012 cable replacement projects. PowerStream has secured agreement with the same procure and install contractor for 2013. The 2013 cable replacement program has been reviewed with the contractor and the contractor has assured that material and installation resources will be made available to meet program schedule requirements.

c) Cable related failures amount to over 50% of the outages caused within the Failed Equipment category for years 2009-2011 and are increasing year over year. See VECC IR#1 for the number of outages.

The average contribution to SAIDI (2009-2011) due to cable related failures is 8.67 minutes and represents 17% of system total SAIDI excluding LOS/MED. It is expected that with increasing cable failures, due to aging cables reaching end of useful life, from 2013 onwards that customer outage minutes and the cable failure SAIDI contribution to overall system SAIDI will increase every year.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

BOARD STAFF INTERROGATORY #14:

Operations Capital Expenditures

Reference(s): <u>E B1/ T1/ S5/p. 11</u>

Table 1 on this page "NPV Analysis of the Service Centre Alternatives" shows that the NPV for Alternative #1 was $33.8 million, while the NPV for Alternative #2 was $30.4 million. Below the table, it is stated that "The only available option meeting PowerStream's requirements was the long term lease of Addiscott," which was Alternative #2.

a) Please provide the key assumptions on which the NPV analysis of Alternatives #1 and #2 was undertaken.
b) Please state whether or not PowerStream considered outright ownership of Addiscott, rather than a long term lease. If yes, please explain why this alternative was not adopted. If not, please explain why not.

RESPONSE:

a) The comparison was between the costs to operate one large operations center in the South versus retaining two separate operating centers, one in Markham and one in Vaughan. The cost to build two separate centers was estimated at approximately $17 million each for land and cost of construction. For purposes of comparison this was converted to a market rate annual lease payment of $1,352,000. This was increased by $150,000 per year to capture the higher OM&A costs for two centers ($300,000 split into 2) compared to a single centre. The Addiscott lease payment was increased by $120,000 per year to account for the cost to rent

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

outside storage in Vaughan. It was assumed in the two center case that PowerStream would continue to rent space at the Joint Operations Center in Vaughan under the same terms for another 10 years. The payments for each case where discounted at PowerStream weighted average cost of capital from its 2009 Cost of Service of 6.30%.

The attached calculation, Appendix F, was used to determine the values used in Table 2 on page 11 of Exhibit B1, Tab 1, Schedule 5.

b) PowerStream attempted to purchase the property but the vendor was unwilling to sell due to their tax consequences. The vendor was only willing to enter into a long term lease arrangement. Due to the difficulty in finding an appropriate location, PowerStream insisted on negotiating an option to purchase the facility at the end of the lease term.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

BOARD STAFF INTERROGATORY #15:

Operations Capital Expenditures

Reference(s): E B1/ T1/ S5/pp. 21-23

On these pages, the three alternatives that PowerStream considered regarding its CIS system are discussed. These are: Alternative 1: Status Quo, Alternative 2: Oracle Based CIS and Alternative 3: SAP Based CIS. PowerStream states that Alternative 2 was chosen.

Please state whether or not this decision was made on the basis of any economic comparison between the three alternatives. If yes, please provide a summary of the results for the three alternatives. If not, please explain why not.

RESPONSE:

No. There was no economic comparison undertaken between the three alternatives. The current T&W system that had been in place since the 1980's and PowerStream had identified several risks associated with the system that make its continuation not viable. (See Exhibit B1, Tab 1, Schedule 5, p. 21).

Based on the discovery process, only two suitable systems solutions were available in North America to enable PowerStream to meet its business objectives – The Oracle CC&B and SAP.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

The Oracle CC&B has Customer Components for the Ontario Marketplace (CCOM), and was compatible with PowerStream's financial systems platform. There were also identified benefits based on Oracle's extensive client base in North America including Toronto Hydro and Enersource Hydro Mississauga. (See Exhibit B1/T1/S5 p.22). Through discussions with Hydro Ottawa, PowerStream learned that Hydro Ottawa too was proceeding with the Oracle system.

SAP also has an extensive client base in North America including utilities in Ontario. However the SAP product did not have specific components to operate in the Ontario market such as the CCOM of Oracle. Information was also not readily available from SAP on potential improvement benefits or details on the cost of the product as compared with Oracle. (See Exhibit B1, Tab 1, Schedule 5, p. 23). Lastly, the SAP platform did not as easily integrate with PowerStream's financial system platform

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

BOARD STAFF INTERROGATORY #16:

Operations Capital Expenditures

Reference(s): <u>E B1/ T1/ S5/p. 29</u>

It is stated that:

"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 (Customer Care and Billing) 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."

a) Please provide an update as to the status of this process and provide the key terms and conditions at this stage of the process.
b) Please state whether costs related to this process have been incorporated into the 2013 Test Year and if so what the costs would be.

RESPONSE:

a) Three bids were received in response to the Systems Integrator RFP. After an extensive evaluation process which included a scoring protocol and interviews, a vendor was selected in April. Currently, and prior to entering into a Master Services Agreement with the vendor, PowerStream and the vendor have mutually agreed to work towards entering into a Letter

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Agreement so as to initiate the discovery process sooner and mitigate scope and cost uncertainties.

Key terms and conditions currently being negotiated include: (i) ownership of intellectual property; (ii) indemnification (iii) limitation of liability; (iv) the description of services and deliverables; and (v) fees.

PowerStream remains on schedule for the new system to “Go Live” by end of Q2 2014.

b) The RFP process in question was completed in 2012. There is no cost related to the RFP process that would impact the 2013 Test Year.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #8:

Reference(s): (A3/T1/S1/p. 6)

The evidence indicates that, with respect to the capital budgeting process, a five-year plan is completed at the beginning of the year. Please explain to what extent, if at all, PowerStream's request for full depreciation has impacted that plan. If the Board rejects PowerStream's request for approval of a full year of depreciation how will this impact the five year plan?

RESPONSE:

PowerStream's request for full year's depreciation was not a factor in the setting of the five-year capital plan. The five-year capital plan is part of the capital planning and budgeting process. It provides a longer term outlook before the preparation of the capital budget which is specific to the next two years.

When the capital budget is prepared, PowerStream considers a number of factors including the availability of funds and maintaining the OEB recommended debt-equity structure.

Approval of a full year's depreciation means that PowerStream will have the funds available to do more of the capital spending identified as necessary through its capital planning processes.

PowerStream cannot say specifically how the five-year plan would be affected if the request for a full year of depreciation is not approved. With less funding, PowerStream may need to defer capital work that otherwise meets the criteria for inclusion in the capital budget.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #9:

Reference(s): (B1/T1/S1/p. 3)

Please provide the Five Year Capital plans prepared in each year for 2009-2011.

RESPONSE:

In 2009 the Five Year Plan was not finalized due to the merger and staffing changes at the time. The 2010 Distribution System Planning Report dated May 14, 2010 and revised September 24, 2010 is attached as Appendix A.

The following Five year plans for 2011 are attached as Appendix B:

- Distribution Design Five Year Plan
- Operations Five Year Plan
- Lines Five Year Plan
- Supply Chain Five Year Plan
- Smart Grid & Metering Five Year Plan
- Information Services Five Year Plan
- Capital Budget Supervisor (Misc. Capital)

The 2011 Engineering Planning Five Year Plan is included in Exhibit B1, Tab 2, Schedule 2.

The 2011 Corporate Five Year Plan is in Exhibit B1, Tab2, Schedule 1.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #10:

Reference(s): (B1/T1/S1/p. 5)

The evidence states that, in preparing the capital budget, 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. Please explain this process and how it was applied to the 2013 budget. What is meant by "affordability" in this context?

RESPONSE:

The five year forecast is updated every year, usually in the spring. During each review, budget targets are set for all areas of the business including capital. The 2013 capital budget included in this application was the result of this process.

The five year forecast is reviewed by management for reasonability. In such review, one of the considerations is the ability to fund the desired level of the capital spending, and that is the context in which the term “affordability” was used.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #11:

Reference(s): (B1/T1/S1/p. 6)

Please provide all materials provided to the EMT and the Board of Directors when seeking approval of the 2012 and 2013 capital budget/capital plans.

RESPONSE:

Please see CCC Interrogatory #2 for the material provided to EMT for the approval of the 2012 and 2013 capital budget. Please see CCC Interrogatory #1 for the material provided to the Board of Directors for the approval of the 2012 and 2013 capital budget.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #12:

Reference(s): (B1/T1/S1/p. 18)

Please provide the KPMG study relating to the Information Services Strategic Plan.

RESPONSE:

The PowerStream IT Strategy is attached as Appendix C.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #13:

Reference(s): (B1/T1/S4)

Please re-cast Table 1 Capital Expenditures to include 2009 Board-approved numbers.

RESPONSE:

The attached Table CCC IR #13 is Table 1 re-cast to include Board approved numbers. Both 2008 Barrie approved and 2009 PowerStream approved have been included.

See Exhibit B1, Tab 1, Schedule 6, pages 1-4 for an explanation of 2008 Barrie Hydro actual versus 2008 Barrie Board approved.

See Exhibit B1, Tab 1, Schedule 6, pages 4-7 for an explanation of 2009 PowerStream actual versus 2009 Board approved.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #14:

Reference(s): (B1/T1/S4)

Please explain what is meant by the comment, "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"? What changes were made and how do they result in additional increases in funds?

RESPONSE:

The changes to the economic model were to consolidate the economic evaluation methodology used in the model and process between Barrie and PowerStream. The economic evaluation methodology, as described in the Distribution System Code, outlines the cost sharing between the utility and the customer for new connections. The following changes have been made and each result in increased costs for PowerStream:

- A change has been made in practice for PowerStream to pay for secondary connections as compared to Developer installed or cost shared as done by the predecessor utilities.
- A change was made in practice for PowerStream to cost share the installation of commercial subdivisions using the economic model evaluation as compared to the commercial subdivisions treated as New Industrial/Commercial Customers who pay fully for service installations as done by the predecessor utilities.
- Lastly, upstream costs are removed from the economic model commencing in 2013 compliant to the Distribution System Code requirement.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #15:

Reference(s): (B1/T1/S4/p. 4)

Please provide a complete business case for the rehabilitation of underground cable. Please set out the projected spending levels for each year beginning in 2009.

RESPONSE:

For Projected Spending Levels see CCC Interrogatory #21.

PowerStream's underground cable rehabilitation program is made up of two primary categories;

1) Cable Replacement Program
2) Cable Injection Program

The Cable Replacement Program for 2013 consists of the following business cases;

1) BC #236 – Cable Replacement North
2) BC #237 – Cable Replacement South
3) BC #231 – Cable Replacement Romfield Subdivision
4) BC #250 – Cable Replacement Emerging

The Cable Injection Program for 2013 consists of the following business cases;

1) BC #234 – Cable Injection North
2) BC #235 – Cable Injection South

See the appended business cases, attached as Appendix D**.**

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #16:

Reference(s): (B1/T1/S4)

Please provide detailed budgets for each the following categories of capital expenditures for each year 2009-2013:

- Sustainment Driven Lines Projects
- Subdivision/Services
- Road Authority Projects
- Additional Capacity
- Growth Driven Lines Projects
- Information/ Communication Systems

RESPONSE:

The detailed budgets for each of the categories in the given years are set out in Table CCC #16, attached to this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #17:

Reference(s): (B1/T1/S4/p. 11)

Please provide detailed calculations to support the NPV analyses.

RESPONSE:

Please see the response to Board Staff IR response #14 filed in this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #18:

Reference(s): (B1/T1/S5/p. 12)

Please provide evidence to support the lease rates negotiated with Bloorguard. How were the rates derived?

RESPONSE:

PowerStream enlisted the services of an independent real estate consulting firm, CRESA Partners (CRESA), to assist in the acquiring the new operations centre. The key criteria for the development of a new Operations Centre included:

- The preference was to own the facility outright, failing which a long term lease with an option to purchase would be required.
- The location must be in either Markham, Richmond Hill or Vaughan to be positioned for good access to the South service area
- The site must be situated adjacent to a 400-series highway to allow for quick response to service calls.
- There must be an outside storage yard and adequate inside storage facilities for many of PowerStream's vehicles.

The search for viable building sites revealed that there were a limited number of opportunities within the geographic parameters that would allow outside storage while providing required proximity to a 400 series highway. Of the two short-listed sites, one in Vaughan proved to be not feasible due to the need to assemble land and go through an expropriation process, with the

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

potential of time delays with an uncertain outcome. As a result, PowerStream determined that the site at 80 Addiscott Court in Markham was the best available alternative to meet its needs. The 14-acre site was not available for outright purchase. PowerStream was able to negotiate a purchase and severance of 2 acres on the site to build a Transformer Station. The balance of the site could not be purchased due to potential tax implications for the owner. As a result, PowerStream proceeded to negotiate a 25-year lease for a purpose-built facility of approximately 107,200 square feet on 12 acres of land, with an option to purchase at the end of the lease term, and first right to purchase in the case of a sale.

Due to the unique design of the facility to meet PowerStream's requirement for outside storage and garage space for specialized vehicles, it was not possible to determine a market lease rate by comparison to similar properties.

In negotiating the lease rates, CRESA determined a market lease rate for the building based on an income approach. CRESA determined that the market would demand a return of between 7.5% and 8%, taking into account the unique nature of the property when completed to PowerStream's specifications. Based on the estimated land and building cost of $30,441,000, the final negotiated lease rates represent an annual return of about 7.8% to the landlord. The final negotiated rental rates represent market rate rent for this facility.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #19:

Reference(s): (B1/T1/S5/p. 15)

Given the new CIS system is planned to be in-service by the end of Q2 2014 what is the impact, if any, on the 2013 revenue requirement?

RESPONSE:

The CIS system application was purchased in 2012. PowerStream's 2013 OM&A budget includes $524,000 for the annual software license fees that allows PowerStream to receive support, future software releases and fixes from Oracle.

There are no other OM&A or capital expenditures related to CIS implementation that would affect the 2013 Revenue Requirement.

Without the new CIS implementation, the 2013 revenue requirement would be decreased by this amount and the corresponding decrease in Working Capital Requirement. Overall decrease in revenue requirement would be $530,000, as compared to the original application.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #20:

Reference(s): (B1/T1/S6/p. 26)

Please provide an estimate of the impact on the 2013 revenue requirement assuming the capital budget was reduced by $10 million and the impact assuming the capital budget was reduced by $20 million. Please include all assumptions

RESPONSE:

The revenue requirement generated by a $10 million investment in Test Year PP&E is about $0.57 million on average. This is based on taking a half-year depreciation, assuming an average asset life of 21.8 years. This average asset life is based on the current PowerStream mix of assets and is calculated based on the information in OEB appendix 2-CD "MIFRS Depreciation Expense 2013", filed in response to Board Staff IR #5. The average asset life depends on the type of capital investment made, so the impact on revenue requirement will be less for capital assets with longer than the average asset life. In this application, PowerStream used a full-year depreciation for the Test Year additions. Under the full year depreciation assumption, the revenue requirement impact of a $10 million investment is about $0.87 million.

Similarly, if the capital budget in the Test Year were reduced by $20 million, the revenue requirement would decrease by $1.7 million under a full-year depreciation for Test Year additions and by about $1.1 million using a half-year depreciation for Test Year additions.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

The revenue requirement amounts are estimated, based on the parameters currently used in PowerStream's revenue requirement model, including Cost of Capital, tax rate and Working Capital Allowance.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #21:

Reference(s): (B1/T1/S6/p. 28)

Please provide a schedule setting out all of the costs for cable rehabilitation program for the years 2009 and beyond. Please include all operating and capital costs of the program and how the costs are treated in the 2013 revenue requirement (O&M vs capital).

RESPONSE:

The following three tables collectively represent the three cost areas of the cable rehabilitation program: 1) Replacement; 2) Injection; and 3) testing.

All costs associated with both cable injection and cable replacement are treated as capital expenditures, with the exception of cable testing which is treated as O&M. Cable testing was introduced in 2012 in order to help identify and prioritize cable rehabilitation candidates. Costs associated with testing are mainly labour, split between Lines and Stations

The Table below sets out the costs for the Cable Replacement costs:

Table CCC #21-1: Cable Replacement Cost

Cable Replacement Cost (Capital)

Year	2009 Actual	2010 Actual	2011 Actual (CGAAP)	2011 Actual (MIFRS)	2012 Bridge	2013 Test
Total Costs	$1.2 M	$1.0 M	$4.1 M	$3.1 M	$ 5.7 M	$14.9 M

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Please note this table does not match the investment summary document Exhibit B1, T1, S8, page 7. The planned annual expenditures in the Investment Summary Document for underground cable replacement does not include all replacement costs.

The Investment Summary Document, Exhibit B1, Tab 1, Schedule 8, page 9 sets out the costs for the cable injection program. The table has been restated below.

Table CCC #21-2: Cable Injection Cost

Cable Injection Cost (Capital)

Year	2009 Actual	2010 Actual	2011 Actual (CGAAP)	2011 Actual (MIFRS)	2012 Bridge	2013 Test
Total Costs	$128 K	$24 K	$359 K	$324 K	$600 K	$4.0 M

The Table below sets out the costs for the O&M component of rehabilitation costs.

Table CCC #21-3: Cable Injection Cost

Cable Testing Cost (O&M)

Year	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Total Costs				$75 K	$ 83 K

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

CCC INTERROGATORY #22:

Reference(s): (B1/T1/S6/p. 27)

Please provide a schedule setting out all of the costs for the pole replacement program and the switch gear replacement program for the years 2009 and beyond. Please explain how PowerStream decides on the pace of replacement for each of these programs.

RESPONSE:

The Investment Summary Document, Exhibit B1, Tab 1, Schedule 8, page 2 sets out the costs for the pole replacement program. The table has been restated below.

Table CCC #22-1: Pole Replacement Program Cost (Capital)

Year	2009 Actual	2010 Actual	2011 Actual (CGAAP)	2011 Actual (MIFRS)	2012 Bridge	2013 Test
Total Costs	$1.1 M	$1.7 M	$1.6M	$1.2M	$2.8 M	$4.0 M

The Investment Summary Document, Exhibit B1, Tab 1, Schedule 8, page 6 sets out the costs for the switchgear replacement program. The table has been restated below.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Table CCC #22-2: Switchgear Replacement Program Cost (Capital)

Year	2009 Actual	2010 Actual	2011 Actual (CGAAP)	2011 Actual (MIFRS)	2012 Bridge	2013 Test
Total Costs	n/a	$1.4 M	$ 648 K	$ 648 K	$ 585 K	$1.2M

The pace of the programs are determined based on addressing safety and reliability related replacement needs in a timely manner, based in part by results from PowerStream's Asset Condition Assessment program, and presenting a smoothed multi-year budget spend program for financial and rate purposes.

For example, the pole replacement program is phased in over a number of years to address poles in "poor" and "very poor" condition recognizing that it would not be realistic to replace all these poles in a single rate year. The ACA program provided improved pole "health" information and identified a high number of poles in "poor" and "very poor" condition that require increased program spending as compared to previous years spending. PowerStream believes that the multi-year program to replace all currently identified "poor" and "very poor" condition poles is prudent from a risk and safety perspective. It is expected that, as existing poles in the "fair", "good" and "very good" categories age and deteriorate, new inspections (every 3 years) and testing (every 5 years) will show at the end of the current program, and on a rolling basis, a similar number of poles in need of replacement. 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.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Similar to the pole program, the planned switchgear replacement program addresses switchgear, currently identified in "poor" and "very poor" condition, through a multi-year program. It is expected that as existing distribution switchgear are aging and deteriorating, new inspection and condition analysis will show that at the end of the current program, and on a rolling basis, a similar number of switchgear will be required to be replaced. 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.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

ENERGY PROBE INTERROGATORY #5:

Reference(s): Exhibit B1, Tab 1, Schedule 4

a) Please provide a version of Table 1 that shows the actual and forecasted capital expenditures excluding the Markham TS #4, the head office building at Cityview, the operations centre at Addiscott and the customer information system. Please add each of these projects on separate lines after the Total Capital Expenditure line in the table.

b) The 2011 actual MIFRS capital expenditures are about $11.2 million lower than the 2011 actual CGAAP figures. Please provide an estimate of the total 2012 and 2013 capital expenditures under CGAAP. Please provide all assumptions used.

RESPONSE:

a) Table EP #5a attached to this Exhibit is a re-stated version of Table #1 with the Markham TS#4, head office building at Cityview, the operations centre at Addiscott and customer information system detailed at the end of the table.

b) The estimated capital expenditures for 2012 under CGAAP are $92,770,000. Table EP #5-1 below, summarizes the differences between the MIFRS and CGAAP capital Expenditures for 2012.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Table EP #5-1: 2012 Capital Expenditures

MIFRS Capital Expenditures 2012	**$76,700,000**
Burdens	$12,200,000
Damage Claims	($700,000)
Interest Capitalization	$250,000
CGAAP Capital Expenditures 2012	**$88,450,000**

The 2012 CGAAP capital expenditures amount was determined based on the 2012 capital budget prepared under MIFRS, adjusted for differences between MIFRS and CGAAP, as follows:

- Burdens – An analysis of 2012 burdens was performed for MIFRS and CGAAP using burden pool budgets and estimated amounts applied to capital / OM&A costs. The total burden costs applied to capital under MIFRS was estimated to be $12.2M lower than under CGAAP. In 2011 the actual difference was $11.2 million

- Damage Claims – The 2012 estimate of $700,000 for damage claims was based on the 2011 actual of $728, 000

- Interest Capitalization – The 2012 estimate for interest capitalization under MIFRS of $300,000 and under CGAAP of $550,000 was based on the 2011 actual amounts under MIFRS of $303,000 and under CGAAP of $537,000

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

In the "*Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*" (EB-2008-0408, dated June 13, 2011), on page 11, the Board states:

> *The Board therefore authorizes a generic deferral account to capture PP&E differences arising only as a result of the 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 MIFRS, including utilities using IRM rate-setting methodology*.

This requires PowerStream to maintain CGAAP comparatives for Property, Plant and Equipment (PP&E) until the first rebasing under MIFRS. As PowerStream is rebasing under MIFRS for 2013 this is up to 2013. Accordingly PowerStream has not undertaken any analysis of what capital amounts would be under CGAAP and variances from MIFRS past 2012. As such, an estimate of capital expenditures for 2013 under CGAAP cannot be provided.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

ENERGY PROBE INTERROGATORY #6:

Reference(s): Exhibit B1, Tab 1, Schedule 4, page 4 &
Exhibit A3, Tab 1, Schedule 4, page 7

Please explain the statement that a large number of assets (such as poles and underground cable) that were installed in the early 1980's are greater than 30 years old and are at or near end of life with the increase in the useful life for these assets as shown in Exhibit A3, Tab 1, Schedule 4 (for example, poles and underground conduit useful lives have increased from 25 years to 40 years).

RESPONSE:

We have interpreted the question to be that you are requesting us to reconcile the statement "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" taken from Exhibit B1, Tab 1, Schedule 4, page 4, line 5 with the information in the depreciation table shown in Exhibit A3, Tab 1, Schedule 4, page 7.

The statement in Exhibit B1, Tab 1, Schedule 4, page 4 was intended to provide a general statement of why PowerStream has increased the Sustainment Capital each year. Assets installed in the early 70's are now 40 years old and approaching many of the asset lives denoted in the depreciation table. With respect to those assets installed in the early 80's, these assets are now 30 years old and although many do not approach the useful life shown in the depreciation table a major class of asset requiring replacement is underground cable. Although the table denotes 45 years of useful life for this asset, PowerStream has kept first generation underground cable at 25 years of useful life.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

PowerStream prudently plans for asset replacement based on the asset condition. The useful lives given in the depreciation table are averages. Some assets may, due to condition be replaced earlier than the average useful life, with some assets replaced later then the average useful life. Present day assets are based on new technologies and typically have longer lives. For example, with poles, better chemical preservatives and treatment processes have greatly increased the protection of the wood from rot. Today's poles are also treated from top to bottom whereas in the past just the base of the pole was treated. If the pole was buried too deep at the time of installation or more commonly if the grade was changed after the fact, the pole rot at the base was accelerated.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

ENERGY PROBE INTERROGATORY #7:

Reference(s): Exhibit B1, Tab 1, Schedule 5, page 12

a) What is the total revenue requirement in the 2013 test year associated with the capital lease treatment of the building portion of the lease? Please provide all calculations, such as return and PILs in the estimation of the revenue requirement.

b) Please provide all the assumptions and calculations used to calculate the net present value of the lease payments associated with the building. In particular, what discount rate was used and how was it determined?

RESPONSE:

a) Capital lease treatment of the building portion of the lease results in the following items factoring into calculating revenue requirement for 2013:

- The average Net Book Value of the Capital lease on the building is included in rate base generating return at the deemed cost of capital; and
- Annual depreciation expense on the building in the amount of $731,000.

The revenue requirement attributable to the capital lease treatment is $1,712,000. The calculation of this amount is shown below in Table EP #7-1:

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Table EP #7-1: 2013 Revenue Requirement on Capital Lease ($000)

			2013
Opening NBV of Capital Lease - Addiscott			$ 16,085
Closing NBV of Capital Lease - Addiscott			$ 15,354
Average NBV of Capital Lease - Addiscott			$ 15,720
Amount added to Rate base			**$ 15,720**
Revenue Requirement Calculation			
Return on Equity	40.0%	9.12%	$ 573
Deemed interest - Short Term debt	4.0%	2.08%	$ 13
Deemed interest - Long Term debt	56.0%	4.96%	$ 437
OM&A			$ -
Depreciation			$ 731
PILs			(42)
Revenue Requirement			**1,712**

Table EP #7-2: PILs Calculation for Table EP#7-1 ($000)

PILs Calculation	**Tax rate**	**Amount**
Net Income		$ 573
Add depreciation		$ 731
Less lease payment deducted		$ (1,430)
Taxable Income		$ (126)
PILS	25.19%	$ (32)
PILS grossed Up		**$ (42)**

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

b) The following assumptions were used in determining the net present value (NPV) of the lease payments associated with the building:

- At the time the lease was negotiated, the fair market value of the land was $11.4 million and of the building was $19.0 million;
- The discount rate used was 6.57%. This is PowerStream's incremental cost of debt based on the estimated rate on a 25 year note or debenture issued in May 2008 as provided by the TD Bank.

See attached Appendix E for the NPV calculation based on the Canadian Institute of Chartered Accountants (CICA) handbook section 3065.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

ENERGY PROBE INTERROGATORY #8:

Reference(s): Exhibit B1, Tab 1, Schedule 5, page 13 &
Exhibit A4, Tab 1, Schedule 1

a) Will the new customer information system be used to provide any services related to the shared services discussed in Exhibit A4, Tab 1, Schedule 1? If yes, how will the associated increase in costs for this new system be recovered from the parties receiving the service?

b) The evidence indicates that the new CIS system is expected to be in service by the end of the second quarter of 2014. Please confirm that PowerStream has not closed any of the CIS related costs to rate base in or before the 2013 test year. If this cannot be confirmed, please explain and show the amounts proposed to be included in rate base in 2013.

RESPONSE:

a) Yes, the new Customer Information System will be used to support shared services. After expiry of the current service agreements, PowerStream will renegotiate the contracts based on then current costs.

b) PowerStream confirms that it has not included any of the new CIS costs in rate base for 2013 or prior.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

ENERGY PROBE INTERROGATORY #9:

Reference(s): Exhibit B1, Tab 1, Schedule 6

Please provide the most recent year-to-date capital expenditures available for 2012 and the corresponding figures for 2011 in the same level of detail as shown in Table 8.

RESPONSE:

See table below for the most recent year-to-date capital expenditures available for 2012 and corresponding figures for 2011. For 2011 the company did not convert monthly data from CGAAP to MIFRS and June YTD 2011 figures are under CGAAP while the 2012 are under MIFRS. **Caution should be exercised as to the direct comparability of the numbers cited.**

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Table EP #9: Capital Expenditures – 2011 YTD and 2012 YTD

YTD to June 30		
CATEGORY	**Actual \$ 2012 (MIFRS)**	**Actual \$ 2011 (CGAAP)**
SUSTAINMENT		
Replacement Program	**$3,249,075**	**$1,184,743**
Sustainment Driven Lines Projects	**$2,322,086**	**$2,655,841**
Emergency / Restoration	**$3,855,268**	**$4,199,812**
Transformer / Municipal Stations	**$144,522**	**$2,204,400**
Emerging Sustainment Capital	**$992,190**	**$396,405**
Total Sustainment	**$10,563,142**	**$10,641,201**
DEVELOPMENT		
Subdivision / Services	**$627,756**	**-$206,057**
Road Authority Projects	**$5,633,757**	**$4,205,425**
Additional Capacity(Transformer/ Municipal Station)	**$32,591**	**$168,042**
Growth Driven Lines Projects	**-$47,048**	**$1,726,790**
Emerging Development Capital	**$320,966**	**-$2,319,118**
Distributed Generation Connections	**-$47,502**	**$15,836**
Total Development	**$6,520,521**	**$3,590,917**
OPERATIONS		
Metering	**$1,070,875**	**$497,891**
Fleet	**$520,130**	**$712,172**
Tools	**$388,858**	**$161,605**

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Buildings	**-$7,227**	**$63,512**
Information / Communication Systems	**$4,492,453**	**$1,089,913**
Purchase of spare equipment	**$0**	**$20,381**
Emerging Operations Capital	**$1,383,817**	**$106,493**
Interest Capitalization	**$605,227**	**$205,906**
Total Operations	**$8,454,132**	**$2,857,872**
Total Capital Expenditure	**$25,537,795**	**$17,089,990**
Capital Deferral Accounts		
Smart Meters	**$0**	**$1,622,618**
Smart Grid	**$34,082**	**$45,016**
Renewable Generation	**$125,140**	**$49,751**
Total Capital Deferral Accounts	**$159,222**	**$1,717,385**

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

ENERGY PROBE INTERROGATORY #10:

Reference(s): Exhibit B1, Tab 1, Schedule 8

a) Please expand the table on page 2 to include the number of poles replaced and the resulting average cost per pole replaced for each year shown.

b) What was the average age of each pole replaced in each year shown in the table on page 2?

c) What is the status of the Flowervale Subdivision project shown on page 11?

d) Please confirm if the in-service date shown on page 17 for planned station circuit breakers is still valid. If not, please provide the current projection of the in-service date.

e) Please update the list of projects shown on pages 30 and 31 to reflect the most recent information available from the municipalities. Please show any impact of additions, deletions or deferrals in the annual figures shown on page 31.

f) Please confirm that the expenditure shown for the New Sandringham MS (page 32) and Vaughn TS #4 Land Purchase (page 34) are not included in the 2013 rate base given that they have in-service dates after the end of the 2013 test year. If this cannot be confirmed, please explain why any portion has been included in the test year rate base.

g) What is the current status of the Midhurst TS project shown on page 36? In particular, is Stage 1 still forecast to go into service by the end of 2012?

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

RESPONSE:

a & b) The combined answer to a & b is shown in the expanded table below.

Table EP #10a-b: Pole Replacements

Year	2009 Actual	2010 Actual	2011 Actual (CGAAP)	2011 Actual (MIFRS)	2012 Bridge	2013 Test
Total Costs	$ 1.1 M	$ 1.7 M	$ 1.6 M	$ 1.2 M	$ 2.8 M	$ 4.0 M
Total Number of Poles	117	127	117	117	244	400
Average Cost per Pole*	$9,402	$13,386	$13,675	$ 10,256	$11,475	$10,000
Average Age	32.7	39	34.6	34.6	31.3	28.4

* The average cost of pole varies depending upon the size and configuration of the poles being replaced. In 2010 PowerStream increased efforts to ensure the highest risk poles were completed first. Some of the key factors in determining risk are the amount of circuits and equipment the pole holds. The more a pole holds, the more costly to change out.

c) The status of the Flowervale Subdivision project is described below:

- Flowervale Phase 1 was completed in 2010.
- Flowervale Phase 2 was completed in 2011.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

- Flowervale Phase 3 is underway. The work order was issued for construction in March 2012. The civil work has been completed. PowerStream Lines crews are scheduled to complete the submersible transformer work and the conversion work in October 2012.

d) The 2012 Vaughan TS2 circuit breaker replacement project is proceeding on schedule. The planned November 2012 in-service date is still valid.

e) The most recent information from the municipalities on planned road projects indicates the following:

The list of updated projects expected for 2012 include:

- Keele St – Steeles Ave to Hwy 407 (**Deletion**)
- Hwy 7 – Warden Ave to Sciberras (**Deferred to 2013**)
- Olde Bayview Ave / Sunset Beach Road (**Deferred to 2013**)
- Snively Street / Drynoch Ave (**Deletion**)
- Markham Main Street Phase 1 (**In progress**)
- Markham Main Street Phase 2 (**Deferred to 2013**)
- Rodick Road Phase 2 **(In progress**)
- YRRT – Hwy 7 – Bayview to Warden (**In progress**)
- Ninth Line – Major Mackenzie to 19th Ave (**Addition**)
- Hwy 50 – Rutherford Road south to Castle Oak Drive (**Addition**)
- Gretel & Iredale Road Reconstruction (**Addition**)
- Cundles & Duckworth Phase 2 (**Addition**)
- Mapleview Drive Phase 3 – Huronia Rd to Country Lane (**Addition**)
- Maria St (**Addition**)
- Country Road 27 & Mapleview (**Addition**)

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

- 400 & Teston Road (**Addition**)

The list of updated projects expected for 2013 include:

- Rutherford Road, Jane to Keele St (**Deletion**)
- Rutherford Road, Keele to Dufferin St (**Deletion**)
- Weston Road, Hwy 7 to Rutherford Road (**Deletion**)
- Barrie – Mapleview Drive – Huronia Rd to Country Lane (**Moved to 2012**)
- Penetanguishene – Maria Street, Phase 2 (**Planned for 2013**)
- YRRT – Hwy 7 – Hwy 400 to Bowes Road (**Planned for 2013**)
- Underground of O/H Lines on ROW (**Planned for 2013**)
- YRRT – Y2.1 – Yonge St, Hwy 7 to Major Mackenzie (**Addition**)
- Lakeshore Drive – Toronto St to Tiffin St (**Addition**)
- Bathurst St – Hwy 7 to Teston Road (**Addition**)
- Olde Bayview Ave / Sunset Beach Road (**Moved to 2013 from 2012**)
- Essa Road – Bryne to Anne (**Addition**)
- Ferndale – Dunlop to Tiffin (**Addition**)
- Markham Main Street Phase 2 (**Moved to 2013 from 2012**)
- Major Mackenzie Drive – Weston to Islington (**Addition**)
- 400 Crossings – King Vaughan Rd and Kirby Rd (**Addition**)

The impact of additions, deletions or deferrals in the annual figures shown on page 31 is as follows:

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Table EP #10: Planned Annual Expenditures (net of contributed capital):

Year	2012 Bridge as Filed	2012 Bridge Revised	2012 Bridge Net Difference	2013 Test as Filed	2013 Test Revised	2013 Test Net Difference
Total Costs	$6.3 M	$7.6M	+$1.3 M	$13.0 M	$13.4M	+ $0.4 M

f) PowerStream can confirm that both the expenditures for the New Sandringham MS and Vaughan TS#4 land purchases have not been included in the 2013 rate base.

g) Construction has commenced on the Stage 1 Midhurst TS feeder project. Stage 1 of the Midhurst TS Project is on schedule to be completed by end of 2012.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

ENERGY PROBE INTERROGATORY #11:

Reference(s): Exhibit B1, Tab 2, Schedule 5, Appendix 1

a) Please explain the significant drop in contributed capital from the levels of about $23 to $24 million in 2010 and 2011 (both CGAAP and MIFRS) to the levels of $15 million in 2012 and $17.7 million in 2013.

b) Based on the most recent year-to-date information for 2012, what is the current level of contributed capital? Please also provide the corresponding figure for the same period in 2011.

Please show the amount of gross capital expenditures related to road authority projects for 2007 through 2013, along with the contributions received related to the projects.

RESPONSE:

a) The major factors in changes in contributed capital are as a follows:

- Change in road authority contributed capital;
- Change in estimated Work-In-Progress (WIP) at year end;
- Change in contributed capital for customer emerging projects;
- Change in volume of subdivision lots budgeted;
- Changes because of MIFRS (It should be noted for 2011, PowerStream did not make adjustments to contributed capital under MIFRS information).

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

b) To properly answer this question, we have to report on both contributed capital as well as deposits received to date which collectively represent the potential for customer contributed capital by year end. Table EP #11b shows both categories and the totals as of June 30.

Table EP #11b: June 30, 2011 vs. 2012 Customer Contributions

June 30 2011 vs. 2012 Customer Contributions			
Year	Deposits	Contributed Capital	Total
YTD June 2012	- $0.5 M *	$16.2 M	$15.7 M
YTD June 2011	$7.8 M	$5.7 M	$13.5 M

* Upon closing jobs the deposits get moved to contributed capital. More money has been moved to contributed capital this year than that which has been received from the customers year-to-date.

c) The gross capital expenditures and contributions related to road authority projects for 2007 through 2013, along with the contributions received related to the projects are shown in Table EP #11c) below.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Table EP #11c: Gross Capital Expenditures Road Authority Projects

ROAD AUTHORITY PROJECTS GROSS CAPITAL EXPENDITURES AND CONTRIBUTED CAPITAL								
	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)**
Gross Actuals	$4,691,294	$5,119,865	$5,635,727	$8,019,366	$12,638,995	$10,766,848	$8,744,041	$17,072,869
Contributed Actuals	-$994,290	-$4,031,186	-$1,693,295	-$2,096,432	-$3,728,539	-$3,548,237	-$2,445,123	-$4,028,636
Net Actuals	$3,697,004	$1,088,679	$3,942,432	$5,922,934	$8,910,456	$7,218,612	$6,298,918	$13,044,233

* The ratio of contributed to gross is low in 2007 and high in 2008 compared to normal. In 2007 there were a number of projects that were completed in 2007 but were not billed until 2008.

** The ratio of contributed to gross is low in 2013 compared to normal. In 2013 there is $3 M for undergrounding plant on the road right-of-way which will have no contributions from the Municipality.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

ENERGY PROBE INTERROGATORY #12:

Reference(s): Exhibit B1, Tab 2, Schedule 5, Appendix 1

a) Does the continuity schedule for 2009 reflect the application of the half year rule for assets added to rate base in the current year?

b) Did PowerStream use the half year rule for capital additions in the figures approved by the Board as part of the 2009 cost of service application?

c) Did Barrie Hydro use the half year rule for capital additions in the figures approved by the Board as part of the 2008 cost of service application?

d) Is the calculation of the depreciation expense for each of 2010 through 2012 consistent with the application of the half year rule (or not) used in 2009? If not, please explain what methodology was used for each of the years 2009 through 2012.

e) Please confirm that the half year rule has not been used for the 2013 test year.

f) Please provide a revised 2013 fixed asset continuity schedule that reflects both the use of the same methodology as approved by the Board for the 2009 cost of service application to 2009 through 2012 and the use of the half year rule for 2013.

RESPONSE:

a) Yes, the 2009 continuity schedule does reflect half year deprecation on new additions.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

b) Yes, PowerStream applied half year depreciation on 2009 capital additions in its 2009 cost of service rate application

c) Yes, Barrie Hydro applied half year depreciation on 2008 capital additions in its 2008 cost of service rate application.

d) Effective in 2010, PowerStream based depreciation on the actual in-service date. As assets are placed into service depreciation is applied beginning in the month the fixed assets are in-service. The actual depreciation on new additions for 2010 and 2011, as shown on exhibit B1, tab 2, schedule 5, were calculated on this basis. For 2012. PowerStream used the half year method of estimating the in-service date in calculating depreciation on additions.

e) Confirmed. PowerStream applied full year depreciation on additions in the 2013 test year, as explained in the Application (Exhibit A1, Tab 2, Schedule 1, page 2, item #6) and Exhibit D1, Tab 4, Schedule 1 (Depreciation and Amortization).

f) See table EP#12-1 attached. Note that this was prepared for response to this IR only and PowerStream is not proposing any change to its application.
PowerStream notes that the use of half year depreciation on forecasted additions is an estimating methodology and not a depreciation methodology. The OEB Filing Requirements for Transmission and Distribution Applications dated June 28, 2012 (EB-2006-0170) deal with how to estimate depreciation for a forecasted test year. In chapter 2, section 2.7.7 Depreciation /Amortization/Depletion, it states:

> *In particular, the Board's general policy for electricity distribution rate setting is that capital additions would normally attract six months of depreciation expense when they enter service in the test year. This is commonly referred to as the "half-year" rule. The applicant must identify its historical practice and its proposal for the test year. Variances*

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

> *from this "half-year" rule, such as calculating depreciation based on the month that an asset enters service, must be documented with supporting rationale.*

This guidance clearly states that when the in-service date can be reasonably forecast depreciation may be calculated on this in-service date, as long as there is evidence to support this.

PowerStream notes that Board provides guidance on the accounting for fixed assets and depreciation in the Accounting Procedures Handbook (APH), issued December 2011. A search of this document revealed no reference to the half-year rule. For historical years, the in-service date is known and it is reasonable to use it. PowerStream submits that this in compliance with the APH.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #17:

Reference(s): [B4/1/1/p.1]

Please provide a table showing the number and value of assets reaching the end of their useful life over each of the last ten years, and over each of the following ten years, to the extent that this can be done by category.

RESPONSE:

PowerStream's fixed asset system does not contain information regarding the quantities for assets. For assets that were formerly pooled there is just a dollar amount for each addition.

PowerStream has provided fully depreciated cost amounts for the years 2009 to 2014. Data constraints prohibit information prior to 2009. See Table SEC 17-1, attached.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #18:

Reference(s): [B1/1/5/p.13]

Please provide details on the procurement process that led to Oracle Customer Care and Billing CIS acquiring the contract to replace the existing system.

RESPONSE:

Please see response to Board Staff IR # 15, filed with this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #19:

Reference(s): [B1/1/5/p.13]

Please provide more detailed information on the CIS transition project and detailed capital expenditures for the project.

RESPONSE:

Please see response to Board Staff IR # 16 for information on the CIS transition project. A detailed capital expenditures report is attached as Table SEC #19.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #20:

Reference(s): [B1/1/5/p.18]

Please provide an update on the expected installation date for the new CIS system.

RESPONSE:

The expected installation date for the new CIS system remains as end of Q2 2014.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #21:

Reference(s): [B1/1/3/p.1]

Please provide the calculations of PP&E per customer.

RESPONSE:

Please see the table below:

Table SEC #21: PP&E Per customer

	2009 - Actual	2010 Actual	2011 CGAAP	2011 MIFRS	2012 Bridge Year	2013 Test Year
	Actual				Forecast	
Number of Customers	317,475	324,595	332,135	332,135	339,452	346,725
PP&E (Average NBV)	$ 537,300,000	$ 576,300,000	$ 632,500,000	$ 636,500,000	$ 677,400,000	$ 717,900,000
PP&E per customer	$ 1,692.4	$ 1,775.4	$ 1,904.3	$ 1,916.4	$ 1,995.6	$ 2,070.5

There are a number of reasons for the year over year increases in PowerStream's PP&E per customer. PowerStream is increasing spending on replacement of older plant that is reaching its end of life. The replacement cost of new plant is considerably higher than plant that is generally 25 to 40 years old. In addition, when the original plant was installed there were significant capital contributions from customers. There are no customer contributions on the replacement of plant reaching end of life. Similarly the cost of new plant for new customers is also higher than the average cost of installed plant. This is driven in part by decreasing capital contributions towards the cost of new plant for new customers due to the changing rules in the economic model for sharing of installation costs and removal of upstream costs.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

SEC INTERROGATORY #22:

Reference(s): [B1/1/8/p.30]

Please provide an update on the expected 2012 road authority projects.

RESPONSE:

Please refer to the response provided to Energy Probe's Interrogatory #10 e), filed in this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

VECC INTERROGATORY #4:

Reference(s): Exhibit B1, Tab 1, Schedule 6, page 25

a) Please provide a table showing for the period 2010 through 2016 the following CIS costs (please modify as necessary to show largest IS categories);

CIS Hardware	2010-2016
CIS Software & Maintenance	
ERP Hardware	
ERP Software & Maintenance	
SCADA Hardware	
SCADA Software & Maintenance	
Outage Management System Hardware	
Outage Management System Software&Maint	
AMI/ODA Hardware	
AMI/ODA Software & Maintenance	
Other IS Hardware	
Other IS Software & Maintenance	
Other IS Maintenance Costs	
IS Consulting Fees	
Other IS Costs (please identify significant categories)	Total IS Capital Costs

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

RESPONSE:

The attached Table VECC #4: IS Capital Costs 2010-2016, reflects PowerStream's best efforts to respond to this interrogatory. The table represents Capital Costs only. For Maintenance and Consulting costs please refer to response to VECC #28, filed at Exhibit J1, Tab 4, Schedule 4.1.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

VECC INTERROGATORY #5:

Reference(s): Exhibit B1,Tab 1, Schedule 8, page 9/ Exhibit D1, Tab 2, Schedule 1, page 5

a) The underground cable injection sustainment program in 2013 is over 10 times the spending in 2011. Please explain how PowerStream is able to carry out this large increase in work. Is to work subcontracted? If so to whom. What was the process for awarding contracts?

b) At Exhibit D1, page 5 it states that in 2012 PowerStream will commence a program to perform VLF testing and currently cables are replaced only once a pattern of failure is clearly established. It appears from then that PowerStream is proposing significant increases in cable replacement and restoration prior to the testing program? If this is correct please explain why PowerStream is not waiting for the results on the VLF program.

RESPONSE:

a) The cable injection work will be completed by external cable injection contractors. There are only two existing cable injection contractors available for work in Canada: Novinium Inc. and Transelec Common Inc.

PowerStream is currently finalizing Long-Term Master Service Agreements with both contractors (five year term). Meetings have been conducted between the contractors and PowerStream's various departments to exchange information about volume of work, process, procedure, and resulting expectations. In addition, drawings outlining injection areas are

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

being created ahead of time. Both PowerStream and the contractors believe that both the 2013 work volume and schedule are realistic and achievable.

PowerStream will use the "unit prices" (this varies for cable size and voltage between contractors) from the Long-Term Mater Service Agreements to select the most cost competitive contractor for a project, depending on project specific factors (e.g. cable segment, cable size and voltage, and number of terminations). The selected contractor will receive a Work Authorization specific to the project.

b) As stated in Exhibit D1, page 5, "The testing forms **part** *[emphasis added]* of PowerStream's Asset Condition Assessment Program and will be used to more proactively identify cables that are reaching end of life."

VLF (Tan-Delta) testing of cables is new to PowerStream this year. This testing method will help ensure the worst cables are being replaced in the system, thus optimizing our cable rehabilitation expenditures.

For 2013 the program cable replacement candidates were selected by age and failure history. The cables in the 2013 program have the worst failure history or are very old. While VLF (Tan-Delta) testing will generally confirm cable condition in this case we have enough related cable information to prioritize this group as our first year program.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

VECC INTERROGATORY #6:

Reference(s): Exhibit B1, Tab 1, Schedule 8, pages 14 - 16

a) Please explain why, notwithstanding a significant increase in sustainment capital expenditures, the amount forecast to be spend on unscheduled replacement of failed distribution equipment is rising between 2012 and 2013.

b) Please explain why notwithstanding a significant increase in sustainment capital expenditures the amount forecast to be spend on unscheduled replacement of failed switchgears failed distribution equipment is rising between 2012 and 2013.

c) Please explain why no amounts were forecast for unscheduled replacement of failed switchgear prior to 2012.

RESPONSE:

a) The unscheduled replacement of failed equipment covers the replacement of equipment, poles, conductors, devices and transformers, within PowerStream's service territory due to unexpected failure or expected imminent failure as discovered through inspection. The expenditures budgeted are based on analysis of historical failures and costs. PowerStream does not anticipate the increase in sustainment capital expenditures to affect the upward trend in unscheduled replacements of failed equipment in the near term.

b) See response a) above as the answer is also applicable to the unscheduled replacement of failed switchgear.

c) Prior to 2012 the costs for unscheduled replacement of failed switchgear were tracked as part of the Unscheduled Replacement of Failed Distribution Equipment; see Exhibit B1, Tab 1,

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Section 8, page 14 & 15. PowerStream did forecast and budget for unplanned distribution switchgear failure implicitly as part of the Failed Distribution Equipment category, but only at a macro level based on historical spending and therefore switchgear costs were not segregated. Beginning in 2012, PowerStream decided to budget switchgear separately to better manage the unscheduled replacement program.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

VECC INTERROGATORY #7:

Reference(s): Exhibit B1, Tab 1, Schedule 8, page 21

a) PowerStream states that it has "*completed eleven SorbWeb installations at MS's*". Yet the table accompanying this section shows no spending on this item in 2012 or 2011. Please explain when these 11 installations were completed.

b) How many SorbWeb installations were completed in 2010?

RESPONSE:

a) The 11 installations were completed as follows:
   2006 – 1 municipal station (MS)
   2007 – 2 municipal stations
   2009 – 4 municipal stations
   2010 – 4 municipal stations

b) Please see the answer 7 a) above.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

VECC INTERROGATORY #8:

Reference(s): Exhibit B1, Tab 1, Schedule 8, page 27

a) Please provide a modified table of the planned annual expenditures for New Subdivision Development which shows (1) the actual/forecast amount expended in each year; and (2) the amount of capital contributions **charged** against that year's expenditure (as opposed to collected in that year). For example:

Planned Annual Expenditures:

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFR	2012 Bridge	2013 Test
Expenditures						
Capital Contribution						

a) Please complete the same form of table Secondary Services and Layouts.
b) Please explain why there were no expenditures for Secondary Services in 2009 and 2010.

RESPONSE:

a) The following table provides the requested information for subdivision development. Capital Contributions represents the customer contributions for closed jobs in a given year. Deposits represent the customer contributions received in the given year for jobs that are work-in-

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

progress at the end of the year. Gross costs are the total costs before customer contributions. Net costs are the remaining costs after customer contributions have been deducted.

PowerStream does not track the amount of capital contributions charged against that year's expenditure. The best information available has been provided.

Residential Subdivisions

	2009 Actual *	2010 Actual *	2011 Actual CGAP**	2011 Actual MIFRS	2012 Bridge Year ***	2013 Test Year ***
Gross Costs	$ 24,544,501	$ 10,377,828	$ 20,350,098	$ 19,369,051	$ 11,232,525	$ 12,554,223
Capital Contributions	$(17,243,070)	$ (7,626,428)	$(11,223,503)	$(11,223,503)	$ (5,616,263)	$ (5,021,689)
Deposits	$ (1,297,201)	$ (3,403,657)	$ (5,100,590)	$ (5,100,590)	$ -	$ -
Net Costs	$ 6,004,229	$ (652,257)	$ 4,026,005	$ 3,044,958	$ 5,616,262	$ 7,532,534

* 2009 and 2010 are best considered in totality due to how Barrie accounts were brought into PowerStream's system combined with financial accounting of Developer Constructed (Option B) subdivisions at that time.
** In the later part of 2011 an increased amount activity of new subdivisions resulted in late year payments (deposits) for projects that were constructed in late 2011 and in early 2012.
*** PowerStream budgets customer contributions expected to be received in a given year and does not break it down into the sub-categories of contributed contributions and deposits.

b) The following table provides the requested information for Secondary Services and Layouts

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

Secondary Services						
	2009 Actual *	2010 Actual *	2011 Actual CGAP	2011 Actual MIFRS	2012 Bridge Year	2013 Test Year
Gross Costs	$ -	$ -	$ 1,393,851	$ 1,022,632	$ 1,310,849	$ 1,478,188
Capital Contributions	$ -	$ -	$ (45,273)	$ (45,273)	$ -	$ -
Deposits	$ -	$ -	$ 157,196	$ 157,196	$ -	$ -
Net Costs	$ -	$ -	$ 1,505,774	$ 1,134,555	$ 1,310,849	$ 1,478,188

* See part c) below for explanation why there are no costs in 2009 and 2010.

Layouts						
	2009 Actual	2010 Actual	2011 Actual CGAP	2011 Actual MIFRS	2012 Bridge Year	2013 Test Year
Gross Costs	$421,582	$975,754	$1,003,445	$733,344	$824,642	$895,573
Contributed	($58,645)	($40,069)	($65,300)	($65,300)	($82,464)	($90,006)
Deposits	$38,433	($11,083)	($15,996)	($15,996)	$0	$0
Net Costs	$401,370	$924,602	$922,149	$652,049	$742,178	$805,567

c) There were expenditures for Secondary Services in 2009 and 2010; however, the costs for Secondary Services were charged to the individual subdivision work orders and then estimates were used to move costs into a Secondary Services work order. A change was made in 2011 to instead charge the Secondary Services to the Secondary Services work order

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

to give proper visibility to the total costs in a year and allow the subdivision work orders to be closed off. Prior year costs were not a true representation of the costs of secondary services so were not included.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

VECC INTERROGATORY #9:

Reference(s): Exhibit B1, Tab 1, Schedule 8, page 31

a) Please provide a table in the form described in VECC interrogatory #7 for Road Authority Projects.

RESPONSE:

a) Please refer to the response provided to Energy Probe's Interrogatory #11 c).

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

VECC INTERROGATORY #10:

Reference(s): Exhibit B1, Tab 1, Schedule 8, page 34

a) In respect to the Vaughan Transformer Station 4, when does PowerStream expect the Class EA process to be complete?
b) When is the anticipated purchase date for land for this project?

Please provide the project timelines which show when the land must be purchased in order for this project to be completed by the summer of 2016.

RESPONSE:

a) PowerStream expects the Class EA process to be completed by June 2013.

b) The anticipated purchase date for land for the Vaughan Transformer Station 4 project is September 2013.

c) Land has to be purchased in 2013 for Engineering Design and Civil work to commence in 2013 and 2014 for an in-service date of 2016.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

VECC INTERROGATORY #11:

Reference(s): Exhibit B1, Tab 1, Schedule 8, page 40

a) Does PowerStream account for Suite Metering separately for both capital and OM&A spending.

RESPONSE:

a) Yes, PowerStream tracks separately suite metering separately for both capital and OM&A.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

VECC INTERROGATORY #12:

Reference(s): Exhibit B1, Tab 1, Schedule 8, page 42

a) Has Hydro One provided the total cost for the Buttonville Metering Upgrade?
b) Has PowerStream been invoiced for any or all of this project?
c) What date has Hydro One provided for completion of this project?

RESPONSE:

a) No, Hydro One has not provided the total costs for the Buttonville Metering Upgrade. As of August 13, 2012, Hydro One has been provided a Purchase Order to complete the site engineering analysis. The detailed cost estimate for the project will be completed once Hydro One's engineering analysis is completed.

b) To-date PowerStream has been invoiced minimal costs from the contractor who will be performing the work for project coordination services.

c) The planned completion of this project continues to be November 2013. The work is being completed by a contractor hired by PowerStream.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)

VECC INTERROGATORY #13:

Reference(s): Exhibit B1, Tab 2, Schedule 2 Five Year Capital Plan

Preamble: The purpose of this interrogatory is to better understand the vintage of the underground cable that is being replaced or refurbished.

a) At section 6.1.2.1 of the Plan is a graph entitled " PowerStream Underground Cable Projected Demographics Total Cable." Using this graph please superimpose all 2013 cable rehabilitation and replacement projects. Please legend the superimpositions (for example Flowervale subdivision Cable Rehabilitation would be shown as a superimposed colour in the appropriate vintage column with height of the superimposition representing [t]he number of kilometers replaced by this project).

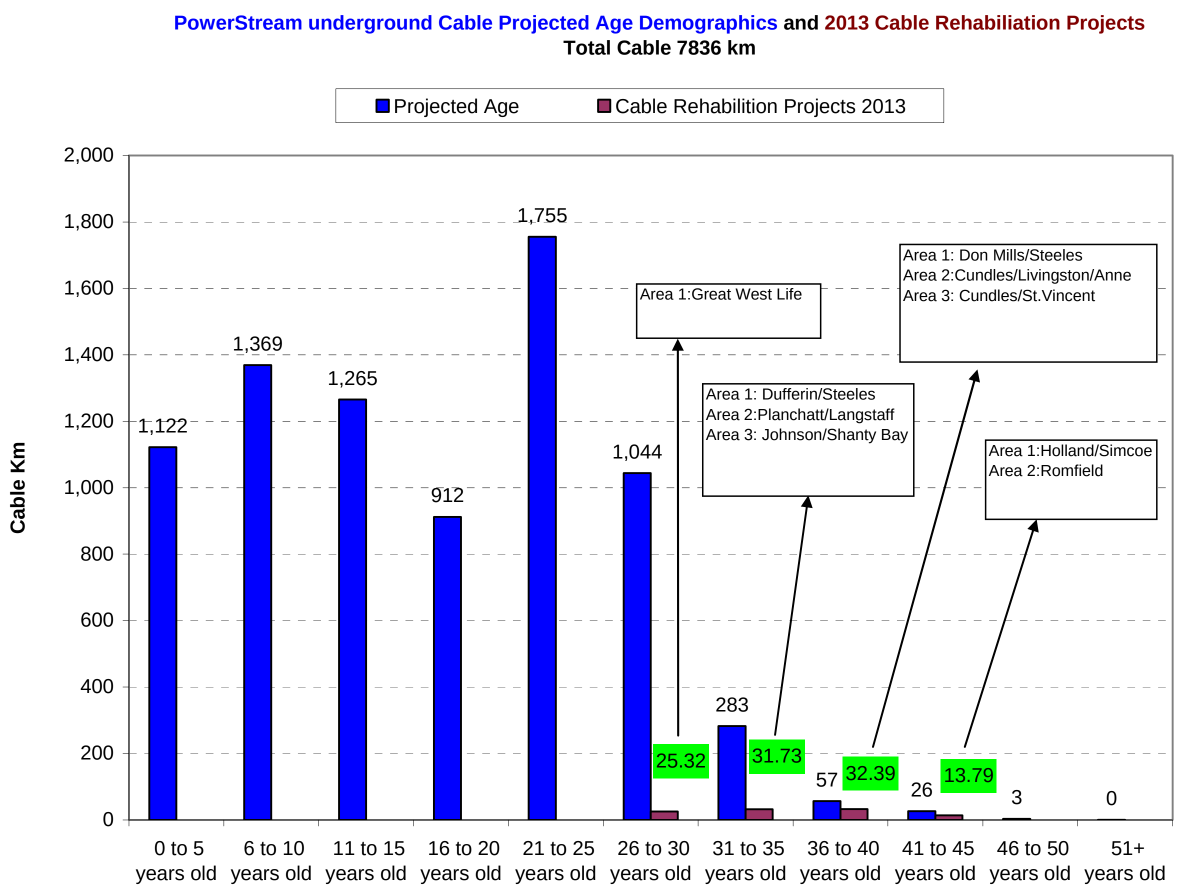
RESPONSE:

Please find attached herewith the graph of the 2013 cable rehabilitation projects superimposed on the projected demographics graph.

RESPONSES TO INTERROGATORIES BY ISSUE

2. RATE BASE (Exhibit B)

2.3 Is the Capital Expenditures forecast for Test Year 2013 appropriate? (B1)



The above graph shows the quantity of the cable rehabilitation in 2013. As can be seen, the 2013 program addresses only a modest quantity of the entire cable population, primarily focusing on cables greater than 26 years of age that are at or near end of life, leaving a considerable amount of cable needing to be addressed in future years.

Capital Expenditures 2007 to Test Year 2013

PROJECT DESCRIPTION	2007 Actual (CGAAP)	2008 Actual (CGAAP)	2008 Barrie Board Approved	2009 PowerStream Board Approved	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	$761,814	$6,987,000	$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	$1,695,000	$8,757,000	$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	$600,000	$2,556,000	$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	$750,000	$3,704,000	$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	$50,000	$414,000	$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	$3,856,814	$22,418,000	$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	$2,532,000	$5,200,000	$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	$1,600,000	$5,892,000	$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	$0	$9,160,000	$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	$737,000	$20,353,000	$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	$1,850,000	$414,000	$858,309	$611,790	$1,032,240	$626,419	$540,569	$435,371
Distributed Generation Connections	$0	$0	$0	$0	$23,941	$79,931	$32,210	($86,236)	$0	$0
Total Development Capital	$8,940,057	$11,256,592	$6,719,000	$41,019,000	$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	$150,000	$1,732,000	$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	$893,575	$887,000	$3,933,516	$3,059,001	$1,172,758	$1,154,496	$2,037,200	$2,932,600
Tools	$466,984	$354,050	$175,275	$310,000	$326,514	$457,226	$640,137	$629,865	$712,810	$596,576
Buildings	$20,993,737	$4,931,129	$132,375	$381,000	$4,846,822	$1,308,312	$176,551	$173,385	$864,930	$221,372
Information / Communication Systems	$1,996,988	$3,345,827	$2,692,250	$5,519,000	$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	$0	$0	$3,099,128	$321,634	($228,589)	($228,721)	$66,000	$127,654
Emerging Operations Capital	$2,341,273	$2,020,446	$0	$0	$944,198	$1,171,867	$768,100	$742,961	$686,770	$120,120
Interest Capitalization	$1,374,013	$850,187	$0	$0	$1,390,473	$1,674,195	$573,560	$340,287	$330,000	$1,317,372
Total Operations Capital	$31,207,803	$20,272,599	$4,043,475	$8,829,000	$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	$14,619,289	$72,266,000	$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	$0	$12,975,000	$17,195,703	$26,731,788	$1,526,739	$1,406,008	$0	$0
Smart Grid	$0	$0	$0	$0	$0	$192,265	$284,912	$281,174	$1,250,000	$650,000
Renewable Generation	$0	$0	$0	$0	$0	$54,046	$470,772	$468,795	$756,361	$77,250
Total Capital Deferral Accounts	$10,536,450	$6,610,918	$0	$12,975,000	$17,195,703	$26,978,099	$2,282,423	$2,155,977	$2,006,361	$727,250

2009 BUDGET				
Category	**Job Description**	**Gross Budget**	**Contributed Budget**	**Net Budget**
Sustain -Driven Lines Projects	OH & UG LED Fault indicator installation Markham, Richmond Hill, Aurora	$362,000	$0	$362,000
Sustain -Driven Lines Projects	Retro fitting vaults and submersible units	$348,000	$0	$348,000
Sustain -Driven Lines Projects	Establish a 27.6kV crossing between OH feeders on the E/W side of Yonge St	$88,000	$0	$88,000
Sustain -Driven Lines Projects	Existing pole line upgrade at Huntington Road from Rutherford Rd to Langstaff Rd	$997,000	$0	$997,000
Sustain -Driven Lines Projects	Phase 2 of Elder Mills MS feeder conversion to 27.6kV - Kleinburg area	$350,000	$0	$350,000
Sustain -Driven Lines Projects	Installation of 12 scadamate switches in various locations	$1,036,000	$0	$1,036,000
Sustain -Driven Lines Projects	Aurora System Remote Fault Indicator Deployment	$93,000	$0	$93,000
Sustain -Driven Lines Projects	Aurora System Renomenclature	$119,000	$0	$119,000
Sustain -Driven Lines Projects	Spacer installations	$30,000	$0	$30,000
Sustain -Driven Lines Projects	Underground primary extension to close loop at Montserrand St & Veterans Dr	$9,000	$0	$9,000
Sustain -Driven Lines Projects	Bayfield Street (vault 37) switching devices	$35,000	$0	$35,000
Sustain -Driven Lines Projects	Saunders Rd - 44kV infill Wellham Rd to Saunders Road	$239,000	$0	$239,000
Sustain -Driven Lines Projects	Huronia Road - Yonge Street to Big Bay Point Road (insulator replacement)	$233,000	$0	$233,000
Sustain -Driven Lines Projects	Yonge Street - Big Bay Point Road to Huronia Road (insulator replacement)	$176,000	$0	$176,000
Sustain -Driven Lines Projects	Distribution - 13.8kV switches (LBGO)	$140,000	$0	$140,000
Sustain -Driven Lines Projects	Sub-Transmission - 44kV switch automation upgrades	$360,000	$0	$360,000
Sustain -Driven Lines Projects	Protection upgrade	$150,000	$0	$150,000
Sustain -Driven Lines Projects	Robert street poleline rebuild	$63,000	$0	$63,000
Sustain -Driven Lines Projects	LRG subdivision - Brown Street rebuild	$252,000	$0	$252,000
Sustain -Driven Lines Projects	Essa Road - Gowan to Anne (concrete pole replacement)	$548,000	$0	$548,000
Sustain -Driven Lines Projects	WIP Sustainment South	$2,000,000	$0	$2,000,000
Sustain -Driven Lines Projects	WIP - Sustainment North	$275,000	$0	$275,000
TOTAL Sustain -Driven Lines Projects				$7,903,000

Develop -Subdivision/Services	ICI - South	$7,261,000	-$7,261,000	$0
Develop -Subdivision/Services	ICI - North	$2,000,000	-$1,900,000	$100,000
Develop -Subdivision/Services	New Res. Services - South	$687,000	-$577,000	$110,000
Develop -Subdivision/Services	New Res. Services - North	$276,000	-$63,000	$213,000
Develop -Subdivision/Services	Small Comm. Services - South	$261,000	-$261,000	$0
Develop -Subdivision/Services	Miscellaneous Projects - North	$775,000	-$200,000	$575,000
Develop -Subdivision/Services	New Subdivision - South	$7,853,000	-$7,853,000	$0
Develop -Subdivision/Services	New Subdivision - North	$5,400,000	-$3,099,000	$2,301,000
Develop -Subdivision/Services	Res. subd. Connections - South	$1,000,000	-$1,000,000	$0
TOTAL - Develop -Subdivision/Services				$3,299,000
Develop -Road Authority Projects	Road Authority Projects - South	$2,736,000	-$778,000	$1,958,000
Develop -Road Authority Projects	Road Authority projects - North	$3,860,000	-$1,146,000	$2,714,000
TOTAL - Develop -Road Authority Projects				$4,672,000
Develop -Add Capacity TS& MS	Markham TS # 4 - 2009 Portion of 3 yr Project	$9,160,000	$0	$9,160,000
Develop -Add Capacity TS& MS	Wholesale metering for new transformer station	$366,000	$0	$366,000
Develop -Add Capacity TS& MS	Park Place MS - Phase	$1,650,000	$0	$1,650,000
TOTAL - Develop -Add Capacity TS& MS				$11,176,000
Develop -Growth Driven Lines Projects	Vaughan TS#2 - Additional feeders from existing stations	$3,770,000	$0	$3,770,000
Develop -Growth Driven Lines Projects	20M23 and 20M24 feeder installations at Centre Street	$2,461,000	$0	$2,461,000
Develop -Growth Driven Lines Projects	20M23 and 20M24 feeder installations at Dufferin Street	$2,150,000	$0	$2,150,000
Develop -Growth Driven Lines Projects	Transformer station egress remediation - MTS#1 and MTS#2	$269,000	$0	$269,000
Develop -Growth Driven Lines Projects	Transformer station egress remediation MTS#3	$119,000	$0	$119,000
Develop -Growth Driven Lines Projects	Radial supply remediation - Double 27.6kV ccts on 9th	$548,000	$0	$548,000
Develop -Growth Driven Lines Projects	Radial supply remediation - Tie crossing Yonge St on Longbridge Rd.	$32,000	$0	$32,000
Develop -Growth Driven Lines Projects	Transformer station egress remediation - MTS#1 and MTS#2	$269,000	$0	$269,000
Develop -Growth Driven Lines Projects	Transformer station egress remediation MTS#3	$119,000	$0	$119,000

Develop -Growth Driven Lines Projects	Markham TS#4 Feeder Egress Part 2, 4 feeders	$4,687,000	$0	$4,687,000
Develop -Growth Driven Lines Projects	Markham TS#4 Feeder Egress, Part 1	$4,796,000	$0	$4,796,000
Develop -Growth Driven Lines Projects	Aurora 44kV line work - feeder work outside Armitage TS	$6,330,000	$0	$6,330,000
Develop -Growth Driven Lines Projects	Transfer of 2 - 44kV feeders to PowerStream (Mulock Dr., Newmarket)	$1,815,000	$0	$1,815,000
Develop -Growth Driven Lines Projects	Transfer of 2 - 44kV feeders to PowerStream - Bayview Ave	$1,446,000	$0	$1,446,000
Develop -Growth Driven Lines Projects	44kV Mapleview Drive - Veterans to Bryne	$629,000	$0	$629,000
Develop -Growth Driven Lines Projects	John Street pole line - Dyment to Lorena (including Hwy 400 crossing)	$404,000	$0	$404,000
Develop -Growth Driven Lines Projects	Park Place - 44kV feeders	$669,000	$0	$669,000
TOTAL - Develop -Growth Driven Lines Projects				$30,513,000
Operatn -Info/Communication Systems	Client Computing	$382,000	$0	$382,000
Operatn -Info/Communication Systems	Infrastructure hardware	$320,000	$0	$320,000
Operatn -Info/Communication Systems	Packaged software	$178,000	$0	$178,000
Operatn -Info/Communication Systems	Technology driven productivity improvement	$445,000	$0	$445,000
Operatn -Info/Communication Systems	JDE fleet module - Enable and setup	$47,000	$0	$47,000
Operatn -Info/Communication Systems	Process Improvement Initiatives	$525,000	$0	$525,000
Operatn -Info/Communication Systems	Implementation of ArcGIS Server	$50,000	$0	$50,000
Operatn -Info/Communication Systems	GIS Aerial Photography (Ortho Images)	$35,000	$0	$35,000
Operatn -Info/Communication Systems	StreetScape Images	$100,000	$0	$100,000
Operatn -Info/Communication Systems	ArcFM Designer PH2 Enhancements	$50,000	$0	$50,000
Operatn -Info/Communication Systems	GIS Data Clean-up Initiative	$100,000	$0	$100,000
Operatn -Info/Communication Systems	JD Edwards enhancements	$535,000	$0	$535,000
Operatn -Info/Communication Systems	Outage management system	$250,000	$0	$250,000
Operatn -Info/Communication Systems	CIS enhancements back office labour	$446,000	$0	$446,000
Operatn -Info/Communication Systems	CDM back office labour	$23,000	$0	$23,000
Operatn -Info/Communication Systems	International Financial Reporting Standards project	$512,000	$0	$512,000
Operatn -Info/Communication Systems	CIS Modifications	$600,000	$0	$600,000
Operatn -Info/Communication Systems	Phone system enhancement	$345,000	$0	$345,000

Operatn -Info/Communication Systems	Additional GIS editing licenses	$40,000	$0	$40,000
Operatn -Info/Communication Systems	Computer Equipment - north	$169,000	$0	$169,000
Operatn -Info/Communication Systems	Computer Equipment - GIS & computer software - north	$138,000	$0	$138,000
TOTAL - Operatn -Info/Communication Systems				$5,290,000

2010 BUDGET

Category	Job Description	Gross Budget	Contributed Budget	Net Budget
Sustain -Driven Lines Project	ESA Due Diligence Inspection - North	$20,405	$0	$20,405
Sustain -Driven Lines Project	ESA due diligence inspection - South	$10,203	$0	$10,203
Sustain -Driven Lines Project	Flowervale conver. cable repla	$1,400,019	$0	$1,400,019
Sustain -Driven Lines Project	Retro fitting vaults and subme	$377,900	$0	$377,900
Sustain -Driven Lines Project	13.8kV Tie MS331 AND MS330	$69,088	$0	$69,088
Sustain -Driven Lines Project	Joint use pole removal - South	$156,011	$0	$156,011
Sustain -Driven Lines Project	Joint Use Pole removal - North	$49,201	$0	$49,201
Sustain -Driven Lines Project	Fault indicator Installation	$300,472	$0	$300,472
Sustain -Driven Lines Project	Purchase 44kV Assets from H1	$500,000	$0	$500,000
Sustain -Driven Lines Project	Replace OH Secondary bus	$454,066	$0	$454,066
Sustain -Driven Lines Project	Convert Rainbow MS	$1,024,813	$0	$1,024,813
Sustain -Driven Lines Project	Fault indicator Installation	$299,809	$0	$299,809
Sustain -Driven Lines Project	WIP Sustainment South	$300,351	$0	$300,351
Sustain -Driven Lines Project	WIP - Sustainment North	99,964.00	0.00	$99,964
TOTAL Sustain -Driven Lines Project				$5,062,302

Develop -Subdivision/Services	ICI - South	$4,410,451	-$4,410,451	$0
Develop -Subdivision/Services	ICI - North	$2,542,410	-$2,542,410	$0
Develop -Subdivision/Services	New Res. Services - South	$384,284	-$268,998	$115,286
Develop -Subdivision/Services	New Res. Services - North	$65,946	-$46,163	$19,783
Develop -Subdivision/Services	Service Upgrades - South	$295,134	-$59,027	$236,107
Develop -Subdivision/Services	Service Upgrades - North	$192,129	-$38,426	$153,703
Develop -Subdivision/Services	Small Comm. Services - South	$646,667	-$646,667	$0
Develop -Subdivision/Services	Small Comm. Services - North	$364,342	-$364,342	$0
Develop -Subdivision/Services	New Subdivision - South	$9,463,626	-$5,678,176	$3,785,450
Develop -Subdivision/Services	New Subdivision - North	$4,350,699	-$2,610,419	$1,740,280
Develop -Subdivision/Services	Secondary Service Lateral - South	$1,808,422	-$1,085,100	$723,322
Develop -Subdivision/Services	Secondary Service Lateral - North	$618,158	-$370,895	$247,263
TOTAL Develop -Subdivision/Services				$7,021,194
Develop -Road Authority Projects	Road Authority projects - South	2,834,693.00	-822,009.00	$2,012,684
Develop -Road Authority Projects	Road Authority projects - North	3,035,276.00	-880,255.00	$2,155,021
TOTAL Develop -Road Authority Projects				$4,167,705
Develop -Add Capacity TS &MS	Construct Park Place MS - 2nd Year	$1,909,822	$0	$1,909,822
Develop -Growth Driven Lines Projects	Install. 2 ccts on new poles	$43,986	$0	$43,986
Develop -Growth Driven Lines Projects	Install. 4 ccts on poles	$51,035	$0	$51,035
Develop -Growth Driven Lines Projects	Additional overhead circuits	$541,092	$0	$541,092
Develop -Growth Driven Lines Projects	Install 27.6kV overhead ccts	$1,152,924	$0	$1,152,924
Develop -Growth Driven Lines Projects	Feeders extension-20M11/M12	$719,810	$0	$719,810
Develop -Growth Driven Lines Projects	Install. 4 UG ctts - MTS4	$55,264	$0	$55,264
Develop -Growth Driven Lines Projects	Install. of 4 cct pole line	$22,951	$0	$22,951
Develop -Growth Driven Lines Projects	MS324 (REAGENS CT.) upgrade	$144,226	$0	$144,226
Develop -Growth Driven Lines Projects	WIP Development South	$5,000,209	$0	$5,000,209

Develop -Growth Driven Lines Projects	WIP Development North	$202,333	$0	$202,333
TOTAL Develop -Growth Driven Lines Projects				$7,933,830
Operatn -Info/Communication Systems	Joint use attachment review	$50,880	$0	$50,880
Operatn -Info/Communication Systems	Client Computing - South	$317,000	$0	$317,000
Operatn -Info/Communication Systems	Server Replacement	$242,116	$0	$242,116
Operatn -Info/Communication Systems	New CIS	$84,800	$0	$84,800
Operatn -Info/Communication Systems	JD Edwards Enhancements	$752,761	$0	$752,761
Operatn -Info/Communication Systems	Printer&Copier Fleet Replmnt.	$224,000	$0	$224,000
Operatn -Info/Communication Systems	Printer&Copier Fleet Replamnt.	$40,000	$0	$40,000
Operatn -Info/Communication Systems	Client Computing	$147,000	$0	$147,000
Operatn -Info/Communication Systems	CIS Modifications	$1,017,600	$0	$1,017,600
Operatn -Info/Communication Systems	IS Virtualization	$69,271	$0	$69,271
Operatn -Info/Communication Systems	StreetScape Images	$100,000	$0	$100,000
Operatn -Info/Communication Systems	CYME Gateway (GIS Integration)	$116,760	$0	$116,760
Operatn -Info/Communication Systems	ArcFM Geodatabase Manager	$40,176	$0	$40,176
Operatn -Info/Communication Systems	GIS Operating map Prints	$182,334	$0	$182,334
Operatn -Info/Communication Systems	IFRS Project	$2,544,000	$0	$2,544,000
Operatn -Info/Communication Systems	Scada Training Simulator	$28,000	$0	$28,000
Operatn -Info/Communication Systems	Asset Management Plan	$373,120	$0	$373,120
Operatn -Info/Communication Systems	Health Index Granularity	$67,840	$0	$67,840
Operatn -Info/Communication Systems	Subdivision data base	$62,752	$0	$62,752
Operatn -Info/Communication Systems	Development of database	$50,880	$0	$50,880
Operatn -Info/Communication Systems	IVR_Phone system enhancement	$497,480	$0	$497,480
Operatn -Info/Communication Systems	IS Security Improvements	$182,080	$0	$182,080
Operatn -Info/Communication Systems	AS400 Upgrade	$648,488	$0	$648,488
Operatn -Info/Communication Systems	Bus. Driven Prod. Improvements	$127,840	$0	$127,840

Operatn -Info/Communication Systems	IS Driven Misc. Projects	$320,985	$0	$320,985
Operatn -Info/Communication Systems	Designer Enhancement project	$156,320	$0	$156,320
Operatn -Info/Communication Systems	ArcGIS Server PHII (BAT Replac	$97,840	$0	$97,840
Operatn -Info/Communication Systems	Mobile GIS for service Layouts	$62,600	$0	$62,600
Operatn -Info/Communication Systems	Digital fault record server	$42,145	$0	$42,145
Operatn -Info/Communication Systems	Corp. Connectivity All TS's	$58,647	$0	$58,647
Operatn -Info/Communication Systems	Replace HMI Computer - MT3	$41,152	$0	$41,152
Operatn -Info/Communication Systems	Video surveillance	$47,298	$0	$47,298
Operatn -Info/Communication Systems	IVR Deployment with OMS	$169,600	$0	$169,600
Operatn -Info/Communication Systems	Voice Radio Comm. Review and Upgrade	$41,152	$0	$41,152
Operatn -Info/Communication Systems	Upgrade Operat. Comm. Infrastructure	$270,634	$0	$270,634
Operatn -Info/Communication Systems	Scada Mont.-SONET Infrastructu	$29,280	$0	$29,280
Operatn -Info/Communication Systems	VRD conversion project	$277,850	$0	$277,850
Operatn -Info/Communication Systems	Bar code reading system	$235,000	$0	$235,000
Operatn -Info/Communication Systems	Process Improvmnt Initiatives	$424,000	$0	$424,000
Operatn -Info/Communication Systems	Standards Merging	$360,060	$0	$360,060
Operatn -Info/Communication Systems	WIP - Operations South	$100,000	$0	$100,000
Operatn -Info/Communication Systems	WIP Operations North	$10,000	$0	$10,000
TOTAL Operatn -Info/Communication Systems				$10,711,741

2011 BUDGET				
Category	**Job Description**	**Gross Budget**	**Contributed Budget**	**Net Budget**
Sustain -Driven Lines Project	4kV cct conductor upgrade	$103,605	$0	$103,605
Sustain -Driven Lines Project	44 kV PME INSTALLATION-138M8	$143,444	$0	$143,444
Sustain -Driven Lines Project	ESA Clearance Issue - Rogers, Tottenham	$57,760	$0	$57,760
Sustain -Driven Lines Project	ESA Clearance Issue - Queen, Tottenham	$107,620	$0	$107,620
Sustain -Driven Lines Project	ESA Clearance Issue - Mill, Tottenham	$96,389	$0	$96,389
Sustain -Driven Lines Project	Install Manual LIS, Major Mac.	$26,534	$0	$26,534
Sustain -Driven Lines Project	Cable Rehab - Belcourt	$931,940	$0	$931,940
Sustain -Driven Lines Project	Cable Rehab - Romfield, Ph 1	$2,921,208	$0	$2,921,208
Sustain -Driven Lines Project	Cable Rehab Varden	$25,826	$0	$25,826
Sustain -Driven Lines Project	Cable Rehab - Village in the Valley	$249,363	$0	$249,363
Sustain -Driven Lines Project	Dist. Automated Switches/Reclosers - South	$753,326	$0	$753,326
Sustain -Driven Lines Project	Dist. Automated Switches/Reclosers - north	$516,630	$0	$516,630
Sustain -Driven Lines Project	Sumbersible TX & Vault Replacement	$299,884	$0	$299,884
Sustain -Driven Lines Project	Cable Rehab - Balding	$711,825	$0	$711,825
Sustain -Driven Lines Project	Joint Use Pole Removal - South	$303,512	$0	$303,512
Sustain -Driven Lines Project	Joint Use Pole Removal - North	$136,030	$0	$136,030
Sustain -Driven Lines Project	Aurora Remote Fault Indicators	$101,070	$0	$101,070
Sustain -Driven Lines Project	44 KV Midhurst Route Investigation	$44,000	$0	$44,000
Sustain -Driven Lines Project	ESA Due Diligence Inspection - South	$8,868	$0	$8,868
Sustain -Driven Lines Project	ESA Due Diligence Inspection - North	$3,694	$0	$3,694
Sustain -Driven Lines Project	Riser Rebuild John St. MS321	$299,115	$0	$299,115

Sustain -Driven Lines Project	Conductor & Pole Upgrade	$602,352	$0	$602,352
Sustain -Driven Lines Project	Fairlane Lake DS Feeder	$64,901	$0	$64,901
Sustain -Driven Lines Project	ESA Clearance Issue - Nelson, Alliston	$287,102	$0	$287,102
Sustain -Driven Lines Project	ESA Clearance Issue - Victoria, Alliston	$287,102	$0	$287,102
Sustain -Driven Lines Project	Convert John / Bayview	$37,360	$0	$37,360
Sustain -Driven Lines Project	Cable Rehab - Flowervale Ph2	$1,994,581	$0	$1,994,581
Sustain -Driven Lines Project	Cable Rehab - Flowervale Ph3 - Design Only	$30,030	$0	$30,030
Sustain -Driven Lines Project	Cable Rehab - Romfield Ph2 - Design Only	$30,030	$0	$30,030
Sustain -Driven Lines Project	Cable Rejuvenation - South	$419,657	$0	$419,657
Sustain -Driven Lines Project	Cable Rejuvenation - North	$419,657	$0	$419,657
Sustain -Driven Lines Project	Submersible Vault & TX Replacement	$622,457	$0	$622,457
Sustain -Driven Lines Project	Convert Rainbow MS Feeders	$1,169,663	$0	$1,169,663
Sustain -Driven Lines Project	FDIR & SCADA	$210,751	$0	$210,751
Sustain -Driven Lines Project	Grid Energy Management	$459,706	$0	$459,706
Sustain -Driven Lines Project	WIP Sustainment South	$935,145	$0	$935,145
Sustain -Driven Lines Project	WIP - Sustainment North	$116,727	$0	$116,727
TOTAL Sustain -Driven Lines Project				$15,528,864
Develop -Subdivision/Services	ICI - South	$4,495,617	-$4,495,617	$0
Develop -Subdivision/Services	ICI - North	$1,776,324	-$1,776,324	$0
Develop -Subdivision/Services	New Res. Services - South	$756,057	-$506,558	$249,499
Develop -Subdivision/Services	New Res. Services - North	$144,715	-$56,438	$88,277
Develop -Subdivision/Services	Service Upgrades - South	$558,525	-$106,120	$452,405
Develop -Subdivision/Services	Service Upgrades - North	$229,825	-$48,263	$181,562
Develop -Subdivision/Services	Small Comm. Services - South	$829,306	-$829,306	$0
Develop -Subdivision/Services	Small Comm. Services - North	$357,790	-$357,790	$0
Develop -Subdivision/Services	New Subdivision - South	$7,747,488	-$3,486,369	$4,261,119

Develop -Subdivision/Services	New Subdivision - North	$2,625,783	-$1,181,603	$1,444,180
Develop -Subdivision/Services	Secondary Service Lateral - South	$1,144,679	-$1,144,679	$0
Develop -Subdivision/Services	Secondary Service Lateral - North	$487,156	-$487,156	$0
TOTAL Develop -Subdivision/Services				$6,677,042
Develop -Road Authority Projects	Road Authority projects - South	$6,946,494	-$1,945,019	$5,001,475
Develop -Road Authority Projects	Road Authority projects - North	$4,126,282	-$1,237,883	$2,888,399
TOTAL Develop -Road Authority Projects				$7,889,874
Develop -Add Capacity TS &MS	NO PROJECTS	$0	$0	$0
Develop -Growth Driven Lines Projects	Markham TS#4 Feeder Egress	$5,730,182	$0	$5,730,182
Develop -Growth Driven Lines Projects	Vaughan TS#4 Planning Ph 1	$44,000	$0	$44,000
Develop -Growth Driven Lines Projects	WIP Development South	$2,191,332	$0	$2,191,332
Develop -Growth Driven Lines Projects	WIP Development North	$226,537	$0	$226,537
TOTAL Develop -Growth Driven Lines Projects				$8,192,051
Operatn -Info/Communication Systems	Lines Mobility Project	$52,800	$0	$52,800
Operatn -Info/Communication Systems	Lines WFM Mobility Project	$123,376	$0	$123,376
Operatn -Info/Communication Systems	Client Computing - South	$374,055	$0	$374,055
Operatn -Info/Communication Systems	Server Replacement	$185,900	$0	$185,900
Operatn -Info/Communication Systems	JD Edwards Enhancements	$330,000	$0	$330,000
Operatn -Info/Communication Systems	Printer&Copier Fleet Replmnt.	$110,000	$0	$110,000
Operatn -Info/Communication Systems	Client Computing	$184,855	$0	$184,855
Operatn -Info/Communication Systems	CIS Modifications	$660,000	$0	$660,000
Operatn -Info/Communication Systems	Smart Meter CIS Modifications	$220,000	$0	$220,000
Operatn -Info/Communication Systems	Enterprise Content Management	$715,000	$0	$715,000
Operatn -Info/Communication Systems	BIZTalk Project	$64,900	$0	$64,900
Operatn -Info/Communication Systems	Formscape Appl Upgrade to Transform	$27,500	$0	$27,500

Operatn -Info/Communication Systems	Ciscona App Upgrade	$22,000	$0	$22,000
Operatn -Info/Communication Systems	SQL Cluster & Upgrade to V2008	$181,500	$0	$181,500
Operatn -Info/Communication Systems	Upgrade Blackberry Server	$16,500	$0	$16,500
Operatn -Info/Communication Systems	Upgrade Active Directory Server	$40,700	$0	$40,700
Operatn -Info/Communication Systems	Virtual Desktop	$93,500	$0	$93,500
Operatn -Info/Communication Systems	Disaster Recovery	$88,000	$0	$88,000
Operatn -Info/Communication Systems	Smart Analytics Enterprise	$55,000	$0	$55,000
Operatn -Info/Communication Systems	MS Bus Productivity Infra Upgrade	$204,490	$0	$204,490
Operatn -Info/Communication Systems	Work and Asset Mgmt Solution	$55,000	$0	$55,000
Operatn -Info/Communication Systems	Implementation of Reliability	$106,251	$0	$106,251
Operatn -Info/Communication Systems	JDE Fleet Module Implementation	$67,012	$0	$67,012
Operatn -Info/Communication Systems	GIS Aerial Photography	$38,500	$0	$38,500
Operatn -Info/Communication Systems	Mobile GIS Pilot Project	$71,500	$0	$71,500
Operatn -Info/Communication Systems	Easement Project	$24,435	$0	$24,435
Operatn -Info/Communication Systems	Replace Legacy Dynamic Fault Equipment	$55,475	$0	$55,475
Operatn -Info/Communication Systems	GL Company Executive Console	$134,200	$0	$134,200
Operatn -Info/Communication Systems	OMS Responder Mobile	$212,001	$0	$212,001
Operatn -Info/Communication Systems	Satellite Phone Installation	$22,194	$0	$22,194
Operatn -Info/Communication Systems	Call Recording Control Room	$57,402	$0	$57,402
Operatn -Info/Communication Systems	SCAD Training Simulator Program	$31,750	$0	$31,750
Operatn -Info/Communication Systems	Website Outage Information	$159,285	$0	$159,285
Operatn -Info/Communication Systems	Replacement of SCADA Host Control	$18,501	$0	$18,501
Operatn -Info/Communication Systems	Licensed Spectrum for Aurora SCADA	$56,751	$0	$56,751
Operatn -Info/Communication Systems	Replace SCADA Workstation PCs	$13,925	$0	$13,925
Operatn -Info/Communication Systems	Process Improvement Initiative	$330,000	$0	$330,000
Operatn -Info/Communication Systems	Customer Care Database	$36,809	$0	$36,809

Operatn -Info/Communication Systems	PS Capital Budget Application	$65,340	$0	$65,340
Operatn -Info/Communication Systems	Enhancements to Capital Budget	$11,000	$0	$11,000
Operatn -Info/Communication Systems	Enhancements of Project Schedu	$11,000	$0	$11,000
Operatn -Info/Communication Systems	Transform AP/AP "Bolt on" soft	$220,000	$0	$220,000
Operatn -Info/Communication Systems	improve payment of US$ invoice	$33,000	$0	$33,000
Operatn -Info/Communication Systems	JDE Improvements	$27,500	$0	$27,500
Operatn -Info/Communication Systems	Expense Module Implementation	$16,500	$0	$16,500
Operatn -Info/Communication Systems	Designer Mobile GPS Project	$29,808	$0	$29,808
Operatn -Info/Communication Systems	Accuracy of Capital Budget	$9,455	$0	$9,455
Operatn -Info/Communication Systems	Subdivision Database	$22,000	$0	$22,000
Operatn -Info/Communication Systems	Project Destiny	$55,000	$0	$55,000
Operatn -Info/Communication Systems	Cluster Exchange & Upgrade 2010	$59,400	$0	$59,400
Operatn -Info/Communication Systems	Storage Expansion	$137,500	$0	$137,500
Operatn -Info/Communication Systems	B2B Infrastructure	$154,000	$0	$154,000
Operatn -Info/Communication Systems	Implement Stns CMMS System (Cascade)	$209,000	$0	$209,000
Operatn -Info/Communication Systems	Streetscape	$115,500	$0	$115,500
Operatn -Info/Communication Systems	2011 Website Enhancements	$44,000	$0	$44,000
Operatn -Info/Communication Systems	Coice Radio Digital Conv. Project	$155,505	$0	$155,505
Operatn -Info/Communication Systems	Vaughan TW#1 T3/T4 HMI Conversion	$63,026	$0	$63,026
Operatn -Info/Communication Systems	Customize JDE Procurement Screens	$55,000	$0	$55,000
Operatn -Info/Communication Systems	WIP - Operations South	$300,300	$0	$300,300
Operatn -Info/Communication Systems	WIP Operations North	$10,000	$0	$10,000
TOTAL Operatn -Info/Communication Systems				$7,044,901

2012 BUDGET				
Category	**Job Description**	**Gross Budget**	**Contributed Budget**	**Net Budget**
Sustain -Driven Lines Project	Delta Service Remediation	$400,070	$0	$400,070
Sustain -Driven Lines Project	Prim Cable/TX Rehab - Flowervale	$1,783,819	$0	$1,783,819
Sustain -Driven Lines Project	Cable Rehab - Romfield	$1,879,539	$0	$1,879,539
Sustain -Driven Lines Project	Cable Rehab-design only - Romfield next Phase	$29,700	$0	$29,700
Sustain -Driven Lines Project	Distribution Automation Switch/Recloser North	$251,175	$0	$251,175
Sustain -Driven Lines Project	Distribution Automation Switches/Reclosers South	$561,440	$0	$561,440
Sustain -Driven Lines Project	Convert T2 to 44 kV Supply	$11,946	$0	$11,946
Sustain -Driven Lines Project	Chg ccts on Bayview to 44 kV	$89,536	$0	$89,536
Sustain -Driven Lines Project	Adding 3 LIS on 80M11	$71,364	$0	$71,364
Sustain -Driven Lines Project	John St. MS(MS321)Riser Rehab	$431,907	$0	$431,907
Sustain -Driven Lines Project	Cable Injection - South	$277,196	$0	$277,196
Sustain -Driven Lines Project	Cable Injection Design - South	$14,850	$0	$14,850
Sustain -Driven Lines Project	Cable Injection - north	$277,196	$0	$277,196
Sustain -Driven Lines Project	Cable Injection Design - north	$59,400	$0	$59,400
Sustain -Driven Lines Project	Joint use pole removal - South	$240,174	$0	$240,174
Sustain -Driven Lines Project	Joint use pole removal - North	$106,810	$0	$106,810
Sustain -Driven Lines Project	Fault Indicator Installation - South	$258,353	$0	$258,353

Sustain -Driven Lines Project	Fault Indicator Installation - North	$256,804	$0	$256,804
Sustain -Driven Lines Project	Fault indicator deployment	$102,370	$0	$102,370
Sustain -Driven Lines Project	ESA Due Diligence Inspection - South	$7,543	$0	$7,543
Sustain -Driven Lines Project	ESA due diligence inspection - North	$3,233	$0	$3,234
Sustain -Driven Lines Project	Cable Replacement - Design Only - North	$40,865	$0	$40,865
Sustain -Driven Lines Project	Cable Replacement - Design Only - South	$163,460	$0	$163,460
Sustain -Driven Lines Project	WIP Sustainment South	$2,500,190	$0	$2,500,190
Sustain -Driven Lines Project	WIP - Sustainment North	$100,870	$0	$100,870
TOTAL Sustain -Driven Lines Project				$9,919,810
Develop -Subdivision/Services	ICI - South	$3,976,204	-$3,817,156	$159,048
Develop -Subdivision/Services	ICI - North	$1,649,821	-$1,639,922	$9,899
Develop -Subdivision/Services	Meter costs after wo closed - South	$436,350	$0	$436,350
Develop -Subdivision/Services	Meter costs after wo closed - North	$116,035	$0	$116,035
Develop -Subdivision/Services	New Res. Services - South	$768,514	-$345,831	$422,683
Develop -Subdivision/Services	New Res. Services - North	$108,188	-$48,685	$59,503
Develop -Subdivision/Services	Service Upgrades - South	$518,031	-$51,803	$466,228
Develop -Subdivision/Services	Service Upgrades - North	$306,611	-$30,661	$275,950
Develop -Subdivision/Services	Small Comm. Services - South	$725,658	-$725,658	$0
Develop -Subdivision/Services	Small Comm. Services - North	$113,482	-$113,482	$0
Develop -Subdivision/Services	New Subdivision - South	$8,448,959	-$4,224,480	$4,224,479
Develop -Subdivision/Services	New Subdivision - North	$2,783,566	-$1,391,783	$1,391,783
Develop -Subdivision/Services	Secondary Service Lateral - South	$881,278	$0	$881,278
Develop -Subdivision/Services	Secondary Service Lateral - North	$429,571	$0	$429,571
Develop -Subdivision/Services	New commercial Subdivisions - South	$299,859	$0	$299,859
Develop -Subdivision/Services	New commercial Subdivisions - North	$296,456	$0	$296,456
TOTAL Develop -Subdivision/Services				$9,469,121

Develop -Road Authority Projects	Road Authority projects - South	$5,294,608	-$1,493,079	$3,801,529
Develop -Road Authority Projects	Road Authority projects - North	$3,449,433	-$952,044	$2,497,389
TOTAL Develop -Road Authority Projects				$6,298,918
Develop -Add Capacity TS &MS	Design - Sandringham New Station	$150,000	$0	$150,000
Develop -Add Capacity TS &MS	Vaughan TS#4 Planning	$27,500	$0	$27,500
Develop -Add Capacity TS &MS	Property - Sandringam New Station	$550,000	$0	$550,000
TOTAL Develop -Add Capacity TS &MS				$727,500
Develop -Growth Driven Lines Projects	Feeder Route Design - Midhrst TS Feeders	$34,241	$0	$34,241
Develop -Growth Driven Lines Projects	Pole line Installation - Dufferin	$638,212	$0	$638,212
Develop -Growth Driven Lines Projects	Bld 1 cct pole line Hwy 50	$416,423	$0	$416,423
Develop -Growth Driven Lines Projects	New 44kV feeder - Midhurst TS - Bayfield	$1,493,875	$0	$1,493,875
Develop -Growth Driven Lines Projects	dble cct 23M5-Sunnidale-Harvie	$30,941	$0	$30,941
Develop -Growth Driven Lines Projects	Hydro 1 purchase, Sunnidale Rd	$110,000	$0	$110,000
Develop -Growth Driven Lines Projects	WIP Development South	$1,200,041	$0	$1,200,041
Develop -Growth Driven Lines Projects	WIP Development North	$100,844	$0	$100,844
TOTAL Develop -Growth Driven Lines Projects				$4,024,577
Operatn -Info/Communication Systems	Lines Mobility	$55,000	$0	$55,000
Operatn -Info/Communication Systems	Lines WFM Mobility Project	$121,000	$0	$121,000
Operatn -Info/Communication Systems	Electronic "Smart" Timesheet	$38,500	$0	$38,500
Operatn -Info/Communication Systems	Client Computing - South	$467,500	$0	$467,500
Operatn -Info/Communication Systems	Printer&Copier Fleet Replmnt.	$110,000	$0	$110,000
Operatn -Info/Communication Systems	CIS Modifications	$495,000	$0	$495,000
Operatn -Info/Communication Systems	Smart Meter CIS Modification	$110,000	$0	$110,000
Operatn -Info/Communication Systems	Avaya phone system upgrade	$27,500	$0	$27,500
Operatn -Info/Communication Systems	Master Data Mngmnt Program	$269,500	$0	$269,500

Operatn -Info/Communication Systems	VDI Project-Phase 2	$110,000	$0	$110,000
Operatn -Info/Communication Systems	Microsoft Bus. Productivity Up	$201,190	$0	$201,190
Operatn -Info/Communication Systems	Microsoft LYNC	$148,500	$0	$148,500
Operatn -Info/Communication Systems	Backup Expansion & Upgrade	$214,500	$0	$214,500
Operatn -Info/Communication Systems	Server Refresh	$150,000	$0	$150,000
Operatn -Info/Communication Systems	EMC Storage Expansion	$220,000	$0	$220,000
Operatn -Info/Communication Systems	File Nexus Upgrade	$60,500	$0	$60,500
Operatn -Info/Communication Systems	Data Centre Expansion	$353,000	$0	$353,000
Operatn -Info/Communication Systems	IPS Expansion	$77,000	$0	$77,000
Operatn -Info/Communication Systems	Implement Stns CMMS (Cascade)	$127,643	$0	$127,643
Operatn -Info/Communication Systems	PI Implementation Ph 2	$29,700	$0	$29,700
Operatn -Info/Communication Systems	JDE Fleet Module Implementation	$60,500	$0	$60,500
Operatn -Info/Communication Systems	StreetScape Image	$115,500	$0	$115,500
Operatn -Info/Communication Systems	GIS Landbase Data	$55,939	$0	$55,939
Operatn -Info/Communication Systems	Communications Tower	$105,594	$0	$105,594
Operatn -Info/Communication Systems	Website enhancements & develop	$88,000	$0	$88,000
Operatn -Info/Communication Systems	Insight License Package	$110,000	$0	$110,000
Operatn -Info/Communication Systems	Map Panel Upgrades Control Rm	$33,000	$0	$33,000
Operatn -Info/Communication Systems	OMS Responder Mobile	$210,118	$0	$210,118
Operatn -Info/Communication Systems	Monitors & Interactive Screens	$150,001	$0	$150,001
Operatn -Info/Communication Systems	OMS-Weather Network Integration	$5,001	$0	$5,001
Operatn -Info/Communication Systems	Replmnt of SCADA wrkstn PC's	$17,686	$0	$17,686
Operatn -Info/Communication Systems	Cyber Security WAN node	$15,360	$0	$15,360
Operatn -Info/Communication Systems	IS Server room upgrade	$66,000	$0	$66,000
Operatn -Info/Communication Systems	Purchase Laptops	$6,600	$0	$6,600
Operatn -Info/Communication Systems	Customize JDE Procurement	$220,000	$0	$220,000

Operatn -Info/Communication Systems	Security System Enhancements - South	$110,000	$0	$110,000
Operatn -Info/Communication Systems	Security System Enhancements - North	$110,000	$0	$110,000
Operatn -Info/Communication Systems	Audio Visual Enhancements	$55,000	$0	$55,000
Operatn -Info/Communication Systems	Security System Enhancements - Addiscott	$55,000	$0	$55,000
Operatn -Info/Communication Systems	Preventative Mtce Software	$8,800	$0	$8,800
Operatn -Info/Communication Systems	Audio Video Connections	$8,800	$0	$8,800
Operatn -Info/Communication Systems	Test/Dev Environment for IVR	$39,600	$0	$39,600
Operatn -Info/Communication Systems	Self serve enhancements to Web	$66,000	$0	$66,000
Operatn -Info/Communication Systems	Customer Care Database	$36,707	$0	$36,707
Operatn -Info/Communication Systems	Fieldworker Collections Ph 2	$28,600	$0	$28,600
Operatn -Info/Communication Systems	CIS Replacement Projects	$12,693,417	$0	$12,693,417
Operatn -Info/Communication Systems	Full Time Mgmt Salary-CIS Repl	$193,930	$0	$193,930
Operatn -Info/Communication Systems	OHSA Signs/Label printer	$5,500	$0	$5,500
Operatn -Info/Communication Systems	Environmental Aspects/Impacts	$4,554	$0	$4,554
Operatn -Info/Communication Systems	Environmental Targets/Objective	$2,530	$0	$2,530
Operatn -Info/Communication Systems	Enhancements to CBMS Database	$50,050	$0	$50,050
Operatn -Info/Communication Systems	Expense Module Implementation	$5,500	$0	$5,500
Operatn -Info/Communication Systems	JDE Improvements	$71,500	$0	$71,500
Operatn -Info/Communication Systems	Applicant Tracking System	$22,000	$0	$22,000
Operatn -Info/Communication Systems	WIP - Operations South	$200,090	$0	$200,090
Operatn -Info/Communication Systems	WIP Operations North	$10,000	$0	$10,000
TOTAL Operatn -Info/Communication Systems				$18,422,910

2013 BUDGET				
Rates Sub Category	**Job Description**	**Gross Budget**	**Contributed Budget**	**Net Budget**
Sustain -Driven Lines Project	Install a LIS tie between 4F1 and 4F2	$23,683	$0	$23,683
Sustain -Driven Lines Project	Concord MS Conversion Phase 1	$74,186	$0	$74,186
Sustain -Driven Lines Project	Elder Mill MS Conversion	$247,961	$0	$247,961
Sustain -Driven Lines Project	Wye transformer Supply Delta Services Remediation	$342,061	$0	$342,061
Sustain -Driven Lines Project	Installing Intellirupters on Feeder MS835 F1 and MS835 F2	$147,002	$0	$147,002
Sustain -Driven Lines Project	Distribution Automation Switch/Recloser North	$295,218	$0	$295,218
Sustain -Driven Lines Project	Distribution Automation Switches/Reclosers South	$741,948	$0	$741,948
Sustain -Driven Lines Project	Replacement of elbow/bushing for single phase pad mounted transformers	$274,125	$0	$274,125
Sustain -Driven Lines Project	44 kV tie of 98M3 & 98M7	$578,809	$0	$578,809
Sustain -Driven Lines Project	4 x 44 kV Load Interrupter Switches (LIS's) at Various Locations for Feeder Balancing.- south	$139,711	$0	$139,711
Sustain -Driven Lines Project	6 x 13.8 kV load interrupter switches (LIS's) - south	$151,142	$0	$151,142
Sustain -Driven Lines Project	4 x 44 kV Load Interrupter Switches (LIS's) at Various Locations for feeder balancing - north	$140,944	$0	$140,944
Sustain -Driven Lines Project	6 x 13.8 kV Load Interrupter Switches (LIS's) - north	$152,600	$0	$152,600
Sustain -Driven Lines Project	Cable Rehab - Romfield	$1,755,272	$0	$1,755,272
Sustain -Driven Lines Project	Cable Injection - north	$788,885	$0	$788,885
Sustain -Driven Lines Project	Cable Injection - South	$3,320,251	$0	$3,320,251
Sustain -Driven Lines Project	Cable Replacement - Design Only - North	$41,199	$0	$41,199
Sustain -Driven Lines Project	Cable Replacement - Design Only - South	$164,797	$0	$164,797
Sustain -Driven Lines Project	Cable Replacement Program - North	$2,747,056	$0	$2,747,056
Sustain -Driven Lines Project	Cable Replacement Program - South	$10,988,224	$0	$10,988,224
Sustain -Driven Lines Project	Cable Rehab-design only - Romfield next Phase	$47,531	$0	$47,531
Sustain -Driven Lines Project	Cable Injection Design - north	$15,222	$0	$15,222

Sustain -Driven Lines Project	Cable Injection Design - south	$60,885	$0	$60,885
TOTAL Sustain -Driven Lines Project				$23,238,712
Develop -Subdivision/Services	ICI - South	$4,244,034	-$4,097,178	$146,856
Develop -Subdivision/Services	ICI - North	$1,750,842	-$1,728,376	$22,466
Develop -Subdivision/Services	Meter costs after wo closed - South	$439,671	$0	$439,671
Develop -Subdivision/Services	Meter costs after wo closed - North	$121,736	$0	$121,736
Develop -Subdivision/Services	New Res. Services - South	$828,042	-$369,374	$458,668
Develop -Subdivision/Services	New Res. Services - North	$116,944	-$52,017	$64,927
Develop -Subdivision/Services	Service Upgrades - South	$562,128	-$56,713	$505,415
Develop -Subdivision/Services	Service Upgrades - North	$333,445	-$33,294	$300,151
Develop -Subdivision/Services	Small Comm. Services - South	$788,591	-$788,591	$0
Develop -Subdivision/Services	Small Comm. Services - North	$129,411	-$129,411	$0
Develop -Subdivision/Services	New Subdivision - South	$9,680,921	-$3,872,369	$5,808,552
Develop -Subdivision/Services	New Subdivision - North	$2,873,302	-$1,149,322	$1,723,980
Develop -Subdivision/Services	Secondary Service Lateral - South	$1,048,450	$0	$1,048,450
Develop -Subdivision/Services	Secondary Service Lateral - North	$429,739	$0	$429,739
Develop -Subdivision/Services	New commercial Subdivisions - South	$305,493	$0	$305,493
Develop -Subdivision/Services	New commercial Subdivisions - North	$296,693	$0	$296,693
TOTAL Develop -Subdivision/Services				$11,672,797
Develop -Road Authority Projects	Road Authority Projects - South	$14,328,306	-$3,268,962	$11,059,344
Develop -Road Authority Projects	Road Authority projects - North	$2,744,563	-$759,674	$1,984,889
TOTAL Develop -Road Authority Proj				$13,044,233
Develop -Add Capacity TS &MS	New Sandringham MS in Barrie - 20mVA	$3,783,906	$0	$3,783,906
Develop -Add Capacity TS &MS	Vaughan TS#4 Land Purchase	$2,200,000	$0	$2,200,000
TOTAL Develop -Add Capacity TS &MS			$0	$5,983,906
Develop -Growth Driven Lines Projects	Long Term Load Transfer (LTLT)	$47,065	$0	$47,065

Develop -Growth Driven Lines Projects	Phase 3-Express 44 kV Feeder (23M26) Midhurst to Ferndale Dr. Road and Harvey Road.	$4,341,140	$0	$4,341,140
Develop -Growth Driven Lines Projects	Design Only - 44kV Double Circuit Pole Line Midhurst to Mapleview & Essa Rd.	$77,151	$0	$77,151
Develop -Growth Driven Lines Projects	Install One 44 kV Cct on Bloomington Rd	$159,437	$0	$159,012
Develop -Growth Driven Lines Projects	Add one 27.6 kV cct to existing pole line on Warden from 16th Ave to MMD	$416,000	$0	$416,000
Develop -Growth Driven Lines Projects	Convert T2 in Aurora MS4 into 44kV Supply	$12,133	$0	$12,133
Develop -Growth Driven Lines Projects	Install second cct on Bathurst St. from S/O Gamble Rd to KVTL approx. 2.5 km	$400,400	$0	$400,400
Develop -Growth Driven Lines Projects	Extend 16kV Single Phase on Kipling Ave south to Teston Rd	$74,077	$0	$74,077
Develop -Growth Driven Lines Projects	Add 2nd cct on existing pole line on Leslie St- Major Mack to Elgin Mills	$364,000	$0	$364,000
Develop -Growth Driven Lines Projects	Pole line installation on Dufferin St - Phase 2	$653,597	$0	$653,597
TOTAL Develop -Growth Driven Lines Projects			$0	$6,544,575
Operatn -Info/Communication Systems	Pilot for Structural Analysis Software	$55,000	$0	$55,000
Operatn -Info/Communication Systems	Pilot for Work Management System	$55,000	$0	$55,000
Operatn -Info/Communication Systems	Lines Mobile Equipment	$44,000	$0	$44,000
Operatn -Info/Communication Systems	JD Edwards Version Upgrade Design/Planning	$471,000	$0	$471,000
Operatn -Info/Communication Systems	Master Data Management - 2013	$138,971	$0	$138,971
Operatn -Info/Communication Systems	Asset Management (Procurement)	$183,000	$0	$183,000
Operatn -Info/Communication Systems	Process Improvement	$130,000	$0	$130,000
Operatn -Info/Communication Systems	Workforce Management	$165,000	$0	$165,000
Operatn -Info/Communication Systems	Data Normalization	$136,000	$0	$136,000
Operatn -Info/Communication Systems	Business Intelligence	$100,000	$0	$100,000
Operatn -Info/Communication Systems	CIS Modifications	$495,000	$0	$495,000
Operatn -Info/Communication Systems	Smart Meter CIS Modifications	$110,000	$0	$110,000
Operatn -Info/Communication Systems	Server Virtualization	$104,500	$0	$104,500
Operatn -Info/Communication Systems	Server Virtualization	$104,500	$0	$104,500
Operatn -Info/Communication Systems	Client Computing	$394,130	$0	$394,130
Operatn -Info/Communication Systems	VDI Project – Phase 3 XenApp & Virtual Desktops Expansion	$54,450	$0	$54,450
Operatn -Info/Communication Systems	Printer & Copier Fleet Replacement	$110,000	$0	$110,000

Operatn -Info/Communication Systems	Server Recovery Procedure for Microsoft Environment	$132,000	$0	$132,000
Operatn -Info/Communication Systems	Expansion of Link between Addiscott & Cityview	$154,000	$0	$154,000
Operatn -Info/Communication Systems	Redesign of Barrie Network	$187,000	$0	$187,000
Operatn -Info/Communication Systems	EMC Storage Expansion	$236,500	$0	$236,500
Operatn -Info/Communication Systems	Server Refresh	$165,000	$0	$165,000
Operatn -Info/Communication Systems	Data Centre Expansion	$82,500	$0	$82,500
Operatn -Info/Communication Systems	Enterprise Infrastructure Hardware Management Solution	$66,000	$0	$66,000
Operatn -Info/Communication Systems	Avaya Phone System Upgrade/Expansion	$335,500	$0	$335,500
Operatn -Info/Communication Systems	CMMS Upgrade / Mobile Computing Customization/ Integration/ Expansion	$55,000	$0	$55,000
Operatn -Info/Communication Systems	Implementation of Stations CMMS system (CASCADE) Phase 3	$127,666	$0	$127,666
Operatn -Info/Communication Systems	GIS Upgrade	$49,500	$0	$49,500
Operatn -Info/Communication Systems	Web Based GIS Improvement - ArcGIS Server	$89,760	$0	$89,760
Operatn -Info/Communication Systems	GIS Aerial Photography (Ortho Images)	$51,051	$0	$51,051
Operatn -Info/Communication Systems	StreetScape Images	$132,957	$0	$132,957
Operatn -Info/Communication Systems	GIS Landbase Data (Parcels, Streets & Points of Interest.)	$55,939	$0	$55,939
Operatn -Info/Communication Systems	GIS Data Clean Up & Quality Assurance and Quality Control	$91,520	$0	$91,520
Operatn -Info/Communication Systems	Current website enhancements and concurrent development of new website.	$88,000	$0	$88,000
Operatn -Info/Communication Systems	OM&A dB enhancement - ph1	$77,000	$0	$77,000
Operatn -Info/Communication Systems	OM&A dB enhancement - ph2	$77,000	$0	$77,000
Operatn -Info/Communication Systems	Work Management Tool for OMS	$110,000	$0	$110,000
Operatn -Info/Communication Systems	Upgrade Responder to 10.X	$101,435	$0	$101,435
Operatn -Info/Communication Systems	Upgrade Barco Server	$37,541	$0	$37,541
Operatn -Info/Communication Systems	Purchase of a new Scada Server Host D	$17,312	$0	$17,312
Operatn -Info/Communication Systems	Replacement of SCADA Workstation PC's	$19,931	$0	$19,931
Operatn -Info/Communication Systems	IntelliTEAM Pilot Project	$274,393	$0	$274,393
Operatn -Info/Communication Systems	EDI electronic data transfers	$27,500	$0	$27,500
Operatn -Info/Communication Systems	Investigation and Implementation of MRP (Material Requirement Planning) Module in JDE	$82,500	$0	$82,500

Operatn -Info/Communication Systems	Project Portfolio Management Solution (PPM)	$110,000	$0	$110,000
Operatn -Info/Communication Systems	CIS Replacement	$15,640,000	$0	$15,640,000
Operatn -Info/Communication Systems	Call Recording (Customer Service & System Control)	$146,300	$0	$146,300
Operatn -Info/Communication Systems	Purchase and Implementation of Optimizer Front End Tool.	$198,000	$0	$198,000
Operatn -Info/Communication Systems	Enhancements to Capital Budget Management System database.	$50,050	$0	$50,050
Operatn -Info/Communication Systems	Transform AP / AP module "bolt on" software	$209,000	$0	$209,000
Operatn -Info/Communication Systems	Expense module implementation	$22,000	$0	$22,000
Operatn -Info/Communication Systems	Improvement for the payment of US$ invoices	$11,000	$0	$11,000
Operatn -Info/Communication Systems	Locate Ticket Management System Purchase	$88,000	$0	$88,000
Operatn -Info/Communication Systems	Dig-Smart Field Drawing tool	$3,850	$0	$3,850
Operatn -Info/Communication Systems	JDE and Designer Integration - Phase 1	$107,883	$0	$107,883
Operatn -Info/Communication Systems	Upgrade of ArcFM Designer because of upgrade to ArcGIS 10	$13,200	$0	$13,200
Operatn -Info/Communication Systems	Subdivision Data Base	$22,660	$0	$22,660
TOTAL Operatn -Info/Communication Systems				$22,396,999

Table EP #5a: Capital Expenditures 2007-2013
Including Markham, Head Office and Addiscott Buildings

B1/T1/S4/Table 1 (Modified as per EP #5 a)

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	$22,839,949	$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)	$1,482,620	$740,597	$591,562	$2,394,644	$150,524	$113,508	$727,500	$5,983,906
Growth Driven Lines Projects	$2,348,220	$1,535,358	$6,211,016	$4,855,699	$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	$7,712,379	$5,422,227	$19,135,690	$17,804,165	$25,829,548	$19,733,172	$21,060,685	$37,680,882

Table EP #5a: Capital Expenditures 2007-2013
Including Markham, Head Office and Addiscott Buildings

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	$75,062	($282,314)	$3,585	$1,561	$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	$5,729,493	$6,756,999
Purchase of spare equipment	$0	$3,345,554	$3,099,128	$321,634	($228,589)	($228,721)	$66,000	$127,654
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	$10,289,128	$15,059,157	$14,240,896	$15,141,658	$10,775,210	$9,399,162	$13,009,463	$14,692,211
Total Capital Expenditure (Without Special Projects)	$35,247,822	$39,577,866	$53,699,370	$56,458,625	$63,241,903	$51,972,285	$64,006,562	$98,638,763
Capital Special Projects								
Markham TS #4 (Removed from Additional Capacity Transformer/ Municipal Stations)	$1,227,678	$5,834,366	$10,180,513	($609,696)	$0	$0	$0	$0
Markham TS #4 Feeders (Removed from Growth Driven Lines Projects)			$5,715,502	$136,642				

Table EP #5a: Capital Expenditures 2007-2013
Including Markham, Head Office and Addiscott Buildings

Cityview Head Office (Removed from Buildings)	$20,892,544	$5,016,307	$109,070	$0	$0	$0	$0	$0
Addiscott Operations Centre (Removed from Buildings)	$26,131	$197,136	$4,734,167	$1,306,751	$0	$0	$0	$0
New CIS (Removed from Information/ Communication Systems)	$0	$0	$0	$0	$0	$0	$12,693,417	$15,640,000
Total Capital Special Projects	$22,146,353	$11,047,809	$20,739,252	$833,697	$0	$0	$12,693,417	$15,640,000
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

Table EP#12-1

Appendix 2-B based on "Half Year Rule" in all years
Fixed Asset Continuity Schedule [MIFRS]

Year 2013

					COST (000's)				ACCUMULATIVE DEPRECIATION (000's)				
CCA Class	**GL account**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Restated Opening Balance (4)**	**Additions**	**Disposals/ Adjustments**	**Restated Closing Balance**	**Restated Opening Balance (5)**	**Restated Additions (3)**	**Disposals/ Adjustments**	**Restated Closing Balance**	**Restated Net Book Value (000's)**
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	4.00%		609	0	0	609	48	32	0	80	530
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%		6,125	15	0	6,140	388	196	0	584	5,556
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	97,006	75	0	97,080	9,283	4,128	0	13,411	83,669
47	1820	Distribution Stations	3.33%	1	21,861	4,021	0	25,883	3,253	1,210	0	4,463	21,420
47	1830	Poles, Towers & Fixtures	2.50%		111,796	9,861	0	121,657	5,002	2,889	0	7,891	113,766
47	1835	O/H Cond & Devices	2.50%		106,058	17,940	(26)	123,972	5,713	3,433	(51)	9,095	114,877
47	1840	U/G Conduit	2.50%		67,601	2,957	(155)	70,403	2,383	1,294	0	3,677	66,726
47	1845	U/G Cond & Devices	2.22%		209,343	37,290	(700)	245,933	10,857	6,127	(198)	16,786	229,147
47	1850	Line Transformers	2.92%	1	145,320	11,683	(1,805)	155,198	12,133	6,607	(577)	18,164	137,034
47	1855	Services (OH and UG)	3.25%	2	57,625	3,789	0	61,414	7,715	3,272	0	10,987	50,427
47	1860	Meters	5.33%	2	22,285	3,195	0	25,480	2,231	1,349	0	3,580	21,900
47	1860	Smart Meters	6.67%		47,295	717	0	48,012	7,175	3,457	0	10,632	37,380
		Subtotal Distribution Assets	n/a		913,881	91,584	(2,686)	1,002,779	66,180	33,994	(826)	99,348	903,431
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	41,411	284	0	41,695	1,859	955	0	2,814	38,881
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	960	508	0	1,468	2,593
10	1920	Computer hardware	20.00%	1	8,835	2,014	0	10,849	3,308	1,916	0	5,224	5,625
12	1925	Computer Software	25.00%		9,865	4,405	0	14,270	4,978	2,737	0	7,715	6,556
10	1930	Transportation	8.33%	1	11,480	2,893	(131)	14,242	2,539	1,634	(17)	4,156	10,086
8	1935	Stores Equipment	10.00%		3	0	0	3	(2)	1	0	(1)	4
8	1940	Tools, Shop & Garage	10.00%		3,232	538	0	3,770	805	446	0	1,251	2,519
8	1955	Communication Equipment	25.00%	2	1,954	65	0	2,019	799	415	0	1,214	805
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	6.67%		8,658	624	0	9,282	2,441	955	0	3,396	5,886
47	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		89,469	10,852	(131)	100,190	17,687	9,566	(17)	27,235	72,955
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,915	0	0	17,915	1,464	731	0	2,195	15,720
		Subtotal Other Capital Assets	n/a		17,915	0	0	17,915	1,464	731	0	2,195	15,720
		Total Assets Before Contributed Capital	n/a		1,021,265	102,436	(2,817)	1,120,884	85,331	44,291	(843)	128,779	992,105
47	1995	Contributed Capital	varies		(258,719)	(17,734)	525	(275,929)	(16,494)	(8,539)	10	(25,023)	(250,906)
		NET DISTRIBUTION ASSETS	n/a		762,546	84,702	(2,292)	844,955	68,837	35,752	(833)	103,756	741,199

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*		
Transportation	$	1,634
Stores Equipment	$	1
Tools, Shop & Garage	$	446
Net Depreciation	$	33,672

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 2 subclass of assets within the asset group

(3) The depreciation for 2013 is restated by recalculating using the half year depreciation rule on 2013 additions. The original filed amount included an additional half year depreciation of $1,569 which has been removed.

(4) The opening cost balance is reduced by $750 as result of applying the half year deprecation rule to 2010 additions. The half year rule resulted in an increase in depreciation resulting in a reduction in the 2010 net book value closing balance which is reclassified as the opening 2011 cost balance under MIFRS. This accumulative depreciation change would carry forward into 2013.

(5) The opening accumulative depreciation balance is increased by $512 as a result of applying the half year depreciation rule to 2011 additions. This change carries forward in the accumulative depreciation

Table SEC 17-1

FULLY DEPRECIATED ASSET COST : 2009-2014 ($000)

GL	Description	2009 CGAAP	2010 CGAAP	2011 CGAAP	2011 MIFRS	2012 MIFRS	2013 MIFRS	2014 MIFRS
1606	Organizational Cost	$ 4	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1806	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1808	Building Structure	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1810	Major Spare Parts	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Stations - other	$ -	$ -	$ -	$ 1,476	$ 936	$ 445	$ 805
1816	Power Transformer - other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1817	Tap Changer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1818	Winding	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1819	Support Steel Structure	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1821	Grounding System	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1822	Protection and Control System TS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1823	SwitchGear and Relays	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1824	Capacitor Banks	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Stations	$ -	$ 437	$ -	$ 3,979	$ 105	$ 129	$ 300
1826	Power Transformer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1827	Protection and Control System	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1828	SwitchGear and Relays	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 293	$ 1,947	$ 1,800	$ -	$ -	$ -	$ -
1835	O/H Cond.& Devices	$ 1,790	$ 5,615	$ 1,451	$ -	$ -	$ -	$ -
1840	U/G Conduit	$ -	$ 3,370	$ 2,053	$ -	$ -	$ -	$ -
1845	U/G Cond & Devices	$ 4,264	$ 11,376	$ 3,664	$ -	$ -	$ -	$ 844
1849	O/H Transformers	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	U/G transformers	$ 2,171	$ 11,124	$ 4,545	$ 324	$ 1,197	$ 1,770	$ 1,764
1855	O/H Services	$ 114	$ 1,904	$ 177	$ 5,438	$ -	$ -	$ -
1856	U/G Services	$ -	$ 369	$ 2,189	$ 2,189	$ 2,989	$ 3,296	$ 2,823
1860	Meters	$ 148	$ 343	$ -	$ -	$ 245	$ -	$ -
1861	Interval Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1862	Smart meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	Building - Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1912	Building - Structure	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1913	Building - Windows	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1914	Barrie Hydro building- Structural	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1916	Barrie Hydro building- Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1911	LH Improvements- JOC/Cochrane	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equip	$ 57	$ 2	$ 61	$ 61	$ 106	$ 22	$ 13
1920	Computer hardware	$ -	$ 2,513	$ 1,660	$ 1,712	$ 1,559	$ 1,751	$ 1,601
1921	Desktops/Laptops	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1922	Servers (including servers and SAN)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1923	MFP's (including all printers)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1924	Switches/Routers	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1611	Computer Software Application	$ 4,322	$ 3,391	$ 2,403	$ -	$ 2,403	$ 2,526	$ 2,988
1926	Computer Software Operations	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1930	Light Vehicles - 1930	$ 36	$ 1,196	$ 1,372	$ -	$ 45	$ 1,132	$ 1,247
1931	Heavy Vehicles - 1931	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1932	Trailers	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage	$ 227	$ 459	$ 293	$ 293	$ 210	$ 556	$ 179
1955	Communication Equipment	$ 4	$ 32	$ 44	$ 284	$ 35	$ 24	$ 735
1956	Wireless Communication Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1961	Process Re-Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	Scada	$ -	$ 834	$ -	$ 3,517	$ 684	$ 587	$ 908
1981	RTU	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1982	Display Wall	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1985	Sentinel Light	$ 2	$ -	$ -	$ -	$ -	$ -	$ -
2005	Property Under Capital Lease OP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2075	Non-Util. Prop. Owned	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TOTAL	**$ 13,432**	**$ 44,913**	**$ 21,713**	**$ 19,274**	**$ 10,514**	**$ 12,238**	**$ 14,207**

CIS Replacement Project - Cost Breakdown

(Taxes and Staff Overhead Burdens NOT Included)

				Capital 2012	Capital 2013	Capital 2014	OM&A 2012	OM&A 2013	OM&A 2014
Software License& Hardware									
Oracle Programs License Fee (CC&B)	$2,360,337								
CCOM portion for the Ontario Market	$298,000								
Oracle Software Licenses		$2,658,337		$2,658,337					
Oracle Support		$578,844					$578,844	$578,844	
Hardware		$1,154,823		$1,154,823					
Other Installation Support		$1,320,000		$440,000	$605,000	$275,000			
			$5,133,160	**$4,253,160**	**$605,000**	**$275,000**	**$578,844**	**$578,844**	
Internal Staff & Resource Costs									
Information Services	$1,706,061			$766,652	$620,072	$319,337			
Customer Service	$2,277,775			$653,426	$1,032,464	$591,885			
Metering	$183,099			$71,510	$73,656	$37,933			
			$4,166,934	**$1,491,588**	**$1,726,192**	**$949,155**			
Legal - Consulting - Other Misc.									
Legal	$337,500			$236,250	$67,500	$33,750			
Consultants	$688,000			$348,000	$220,000	$120,000			
Misc. Expenses & Office Space	$1,177,125			$446,934	$526,794	$203,397			
Project Manager	$991,980			$368,280	$394,350	$229,350			
			$3,194,605	**$1,399,464**	**$1,208,644**	**$586,497**			
Integration									
Integration Consultant			**$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**			

Table VECC #4: IS Capital Costs – 2010-2016

VECC #4 - IS Costs 2010 -2016 - Capital Costs Only								
	2010 Actual	**2011 Actual CGAAP**	**2011 Actual MIFRS**	**2012 Budget - Bridge Year**	**2013 Budget - Test Year**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**
CIS	$554,037	$767,760	$749,861	$13,520,947	$16,245,000	$6,710,000	$510,000	$538,000
ERP	$863,362	$351,520	$350,882	$357,500	$795,500	$653,000	$653,000	$690,000
SCADA	$66,345	$48,283	$47,866	$0	$37,243	$115,004	$115,005	$115,006
Outage Management System	$69,800	$248,073	$248,073	$215,119	$211,435	$0	$50,000	$0
AMI Communications/ODA	$0	$0	$0	$220,000	$0	$200,000	$350,000	$300,000
IS Hardware - computers/printers	$505,231	$452,038	$449,813	$601,786	$504,130	$462,000	$452,000	$895,000
IS department network system enhancements (includes servers)	$395,415	$1,252,555	$1,241,853	$1,534,690	$1,241,491	$1,290,000	$1,380,000	$970,000
GIS & Related Software	$393,100	$227,910	$227,814	$171,439	$591,810	$380,010	$322,380	$268,400
Asset Management System	$0	$0	$0	$0	$0	$315,000	$2,396,080	$0
Workforce Management System (includes Mobile)	$22,050	$51,890	$51,890	$176,000	$209,000	$900,400	$746,400	$84,872
Business Intelligence (includes Document Management)	$0	$0	$0	$269,500	$100,000	$0	$0	$2,821,000
Other	$2,677,534	$1,128,119	$1,051,083	$1,575,929	$2,461,390	$1,925,300	$1,572,135	$2,141,722
TOTAL	**$5,546,874**	**$4,528,148**	**$4,419,136**	**$18,642,910**	**$22,396,999**	**$12,950,714**	**$8,547,000**	**$8,824,000**

Distribution System Planning Report

2010

Prepared by: System Planning

May 14, 2010

Revised: September 24, 2010

TABLE OF CONTENTS

POWERSTREAM MISSION STATEMENT

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

POWERSTREAM VISION STATEMENT

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

Executive Summary

The 2010 PowerStream Distribution System Planning Report (DSPR) provides information on PowerStream's planning processes and the plans for system augmentation for the five-year period 2010 – 2014. The Report also provides a long term vision of capital replacement/refurbishment expenditures through the application of PowerStream's Asset Condition Assessment (ACA) model that balances the risk of asset failure with cost of mitigation.

Growth:

PowerStream continues to experience a high level of growth. System Peak demand is expected to grow at a rate of approximately 3.0% annually over the period 2010-2014. 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. One of the two largest key expenditures required to service new growth is a new transformer station, Markham TS #4, expected to be in service in 2010. The majority of the $20 million cost of the station has been spent in the 2008 – 2009 time frame, with a staged feeder connection plan from 2010-2012. The other is a new transformer station, Vaughan TS #4, expected to be in service in 2015–16 timeframe. The station cost is estimated at $23 million. The first phase of feeder egress and grid integration is estimated at $5 million.

Reliability:

Reliability driven projects have been established to maintain current levels of service to customers compared to the previous 3 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. In 2009, the focus was continuing on implementing measures to ensure our planning philosophy guidelines are adhered to, including the delivery of two spare transformers for each of the transformer station types. In 2010, reliability measures will be addressed through the continued refinement and development of the Asset Condition Assessment program, feeder reconfiguration and balancing, radial feeder supply remediation, distribution automation, voltage conversion, worst performing feeder (WPF) management, and participation on the smart grid initiative.

Other capital expenditures are driven externally by regulatory or grid authority directives.

Capital Projects:

For the longer term, capital expenditures will be augmented through a detailed application of our Asset Condition Assessment models and other system and component analyses. All proposed capital projects will be substantiated with business case (either full business case or mini business case) and prioritized during the capital budget review and approval process. In 2010 we will continue with ACA Phase 1 (TS Transformers), ACA Phase 2 (MS Transformers, Circuit Breakers, Primary Underground Cables), and ACA Phase 3 (Distribution Transformers, Distribution Switchgears, TS Switches, Wood Poles, Capacitors, Reactors).

The forecasts for the 2010-2014 capital financial requirements for the System Planning and Station areas are shown in Table 1 and Table 2 respectively.

Table 1 - PowerStream Total - Summary of Recommended Capital from System Planning ($000)

OEB Category	2010	2011	2012	2013	2014
Sustainment Capital	7,709	17,021	20,678	22,460	16,650
Development Capital	3,006	14,842	15,786	10,116	7,500
Operations Capital	260	0	0	0	0
Total	10,975	31,863	36,464	32,576	24,150

Table 2 - PowerStream Total - Summary of Recommended Capital from Stations ($000)					
OEB Category	**2010**	**2011**	**2012**	**2013**	**2014**
Sustainment Capital	2,804	2,502	1,923	2,727	1,893
Development Capital	1,178	0	0	4,159	19,413
Operations Capital	0	0	0	0	0
Total	3,982	2,502	1,923	6,886	21,306

The recommended five year capital plan for System Planning and Stations are listed in Appendix 3 and Appendix 4 respectively.

Overall Assessment:

The overall assessment is that the proposed capital program, in conjunction with an effective annual maintenance program, will accommodate growth needs and maintain current levels of service reliability to customers.

As the system assets get older, the probability of failure will increase, and the cost to refurbish or replace these assets will increase. Sufficient capital and OM&A funding will be required to ensure that system reliability will not be negatively impacted.

Some Challenges:

Two key high quantity/cost assets that may present future funding challenges are underground primary cable and wood poles.

PowerStream has approx. 7,700 km of underground primary cable length, the vast majority of which is direct buried and the rest is in duct. According to industry average, useful life of primary Tree Retardant XLPE Cable direct buried is 25 – 35 years with typical useful life of 30 years; and useful life of primary Tree Retardant XLPE Cable in duct is 35 – 55 years with typical useful life of 40 years. At a unit replacement cost of $250 per metre, the total cost to replace all 7,700 km of cable would be $1.9 billion. Actual cable life is expected to be 35+ years for the majority of our plant installations and replacement funding profiles will be developed to smooth out budgetary impacts.

PowerStream has approx. 44,000 wood poles. According to industry average, useful life of wood pole is 35 – 75 years with typical useful life of 45 years. Pole strength is the key variable that is considered in determining the need for replacement. A 60% strength threshold value for replacement is used based on current CSA Standards. At a unit replacement cost of $8,000 per pole, the total cost to replace all 44,000 poles would be $352 million. Replacement funding profiles will consider pole age/strength demographics and will be developed to smooth out budgetary impacts.

New Initiatives:

There are a number of new initiatives that will have impacts on PowerStream distribution system such as the Green Energy Act, CDM Program, Renewable Generation, Distributed Generation Connection, and Smart Grid. PowerStream will incorporate these initiatives into its short-term and long-term planning and operations.
It is expected that PowerStream will have the capability to facilitate and to deliver the results on these initiatives.

1.0 Introduction and Purpose

The 2010 PowerStream Distribution System Planning Report (DSPR) provides information on the planning processes that are in place to ensure the on-going successful operation of the distribution system. Specific outcomes of this report are designed to:

- Provide support for the corporate mission and vision statements and current key initiatives
- Facilitate the efficient development of the distribution system to satisfy customer demand and reliability needs through a 10 year load growth horizon
- Provide a forward looking view of expected capital and distribution related expenditures to support PowerStream's regulatory rate submission cases
- Identify short-term period constraints and associated capital solutions for annual or multi-year budget preparation
- Comply with regulatory/legal obligations (if any) to report on PowerStream's asset management plans and processes

2.0 Distribution System Planning Objectives

The System Planning Group is responsible for the long-term development of the distribution system.

> ***The planning objective is to determine the optimum level of investment in distribution capacity and the optimum configuration of the distribution system***

These objectives are accomplished by having due regard to:

- Corporate objectives
- Stakeholder interests
- Relative costs and benefits associated with alternative distribution development strategies
- Acceptable levels of risk
- Environmental factors that directly or indirectly impact on the efficient and reliable operation of the distribution network
- Defensible processes for the selection of capacity and reliability related projects

In carrying out distribution activities to support the Corporate Mission and Vision statements, stakeholder interests are considered and factored into the short and long range planning processes. Stakeholder interests vary and at times can be either complementary or conflicting. As a part of the planning process, assumptions are made about the stakeholder interests.
The assumptions and related stakeholder interests are shown in Table 3.

3.0 Distribution System Planning Information

Service Territory

PowerStream is the second largest municipally-owned electricity distribution company in Ontario, serving more than 320,000 residential and business customers in 11 Simcoe County and York region communities including Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan through a mix of 13.8kV, 27.6kV and 44kV distribution infrastructure.

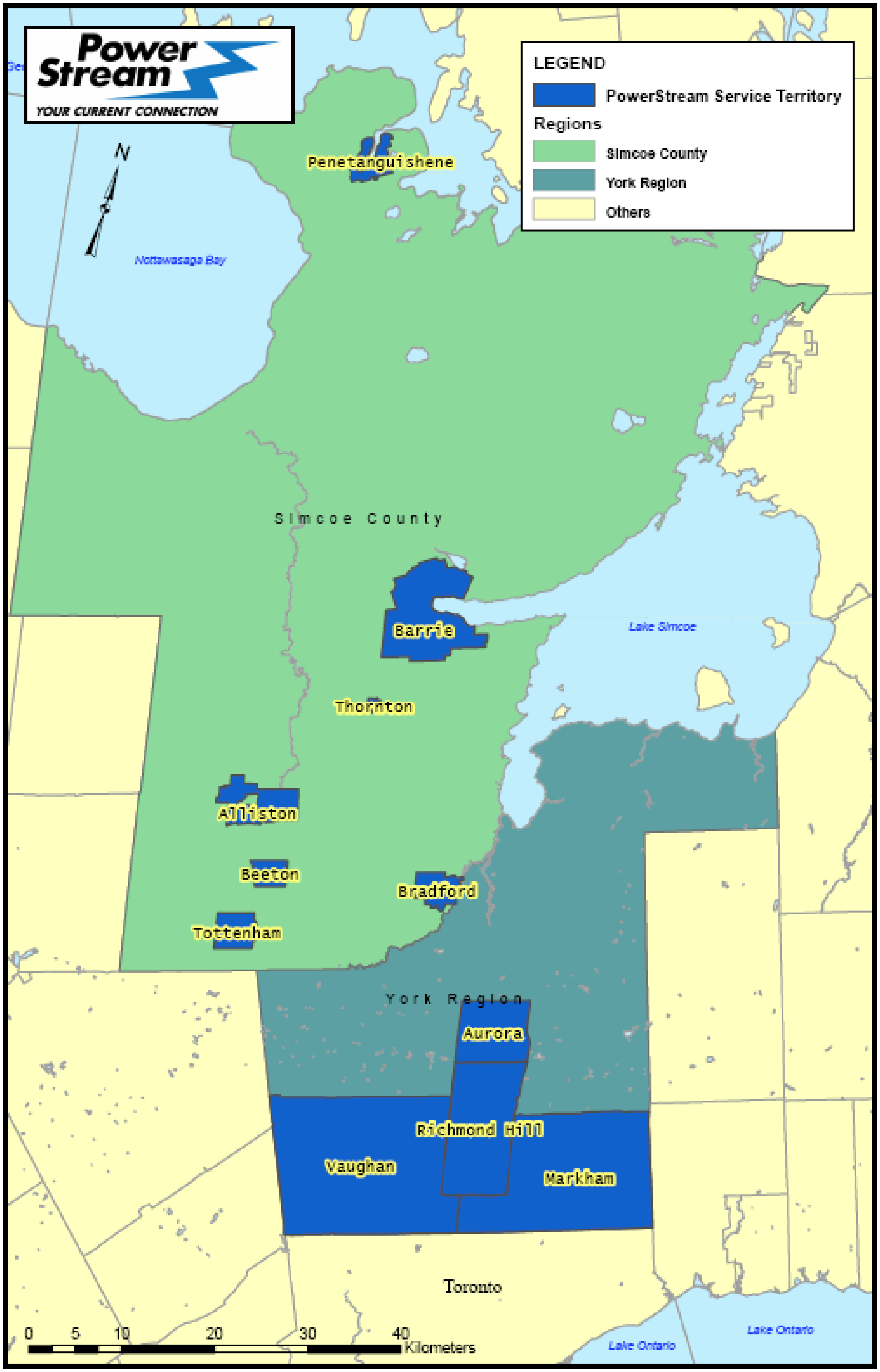
PowerStream's service territory is shown in Map 1.

Summary of the Distribution System

PowerStream's distribution system is summarized in the Fast Facts Table.

Table 3 – Stakeholder Interests

Stakeholders	Stakeholder Needs	Stakeholder Interests	Stakeholder Perception of Planning Risks
PowerStream Corporation	Accurate external/internal information to set policy	Achieve mission vision and objectives	Financial loss due to sub-optimization of operations; brand value deterioration
Shareholders	Stable rate of return	Safe long term investment	Financial and political pitfalls
Ontario Power Authority (OPA)	Accurate load forecasting	Comprehensive utility forecasting process	Inaccurate information contribution to the IPSP
Independent Electricity System Operator (IESO)	Accurate real-time information and market rule compliance by market participants	Utility adherence to technical and communication protocols	Inaccurate or untimely information for SIA
Hydro One Network (HONI)	Activity coordination	Coordination of transmission and distribution growth needs	Inaccurate forecasts affecting resource commitments
Generators	Stable market and ability to connect to distribution system	Clear rules and processes for connection	Distribution congestion affecting plant location and costs
Retailers	Reliable supply to customers	Maximize contract revenues	Loss of revenue
Provincial Government	Efficient, low cost and reliable market	Reliable supply to stimulate growth and political goodwill	Localized negative political impact
Ontario Energy Board (OEB)	Efficient, low cost and reliable market; regulatory compliance	Minimization of regulatory intervention	Regulatory intervention and political decision risks
Municipalities(non-shareholders)	Reliable supply to customers	Consultations on activities within municipal boundaries; visual aesthetics	Supply/reliability shortfalls affecting their constituents
Residential Customer	Reliable supply and low rates	Aesthetics	Supply/reliability shortfalls; price concerns
Small Commercial	Reliable supply and low rates	Rate stabilization or reduction	Supply/reliability shortfalls; price concerns affecting business plans
Large Commercial/Industrial	Reliable supply and low rates	Rate stabilization or reduction	Supply/reliability shortfalls; price concerns affecting business plans



Power Stream
YOUR CURRENT CONNECTION
LEGEND
PowerStream Service Territory
Regions
Simcoe County
York Region
Others
N
Nottawasaga Bay
Penetanguishene
Simcoe County
Barrie
Lake Simcoe
Thornton
Alliston
Beeton
Bradford
Tottenham
York Region
Aurora
Richmond Hill
Vaughan
Markham
Toronto
0 5 10 20 30 40
Kilometers
Lake Ontario
Lake Ontario

PowerStream Fast Facts Table – December 31, 2009

Own and operate the second largest municipally-owned electricity distribution system in Ontario with distribution assets valued at:	$923 million
A distribution system consisting of -	
Overhead circuit wires:	2,749 km
Underground cable (Note: circuit length, not cable length):	4,922 km
Transformer stations:	10
Municipal substations:	56
Transformers:	41,995
Switchgear:	1,789
Poles and pole structures:	43,590
Total Customers	320,869
Residential:	283,665
Commercial under 50 kW demand:	32,375
Commercial over 50 kW demand:	4,654
Large industrial user:	1
Sentinel lights:	135
Street lighting:	37
Geographical size of service territory:	806.6 km^2
Total electricity billed in 2009:	8,004 GWh
2009 system peak demand:	1,763 MW
All-time system peak demand:	1,890 MW
Average annual electricity consumption billed in 2009 -	
Residential - per customer:	9,093 kWh
Commercial - per customer:	145,808 kWh
Full-time employees:	493

4.0 Distribution System Planning Process

4.1 General Planning Process

Distribution System Planning can be defined as a rational process comprising field measurements and analytical activities, which collectively ensure that specifications and authorization, including appropriate lead times, are available for the most economic expansion and modification of the distribution system to meet the electrical supply requirements of customers.

Distribution Planning is a year round process. Issues of growth and reliability are evaluated on an on-going basis to determine optimal solutions that feed into the annual budgeting process. Corporate and stakeholder interests are taken into consideration when solutions are formulated.

The typical planning cycle consists 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.

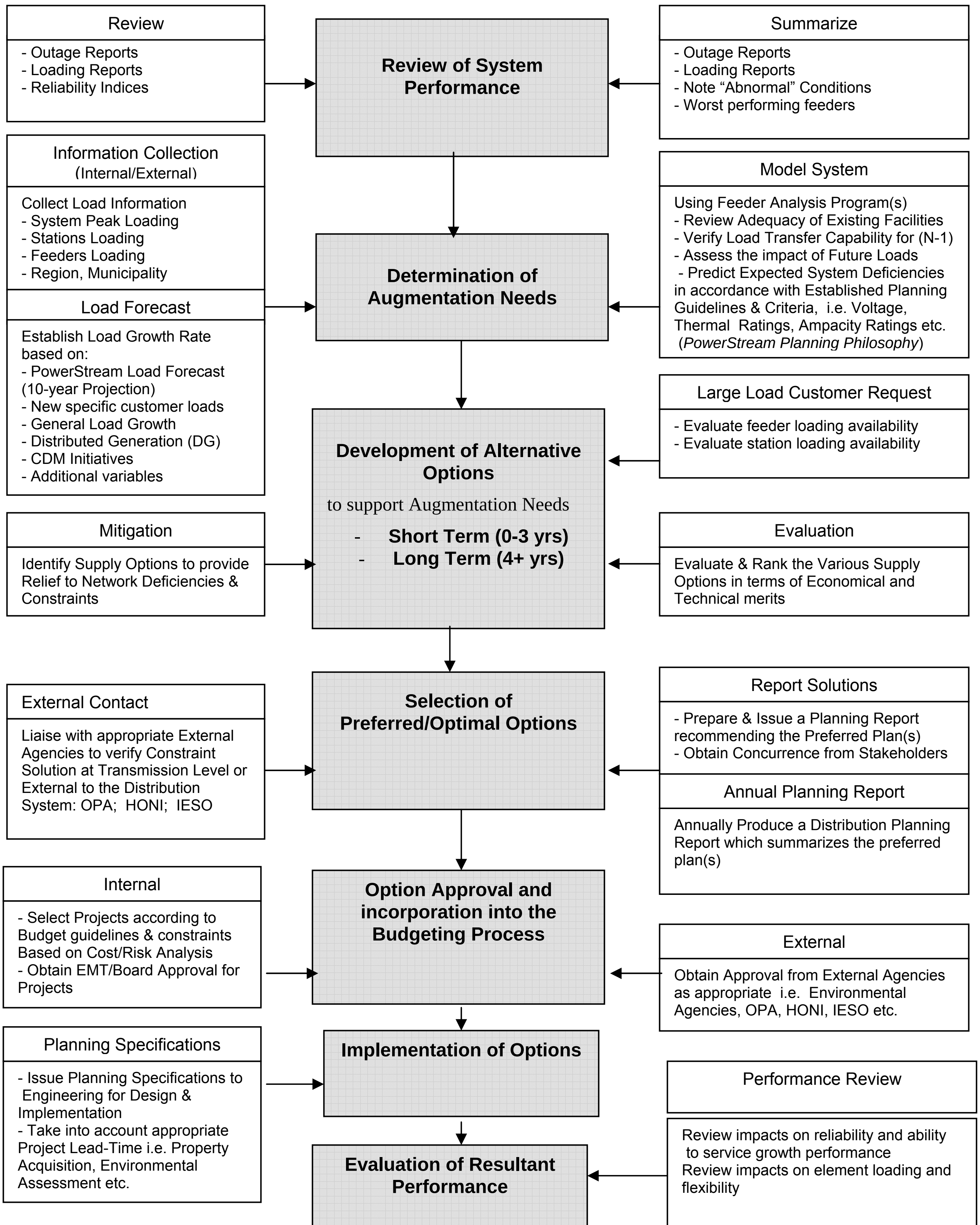
4.2 Annual Studies and Reports

Each year, System Planning studies the performance of the distribution system and prepares the following reports:

- Load Balancing & System Reconfiguration Plan" for PowerStream South (27.6kV system)
- Load Balancing & System Reconfiguration Plan" for PowerStream North (44kV and 13.8kV 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
- Asset Condition Assessment

As a result of these studies, capital projects may be recommended for submission to the budget process.

Figure 1 – Distribution System Planning Process



5.0 Distribution System Planning Philosophy, Standards, Guidelines, and Practices

5.1 Planning Philosophy

The PowerStream's Planning Philosophy document was developed through a multi-step process review and analysis of industry best practices in this area. The Planning Philosophy document covers activities relating to:

- Distribution Design
- Distribution Capacity Planning
- Distribution Risk Assessment
- Distribution Reliability Planning

5.1.1 Distribution Design

Nearly all loads, within PowerStream's 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.

5.1.2 Distribution Capacity Planning and Risk Assessment

Although 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 (<50kV 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.

5.1.3 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".

The Ontario Energy Board requires that all distributors monitor the four basic system indices of SAIDI, SAIFI, CAIDI, and MAIFI on a monthly basis and report them annually. These four basic system indices are defined as follows:

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)

The Ontario Energy Board's Guidelines on reliability performance are as follows:
"Utilities that have at least 3 years of data on the Service Reliability Indices should at minimum remain within the range of their historic performance. All utilities are required to monitor the indices monthly and report to the Board on an annual basis".

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
- Excluding Major Event Days
- 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.

5.2 Planning Standards, Guidelines, and Practices

Below is a summary of PowerStream's Distribution Planning Standards, which consist of Criteria, Practices and Guidelines.

System Voltages

- The primary supply voltages for PowerStream shall be 13.8kV, 27.6kV and 44kV. Selection is governed by the Conditions of Service.

Load Forecast (Practice)

- An annual summer/winter peak demand load forecast is prepared by System Planning for each transformer station and associated feeders (usually over a 10 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. See Section 2.8 for details.

Feeder Loading (Guideline)

- All 27.6 kV and 44kV 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 27.6kV feeder loading will be planned to a maximum of 400 amps and 600 amps under normal and emergency operation respectively, and three phase 44kV feeder will be planned to a maximum of 320 to 380 amps (approx. 25 to 30 MVA) under normal operation, and 600 amps (approx. 48 MVA) under emergency operation.
- A planned load guide of 300A 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 egress cables.

Station Transformer Loading (Guideline)

- Station Transformers maximum allowable loading, under contingency conditions, is the 10-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 limited time rating (LTR)

Number of Feeders at Transformer Stations (Practice)

- For the purpose of determining the number of feeders emanating 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 10-day LTR of 170 MVA, the number of feeders is 12 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 2 to 4 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-contigency 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 MCM Cu, XLPE (in a concrete encased duct bank where required) will be used for a length from the TS 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 MCM Cu, XLPE will be used.
- For the overhead part of the feeder main conductor, 556 MCM Al will be used. Overhead laterals of more than 200A that could be tied to another feeder or feeder lateral will also have 556 MCM Al conductors. The neutral conductor will also be 556 MCM Al within a distance of 1.0 km from the transformer station. Beyond a distance of 1.0 km, from the transformer station, 336 MCM 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 failure of a "major network component".

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. PowerStream applies the following criteria for the selection of remote switching :

    a) Distribution feeder should be segmented, via automated switches, every 8,495 customer kilometers for 27.6 kV feeders, and 7,539 customer kilometers for 44 kV feeders (based on cost/benefit analysis using $87,500 per installed switch).

    b) Feeder shall be segmented by RTU switches so that the loading of each segment is no more than 150A.

    c) RTU switches should be deployed to satisfy System Control operational requirements.

Industry Standards

- Industry planning standards that are an integral part of “good utility practice” and are common to all distribution utilities are summarized in Appendix 1.

Protection Philosophy

- PowerStream is primarily an overhead distribution system. Feeder protection shall incorporate appropriate autoreclose settings to mitigate the impact of transient faults. In certain circumstances the autoreclose 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

- 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 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

- Municipal Stations will continue to be constructed as required in areas of 44kV primary supply. The MS secondary supply voltage shall be 27.6 kV or 13.8kV as determined by the nature and configuration of the load.
- Municipal Stations will not be constructed in areas of 27.6kV primary supply. New load will not be added to existing Municipal Stations unless a 27.6kV supply is not available or financially justified. Existing MS load shall be converted to 27.6 kV when cost/reliability justified.

6.0 Distribution System Conditions – Asset Condition Assessment (ACA)

In order to achieve success, a business enterprise needs to optimally manage the risks associated with its assets. Optimal asset management strategies are based on a holistic view, covering all business assets.

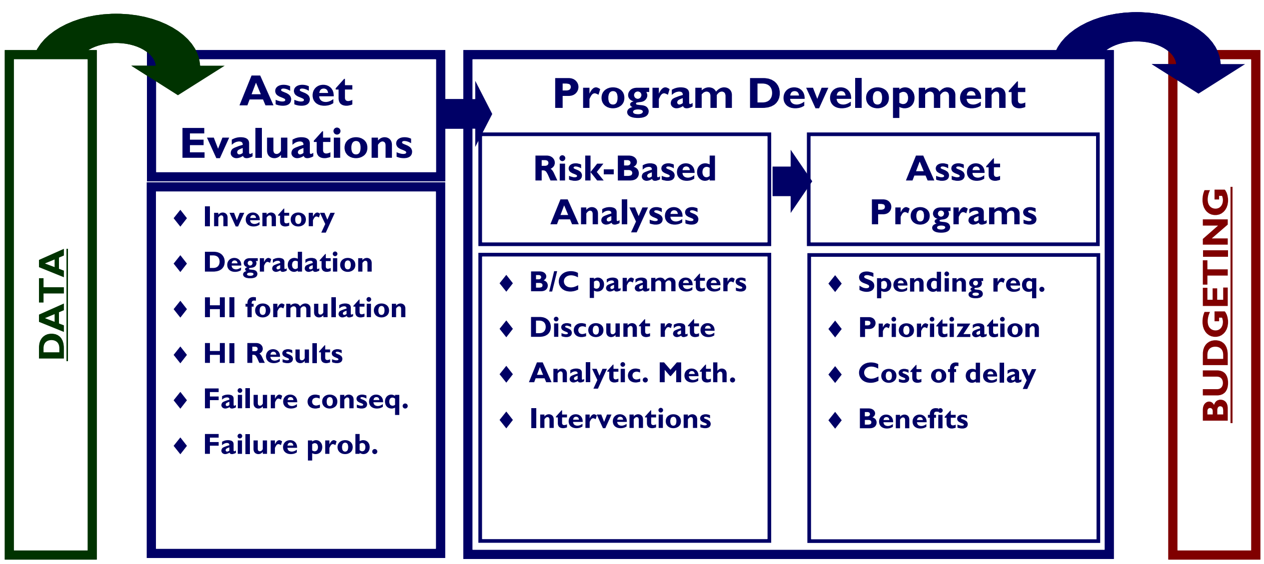
For a power distribution company, optimal management of the physical assets plays a crucial role in ensuring the company’s success. Risk of failure of in-service assets can have significant consequences that include worsening of supply system reliability, asset impairment, adverse safety impacts, adverse environmental impacts and potential third party damage. Risk mitigation, on the other hand, often requires substantial investments in form of either capital expenditure or maintenance activities and impacts both the rate payers and shareholders. Best-in-class asset management strategies involve achieving the right balance between the risk of failure and the cost of risk mitigation.

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.

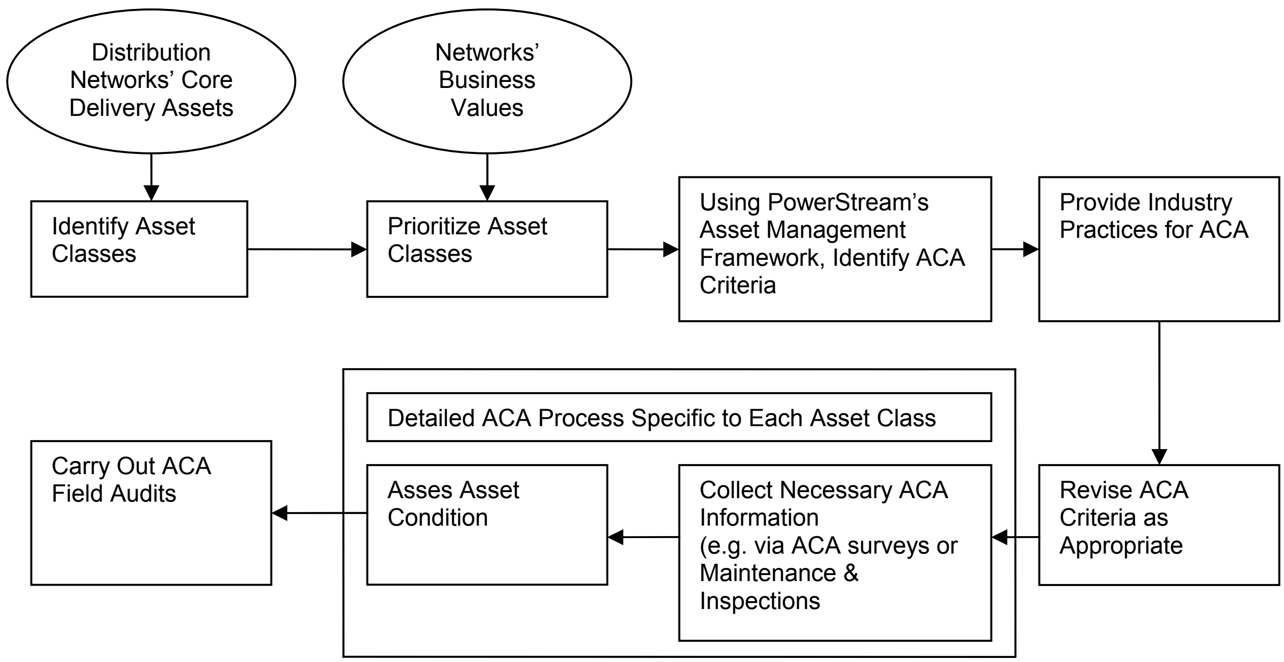
Figure 2 – Asset Management Framework



As the first step in adopting optimal asset management, an objective yardstick for accurate and quantitative measurement of the health and condition of major assets, which would provide repeatable results at any moment in time, needs to be developed. 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 categories ranging from “very poor” to “like new” conditions, and 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 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's Overall Asset Condition Assessment Process is illustrated in Figure 3.

Figure 3 - PowerStream's Overall Asset Condition Assessment Process



Priority Classes for Asset Condition Assessment

PowerStream to optimizes the ACA effort by concentrating initial efforts on those assets that represent the highest priority, have a high asset value and represent a high risk to the business.

This process can be accomplished by grouping the assets into logical asset classes. These classes can be further grouped into three categories and prioritised into Priority 1 (P1); Priority 2 (P2) and Priority 3 (P3) based on the asset value to the business, as shown in Table 4.

Priority 1 assets represent the highest priority assets and are of high value in terms of program expenditures or high risk to the business.

Priority 2 assets are second in priority with moderate program expenditures and moderate risk to the business.

Priority 3 assets are the lowest in priority with low program expenditures or low risk to the business. A number of assets in this category are considered "run-to-failure" assets. Assets in this category tend to have relatively consistent historical spending.

For the assets, detailed asset condition assessments are carried out that involve documenting asset description, demographics, condition criteria, comparison with industry practice and condition assessment results. Program development to prioritize spending will be part of the budgeting process. Limited program emphasis will be placed on the asset condition of P3 assets, because acquiring asset condition information on these assets is of “low” value for the following reasons:

- The assets are of low dollar value in terms of on-going investments, and it is not cost effective or practical to collect ACA information on these assets, e.g. distribution line fuses
- When these assets fail, risks and consequence costs are considered relatively low, and managed processes exist to quickly identify and repair or replace assets that have failed, or are about to fail (“run-to-failure”), e.g. pole-top transformers
- Programs that are developed are likely to support historical replacement expenditures in the respective asset category

Table 4 – ACA Priority Categories

Priority 1 (P1)	Priority 2 (P2)	Priority 3 (P3)
TS (Transformer Station) Transformers	Underground Primary Cables & Terminations	Distribution Transformers (pole/pad mount)
System Spare Transformers	TS Stations Egress Cables & Terminations	Fuses
MS (Municipal Station) Transformers	Station Capacitors & Reactors	Fault Indicators
TS Breakers	Distribution Switchgear	Substation Sites & Structures
MS Breakers/Reclosers	Wood Poles	TS Oil Containment System
MS Primary Switches	Overhead Conductors	RTU (Remote Terminal Unit)
230 kV TS Switches	Insulators	Protection/Control Relay Building
		Switches: Scada-Mate, Alduti, In-Line

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.
Currently, PowerStream has the Kinectrics ACA models for the following assets:

- TS Transformers
- MS Transformers
- Station Breakers and Reclosers
- MS Primary Switches
- 230 kV TS Switches
- Station Capacitors
- Station Reactors

- Distribution Transformers
- Distribution Switchgears
- Underground Primary Cables

Existing ACA asset counts for PowerStream South and PowerStream North are summarized in Table 5.

Table 5 - PowerStream ACA Asset Counts

Asset	South	North	Total
TS Transformer	22	0	22
MS Transformer	25	41	66
Station Breaker and Recloser	239	139	378
MS Primary Switch	25	57	82
230 kV TS Switch	20	0	20
Station Capacitor	4	0	4
Station Reactor	22	0	22
Distribution Transformer	34,299	9,236	43,535
Distribution Switchgear	1,650	276	1,926
Wood Pole	34,407	10,167	44,574
Underground Primary Cable (cable km)	6,588	1,159	7,747

The following is a summary status of the asset conditions.

TS Transformer: no immediate replacement required.

MS Transformers: no immediate replacement required.

Station Breakers and Reclosers:
It is recommended to replace approx. 11 units per year over the next 5 years.

MS Primary Switches: no immediate replacement required.

230 kV TS Switches: no immediate replacement required.

Station Capacitors: no immediate replacement required.

Station Reactors: no immediate replacement required.

Distribution Transformers:
Currently, due to data gap, the ACA Distribution Transformer model is not used to generate recommended proactive replacement program. Distribution transformers are replaced when they fail (“run-to-failure”). For the small sample of transformers population that have age information, about 10% of the transformers are rated as “poor” or “very poor”.

Distribution Switchgear:
Approx. 10% of the switchgear units are rated as “poor” or “very poor”. It is recommended to replace 25 switchgear units per year in a programmed fashion to reduce this number.

Wood Poles:
The current pole testing program will be completed by 2011. Due to data gap, the Health Index is not being used for pole replacement purpose. Instead, the pole remaining strength is used to prioritize the annual replacement. According to CSA Standard, poles that have remaining strength of 60% or less should be reinforced or replaced.

Clause 8.3.1.3 of CAN/CSA-C22.3 No.1-06 states:
“When the strength of a structure has deteriorated to 60% of the required capacity, the structure shall be reinforced or replaced”

PowerStream has approx. 44,000 wood poles. According to industry average, useful life of wood pole is 35 – 75 years with typical useful life of 45 years. Pole strength is the key variable that is considered in determining the need for replacement. A 60% strength threshold value for replacement is used based on current CSA Standards. At a unit replacement cost of $8,000 per pole, the total cost to replace all 44,000 poles would be $352 million. Replacement funding profiles will consider pole age/strength demographics and will be developed to smooth out budgetary impacts.

Underground Primary Cables:
PowerStream has significant inventory of in-service underground primary cables. Because there is limited condition data available due to the lack of in-service cable test data, there is no health index formulation calculated for underground primary cables. Benefit/Cost ratio is considered in the intervention decision, which could be cable replacement or cable injection.

With respect to cable replacement, PowerStream has started a cable replacement project at one subdivision. This project will span over 3 years (2010, 2011, and 2012) and cover approx. 9.2 km of cables.

With respect to cable injection technology, PowerStream has completed a pilot project, and is considering additional pilot projects to gain more experience on the technology, process, and cost effectiveness. The pilot injection project covered approx. 3.4 km of cables.

PowerStream has approx. 7,700 km of underground primary cable length, the vast majority of which is direct buried and the rest is in duct. According to industry average, useful life of primary Tree Retardant XLPE Cable direct buried is 25 – 35 years with typical useful life of 30 years; and useful life of primary Tree Retardant XLPE Cable in duct is 35 – 55 years with typical useful life of 40 years. At a unit replacement cost of $250 per metre, the total cost to replace all 7,700 km of cable would be $1.9 billion. Actual cable life is expected to be 35+ years for the majority of our plant installations and replacement funding profiles will be developed to smooth out budgetary impacts.

The recommended fundings for the replacement of various asset classes over the next five years are summarized in Table 6.

Table 6 - PowerStream Recommended 5 Year ACA Projects (costs = $000)

Project Title	2010	2011	2012	2013	2014	Remarks
Planned pole replacement program (ACA) - South	$510	$1,000	$1,000	$1,000	$1,000	Replace approx. 100 poles/year
Planned distribution switchgear replacement program (ACA) - South	$1,360	$1,400	$1,400	$1,400	$1,400	Replace approx. 28 units/year
Planned circuit breaker and recloser replacement program (ACA) - South	$1,100	$1,100	$1,100	$1,100	$1,100	Replace approx. 11 units/year
Planned primary cable replacement program (ACA) - South		$2,000	$2,000	$2,000	$2,000	Replace approx. 8,000m/year
Planned station primary switch replacement program (ACA) - South			$500	$500	$500	Replace 2 units/year
Primary Cable Injection projects (ACA) - South		$300	$300	$300	$300	Inject approx. 5000m/year x $60/m
Station Soil Testing Program - South	$100	$100				
Planned pole replacement program (ACA) - North	$500	$700	$700	$700	$700	Replace approx. 70 poles/year
Planned distribution switchgear replacement program (ACA) - North	$263	$500	$500	$500	$500	Replace approx. 10 units/year
Planned circuit breaker and recloser replacement program (ACA) - North		$300	$300	$300	$300	Replace 3 units/year
Planned primary cable replacement program (ACA) - North		$2,000	$2,000	$2,000	$2,000	Replace approx. 8,000m/year
Planned station primary switch replacement program (ACA) - North		$200	$200	$200	$200	Replace 2 units/year
Primary Cable Injection (ACA) - North		$300	$300	$300	$300	Inject approx. 5000m/year x $60/m
Station Soil Testing Program - North	$50	$50				
Total	$3,883	$9,950	$10,300	$10,300	$10,300	

7.0 Distribution System Capacity

7.1 Load Forecast (2010 – 2019)

PowerStream prepares an annual load forecast for the upcoming ten year period.

The load forecast is prepared by comparing trend analysis software results to weather normalized end use forecasts. The weather normalization is based on normal; hot; and extreme conditions, while the end use forecast is based on normal; low; and high growth scenarios. All forecasts include CDM and price elasticity impacts.

The load forecast for the period of 2010 – 2019 for PowerStream South and PowerStream North are summarized in Table A and Table B respectively.

Regarding the annual CDM targets for peak reduction purpose, the OEB has released preliminary CDM targets for LDCs. PowerStream's preliminary targets call for 410 GWH of energy and 96 MW of demand peak to be reduced from 2011 to 2014. These targets have been factored into the load forecast.

Three different forecast results are utilized depending on the audience and application.

1. Submission to Hydro One, the IESO, the OPA and the OEB
The coincident peak demand forecasts of Base growth under the "1 in 2" (normal) and "1 in 10" (hot) weather scenarios with annual peak reduction through CDM targets and with price elasticity impact are provided to external agencies for capacity planning purposes.

2. Internal Financial/Revenue Forecast Purposes
The coincident peak demand forecasts of Base growth under the "1 in 2" (normal) weather scenarios with annual peak reduction through CDM, and with price elasticity impact are provided for internal financial/revenue forecast purposes.

3. System Capacity Adequacy Assessment
Coincident peak demand forecasts of Base growth under the "1 in 10" (hot) weather scenario without price impact are provided for system capacity adequacy assessment.

Resource Adequacy Assessment:

Adequacy assessment is performed under the following scenarios:

(a) Based on Base Growth, No Price Impact, No Future CDM & 1-in-10 Weather

The PowerStream South load forecast indicated that the future station resources will be required as follows:

2015 – TS4 in Vaughan (170MVA capacity)
2017 – TS5 in Markham (170MVA capacity)

The PowerStream North load forecast indicated that no new TS is required in PowerStream North within the forecast horizon. However 2 new feeders will be required as follows:

2015 – 1 new 44 kV feeder from Midhurst TS2 (T3/T4)
2018 – 1 new 44 kV feeder from Midhurst TS2 (T3/T4)

(b) Based on Base Growth, Price Impact, Future CDM & 1-in-10 Weather

The PowerStream South load forecast indicated that the future station resources will be required as follows:

2016 – TS4 in Vaughan (170MVA capacity)

2018 – TS5 in Markham (170MVA capacity)
The PowerStream North load forecast indicated that one new feeder will be required as follows:

2018 – 1 new 44 kV feeder from Midhurst TS2 (T3/T4)

Table A: PowerStream South Coincident Peak Demand Forecast -Base growth (MW)

Purpose	Item	Weather	CDM	Price Elast.	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OPA/OEB	Peak (MW)	1-in-2	Yes	Yes	1,465	1,530	1,568	1,601	1,636	1,671	1,725	1,783	1,843	1,905	1,970
		1-in-10				1,634	1,676	1,712	1,751	1,790	1,848	1,911	1,975	2,042	2,111
Financial/ Revenue	Peak (MW)	1-in-2	Yes	Yes	1,465	1,530	1,568	1,601	1,636	1,671	1,725	1,783	1,843	1,905	1,970
	Peak (MVA)	1-in-2			1,628	1,700	1,743	1,779	1,818	1,857	1,916	1,982	2,048	2,117	2,189
Capacity Assessment	Peak (MW)	1-in-10	No	No	1,465	1,657	1,709	1,762	1,816	1,871	1,930	1,992	2,055	2,120	2,188
	Peak (MVA)	1-in-10			1,637	1,841	1,898	1,957	2,018	2,079	2,145	2,213	2,283	2,356	2,431

*Actual

Table B: PowerStream North Coincident Peak Demand Forecast -Base growth (MW)

Purpose	Item	Weather	CDM	Price Elast.	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OPA/OEB	Peak (MW)	1 in 2	Yes	Yes	303	308	315	322	329	337	344	353	362	371	381
		1 in 10				326	333	341	349	358	365	375	384	394	404
Financial/ Revenue	Peak (MW)	1 in 2	Yes	Yes	303	308	315	322	329	337	344	353	362	371	381
	Peak (MVA)	1 in 2			337	342	350	358	366	375	383	393	402	412	423
Capacity Assessment	Peak (MW)	1 in 10	No	No	303	338	349	359	370	381	391	402	413	425	436
	Peak (MVA)	1 in 10			337	376	387	399	411	423	435	447	459	472	485

*Actual

8.0 Distribution System Reliability Performance

8.1 System Reliability

In January 2009, PowerStream and Barrie Hydro merged into one company. During 2009, there were two control rooms responsible for system outage statistics, one for “PowerStream North” (former Barrie Hydro service territory), and one for “PowerStream South” (former PowerStream service territory). As a result, two sets of system reliability statistics were maintained in 2009, one for PowerStream North and one for PowerStream South. In addition to these two sets of statistics, a third set was created for “PowerStream Total” which is the combined PowerStream (North and South).

To facilitate for the data analysis, reliability data was further categorized into the following four groupings:

- All Events: data is inclusive of all outage cause codes.
- Excluding Loss of Supply (LOS): outages that resulted because of Hydro One's feeder or transmission outage are excluded from the calculation.
- Excluding Major Event Days (MED): outages that resulted because of major event which contributed significant interruption duration in one day are excluded from the calculation. The threshold interruption duration to determine a day an MED is calculated based on IEEE 1366 Standard which is a well adopted methodology in electric power utility industry.
- Excluding Loss of Supply (LOS) and Major Event Days (MED): Outages that resulted because of a loss of supply from Hydro One's system or Major Event Days are excluded from the calculation.

Based on the above definitions, the reliability performance for PowerStream North, PowerStream South, and PowerStream Total for the past 3 years are tabulated in Tables 7, 8, 9, and 10 respectively.

Starting in 2010, PowerStream will set the annual reliability targets for PowerStream as a combined system. For 2010, the reliability targets were set to be equal to the previous 3-year average of the combined PowerStream actual reliability (2009, 2008, and 2007). The 2010 reliability targets are tabulated in Table 11.

In 2010 the OEB requested that LDCs monitor and report on MAIFI. For 2010, PowerStream will only monitor and report on this index. No MAIFI target will be set for 2010. As data is compiled for this reliability index, it will be possible to set targets based on 3-year averages similar to the other reliability indexes.

Reliability performance will be monitored by the PowerStream Reliability Committee which comprises members from various business units across the organization, and has the mandate to manage and improve reliability.
In its 2010 Strategic Direction - Five Year Critical Success Factors, PowerStream has set aggressive targets to improve reliability over a period of five years. To achieve the reliability goals it is expected that PowerStream must put additional effort in many work programs that have positive impacts to reliability. Although the details are yet to be developed and approved, it is expected that the work programs will span across many business units and include continuous improvements and best practice implementation on the following processes and tools:

- Planning
- Design
- Construction
- Inspection
- Maintenance
- Operations
- Distribution Automation
- Smart Grid Technologies
- Outage Response & Outage Management
- Records System
- Coordination of Work Programs
- Hydro One's System Performance impacting PowerStream

Table 7 - All Events

	PowerStream North All Events			PowerStream South All Events			PowerStream Total All Events		
Index	2007	2008	2009	2007	2008	2009	2007	2008	2009
SAIDI	2.382	2.830	2.841	2.168	1.004	1.730	2.216	1.409	1.975
SAIFI	3.227	3.356	1.779	1.543	0.922	1.079	1.923	1.463	1.233
CAIDI	0.738	0.843	1.597	1.405	1.089	1.603	1.152	0.964	1.601
IOR	0.999728	0.999678	0.999676	0.999753	0.999886	0.999803	0.999747	0.999840	0.999775

Table 8 - Excluding Loss of Supply (LOS)

	PowerStream North Excluding LOS			PowerStream South Excluding LOS			PowerStream Total Excluding LOS		
Index	2007	2008	2009	2007	2008	2009	2007	2008	2009
SAIDI	1.905	1.878	1.893	2.163	0.893	1.498	2.105	1.112	1.585
SAIFI	2.934	2.339	1.332	1.471	0.808	0.996	1.801	1.148	1.070
CAIDI	0.649	0.803	1.421	1.470	1.105	1.504	1.168	0.968	1.481
IOR	0.999782	0.999786	0.999784	0.999753	0.999898	0.999829	0.99976	0.999873	0.999819

Table 9 - Excluding Major Event Days (MED)

	PowerStream North Excluding MED			PowerStream South Excluding MED			PowerStream Total Excluding MED		
Index	2007	2008	2009	2007	2008	2009	2007	2008	2009
SAIDI	2.382	2.830	2.841	0.902	1.004	0.723	1.236	1.409	1.190
SAIFI	3.227	3.356	1.779	1.154	0.922	0.796	1.622	1.463	1.013
CAIDI	0.738	0.843	1.597	0.782	1.089	0.908	0.762	0.964	1.175
IOR	0.999728	0.999678	0.999676	0.999897	0.999886	0.999917	0.999859	0.999840	0.999864

Table 10 - Excluding Loss of Supply (LOS) and Major Event days (MED)

	PowerStream North Excluding LOS & MED			PowerStream South Excluding LOS & MED			PowerStream Total Excluding LOS & MED		
Index	2007	2008	2009	2007	2008	2009	2007	2008	2009
SAIDI	1.905	1.878	1.893	0.897	0.893	0.719	1.125	1.112	0.978
SAIFI	2.934	2.339	1.332	1.082	0.808	0.747	1.500	1.148	0.875
CAIDI	0.649	0.803	1.421	0.829	1.105	0.964	0.750	0.968	1.117
IOR	0.999782	0.999786	0.999784	0.999898	0.999898	0.999918	0.999872	0.999873	0.999888

Table 11 – PowerStream 2010 Reliability Targets

2010 Targets	CAIDI (hours)	SAIFI	SAIDI (hours)	IOR
All Events	1.239	1.540	1.867	0.999787
Excluding Loss of Supply	1.206	1.340	1.601	0.999817
Excluding Major Event Days	0.967	1.366	1.278	0.999854
Excluding Loss of Supply and Major Event Days	0.945	1.175	1.072	0.999878

8.2 Feeder Reliability - Worst Performing Feeders (WPF)

To facilitate prioritizing effort to improve reliability, PowerStream has started the practice to identify the worst performing feeders in the system so that remediation work can be implemented on a feeder-by-feeder basis.

For 2010, PowerStream will identify a total of 20 worst performing feeders based on feeder reliability data over the past 3 years (2009, 2008, and 2007). Both feeder interruption duration and feeder interruption frequency will be taken into consideration. In addition, field inputs from Lines and Operations will also be considered. Remediation work will be implemented. Feeder performance will be monitored and reported regularly for a period of 3 years to confirm improvement has been achieved. PowerStream's goal is to remove 80% of the worst performing feeders from the WPF listing after 3 years.
Feeder reliability performance is ranked based on the following formula:

Feeder Score = 0.5 *FAIDI + 0.5*FAIFI

Where:
FAIDI = Feeder Average Interruption Duration Index
FAIFI = Feeder Average Interruption Frequency Index

Feeders that have the highest Feeder Scores are considered less reliable and will be targeted for detailed reviews and corrective actions.

8.3 Hydro One's Feeders impacting PowerStream's Reliability

In PowerStream North service territory, there are a number of 44 kV feeders that are owned and operated by Hydro One. In majority of cases, when these Hydro One feeders encounter outages, PowerStream's customer will also encounter outages. The reliability of these Hydro One's feeders has a direct impact on PowerStream's customers. Upon reviewing outage information in PowerStream North over the last 3 years, it was noted that many of Hydro One's feeders exhibited operational performance issues that merited review and potential corrective actions. As a result, the PowerStream Reliability Committee has initiated discussion with Hydro One with the intent to work with Hydro One finding solutions to improve reliability performance for these feeders.

9.0 Distribution System Contingency Plan

Contingency Plans are required to deal with any asset related event that affects the proper functioning of the distribution system. Contingency planning with respect to this document will deal with potential high impact low probability (HILP) events that can have major repercussions on the distribution system and our customers. This will mostly apply to Priority 1 assets. All other events, that are generally regular occurrences, low impact, low scope and have established processes to deal with them, are not part of this document. The HILP events considered here are shown in the Table 12 below:

Table 12 – Contingency Plans

Asset Class	Contingency Event	Contingency Plan
TS Power Transformers	Transformer failure requiring off-site servicing	1. Spare Transformer 2. Storage location for spare 3. Individual plans to move spare to affected TS 4. Individual connection plans for each TS configuration
TS Switchgear Cell(s)	Cell or multi-cell failure	1. Spares – Critical parts list 2. Contact plan for manufacturer repair support 3. Spare cell 4. Feeder emergency loading capability
230kV switches	Switch failure – non-repairable	1. Spare switch(s)/parts 2. Storage location for spare(s) 3. Individual mounting plan(s) for each TS structure
TS Feeder cables	Failure of one or more underground cables	1. Spare cable reel
TS Capacitor banks	Failure of significant portion of capacitor bank	1. Spare Capacitor cans 2. Contact plan for manufacturer repair support
TS Reactor failure	Failure of reactor	1. Spare reactor
Station RTU	Failure of RTU leading to loss of station control	1. Standby staff to man station 2. Contact plan for manufacturer repair support
Station Protective Devices	Device failure leading to full/partial loss of station	1. Spare – Critical Parts list
Poles	Loss of high number of pole structures through high impact event(severe weather, etc.)	1. Stock poles 2. Supplier stock 3. Neighbouring LDC stock

In all cases if available contingency measures prove insufficient, rotating load shedding may be required to ensure equipment is not loaded beyond approved tolerances.

10.0 New Initiatives

10.1 Green Energy & Green Economy Act, 2009

The Green Energy & Green Economy Act, 2009 establishes responsibilities for the Ontario Energy Board and other entities in achieving the objectives of conservation, renewable generation, and smart grid.

The OEB has three new objectives:

- The promotion of renewable energy, including the timely connection of renewable energy projects to transmission and distribution systems
- The promotion of conservation and demand management

- The facilitation of the implementation of a smart grid

The OEB has a number of initiatives that will have impacts to PowerStream. Four of such initiatives are described:

Initiative 1: Green Energy Act Implementation Readiness Program
- Planning activities to provide practical information to help electricity distributors prepare and implement their new responsibilities.

Initiative 2: Infrastructure Development & Planning for Renewable Generation
- Amending the Distribution System Code and the Affiliates Relationship Code to reflect the ability of electricity distributors to own and operate certain renewable and other generation facilities as well as energy storage facilities.
- The regulatory treatment of infrastructure investment associated with the accommodation of renewable generation and smart grid development.
- Revising the distributed generation connection cost responsibility between a distributor and a generator.
- Amending the Distribution System Code regarding distribution capacity allocation reform.

Initiative 3: Distribution System Plans for Renewable Generation Connection and Smart Grid
- Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence.
- Distribution System Planning Guidelines.

Initiative 4: Conservation & Demand Management
- The OEB is working with the Ministry of Energy and the OPA to develop CDM targets and reporting process for LDCs.

10.2 Conservation & Demand Management (CDM)

The development of our CDM strategy, and the resource plan, start with the specification of the programs as defined in the OPA programs for the transitional year in 2010

It is anticipated that the role of the OPA will be to work in a more collaborative approach with the LDC's and the EDA as per new Ministry of Energy directives. Since 2010 is a transition year a significant amount of time and resources will have to be spent on aligning PowerStreams CDM programs that will be able to meet OEB directed conservation targets by end of 2014.

In 2009 we achieved a reduction of 17 MW and 45.7 million kWh within our service territory. The four year target (from 2011 to 2014) is 96 MW demand reduction and 410 GWh energy reduction.

Projected CDM Reduction

Year	2010	2011	2012	2013	2014	Total
MW reduced	12	21	25	25	25	96 MW + 12 MW (2010)
GWh reduced	35	80	110	110	110	410 GWh + 35 GWh (2010)

During the 2010 transition year, we will continue to support the existing OPA funding structure and focus on planning and defining our strategies for the 4-year CDM programs that will begin in 2011.

10.3 Distributed Generation (DG)

PowerStream continues facilitating for distributed generation connections to its distribution system.

PowerStream can, depending on the details of the individual projects, defer capital expenditure to upgrade the distribution system capacity.

PowerStream follows the connection processes in the OEB Distribution System Code for a customer owned generator, which are based on the Generator Classification (Micro, Small, Mid-sized, and Large) as shown below:

Generator Classification:	Rating:
Micro	≤10 kW
Small	a) ≤ 500 kW connected on distribution system voltage < 15 kV
	b) ≤ 1 MW connected on distribution system voltage ≥ 15 kV
Mid-sized	a) > 500 kW but < 10 MW connected on distribution system voltage < 15 kV
	b) > 1 MW but < 10 MW connected on distribution system voltage ≥15 kV
Large	≥ 10 MW

Currently, there are 21 DG projects with a total capacity of 11.3 MW connected to PowerStream system as follows.
- Micro: 12 projects, total 35 kW
- Small: 7 projects, total 2,488 kW
- Mid-sized: 2 projects, total 8,730 kW
- Large: none

In addition, PowerStream also facilitates the following two OPA programs for the connection of generators producing energy from renewable energy source.

OPA FIT Program:

OPA feed-in tariff or FIT Program offers guaranteed pricing structure for renewable electricity production projects that are greater than 10 kW in size. It offers stable prices under long-term contracts for energy generated from renewable sources, including:

- biomass
- biogas
- landfill gas
- on-shore and off-shore wind
- solar photovoltaic (PV)
- waterpower.

There are 112 FIT applications with a potential total size of 25.7 MW inside of PowerStream service territory.

OPA microFIT Program:

OPA microFIT Program offers guaranteed pricing structure for renewable electricity production projects that are 10 kW or less in size. It offers stable prices under long-term contracts for energy generated from renewable sources.

There are 173 microFIT applications with a potential total size of 1.2 MW inside of PowerStream service territory.

Potential DG Penetration Rate at PowerStream:
Based on available information on the existing and potential DG projects inside of PowerStream territory, the total gross capacity of all existing and potential DG projects is approximately 38.2 MW, which represent approx. 2% of PowerStream peak load in 2009 of 1,763 MW. It is, however, expected that not all potential DG projects will materialize.

Current assessment is that PowerStream will have the capability to facilitate for DG connections for a foreseeable future.

10.4 Smart Grid

In May 2009, the province passed Ontario Green Energy and Green Economy Act to define a future sustainable energy economy and become a world-leading clean-tech industry with aggressive targets in energy conservation and the development of renewable energy. The Act provided a new objective for the OEB to facilitate the smart grid.

Smart Grid refers to the same basic infrastructure for electricity distribution we know today except it applies new technology to provide a more reliable, more resilient and more flexible distribution system. The new technology comprises:

- advanced analytics and automation
- smart devices and sensor technology
- two way communication systems

Smart grid provides more efficient and more automatic operation of the distribution system, provides more information to the customer to empower them with more control over their energy usage, will support the incorporation of multiple energy sources, generation, demand response, renewable energy sources and energy efficiency technologies.

In early 2010, PowerStream formed a Smart Grid department in the organization, the objective of which was to develop and facilitate the implementation of the vision and strategic plan for the company that is aligned with its corporate vision and long term objectives. Consistent with the corporate vision to be industry best-in-class, the Smart Grid Task Force mission is to make PowerStream an industry leader in the prudent and safe application of Smart Grid technologies to provide the best value to its customers and its shareholders.

By mid-2010, a draft of the Smart Grid strategic plan should be completed. From this plan, a five year business plan will evolve, identifying various smart grid initiatives and projects with supporting business cases.

11.0 Five-Year Capital Work Plans

11.1 Distribution Five-Year Capital Work Plan

On an annual basis, the System Planning Group prepares a Distribution Five-Year Capital Work Plan. The plan lists the approved and potential capital projects according to the OEB rate case categories. The details are included in Appendix 3.

11.2 Station Five-Year Capital Work Plan

On an annual basis, the Station Design & Construction Group prepares a Station Five-Year Capital Work Plan. The plan lists the approved and potential capital projects according to the OEB rate case categories. The details are included in Appendix 4.

12.0 Review of Previous System Planning Report

The previous planning report needs to be annually reviewed to:

1. determine actual progress versus the plan
2. evaluate and compare actual performance of the plan against targeted performance objectives
3. identify any gaps in the plan and resultant performance improvement initiatives

Plan Progress

The 2009 Budget identified a number system augmentation projects. Status of those projects is shown in Tables 13 and 14.

Table 13 - System Planning Projects

Recommended Projects	Details	Received Budget Approval	Project Completed
Pole Replacement Program (ACA)	Replace poles	Yes	Yes
Distribution Switchgear Replacement Program (ACA)	Replace switchgear	Yes	Yes
Station Circuit Breaker Replacement Program (ACA) – Vaughan TS1	Replace station circuit breakers	Yes	Yes
Distribution Automation Switch Installation	Install DA switches	Yes	Yes
Retrofitting Vaults and Submersible Units	Plant Retrofitting	Yes	Yes
Markham TS #4 Feeder Egress - Part 1 and Part 2	Plant	Yes	Yes
Transfer of 2 – 44 kV Feeders from Armitage TS (Newmarket) to PowerStream (Aurora/Newmarket boundary)	Plant	Yes	Yes

Table 14 – Station Design & Construction Projects

Recommended Projects	Details	Received Budget Approval	Project Completed
New Transfer Trip Protection at Greenwood TS and Torstar TS	Install transfer trip protection	Yes	Yes
Transformer on-line Analysis	Plant	Yes	Yes
Transformer Temperature Monitoring – Markham TS #1, #2, and #3	Plant	Yes	Yes
Markham TS #4 – 2009 portion of 3-year project	New TS	Yes	Yes

Performance Targets

The reliability performances for 2009 in comparison to the previous 3-year average (2008, 2007, and 2006) for PowerStream North, PowerStream South, and PowerStream Total, under various scenarios, are shown in the following Tables:

Table 1A & 1B – All Events
Table 2A & 2B – Excluding Loss of Supply (LOS)
Table 3A & 3B – Excluding Major Event Days (MED)
Table 4A & 4B – Excluding Loss of Supply and Major Event Days

The results show that, for PowerStream Total (combined North & South):

- **All Events:** 2009 SAIDI is worse than the previous 3-year average (1.975 vs. 1.713)
  2009 SAIFI is better than the previous 3-year average (1.233 vs. 1.658)
- **Excluding LOS:** 2009 SAIDI is worse than the previous 3-year average (1.585 vs. 1.495)
  2009 SAIFI is better than the previous 3-year average (1.070 vs. 1.458)
- **Excluding MED:** 2009 SAIDI is better than the previous 3-year average (1.190 vs. 1.386)
  2009 SAIFI is better than the previous 3-year average (1.013 vs. 1.557)
- **Excluding LOS & MED:** 2009 SAIDI is better than the previous 3-year average (0.978 vs. 1.168)
  2009 SAIFI is better than the previous 3-year average (0.875 vs. 1.358)

Going forward, the PowerStream Reliability Committee will monitor closely the system reliability and take actions to improve reliability as required.

Table 1A - All Events

	PowerStream North			All Events		PowerStream South			All Events	
Index	2006	2007	2008	3-year Average	2009	2006	2007	2008	3-year Average	2009
SAIDI	3.678	2.382	2.830	2.963	2.841	0.872	2.168	1.004	1.348	1.730
SAIFI	3.292	3.227	3.356	3.292	1.779	1.082	1.543	0.922	1.182	1.079
CAIDI	1.117	0.738	0.843	0.899	1.597	0.806	1.405	1.089	1.100	1.603
IOR	0.999580	0.999728	0.999678	0.999662	0.999676	0.999900	0.999753	0.999886	0.999846	0.999803

Table 1B - All Events

	PowerStream Total			All Events	
Index	2006	2007	2008	3-year Average	2009
SAIDI	1.513	2.216	1.409	1.713	1.975
SAIFI	1.587	1.923	1.463	1.658	1.233
CAIDI	0.953	1.152	0.964	1.023	1.601
IOR	0.999827	0.999747	0.999840	0.999804	0.999775

Table 2A - Excluding Loss of Supply (LOS)

	PowerStream North			Excluding LOS		PowerStream South			Excluding LOS	
Index	2006	2007	2008	3-year Average	2009	2006	2007	2008	3-year Average	2009
SAIDI	2.701	1.905	1.878	2.161	1.893	0.844	2.163	0.893	1.300	1.498
SAIFI	2.876	2.934	2.339	2.716	1.332	0.997	1.471	0.808	1.092	0.996
CAIDI	0.939	0.649	0.803	0.797	1.421	0.847	1.470	1.105	1.141	1.504
IOR	0.999692	0.999782	0.999786	0.999753	0.999784	0.999904	0.999753	0.999898	0.999852	0.999829

Table 2B - Excluding Loss of Supply (LOS)

	PowerStream Total			Excluding LOS	
Index	2006	2007	2008	3-year Average	2009
SAIDI	1.268	2.105	1.112	1.495	1.585
SAIFI	1.426	1.801	1.148	1.458	1.070
CAIDI	0.889	1.168	0.968	1.008	1.481
IOR	0.999855	0.99976	0.999873	0.999829	0.999819

Table 3A - Excluding Major Event Days (MED)

	PowerStream North			Excluding MED		PowerStream South			Excluding MED	
Index	2006	2007	2008	3-year Average	2009	2006	2007	2008	3-year Average	2009
SAIDI	3.678	2.382	2.830	2.963	2.841	0.872	0.902	1.004	0.926	0.723
SAIFI	3.292	3.227	3.356	3.292	1.779	1.082	1.154	0.922	1.053	0.796
CAIDI	1.117	0.738	0.843	0.899	1.597	0.806	0.782	1.089	0.892	0.908
IOR	0.99958	0.999728	0.999678	0.999662	0.999676	0.999900	0.999897	0.999886	0.999894	0.999917

Table 3B - Excluding Major Event Days (MED)

	PowerStream Total			Excluding LOS	
Index	2006	2007	2008	3-year Average	2009
SAIDI	1.513	1.236	1.409	1.386	1.190
SAIFI	1.587	1.622	1.463	1.557	1.013
CAIDI	0.953	0.762	0.964	0.893	1.175
IOR	0.999827	0.999859	0.999840	0.999842	0.999864

Table 4A - Excluding Loss of Supply (LOS) and Major Event days (MED)

	PowerStream North Excluding LOS & MED					PowerStream South Excluding LOS & MED				
Index	2006	2007	2008	3-year Average	2009	2006	2007	2008	3-year Average	2009
SAIDI	2.701	1.905	1.878	2.161	1.893	0.844	0.897	0.893	0.878	0.719
SAIFI	2.876	2.934	2.339	2.716	1.332	0.997	1.082	0.808	0.962	0.747
CAIDI	0.939	0.649	0.803	0.797	1.421	0.847	0.829	1.105	0.927	0.964
IOR	0.999692	0.999782	0.999786	0.999753	0.999784	0.999904	0.999898	0.999898	0.999900	0.999918

Table 4B - Excluding LOS and MED

	PowerStream Total Excluding LOS & MED				
Index	2006	2007	2008	3-year Average	2009
SAIDI	1.268	1.125	1.112	1.168	0.978
SAIFI	1.426	1.500	1.148	1.358	0.875
CAIDI	0.889	0.750	0.968	0.869	1.117
IOR	0.999855	0.999872	0.999873	0.999867	0.999888

Appendix 1

Distribution System Planning Standards (Criteria, Practices & Guidelines)

Following is a summary of general Distribution System Planning Standards, common to all LDCs,, which consist of Criteria, Practices and Guidelines. The are an integral part of "good utility practice" in distribution planning.

Voltage Level (Criteria)
Service voltages shall comply with the standards of the Canadian Standards Association, CSA Standard CAN3-C235-83.

CSA Standard CAN3-C235-83 "Preferred Voltage Levels for AC System, 0 to 50,000 volts"

Recommended Voltage Variation Limits for Circuits up to 1000 volts, at Service Entrance

Nominal System Voltage	Voltage Variation Limits for Circuits up to 1000 v, at Service Entrances			
	Extreme Operating Conditions	Normal Operating Conditions		Extreme Operating Conditions
Single-Phase				
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635
Three-Phase 4 - Conductor				
120/208 Y	110/190	112/194	125/216	127/220
240/416 Y	220/380	224/388	250/432	254/440
277/480 Y	245/424	254/440	288/500	293/508
347/600 Y	306/530	318/550	360/625	367/635
Three-Phase 3 - Conductor				
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635

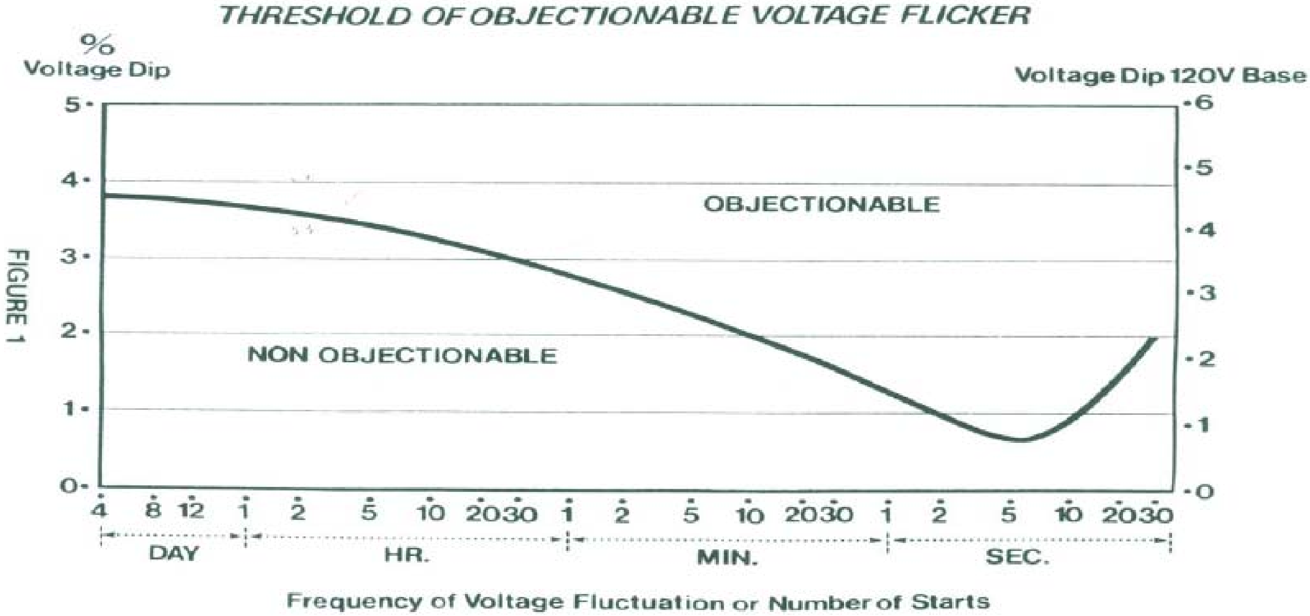
Voltage Unbalance (Guideline)
Voltage unbalance is defined as the maximum phase voltage deviation from the average phase voltage, as a percentage of the average phase voltage. All single-phase load additions shall be connected to the main feeder in a manner to balance the overall three-phase load with respect to voltage. The goal is to maintain the individual phase voltages of a main three-phase feeder to within 3% of each other.

Current Unbalance (Guideline)

Current unbalance is defined as the neutral current or approximately the maximum phase current deviation from the average phase current, as a percentage of the average phase current. Feeders with a phase current deviation in excess of 20% from average will be considered for rebalancing.

Voltage Flicker (Guideline)
Flicker can be defined as a perceptible change in lamp output produced by a sudden change in supply voltage.

THRESHOLD OF OBJECTIONABLE VOLTAGE FLICKER



Neutral Potential (Guideline)
Neutral Potential of up to 10 Volts is acceptable.

Power Factor (Guideline)
Power Factor on feeders as measured at the station bus shall be kept at a minimum of 95% at peak load and a maximum of 100% at light load periods.

Feeder Line Loss Reduction (Practice)
Losses on three phase feeders should be kept to a minimum through the use of appropriately sized conductor, optimal feeder loading and load sharing, phase balancing, and in some cases, applications of shunt capacitors. At the present time the industry standard for a typical Urban utility is in the range of 2.5 -3.5%.

Harmonics (Guideline)
Harmonics are frequencies other than the standard 60-cycle waveform, which can contribute to the malfunction or inefficient operation of electrical devices. Harmonics are usually introduced onto the distribution feeders via non-linear equipment and can be propagated through the system. All customer owned equipment that is connected to the distribution system would be required to comply with the applicable standard such as the IEEE 519 and IEEE STD. #519-1992.

Reliability (Guideline)
The Regulator's Guidelines are as follows:
"Utilities that have at least 3 years of data on the Service Reliability Indices should at minimum remain within the range of their historic performance. All utilities are required to monitor the indices monthly and report to the Board on an annual basis".

Maximum Fault Duration and Ground Potential Rise (Criteria)

Maximum fault duration on lines involving joint use with communication facilities is 3 sec.
Maximum neutral Ground Potential Rise (GPR) is 3000 Volts (CSA C22.3, #5)

Thermal Loading
During normal operating conditions (all elements in service) the load on all network elements should not exceed established normal ratings (continuous loadability). In contingency condition (loss of a major network element), the load on the remaining elements should not exceed established emergency/limited time ratings. Emergency ratings indicate loadability of equipment for short periods of time and accepting a loss of life of the equipment.

Overhead Conductors (Guideline)
The maximum conductor ampacity based on Perpendicular Wind of 0.61 m/s, Conductor Temperature 90° C, and Ambient Temp. 30° C is as follows:

Conductor	Ampacity
556 Al	**777 A.**
336 Al	**564 A.**
4/0 ACSR	**422 A.**
3/0 ACSR	**365 A.**
1/0 ACSR	**273 A.**

Underground Feeder Station Egress Cables (Guideline)
All new underground station egress cables can be Single-Point or Two-Point bonded. When Single-Point bonded is used, a separate neutral is required. The size of the neutral cable shall be no smaller that two sizes below the phase conductor.

The following table shows typical cable ampacities for both grounding options. For site-specific normal and emergency rating, site-specific calculations should be carried out.

The following ampacities are based on 90° C for conductor, 25° C for ambient (soil), thermal resistivity of soil is 90°C cm/watt, and burial depth is approximately 3 m.

Cable Size	Circuits in Duct bank	Two-Point bonded	Single-Point bonded
500 MCM XLPE, Cu*	1	395 A	542 A
750 MCM XLPE, Cu*	1	439 A	678 A
1000 MCM XLPE, Al*	1	-	617 A
750 MCM XLPE, Cu*	2	373 A	576 A
1000 MCM XLPE, Al*	2	-	524 A
1000 MCM XLPE, Cu*	2	-	630 A

A general guideline for determining cable ampacity for multiple feeders in a duct bank is to find the rating from the cable manufacturer for the particular cable in duct and then apply a de-rating factor of 0.7.

Appendix 2

Asset Condition Assessment Framework

The following sections describe the asset management framework in detail. The framework basically comprises of the following three elements:

- Management process for a specific asset class
- Overall asset management planning process
- Process for development of a budget for unscheduled maintenance.

Management Process for a Specific Asset Class

Figure 1 shows the flowchart recommended to be employed to support decisions for a specific asset class. This process employs inputs related to asset condition, criticality, and functionality to perform risk-based economic analysis. The results of this analysis will be evaluated against external drivers, such as corporate goals, regulatory requirements, and health and safety goals, to produce an intermediate program. This intermediate program will be initially developed, considering only the single asset group in question. The program will then be considered for all asset group in optimizing the overall asset management plan.

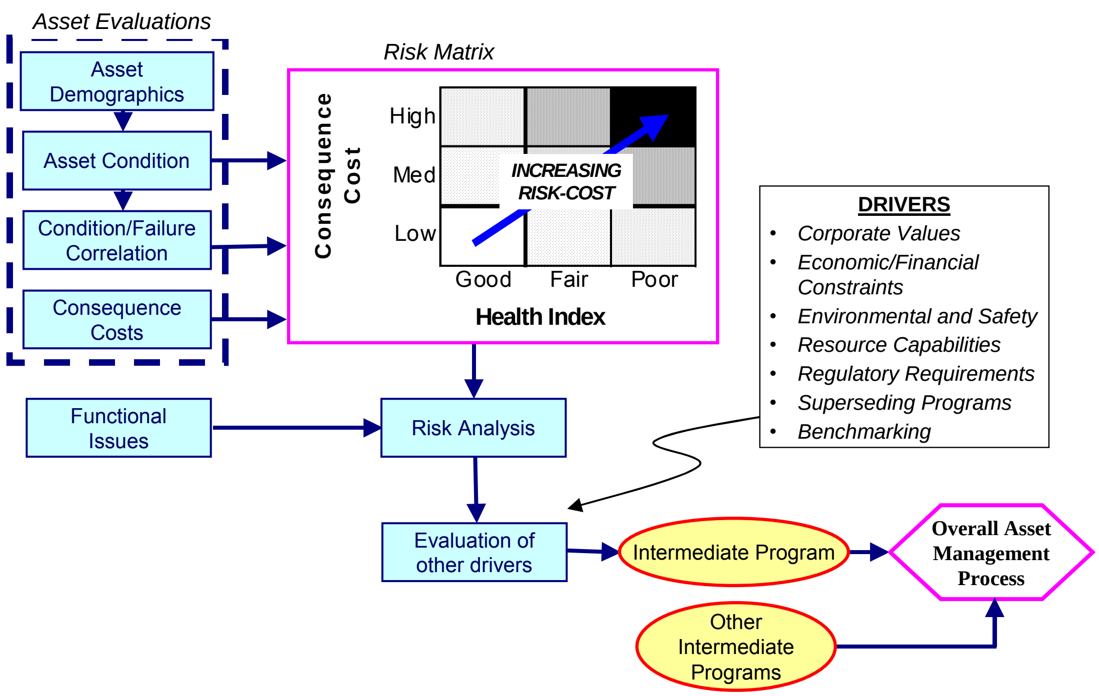


Figure 1 - Management Process for a Specific Asset Group

Asset Evaluation Inputs

The first group of inputs is grouped under Asset Evaluation inputs, as shown inside the dashed box. These inputs define the status of health and condition of existing asset categories, providing an indication of probability of failure risk as well as the consequences of failure. In order for the model to provide accurate results with high confidence levels, it is important that the required information on assets be available.

Asset Demographics includes historic information on assets to permit them to be divided into appropriate categories, so that assets within each category can be independently assessed. Common asset demographic

input parameters include asset age, asset quantity, asset type, installation location, and other distinguishing parameters of use.
Asset Condition input parameters include results of visual inspections, in-situ testing, laboratory testing or other diagnostics that might provide information on asset health and condition. By assigning appropriate weights to various condition indicators, a normalized health index, indicating the asset health on a scale of "0 to 100" is intended to be developed.

Condition/Failure Correlation is based on historic failure modes and trends and translates the asset demographic and asset condition information into failure probability. Equipment procurement specifications, historic loading trends, environmental conditions and past preventative maintenance practices, all play a role in determining asset failure probability and will be taken into account.

Consequence Cost is the sum of all anticipated financial consequences of asset failure based on probabilistic model, which is a function of the criticality of the asset within the supply system network. Consequence costs include asset replacement cost, customer loss due to power interruption, other customer damage, environmental and safety effects, and all other impacts. All tangible consequences of asset failure will be expressed quantitatively; by taking into account asset functions, (e.g., dead-end poles versus tangent poles; heavily-loaded transformers versus lightly-loaded ones).

In addition to the asset evaluation inputs described above, there are external drivers that impact the investment decisions. Table 1 lists the asset evaluation inputs along with the external program drivers that can be employed during in the asset specific management process. This list should not be considered exhaustive; it is intended to give an idea of the types of inputs expected to be included in the final process.

Table 1 - Asset Management Process Inputs

Process Inputs	Input Types	
	Asset Evaluation	Program Drivers
1. Condition	A	
2. Performance (including outliers)	A	
3. Benchmarking	A	P
4. Criticality	A	
5. Consequence cost	A	
6. Corporate values		P
7. Regulatory requirements (ie, OEB)		P
8. Safety and environmental	A	P
9. Tertiary regulation (ie, legislative)	A	P
10. Cost and benefit of action		P
11. Probabilities	A	
12. Capacity and ratings	A	
13. Resource cababilities		P
14. Target IRR, NPV, etc.		P
15. Cash flow		P
16. Duration in specific environment	A	
17. Industry standards	A	
18. Demographics	A	
19. Politics and history		P
20. Stakeholders and customers		P
21. Industry peer (ie, transmission)		P
22. External drivers (ie, development)		P
23. Obsolescence or new technology	A	
24. Options	A	
25. Demand projections	A	
26. Depreciation		P

Risk Matrix
The risk matrix is used to prioritize assets based on valuation of the risk, which is defined as the product of failure probability and consequence cost. The entire population within an asset group is distributed throughout the matrix, based on the asset failure probability and the consequence risk cost for each member. Those assets further right and up in the matrix carry more risk, and are therefore higher priority, than those lower and left.

Functional Inputs
Functional inputs reflect operational factors affecting asset's ability to carry out its intended functions and include capacity, voltage level, short-circuit level, or other characteristics of the equipment that may affect the plan for the asset for reasons other than their condition or risk. These inputs relate the capability of the asset to the operational requirements, for example heavy loading on a transformer, that will influence or drive a requirement to replace the asset.

Risk-Based Economic Analysis
The economic analysis combines the asset's risk profile and functional issues and compares them with risk mitigation investment requirements to develop an economically sound overall plan for maintaining or replacing the asset.

Assessment of Other External Drivers
All tangible costs and benefits will be considered in the economic and risk analysis. However, some external drivers may be difficult to quantify or may simply be significantly more important and may override other considerations. These will be considered separately as a series of "gates" through which the asset plan must pass. As indicated in Figure 2, these external drivers include:

- Corporate values
- Economic and financial constraints
- Environment and safety
- Resource capabilities
- Regulatory requirements
- Superseding programs
- Benchmarks

One benefit of considering these drivers after the economic analysis is that it clearly demonstrates the cost of the drivers based on the changes in the asset program.

Intermediate Program
The final output of this process is the Intermediate Program. This is an optimized plan for the single asset group or program considered, without considering its effects or interactions with any other assets/programs. The intermediate program will have the following characteristics:

- Internal prioritization, directs resources to the highest-risk assets.
- Cost/benefit streams, including risk-cost
- Makes the business case for spending on the specific asset group/program
- Provides justification for the investment to PowerStream shareholders and regulators

Overall Asset Management Planning Process

The flow chart in Figure 2 below shows the process for prioritizing and optimizing among the intermediate asset programs to develop a final asset management plan.

The key parameters of this process are described in the following.

Input, Intermediate Programs

The primary inputs to the process are the intermediate programs developed for each asset groups individually, as described previously. This input includes not only the programs themselves, but also the economic, risk, and other information supporting those programs, which is necessary to make good decisions about trade-offs among the programs.

External Drivers
The same drivers considered in developing the intermediate programs are again considered with regard to development of the overall program. This is to ensure that these overriding requirements are taken into consideration while adopting the overall program.

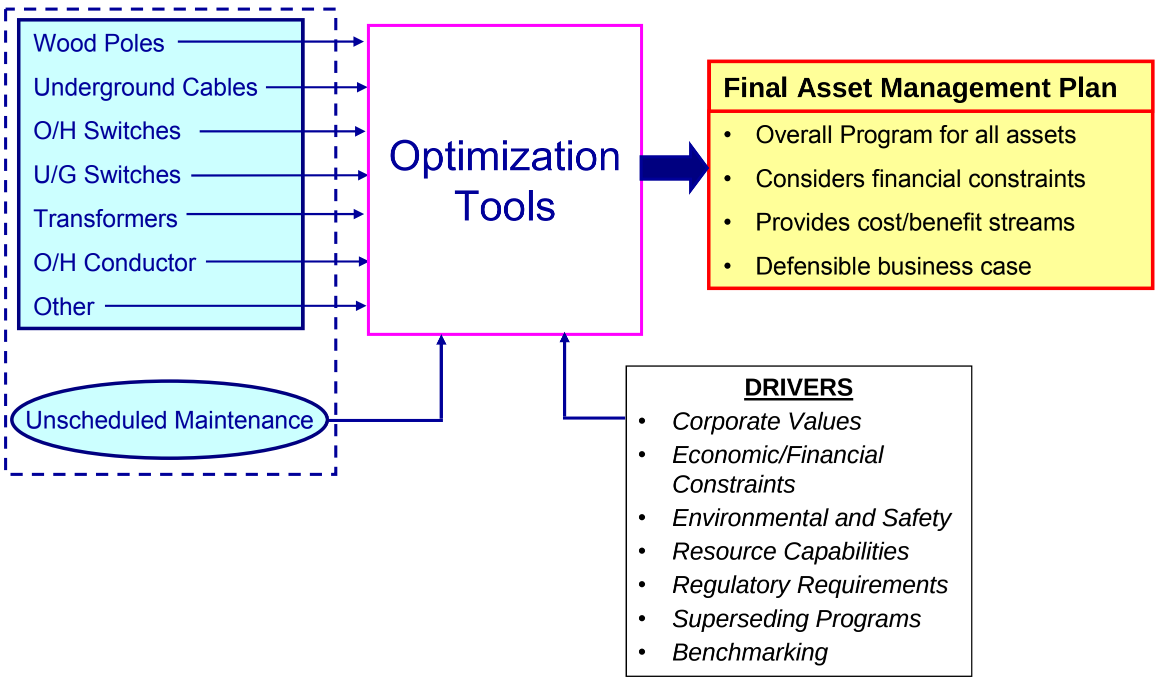


Figure 2 – Overall Asset Management Process

Optimization Process
The optimization process influences and ranks investment plans for all assets, by taking into consideration risk, functionality, corporate goals, regulatory requirements, and other drivers, to maximize the benefit to PowerStream from its investments.

Final Asset Management Plan
The final plan will provide a defensible business case for the spending projects and programs identified. It will also provide a basis for adjusting spending as unexpected events arise.

Appendix 3

Five Year Capital Work Plan

System Planning

2010 - 2014

Prepared by: System Planning

February 9, 2010

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Selected capital projects are recommended by System Planning for design and construction for the five-year period between 2010 and 2014.

The projects are categorized according to the OEB rate case categories of:

- Sustainment Capital
- Development Capital
- Operations Capital

In general, the capital projects are required to accommodate future specific customer connections or general load growth; to maintain system reliability to an acceptable level; and to replace aging, end-of-life equipments based on the results of the Asset Condition Assessment (ACA) process.
The projects cover the following types:

- Planned Replacement based on ACA results:
  - Poles
  - Distribution Switchgears
  - Station Circuit Breakers and Reclosers
  - Underground Primary Cable Replacement and Injection
  - Station Primary Switches
- Distribution Automation
- Distribution Expansion to provide capacity
- Radial Supply Remediation
- Voltage Conversion
- System Reconfiguration to address operations and reliability concerns

It should be noted that, as future emerging issues arise, the scope, 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 reviewed and approved during the annual budget review and approval process.

As PowerStream North and PowerStream South will continue to have two separate rate zones for at least one or more years, the capital projects are further divided into North and South projects.

The forecasts for the funding requirements for PowerStream North, PowerStream South, and the Total PowerStream are summarized in Table 1, Table 2, and Table 3 respectively.

The proposed capital projects for PowerStream North and PowerStream South, with associated OEB categories, are listed in Table 4 and Table 5 respectively.

Table 1 - PowerStream North - Summary of Proposed Capital from System Planning

OEB Category	2010	2011	2012	2013	2014
Sustainment - North	1,382,000	5,300,000	5,000,000	5,000,000	5,000,000
Development - North	419,000	1,400,000	3,000,000	2,000,000	2,000,000
Operations - North	0	0	0	0	0
Total - North	1,801,000	6,700,000	8,000,000	7,000,000	7,000,000

Table 2 - PowerStream South - Summary of Proposed Capital from System Planning					
OEB Category	**2010**	**2011**	**2012**	**2013**	**2014**
Sustainment - South	6,327,000	11,721,000	15,678,000	17,460,000	11,650,000
Development - South	2,587,000	13,442,000	10,786,000	8,116,000	5,500,000
Operations - South	260,000	0	0	0	0
Total - South	9,174,000	25,163,000	26,464,000	25,576,000	17,150,000

Table 3 - PowerStream Total - Summary of Proposed Capital from System Planning					
OEB Category	**2010**	**2011**	**2012**	**2013**	**2014**
Sustainment - North & South	7,709,000	17,021,000	20,678,000	22,460,000	16,650,000
Development - North & South	3,006,000	14,842,000	13,786,000	10,116,000	7,500,000
Operations - North & South	260,000	0	0	0	0
Total - North & South	10,975,000	31,863,000	34,464,000	32,576,000	24,150,000

1.0 INTRODUCTION

1.1 Purpose

This report provides a summary listing of the recommended capital projects for the five-year period between 2010 and 2014, including:

a) projects System Planning has identified based on system needs;
b) budgetary estimates of the recommended projects; and
c) summary of the total estimated recommended costs by OEB categories.

1.2 Background

Selected capital projects are recommended by System Planning for design and construction for the five-year period between 2010 and 2014.
The projects are categorized according to the OEB rate case categories of:

- Sustainment Capital
- Development Capital
- Operations Capital

Generally, PowerStream capital work originate from projects driven by the Cities, Towns, Regions, Ministry of Transportation, new subdivisions, customers installing new services or upgrading their electrical service capacities. Capital work are also required to maintain acceptable reliability to its customers; to address operations and safety issues; and to replace the aging , end-of-life equipments based on the results of the Asset Condition Assessment (ACA) process. These projects are referred to as “Controllable Capital Projects”. There are cases where a project is formulated to address more than one issue listed above.
The proposed projects cover the following project types:

A. Planned Replacement based on ACA results:
    - Poles
    - Distribution Switchgears
    - Station Circuit Breakers and Reclosers
    - Underground Primary Cable Replacement and Injection
    - Station Primary Switches
B. Distribution Automation
C. Distribution Expansion to provide Capacity
D. Radial Supply Remediation
E. Voltage Conversion
F. System Reconfiguration to address operations and reliability concerns

Below are brief descriptions of the project types.

A. Planned Replacement from the ACA Program

The Asset Condition Assessment Program is the continuation of work from 2006, 2007, 2008, and 2009. The ACA Program covers the following asset classes:

- TS Transformers
- MS Transformers
- Station Circuit Breakers and Reclosers
- Station High Voltage Switches
- Station Capacitors and Reactors
- Distribution Transformers
- Distribution Switchgears
- Underground Primary Cables
- Wood Poles

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: Field Expert 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.

Some examples of this project type include projects PSN#1, PSN#2, PSN#3, PSN#4, PSN#5, PSS#6, PSS#18, PSS#19, PSS#20, PSS#21, PSS#22, PSS#23.

B. Distribution Automation

Although in general distribution automation will improve power outage planning and 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.

Some examples of this project type include projects PSN#13, PSS#19.

C. Distribution Expansion to provide Capacity

To accommodate specific individual new customer load connections or general system load growth, PowerStream must expand or re-configure or upgrade the existing distribution system. This may be required at the equipment, feeder, or station level.

Every year System Planning conducts load forecast study to identify capacity short fall and recommends projects to ensure sufficient capacity for the customer demands.

According to the latest Load Forecast, for the five-year period from 2010 – 2014, the average annual growth rate for PowerStream North and PowerStream South is 2.8% and 3.0% respectively.

During this five-year period, no new TS are required in PowerStream North, but there is a need for a new Vaughan TS#4 in PowerStream South with the in-service date in 2014.

Some examples of this project type include projects PSN#10, PSN#15, PSN#18, PSN#19, PSS#41, PSS#42, PSS#44, PSS#45, PSS#66, PSS#69.

D. Radial Supply Remediation

The vast majority of PowerStream distribution system is designed as an open grid system with multiple interconnections between the feeders. Under this supply scheme, when a 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.

According to the PowerStream South Radial Supply Review Report, 72 radial supply locations exist in the following formats:

- 16 kV single phase in rural areas
- 27.6 kV three phase lateral circuits
- The ends of 27.6 kV three phase main feeders
- Three phase 13.8 kV and 8.3 kV feeders

The remediation projects are formulated based on the following criteria:

- Number of customers and the length of radial supplies
- Requirements from System Control
- kVA connected
- Feasibility to remediate

Examples of this project type include PSS#26, PSS#27, PSS#28, PSS#30, PSS#32, PSS#47, PSS#48, PSS#50, PSS#51, PSS#57, PSS#58, PSS#69, PSS#77, PSS#78.

E. Voltage Conversion

PowerStream has a number of Municipal Stations (MS) providing supply feeders at 8.32 kV and 13.8 kV levels. In general, 8.32 kV and 13.8 kV systems have higher distribution losses than do the higher voltage systems such as 27.6 kV systems.
Another operations issue of the 8.32 kV and 13.8 kV MS is that some MS's have a single transformer and long single feeder which make power outage restoration difficult, and as a result have 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.

Examples of this project type include projects PSS#36, PSS#37, PSS#38, PSS#54, PSS#55, PSS#63, PSS#70, PSS#71, PSS#79.

F. System Re-configuration

System Planning, in consultation with System Control and Lines, will recommend projects to resolve feeder loading balancing and load transfer capability under normal and emergency situations. Operations and safety issues will be considered.
Examples of this project type include projects PSN#11, PSN#18, PSS#82, PSS#83.

It should be stated that monitoring of the system performance is an on-going undertaking and involves discussions with Lines, Operations and the Reliability Committee. Projection of specific projects for a five-year window is not an accurate exercise. As time goes on into the future, there will be emerging issues arise that will affect the priority, scope, and cost of each project. As a result, the Five - Year Capital Work Plan will be monitored, revisited and revised every year, or more often as required.

1.3 Capital Project Justification & Budget Approval

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" which is posted in PowerStream Inflow.

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:

- Business Excellence (weighting factor = 31.4%)
- Customer Satisfaction (weighting factor = 28.8%)
- Financial (weighting factor = 18.9%)
- Health & Safety (weighting factor = 12.4%)
- Environmental Sustainability (weighting factor = 8.5%)

2.0 CAPITAL PROJECTS

2.1 SUSTAINMENT CAPITAL PROJECTS

Sustainment capital is defined to include projects that replace depleted asset to maintain reliability of the distribution system so that it will continue to function as intended. In general, this includes the replacement of overhead and underground lines, 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 switchgears, underground primary cables, station circuit breakers and reclosers).

The proposed sustainment capital projects for PowerStream North and PowerStream South are included in Table 4 and Table 5 respectively.

One significant project is the replacement of end-of-life direct buried underground cable in older subdivisions. This is a challenge for PowerStream because there is significant amount of existing direct buried underground cable, and cable replacement projects are very expensive. For a certain types of cables, alternative solution to cable replacement is cable injection. PowerStream will continue with some "pilot" projects on cable injection to gain more experience on the technology and process. Currently no long term decision has been made on cable injection.

2.2 DEVELOPMENT CAPITAL PROJECTS

Development capital projects are those projects that involve system expansion and relocation due to growth and/or are undertaken to satisfy external demands. This category includes relocation and expansion of distribution system plant to supply new customers and new developments.

One significant project is the construction of the new Vaughan TS#4 and associated feeders, which is required in 2014.

The proposed development capital projects for PowerStream North and PowerStream South are included in Table 4 and Table 5 respectively.

2.3 OPERATIONS CAPITAL PROJECTS

Operations capital is defined to include the projects that support the day-to-day operations of the distribution system.

The proposed operations capital projects for PowerStream North and PowerStream South are included in Table 4 and Table 5 respectively.

3.0 SUMMARY

The forecasts for the funding requirements for PowerStream North, PowerStream South, and Total PowerStream are summarized Table 1, Table 2, and Table 3 respectively.

Table 1 - PowerStream North - Summary of Proposed Capital from System Planning

OEB Category	2010	2011	2012	2013	2014
Sustainment - North	1,382,000	5,300,000	5,000,000	5,000,000	5,000,000
Development - North	419,000	1,400,000	3,000,000	2,000,000	2,000,000
Operations - North	0	0	0	0	0
Total - North	1,801,000	6,700,000	8,000,000	7,000,000	7,000,000

Table 2 - PowerStream South - Summary of Proposed Capital from System Planning

OEB Category	2010	2011	2012	2013	2014
Sustainment - South	6,327,000	11,721,000	15,678,000	17,460,000	11,650,000
Development - South	2,587,000	13,442,000	10,786,000	8,116,000	5,500,000
Operations - South	260,000	0	0	0	0
Total - South	9,174,000	25,163,000	26,464,000	25,576,000	17,150,000

Table 3 - PowerStream Total - Summary of Proposed Capital from System Planning

OEB Category	2010	2011	2012	2013	2014
Sustainment - North & South	7,709,000	17,021,000	20,678,000	22,460,000	16,650,000
Development - North & South	3,006,000	14,842,000	13,786,000	10,116,000	7,500,000
Operations - North & South	260,000	0	0	0	0
Total - North & South	10,975,000	31,863,000	34,464,000	32,576,000	24,150,000

Table 4 - PowerStream North - Proposed Capital Projects from System Planning ($000)

Proj #	Project Title	OEB	2010	2011	2012	2013	2014	Remarks
PSN#1	Planned Pole Replacement Program (ACA) - North	Sust	500,000	700,000	700,000	700,000	700,000	JB7- Replace approx. 70 poles/year
PSN#2	Planned Distribution Switchgear Replacement Program (ACA) - North	Sust	263,000	500,000	500,000	500,000	500,000	JB9 - Replace approx. 10 units/year
PSN#3	Planned Circuit Breaker and Recloser Replacement Program (ACA) - North	Sust		300,000	300,000	300,000	300,000	Replace approx. 3 units/year
PSN#4	Planned Primary Cable Replacement Program (ACA) – North	Sust		1,000,000	2,000,000	2,000,000	2,000,000	Replace approx. 8,000 m/year
PSN#5	Primary Cable Injection Program (ACA) - “Pilot” Projects - North	Sust		300,000	300,000	300,000	300,000	Inject approx. 5000 m/year x $60/m
PSN#6	Planned Station Primary Switch Replacement Program (ACA) – North	Sust		200,000	200,000	200,000	200,000	Replace approx. 2 HV switches/year
PSN#7	Station Soil Testing Program - North	Sust	50,000	50,000				JB14
PSN#8	Purchase of 44 kV Assets from Hydro One (approx. 70 poles in Bradford) - North	Sust		600,000				
PSN#9	Purchase of 44 kV Assets from Hydro One (approx. a total 8 km of pole line in Barrie, Alliston, Tottenham) - North	Sust	500,000					8 km of pole line in Barrie, Alliston & Tottenham
PSN#10	MS324 (Reagans) Upgrade - Add 2 - 13.8 kV Feeders - North	Devel	144,000					TB10
PSN#11	13.8 kV Tie - MS331 x MS330 - Alliston - North	Sust	69,000					TB8
PSN#12	Interim 44 kV Supply to Commodore TD Data Centre - North	Devel	275,000					TB4
PSN#13	Distribution Automation - Installation of Automatic Switches - North	Sust			500,000	500,000	500,000	Locations to be determined
PSN#14	Worst Performing Feeders (WPF) - Implementing solutions to improve feeder reliability. List of projects to be provided - North	Sust		500,000	500,000	500,000	500,000	Locations to be determined

Proj #	Project Title	OEB	2010	2011	2012	2013	2014	Remarks
PSN#15	Expansion 44 kV Feeders (From Midhurst TS to Barrie South, 20km) - North	Devel			2,000,000	2,000,000	2,000,000	Build 20 km of double circuit line from Midhurst to Mapleview for in-service in 2014
PSN#16	Expansion Distribution - New 10 MVA Substation in Tottenham (Replace MS 835 Mill St.) In-service in 2012 - North	Devel		600,000	1,000,000			Station MS835 req. appr. $500k of rehab work, the site is leased from Town.
PSN#17	Fairlane DS, 8.32 kV Feeder - Add Scada controlled recloser - North	Sust		150,000				
PSN#18	Park Place MS-13.8 kV Feeder Integration and Load Transfer from adjacent Station(s) - North	Devel		500,000				
PSN#19	Expansion 44 kV and 13.8 kV Feeders in Bradford (From Holland & Middletown to Middletown & Conc. #6., approx. 1.5 km) - North	Devel		300,000				
PSN#20	South Simcoe Study (accommodate load transfers from Midhurst T1/T2 to Midhurst T3/T4) - North	Sust						Costs to be determined
PSN#21	Belcourt Ave Subdivision UG cable Rehab – Phase 2 - North	Sust		1,000,000				Phase 1 was completed in 2009
	Total		1,801,000	6,700,000	8,000,000	7,000,000	7,000,000	

Table 5 - PowerStream South - Proposed Capital Projects from System Planning ($000)

Proj #	Project Title	OEB	2010	2011	2012	2013	2014	Remarks
PSS#1	Add additional ccts on pole line - Major Mackenzie Dr from west of Dufferin St to Keele St - South	Devel	541,000					SG147
PSS#2	Install 2-27.6 kV overhead ccts - Hwy 7 from 9th Line to Reesor Road - South	Devel	1,153,000					SG148
PSS#3	Retro-fitting Vaults and Submersible units - Various locations in the Town of Richmond Hill and Town of Markham - South	Sust	378,000	378,000	378,000			SGKD149
PSS#4	Replace existing overhead secondary bus - Arnold Avenue Area V1 - South	Sust	454,000					SGSC128
PSS#5	Extend Feeders 20M11/M12 into Markham providing a tie between Greenwood TS, Richmond Hill TS & Leslie TS - South	Devel	720,000					SGTB102
PSS#6	Radial Supply Remediation - Convert Rainbow MS Feeders to 27.6 kV - South	Sust	1,025,000					SGTB112
PSS#7	Markham TS#4 feeder egress - 4 ccts on hydro easement (DESIGN ONLY) - South	Devel	24,000					SG139
PSS#8	Markham TS#4 - Install 4 ccts on new pole line (DESIGN ONLY) - South	Devel	23,000					SG140
PSS#9	Markham TS#4 - Install 4 ccts in underground duct bank for MTS4 (DESIGN ONLY) - South	Devel	31,000					SG141
PSS#10	Install 2-27.6 kV ccts on poles - 14th Ave from 9th Line east to Reesor Road (DESIGN ONLY) - South	Devel	44,000					SG146
PSS#11	Install 4-27.6 kV ccts on poles - 14th Ave from Hwy 48 to 9th Line Markham (DESIGN ONLY) - South	Devel	51,000					SG149
PSS#12	Primary Cable Replacement - Markham Meadow (Flowervale) Subdivision - Phase I - South	Sust	1,400,000					SG165
PSS#13	Primary Cable Replacement - Markham Meadow (Flowervale) Subdivision - Phase II - South	Sust		1,400,000				SG

Proj #	Project Title	OEB	2010	2011	2012	2013	2014	Remarks
PSS#14	Primary Cable Replacement - Markham Meadow (Flowervale) Subdivision - Phase III - South	Sust			1,400,000			SG
PSS#15	Primary Cable Replacement - Romfield Subdivision Phase 1 - South of Hwy 407, Markham - South	Sust		1,000,000	1,000,000	260,000		SG1238
PSS#16	ACA Initiative - Asset Management Plan - Enhancement to existing system - South	Opers	220,000					JB11
PSS#17	ACA Initiative - Health Index Granularity - Enhancement to existing system - South	Opers	40,000					JB12
PSS#18	Planned Pole Replacement Program (ACA) - South	Sust	510,000	1,000,000	1,000,000	1,000,000	1,000,000	JB1 - Replace approx. 100 poles/year
PSS#19	Planned Distribution Switchgear Replacement Program (ACA) - South	Sust	1,360,000	1,400,000	1,400,000	1,400,000	1,400,000	JB3 - Replace approx 28 units/year
PSS#20	Planned Circuit Breaker and Recloser Replacement Program (ACA) - South	Sust	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	JB5 - Replace approx. 11 units/year
PSS#21	Planned Primary Cable Replacement Program (ACA) - South	Sust		2,000,000	2,000,000	2,000,000	2,000,000	Replace approx. 8,000 m/year
PSS#22	Primary Cable Injection Program (ACA) – "Pilot" Projects - South	Sust		300,000	300,000	300,000	300,000	Inject approx. 5,000 m/year x $60/m
PSS#23	Planned Station Primary Switch Replacement Program (ACA) – South	Sust			500,000	500,000	500,000	Replace approx. 2 units/year
PSS#24	Station Soil Testing Program - South	Sust	100,000	100,000				JB13
PSS#25	Distribution Automation - Installation of Scada-Mate automatic switches at various locations - South	Sust		1,352,000	1,400,000	1,400,000	1,400,000	SGTB129 - Locations to be determined
PSS#26	Radial Supply Remediation - One 27.6 kV cct on 19th Ave from Leslie to Woodbine Ave - South	Devel		1,053,000				SGTB125

Proj #	Project Title	OEB	2010	2011	2012	2013	2014	Remarks
PSS#27	Radial Supply Remediation - Installation of additional 27.6 kV cct on existing poles on Woodbine Ave from Elgin Mills Rd to 19th Ave - South	Devel		491,000				SGTB124
PSS#28	Radial Supply Remediation - Double 27.6 kV ccts on McNaughton Rd from CNR east to Major Mackenzie Dr - South	Devel		500,000				SG137
PSS#29	Install Double 27.6 kV ccts on 16th Ave from 9th Line to Reesor Rd - South	Devel		1,046,000				SGSC131
PSS#30	Radial Supply Remediation - Second supply to Doney Cr from Highway 7 & Keele St - South	Devel		71,000				SG130
PSS#31	Install additional 3 phase cct on existing pole line on Dufferin St from Major Mackenzie Dr to Teston Rd - South	Devel		344,000				SG102
PSS#32	Radial Supply Remediation - Rebuild one 27.6 kV cct on Reesor Rd from Major Mackenzie Dr to 19th Ave - South	Devel		500,000				
PSS#33	Replacement of 60 submersible transformers in Markham area - 2nd phase - South	Sust			1,500,000	1,500,000	1,500,000	TB134 - Recommeded by Lines.
PSS#34	Install OH & UG LED Fault Indicators in Vaughan, Richnond Hill, Aurora - South	Sust		391,000				Recommended by Lines
PSS#35	Aurora system Remote Fault Indicator Deployment - South	Sust		300,000				Recommended by System Control
PSS#36	Elders MS conversion to 27.6 kV phase II - South	Sust		500,000				
PSS#37	Amber F3 conversion phase 2 - eliminate delta transformers - South	Sust			500,000			
PSS#38	Amber F3 conversion phase 3 - eliminate delta transformers - South	Sust				500,000		

Proj #	Project Title	OEB	2010	2011	2012	2013	2014	Remarks
PSS#39	TransCanada Pipe Lines Supply Option 2: Weston Rd – south of Kirby Sideroad to Major Mackenzie Dr , west to Hwy # 27, south to Rutherford Rd – west of Hwy # 27 - South	Devel		0				Project was estimated at $3,000,000. However project was cancelled by TransCanada on Feb 3, 2010.
PSS#40	TransCanada Pipe Lines Supply Option 1: Nashville Rd - Kleinburg TS, east to Huntington Rd, east to Hwy # 27, north to Kirby Sideroad, east to Weston Rd, to Rimwood Subdivision - South	Devel		0				Project was estimated at $3,000,000. However project was cancelled by TransCanada on Feb 3, 2010.
PSS#41	Markham TS#4 feeder egress - 4 ccts on hydro easement (DESIGN in 2010) - South	Devel		127,000				SG139
PSS#42	Markham TS#4 - Install 4 ccts on new pole line (DESIGN in 2010) - South	Devel		1,057,000				SG140
PSS#43	Markham TS#4 - Install 4 ccts in underground duct bank for MTS4 (DESIGN in 2010) - South	Devel		3,545,000				SG141
PSS#44	Install 2-27.6 kV ccts on poles - 14th Ave from 9th Line east to Reesor Road (DESIGN in 2010) - South	Devel		1,235,000				SG146
PSS#45	Install 4-27.6 kV ccts on poles - 14th Ave from Hwy 48 to 9th Line Markham (DESIGN in 2010) - South	Devel		2,373,000				SG149
PSS#46	Install second cct on Bathurst St from S/O Gamble Rd to KVTL approx 2.5 km - South	Devel			385,000			SG129
PSS#47	Radial Supply Remediation - Double 27.6 kV ccts on Major Mackenzie Dr from 9th Line to Reesor Rd - South	Devel			986,000			SG131
PSS#48	Radial Supply Remediation - Convert 13.8 kV feeder on Miller Ave to 27.6 kV supply - South	Devel			1,015,000			JN137
PSS#49	Double ccts on Reesor Rd from 14th Ave to 16th Ave - South	Devel				3,988,000		JN141

Proj #	Project Title	OEB	2010	2011	2012	2013	2014	Remarks
PSS#50	Radial Supply Remediation - Install 1 - 27.6 kV cct with future framing for additional 1-27.6 kV cct on 19th Ave from Woodbine Ave to Kennedy Rd - South	Devel				1,114,000		TB123
PSS$51	Radial Supply Remediation - Install 1 - 27.6 kV cct with future framing for additional 1-27.6 kV cct on 19th Ave from Kennedy Rd to McCowan Rd - South	Devel				1,114,000		TB126
PSS#52	407 Transitway (OH and UG crossing – Jane, Keele, Centre, Dufferin, Bathurst, Yonge, Bayview, Leslie, Hwy 400, Woodbine, Warden, Kennedy) - South	Sust				4,000,000		OH & UG crossings
PSS#53	Worst Performing Feeders (WPF) - Implementing solutions to improve feeder reliability. List of projects to be provided - South	Sust		500,000	500,000	500,000	500,000	Locations to be determined
PSS#54	Concord MS conversion to 27.6 kV Phase 1 - Peelar Rd & Creditstone Rd & Maple Crete Rd - South	Sust			1,000,000			
PSS#55	Amber F2 conversion to 27.6 kV - South	Sust			500,000			
PSS#56	Steeles Ave to 407 West side of Yonge, VAUGHAN (RECOMMENDED BY LINES) - South	Sust			500,000			
PSS#57	Radial Supply Remediation - One 27.6kV cct on Leslie St from Bethesda Rd to Bloomington Rd - South	Devel			300,000			
PSS#58	Radial Supply Remediation - One 27.6kV cct on Kennedy Rd from Elgin Mills Rd to 19th Ave - South	Devel			600,000			
PSS#59	Radial Supply Remediation - One UG cct on Islington Ave from the end of 22M11 to Nashville Rd - South	Devel			600,000			
PSS#60	One additional cct on Steeles Ave from Jane St to Keele St to supply subway station - South	Devel			800,000			

Proj #	Project Title	OEB	2010	2011	2012	2013	2014	Remarks
PSS#61	One additional cct on Hwy 7 from Jane St to Hwy 400 to supply subway station - South	Devel			800,000			
PSS#62	Rebuild pole line on Miller Ave to 27.6 kV and convert the customers to 27.6 kV (Markham AMB-F1) - South	Sust			300,000			
PSS#63	Elders MS conversion to 27.6 kV phase III - South	Sust			400,000			
PSS#64	Add 2 ccts on Hwy 7 between Rodick Rd and Warden Ave - South	Devel			600,000			
PSS#65	Add 2 ccts on Warden Ave between Hwy 7 and 16th Ave, 3 ccts between 16th Ave and Major Mackenzie Dr - South	Devel			4,000,000			
PSS#66	Add 1 cct on 16th Ave between Woodbine Ave and Leslie St - South	Devel			300,000			
PSS#67	Add second cct on Leslie St from 16th Ave and Major Mackenzie Dr - South	Devel			400,000			
PSS#68	New Vaughan TS #4 - Year 1, Year 2, Year 3 (3 - year project) - South	Devel		1,000,000				in-service in 2014
PSS#69	New Vaughan TS #4 - Feeder Egress Phase 1 - 4 feeders - South	Devel					5,000,000	in-service in 2014
PSS#70	Concord MS conversion to 27.6 kV Phase 2 - Bowes Rd & Rivermede Rd - South	Sust				500,000		
PSS#71	Morgan MS conversion to 27.6 kV - South	Sust				1,000,000		
PSS#72	Laureleaf and Steeles Area Markham (RECOMMENDED BY LINES) - South	Sust				500,000		
PSS#73	Cachet Area Markham (RECOMMENDED BY LINES) - South	Sust				500,000		
PSS#74	Murray Drive Aurora (RECOMMENDED BY LINES) - South	Sust				500,000		
PSS#75	Add second cct on Leslie St from Major Mackenzie Dr to Elgin Mills Rd - South	Devel				400,000		
PSS#76	Add second cct on Elgin Mills Rd from Woodbine Ave to Leslie St - South	Devel				400,000		

Proj #	Project Title	OEB	2010	2011	2012	2013	2014	Remarks
PSS#77	Radial Supply Remediation - One 27.6kV cct on McCowan Rd from Elgin Mills Rd to 19th Ave - South	Devel				550,000		
PSS#78	Radial Supply Remediation - One 27.6kV cct on 19th Ave from McCowan Rd to Hwy 48 - South	Devel				550,000		
PSS#79	King MS conversion to 27.6 kV - in conjunction with Vaughan TS4 feeders - South	Sust					1,000,000	
PSS#80	Wells Street Aurora (RECOMMENDED BY LINES) - South	Sust					400,000	
PSS#81	Re-route 22M3 in Markham to Esna Park to offload 22M5/22M6 on Rodick via the new railway bridge - South	Devel					500,000	
PSS#82	Aurora - Re-conductor Mill St from 3/0 to 336 - build feeder tie between MS3 and MS1 - South	Sust					500,000	
PSS#83	Feeder balancing - Aurora - Install LIS between 4F1 and 4F2 - South	Sust					50,000	
PSS#84	Aurora MS9 - New MS - South	Devel						
	Total		9,174,000	25,163,000	26,464,000	25,576,000	17,150,000	

Five Year Capital Work Plan
Station Design & Construction
Engineering Planning Division
2010 - 2014

Prepared by: *Glenn Allen, P. Eng.*
Manager, Station Design & Construction

Reviewed by: *Ted Wojcinski, P. Eng.*
Vice President, Engineering Planning

5 Year Capital Work Plan, Station Design & Construction 2010 - 2014

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Selected projects are recommended by Stations Design & Construction for implementation for the five-year period between 2010 and 2014.

As has been performed in previous editions of this document, the projects have been categorized as:

- Special Projects
- Reliability Projects
- Capacity Projects

The 2009 Rate Submission has required that the projects also be designated with the OEB rate case categories of:

- Sustainment Capital
- Development Capital
- Operations Capital

The forecasts for the dollar requirements on a yearly basis are shown in Tables 1A and 1B.

TABLE 1A: SUMMARY OF TOTAL RECOMMENDED CAPITAL DOLLARS

Category	2010 BUDGET $000	2011 BUDGET $000	2012 BUDGET $000	2013 BUDGET $000	2014 BUDGET $000
Special Projects	2,022	761	919	821	1,696
Reliability Projects	782	739	1,004	1,906	378
Capacity Projects	1,178	0	0	4,159	19,413
TOTAL DOLLARS	3,982	1,500	1,923	6,886	21,487

TABLE 1B: SUMMARY CAPITAL DOLLARS BY OEB CATEGORY

Category	2010 BUDGET $000	2011 BUDGET $000	2012 BUDGET $000	2013 BUDGET $000	2014 BUDGET $000
Sustainment	2,804	1,500	1,923	2,727	2,074
Development	1,178	0	0	4,159	19,413
Operations	0	0	0	0	0
TOTAL DOLLARS	3,982	1,500	1,923	6,886	21,487

1.0 INTRODUCTION

1.1 Background

Selected projects are recommended by Stations Design & Construction for implementation over the five-year period between 2010 and 2014.

As has been performed in previous editions of this document, the projects have been categorized as:

- Special Projects
- Reliability Projects
- Capacity Projects

OEB Rate Submissions require that projects also be designated with the OEB rate case categories of:

- Sustainment Capital
- Development Capital
- Operations Capital

Generally, PowerStream's capital work originates from construction driven by the Cities of Vaughan and Barrie, the Towns of Markham, Richmond Hill and Aurora, the Region of York, Simcoe County, Ministry of Transportation, development of new subdivisions which require services or facilities that are not presently in place and customers installing new services or customers upgrading their electrical service capacities.

Work recommended in this document supports projects that are not, in general, driven by direct legal need, governmental or regulatory bodies, and for those that have not been dictated as a requirement - they have been previously considered "controllable" projects. These projects are aimed at improvements to system reliability and for providing additional capacity.

It should be stated that monitoring of the system's performance is an on-going undertaking and involves discussions with Operations and the Reliability Committee. Projection of specific projects for a five-year window is not an accurate exercise. Where stated, placeholders for anticipated projects have been recommended.

1.2 Purpose

This report provides the background support and justifications for projects, specifically;

a) detailing all projects Station Design has identified to complete,
b) providing budgetary estimates of the recommended projects,
c) providing an overview of the scope of each of the projects,
d) providing a summary of the total estimated recommended costs by category, and
e) performing risk, performance improvement estimates and priority rankings, where possible.

In the event that a project requires a performance improvement estimate, or a risk assessment, they will be included in the Appendices.

1.4 Capital Project Justification & Budget Approval

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” which is posted in PowerStream Inflow.

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:

- Business Excellence (weighting factor = 31.4%)
- Customer Satisfaction (weighting factor = 28.8%)
- Financial (weighting factor = 18.9%)
- Health & Safety (weighting factor = 12.4%)
- Environmental Sustainability (weighting factor = 8.5%)

PROJECTS

2.1 SPECIAL PROJECTS

Each year, there are a number of issues that arise resulting in initiatives to provide solutions. These are listed below.

2.1.1 Transformer Stations

Project SP1: On-line Monitoring of Transformer Oil (2010-2014)
GA401, GA501, GA601, GA701 & GA801

This project is a continuation of work started in 2008 to implement real time transformer gas in oil telemetry at Markham TS #1.

This project will provide real time transformer gas in oil telemetry, temperature and operational status to PowerStream's control room and to Station Maintenance staff at their desk. The gas in oil measurement will be integrated with winding & oil temperature, tap position, cooling fan and pump status as well as oil level & pressure alarms in a control unit in each transformer. All of this data will be analysed in real time to provide the following operation and maintenance information:

- Gas in oil readings and gas in oil trend charts, this information will alert staff to incipient problems so that the transformer can be proactively removed from service before failure,
- Transformer oil and winding temperature indication, this information will be used to automatically perform insulation life loss calculations,
- Calculate maximum load carrying capability for current ambient temperature, and
- Monitor the status and effectiveness of cooling fans and pumps.

On-line gas in oil analysis is currently implemented at Markham TS #1 & #3, Richmond Hill TS #1 & #2 and Vaughan TS #3, but is not implemented at Markham TS #2 or at Vaughan TS #1 & #2. The scope of this project will be to install transformer gas-in-oil telemetry and on-line analysis control units for the transformers at Markham TS #2, Richmond Hill TS #1 as well as Vaughan TS #1 and #2.

The remaining gas in oil monitoring and analysis equipment will be installed over a six year period between 2010 and 2015. The expected costs, including burdens, are shown below in Table 2:

Table 2 – Summary of On-Line Transformer Oil Monitoring Project Costs

Year	Station	Cost	Project ID
2008	Markham TS #1	$129,000	GA201
2009	Markham TS #3 – T1, T2, T3 & T4	$227,000	GA301
2010	Markham TS #2 – T1 & T2	$163,000	GA401
2011	Vaughan TS #1 – T1 & T2	$163,000	GA501
2012	Vaughan TS #1 – T3 & T4	$165,000	GA601
2013	Vaughan TS #2	$154,000	GA701
2014	Richmond Hill TS #1	$181,000	GA801

Project SP2: On-line Monitoring of MS Transformers (2010-2013) GA402, GA509, GA602, GA702

This project will provide real time transformer temperature monitoring and telemetry to PowerStream's control room and to Station Maintenance staff. The scope of this project will be to provide transformer temperature telemetry for the transformers at:

- MS432 Fletcher Alliston, MS834 Nolan Tottenham, and MS422 Robert Penetang,
- Two additional Barrie MS transformers, and
- Aurora MS 1, 2, 3, 4, 5 & 6.

The transformer temperature monitoring and telemetry equipment will be installed over a four year period between 2010 and 2013. The expected costs are shown below in Table 3:

Table 3 – Summary of On-Line Transformer Temperature Monitoring Project Costs

Year	Station	Cost	Project ID
2010	MS432, MS834, MS422	$54,000	GA402
2011	2 transformers, Barrie MS	$25,000	GA509
2012	Aurora MS 1, 2 & 3	$48,000	GA602
2013	Aurora MS 4, 5 & 6	$49,000	GA702

Project SP3: On-site storage at Transformer Stations (2011) GA306

PowerStream is in the process of consolidating its East and West Service Centres into one new service centre in Markham. As a result of these changes there will be a net reduction in the amount of storage space available for transformer station spare parts and workshop space for trades staff. For this reason Asset Management has decided to store spare parts for transformer stations on site. The storage structure at Richmond Hill TS #1 will also be heated and used as a shop facility.

The estimated cost of site preparation for the on-site storage structure at Richmond Hill Transformer Station is $44,000, including burdens.

Project SP4: Install Perimeter Lighting at Richmond Hill TS #1 & #2 (2011) GA307

Install improved perimeter lighting in the switchyard at Richmond Hill TS #1 & #2. The purpose of the switchyard lighting is to provide the appropriate illumination for video surveillance along the station perimeter. Since the station is in an urban area the lighting will designed so that it will not glare into nearby properties.

This project was originally submitted for 2009, but deferred to 2011 because of low priority.

The estimated cost for the perimeter lighting is $37,000, including burdens.

Project SP5: Install Capacitor Banks at Torstar TS (2010) GA105

This project is to install capacitor banks at Torstar TS to meet IESO power factor requirements. The scope of the project includes Installation of two 20MVAR outdoor, externally fused, capacitor banks, two 28kV indoor breakers as well as associated cables & ductwork.

The Market Rules require that wholesale customers and distributors connected to the IESO controlled grid shall operate at a power factor within the range of 90% lagging to 90% leading as measured at the defined meter point.[1]

During the summer of 2005, the power factor at Torstar TS was measured as low as 76% by the

IESO. For this reason, the IESO stated in the Greenwood MTS Expansion-System Impact Assessment Report, “It is required that LV shunt capacitors be installed with the new transformers at Greenwood TS, Vaughan TS #2 and Vaughan TS #3”.[2]

The approximate cost of the two units is $1,056,000, including burdens.

Other options for distributing the required power factor correction capacitors on the distribution system were also explored in 2009. If a cost effective option for placing the capacitors outside the station can be found the cost of this project may be reduced.

Reference Documentation:
1-Market Rules for the Ontario Electricity Market, IESO, June 2008
2-Greenwood MTS Expansion-System Impact Assessment Report, IESO, November 2005

Project SP6: Connect Jackson TS and Lazenby TS to Town Water & Sewage (2012) GA406

At present there is no washroom facility at Lazenby TS #1 & #2 and the sewage at Jackson TS is stored in a holding tank.

The scope of this project will be to:

1. Connect Jackson TS to town water & sewage and eliminate the sewage holding tank, if water and sewage are available.
2. Connect Lazenby TS #1 to town water & sewage and install washroom facilities.

This will be a 2012 project at an estimated cost of $161,000, including burdens.

Project SP7: Install Capacitor Banks at Markham TS #2 (2014) GA502

This project is to install capacitor banks at Markham TS #2 to meet IESO power factor requirements. The scope of the project includes Installation of two 20MVAR outdoor, externally fused, capacitor banks, two 28kV outdoor breakers as well as associated cables & ductwork.

The approximate cost of the two units is $910,000, including burdens.

Project SP8: Replacement of Legacy RTU and Recloser Controllers at Morgan MS (2011) GA520

This project entails the installation of new communication equipment, 2 new Cooper Form 6 Recloser Controllers and 2 new SEL2411s programmable I/O devices at Morgan MS, replacing the legacy, end of life, TG5100 RTU and aging Form 3 Recloser Controllers and problematic leased Bell line.

The RTU has reached end of life and there are no replacement parts for it. In order to keep it going, if some component of the RTU fails, we scramble to find something to get it running again. The same is true for the existing Form 3 Recloser control. They have reached end of life. The new Form 6 is a RTU and Recloser Control all in one. The Form 6 allows more versatility in protection settings and provides more extensive fault recording and reporting capabilities which will help decrease outage times. Replacing the RTU with the new Form 6 also allows us to utilize the existing DNP licensed wireless footprint from MTS3 and retire the problematic and expensive land line that we lease from Bell at $1000/month.

This will be a 2011 project at an estimated cost of $31,000, including burdens.

Project SP9: On-Line Dissolved Gas in Oil Monitor MS Transformer - Barrie (2012-2014) GA609, GA709, GA809

Install on-Line Dissolved Gas in Oil Monitor for 20MVA MS Transformers. Provide telemetry back to control room.

The transformer dissolved gas in oil monitoring and telemetry equipment will be installed over a three year period between 2012 and 2014. The expected costs are shown below in Table 4:

Table 4 – Summary of On-Line Gas in Oil Transformer Monitoring Project Costs

Year	Station	Cost	Project ID
2012	MS301, 381 Anne St Barrie	$37,000	GA609
2013	MS302, 169 Saunders Rd. Barrie	$38,000	GA709
2014	MS303, 202 Ferndale Dr. N, Barrie	$39,000	GA809

Once this work has been completed, three 20MVA MS transformers will still need to have dissolved gas in oil monitoring added. It is expected that this work will be completed in 2015, 2016 and 2017.

Project SP10: Install Oil Containment Systems at PS South Stations (2010 to 2014) GA414, GA514, GA614, GA714, GA814

This project is to install Sorbweb oil containment systems at Power Stream South Stations

The transformer oil containment will be installed over a five year period between 2010 and 2014. The expected costs are shown below in Table 5:

Table 5 – Summary of Oil Containment Project Costs

Year	Station	Cost	Project ID
2010	Aurora MS#4, T1 &T2	$139,000	GA414
2011	Aurora MS#6, T1	$105,000	GA514
2012	Two PS South stations	$201,000	GA614
2013	Two PS South stations	$208,000	GA714
2014	Two PS South stations	$214,000	GA814

Project SP11: Install Oil Containment Systems at PS North Stations (2010 to 2014)
GA413, GA513, GA613, GA713, GA813

This project is to install Sorbweb oil containment systems at Power Stream North Stations

The transformer oil containment will be installed over a five year period between 2010 and 2014. The expected costs are shown below in Table 6:

Table 6 – Summary of Oil Containment Project Costs

Year	Station	Cost	Project ID
2010	MS411, 308 Innisfil Street, Barrie MS834 Nolan Rd. Tottenham	$139,000	GA413
2011	MS405, 184 Innisfil Street, Barrie MS423, 5 Bellisle Road, Penetang	$195,000	GA513
2012	MS417, 119 St. Vincent St., Barrie MS404, 349 Blake St., Barrie	$201,000	GA613
2013	MS409, 348 Duckworth St., Barrie MS413, 174 Letitia St., Barrie	$208,000	GA713
2014	MS407, 43 Cundles Rd E, Barrie MS410, 31 Ferndale Drive, Barrie	$214,000	GA813

Project SP13: Install Video Surveillance at PS North Stations (2010 to 2013)
GA415, GA515, GA615, GA715

This project is to install video surveillance at Power Stream North Stations.

The video surveillance equipment will be installed over a four year period between 2010 and 2013. The expected costs are shown below in Table 7:

Table 7 – Summary of Video Surveillance Project Costs

Year	Station	Cost	Project ID
2010	MS409, MS412, MS413,	$32,000	GA415

	MS322, MS431, MS432		
2011	MS304, MS306, MS402, MS404, MS410, MS414	$34,000	GA515
2012	MS301, MS303, MS305, MS408, MS415, MS835	$35,000	GA615
2013	MS419, MS323, MS324, MS336, MS424	$30,000	GA715

Project SP14: Install Air-conditioning at MTS #1 & MTS #3 (2010) GA431

Supply and install 2 Ton Mitsubishi ductless split unit rated for -40 F. Set up outdoor unit on the ground outside of the building. Mount indoor unit on the wall inside room. Supply and install electrical and control wiring for both indoor and outdoor unit c/w new breakers and rigid conduits. Supply and install drain line to the nearest drain.

1. Air conditioning at MTS #1 is only a widow air conditioning unit that has worn out and failed. Recommend replace with properly rated central unit.
2. Air conditioning for back-up control room is shared with equipment room air conditioning, resulting in poor control of temperature in control room. Recommend to add with properly rated central unit for the back-up control room.

Options considered:
1. Do nothing
2. Install Air-conditioning - MTS #1 & MTS #3
3. Install Air-conditioning - MTS #3 only

Option 2 is recommended, Install Air-conditioning - MTS #1 & MTS #3

The approximate cost of the two units is $38,000, including burdens.

Project SP15: Paint Transformers at PS North Stations (2010 to 2014) GA418, GA518, GA618, GA718, GA818

This project is to paint the Transformers at two PowerStream North Stations each year over a five year period between 2010 and 2014. The expected costs are shown below in Table 8:

Table 8 – PS North MS Transformer Painting Project Costs

Year	Cost	Project ID
2010	$39,000	GA418
2011	$41,000	GA518
2012	$42,000	GA618
2013	$44,000	GA718
2014	$45,000	GA818

Project SP16: Paint Transformers at PS South Stations (2010 to 2014)
GA417, GA517, GA617, GA717, GA817

This project is to paint the Transformers at two PowerStream North Stations each year over a five year period between 2010 and 2014. The expected costs are shown below in Table 9:

Table 9 – PS South MS Transformer Painting Project Costs

Year	Station	Cost	Project ID
2010	Aurora MS #1 T1 & T2	$31,000	GA417
2011	AMS #6 T1 & Metalclad AMS #5 T1 & Metalclad	$47,000	GA517
2012	AMS #5 T2 & Metalclad	$28,000	GA617
2013	4 Transformers - MS TBD	$90,000	GA717
2014	4 Transformers - MS TBD	$93,000	GA817

Project SP17: Digital Fault Record Server (2010) GA419

Install a Digital Fault Record Server at the PowerStream Operations centre to collect and store fault records for PS South and North Stations.

The approximate cost of the project is $42,000, including burdens.

Project SP18: Replacement of Legacy RTU and Recloser Controllers at John MS (2010)
GA425

This project entails the installation of new communication equipment, 4 new Cooper Form 6 Recloser Controllers and 2 new SEL2411s programmable I/O devices at John MS, replacing the legacy, end of life, TG5100 RTU and aging Form 3 Recloser Controllers and problematic leased Bell line.

The RTU has reached end of life and there are no replacement parts for it. In order to keep it going, if some component of the RTU fails, we scramble to find something to get it running again. The same is true for the existing Form 3 Recloser control. They have reached end of life. The new Form 6 is a RTU and Recloser Control all in one. The Form 6 allows more versatility in protection settings and provides more extensive fault recording and reporting capabilities. Replacing the RTU with the new Form 6 also allows us to utilize the existing DNP licensed wireless footprint from MTS3 and retire the problematic and expensive land line we lease from Bell at $1000/month.

Options considered:
1) Manage to keep the RTU running until all the spare parts we have squirreled away runs out. This is unacceptable because System Control needs to remotely control this station.
2) Convert all of the load out of the station to a different voltage class so this station is not required.
3) Replace with a different suite of electronic equipment that is not compatible with the existing recloser and therefore more expensive to integrate and implement.

The approximate cost of the project is $107,000, including burdens.

Project SP19: Replacement of Legacy RTU and Recloser Controllers at Baythorn MS (2010) GA426

This project entails leveraging the full value from the existing installed station assets and retiring the end of life TG9000 RTU and saving the leased Bell Line costs.

The RTU has reached end of life and there are no replacement parts for it. In order to keep it going, if some component of the RTU fails, P&C scramble to find something to get it running again. Replacing the RTU allows us to utilize the existing DNP licensed wireless footprint from MTS3 and retire the problematic and expensive land line that we lease from Bell at $1000/month.

This will be a 2010 project at an estimated cost of $63,000, including burdens.

Project SP20: Corporate Connectivity from all TSs (2010) GA427

The project entails the purchase and installation of the JMUX Ether 100 Interface Cards and reconfiguration of equipment to provide Ethernet connectivity to the corporate network from any TS.

The quantity of various types of equipment used to protect and control our distribution network is increasing in number and in complexity. Manuals, drivers, and internet access to manufacturers website for support is required at our major facilities. It has become impractical and burdensome to physical transport the reams of information required. Email is often required at facilities to receive direct vendor communication to site.

This feature currently exists at MTS#3 and has proven beneficial and productive. This also allows for telephone hook-up into the corporate VOIP and to save on monthly Bell costs at each facility.

This will be a 2010 project at an estimated cost of $59,000, including burdens.

Project SP21: Pave Station Driveways - Barrie (2011) GA429

Pave station driveways at Ferndale South MS, Blake MS and St Vincent MS in PowerStream North.

This will be a 2011 project at an estimated cost of $26,000, including burdens.

Project SP22: Replace Human Machine Interface (HMI) Computer (2010) GA430

Replace the Human Machine Interface (HMI) Computer at Markham TS #3. The HMI computer has been in-service for over 5 years. It is at the age where components, especially the hard drive, start to wear out.

Options considered:
1. Do nothing
2. Add a second hard drive to provide redundant data storage.
3. Replace the Human Machine Interface (HMI) Computer

The replace the Human Machine Interface (HMI) Computer option is recommended

This will be a 2010 project at an estimated cost of $34,000, including burdens.

Project SP23: Security and Safety Vegetation for a Transformer Station (2011) GA521

Install vegetation at Greenwood TS to enhance security and safety.

This will be a 2011 project at an estimated cost of $39,000, including burdens.

2.2 RELIABILITY PROJECTS

2.2.1 <u>Transformer Stations</u>

Project R1: Separate Transformer & Breaker SCADA Alarms Markham TS #1 & TS #2 (2011) GA303

Decouple Transformer Gas/Differential Alarms and breaker SF6/trouble alarms at MTS #1 & #2. This project was originally submitted for 2009, but deferred to 2011 because of low priority.

Currently the Transformer Gas/Differential Alarms and breaker SF6/trouble alarms appear as one combined alarm on the station annunciator and on the SCADA. If one of the combined alarms comes into the control room, the system controller does not know if the problem is Transformer Gas, Transformer Differential Alarms, Breaker SF6 or Breaker trouble. Separating these alarms will give the system controller more specific information when one of these situations occurs. The scope of this project will be to separate each of the combined transformer and breaker alarms into two separate alarms.

The approximate cost of the project is $81,000, including burdens.

Project R2: Battery Bank Replacement - Greenwood TS & Torstar TS (2011, 2013) GA504, GA704

Replace worn out batteries at Greenwood TS and improve reliability of the DC supply for Greenwood TS #1 Expansion in 2011. Replace worn out batteries at Torstar TS in 2013.

Replace both 125 V battery banks at Greenwood TS. Install one of the new battery banks in the existing battery room at Greenwood TS. Install the other new bank in the basement of the Greenwood TS expansion control building. A partition would need to be installed and ventilation added to create a battery room.

The 2011 project cost is estimated at $53,000, including burdens and the 2013 project cost is estimated at $28,000, including burdens.

Project R3: High Set Instantaneous Feeder Protection - Markham (2010-2012) GA403, GA503 & GA604

This project was initiated, because Markham TS #1, #2 & # 3 feeder protections do not have high set instantaneous elements (50a). The feeder protections at these stations are also an older design that cannot accept the settings required to implement PowerStream’s Trip Saving protection philosophy.

The scope of this project is to replace the feeder protections at Markham TS #1 in 2010, TS#2 in 2011 and TS #3 in 2012.

The 2010 project cost is estimated at $125,000, the 2011 project cost is estimated at 144,000, including burdens and the 2012 project cost is estimated at 190,000, including burdens.
.

Project R4: Backup Station Service Lazenby TS (2011) GA405

This project was initiated to permit a single back-up generator to provide station service power to both Lazenby TS #1 and to Lazenby TS #2. Lazenby TS#2 has already been equipped with an external generator connection facility. A cable trench has been constructed between the two station control buildings. All that remains is to provide a connection between the station service panels in each building.

The scope of this project is to install a backup AC station service connection from Lazenby TS #2 to Lazenby TS #1

This project is expected to be completed in 2011 at an estimated cost of $26,000, including burdens.

Project R5: Torstar TS Feeder Protection Upgrade (2013) GA407

Replace the aging ABB DPU feeder protection relays at Torstar TS with a new HMI and feeder protection IED's. The new HMI would link to the new feeder IED's providing analog & digital telemetry and remote control for the control room via the SCADA master. Engineering would be contracted out, installation would be by P&C.

This project is expected to be completed in 2013 at an estimated cost of $290,000, including burdens.

Project R6: Protection upgrade - Richmond Hill TS #2 (2012) GA107

This project was initiated in response to problems with and lack of manufacturer support for the existing Alstom protection relays at Lazenby TS #2.

The project scope includes the following; upgrade Bus, Line & Transformer protections and install new Human Machine Interface (HMI) at Lazenby TS #2. Upgrade Feeder protections at Lazenby TS #2 and install new HMI in Lazenby TS #1 in. Engineering would be provided by an engineering consultant, installation to be completed by P&C.

The project is expected to be completed in 2012 at an estimated cost of $431,000, including burdens.

Project R7: Cooling for Vaughan TS #3 Capacitor Banks (2010) GA421

Provide Cooling for Vaughan TS #3 Capacitor banks. The two 20MVar capacitor banks at VTS #3 are housed in the basement of the control building. An investigation has shown that the capacitor banks run at temperatures above the manufacturer’s recommended rating. Cooling is being provided to keep the operating temperature within the manufacturer’s design rating.

The project is expected to be completed in 2010 at an estimated cost of $53,000, including burdens.

Project R8: Spare TS Capacitor Cans (2011, 2013) GA506, GA706

Purchase Spare TS Capacitor Cans for VTS #3. Experience has shown that about 5 capacitor cans fail every 2 years.

The 2011 project cost is estimated at $9,000 and the 2013 project cost is estimated at $10,000, including burdens.

Project R9: Remediate Corrosive Sulphur - Richmond Hill TS #1 (2010) GA423

Remediate Corrosive Sulphur - T1 & T2 Richmond Hill TS #1. High levels of corrosive sulphur have been found in the T1 and T2 oil. The purpose of this project is to investigate the cause and remove the sulphur from the transformer and the oil.

The 2010 project cost is estimated at $207,000, including burdens.

Project R10: Low Voltage Bushing Replacement - Transformer Station (2010 - 2014) GA422, GA519, GA619, GA719, GA819

Replace the low voltage bushings on T1 at Markham TS #1 in 2010, T1 & T2 at Markham TS #2 in 2011, T1 & T2 on Vaughan TS #1 in 2012, T1 & T2 at Markham TS #3 in 2013 and T1 & T2 on Vaughan TS #3 in 2014.

One of the low voltage (LV) bushings on T2 transformer at MTS #1 has failed and was replaced along with the other T2 LV bushings. Investigation has shown that there is a design flaw in the bushings. The LV bushings on MTS #1 T1, MTS #2 T1 & T2, MTS #3 T1 & T2, VTS #1 T1 & T2 and VTS #3 T1 & T2 are being replaced as well.

The 2010 project cost is estimated at $156,000, the 2011 project cost is estimated at $325,000, the 2012 project cost is estimated at $335,000, the 2013 project cost is estimated at $345,000 and the 2014 project cost is estimated at $355,000, including burdens.

Table 10 – PS Low Voltage Bushing Replacement - Project Costs

Year	Station	Cost	Project ID
2010	Markham TS #1 T1	$156,000	GA422
2011	Markham TS #2	$325,000	GA519
2012	Vaughan TS#1 T1 & T2	$335,000	GA619
2013	Markham TS#3 T1 & T2	$345,000	GA719
2014	Vaughan TS #3	$355,000	GA819

Project R11: Replacement of RHTS#1 Basement Switch Operators (2010) GA428

The current switch operators on the basement SF6 switchgear in RTS#1 have reached end of life and are no longer serviceable. This project involves changing out motors, control panel (comes with relays), and interfacing to existing station RTU.

Of the fifteen currently installed motor operators, five are non-functional and unable to be repaired. The remaining ten motors are problematic at best and are not considered usable system assets. The basement switching apparatus provide system control the flexibility to maneuver load to other healthy sources within a station should a circuit breaker fail or be removed for service or maintenance.

The 2010 project cost is estimated at $138,000, including burdens.

2.2.2 **Municipal Stations**

Project R12: Replace Reclosers and 13.8kV Bus at Aurora MS 1 (2013) ***GA304***

This project was initiated as a result of numerous outages, in 2006 and 2007, at Aurora MS #1. The outages were caused by problems on the 13.8kV bus and reclosers, as follows:

- A Red phase insulator failed on the secondary bus causing a lengthy station outage,
- The F2 recloser failed and was replaced by a similar vintage recloser borrowed from John MS in Markham,
- MS 1 is the only station with outdoor bus in Aurora and as such is susceptible to outages caused by animal related flashovers, and
- MS 1 is 40 years old and there is reason to believe the outdoor equipment may be reaching the end of its useful life.

The project scope includes replacing the existing outdoor 13.8kV bus and reclosers with enclosed switches and vacuum interrupters similar to the design of the new Aurora MS 7. The existing transformers, 44kV structures and SCADA RTU would be retained. However, a study of the refurbishment options is underway.

This project is expected to be completed in 2013 at an estimated cost of $1,218,000. However, a study of the refurbishment options is underway. Once the report has been completed, the cost estimate may be revised.

Reference Documentation:
Aurora MS 1 Station Outage – Protection Coordination Review, October 29, 2006
Aurora MS 1 Refurbishment Study and Report, January 2009

Project R13: Station Fence Upgrade (2011, 2012) ***GA411, GA511***

Upgrade Station fences, PowerStream North stations. Some of the older station fences in PS North are only 2m high and do not comply with current standards.

The 2011 project cost is estimated at $24,000, and the 2012 project cost is estimated at $25,000, including burdens.

Project R14: Replace Battery Banks - PowerStream South MS's (2010, 2012, 2014) ***GA410, GA610, GA810***

Replace Battery Banks at 2 PowerStream South MS's. Station batteries have a typical life of 15 to 20 years. By replacing the battery bank, in one PowerStream South municipal station (MS), every other year, each MS battery bank will be replaced approximately every 20 years.

The 2010 project cost is estimated at $7,000, the 2012 project cost is estimated at $7,000, including burdens and the 2014 project cost is estimated at $8,000, including burdens.

Table 11 – Replace PS South MS Battery Banks - Project Costs

Year	Cost	Project ID
2010	$7,000	GA410
2012	$7,000	GA610
2014	$8,000	GA810

Project R15: Replace Battery Banks - PowerStream North MS's (2011-2014)
GA409, GA505, GA605, GA705, GA805

Replace Battery Banks at 2 PowerStream North MS's. Station batteries have a typical life of 15 to 20 years. By replacing the battery bank, in two PowerStream North municipal stations (MS), every year, each MS battery bank will be replaced approximately every 20 years.

The 2010 project cost is estimated at $17,000, the 2011 project cost is estimated at $14,000, the 2012 project cost is estimated at $16,000, the 2013 project cost is estimated at $15,000, and the 2014 project cost is estimated at $15,000, including burdens.

Table 12 – Replace PS North MS Battery Banks - Project Costs

Year	Cost	Project ID
2010	$17,000	GA409
2011	$14,000	GA505
2012	$16,000	GA605
2013	$15,000	GA705
2014	$15,000	GA805

Project R16: Spare 46kV S&C Circuit Switcher (2011) ***GA420***

Acquire a spare 46kV S&C Circuit Switcher, for use in PowerStream North

The project is expected to be completed in 2011 at an estimated cost of $63,000, including burdens.

Project R17: Rebuild Aging Municipal Station Reclosers (2010) ***GA424***

Rebuild reclosers at AMS #1, Amber MS, John MS, & Morgan MS.

The 2010 project cost is estimated at $79,000, including burdens.

2.3 CAPACITY PROJECTS

2.3.1 Station Construction to Support Load Growth

Load growth in the PowerStream service area has made additional 230kV to 28kV and 44kV to 28kV transformation capacity necessary. The following project is recommended.

Project C1: New transformer station, to be built in Vaughan (2012-2015)

GA600, GA700 & GA800

Vaughan TS#4 is planned for an in-service date of 2014. The estimated cost to construct the new station is shown below in Table 10.

Station Component	Cost $000
Engineering Design	675
Approvals (EA, IESO, Permits)	56
Hydro One CCRA	72
Transformers	8666
28kV Switchgear	2730
Protection, Metering , Control	738
230 kV Switches	70
Primary Metering (Revenue)	207
Grounding Reactors	63
230kV Insulators	18
Station Service Transformers (2)	225
DC System	56
20MVAR Cap Banks (2)	311
28kV Cable	788
Site Supervisor	101
Civil Contract	3000
Electrical Contract	1013
Commissioning	148
Construction Cost	**$18,937**
10% Contingency	$1,894
Subtotal	**$20,831**
PST	$1,666
Total Cost	**$22,497**

Table 13 – Vaughan TS #4 Estimated Component Costs

Vaughan TS#4 is planned for an in-service date of between 2014 and 2015, depending on CDM initiatives (currently forecasted to be 2015).

If a site is acquired in time for a 2015 in-service date, we expect to spend $4,159,000 in 2013 (GA600), $17,820,000 in 2014 (GA700), and $927,000 in 2015 (GA800).

2.3.2 Projects Required to Support Growth in Barrie

Project C2: ***New Municipal Station, to be built in Barrie (2009 - 2010)*** ***GA208***

PowerStream is planning to construct a new 44/13.8kV Municipal Station in Barrie. The new Park Place MS will include:

- 20 MVA 44/13.8 kV Transformer
- four 13.8kV vacuum circuit breakers and feeders
- one 44kV indoor circuit breaker

In-service is planned for the 2nd or 3rd quarter of 2010. The 2010 expenditure is estimated at $1,178,000, including burdens.

2.3.3 Projects Required to Support Growth in Aurora

Project C3: ***New Municipal Station, to be built in Aurora (2012)*** ***GA404***

PowerStream is planning to construct a new Municipal Station on the East side of Aurora to meet anticipated new demand. The station will be designated Aurora MS 9. The purpose of MS 9 will be to augment the 28kV supply from Aurora MS 7 and MS 8.

This project is expected to be completed in 2014 at an estimated cost of $1,593,000, including burdens.

2.4 UNBUDGETED PROJECTS

Each year, there are several projects which are required due to investigations resulting from agencies inquiries, unanticipated development or distribution system requirements that do not get budgeted for.

Additionally, there may be necessary expenditures as a result of the asset condition assessment project. Funds should be carried to allow for replacement or refurbishment as dictated by the reports.

Stations Design has not budgeted for any unbudgeted projects.

3.0 SUMMARY

Table 11 summarizes the capital spending anticipated for 2010 to 2014.

TABLE 11: SUMMARY OF TOTAL RECOMMENDED CAPITAL DOLLARS

WO SERIES	2010 BUDGET $	2011 BUDGET $	2012 BUDGET $	2013 BUDGET $	2014 BUDGET $
Special Projects					
SP1: On-line Monitor/DGA TS Transformer	$163,000	$163,000	$165,000	$154,000	$181,000
SP2: On-line Monitor MS Transformers	$54,000	$25,000	$48,000	$49,000	$0
SP3: MTS#3 – On-site storage	$0	$44,000	$0	$0	$0
SP4: Install Perimeter Lighting at RH TS#1 & 2	$0	$37,000	$0	$0	$0
SP5: Install Capacitor Banks at Torstar TS	$1,056,000	$0	$0	$0	$0
SP6: Jackson TS & Lazenby TS – Water & Sewage	$0	$0	$161,000	$0	$0
SP7: Install Capacitor bank at Markham TS #2	$0	$0	$0	$0	$910,000
SP8: Replace RTU & Controllers - Morgan MS	$0	$31,000	$0	$0	$0
SP9: On-line DGA Barrie MS Transformers	$0	$0	$37,000	$38,000	$39,000
SP10: Oil containment PS South MS's	$139,000	$105,000	$201,000	$208,000	$214,000
SP11: Oil containment PS North MS's	$139,000	$195,000	$201,000	$208,000	$214,000
SP13: Video Surveillance PS North MS	$32,000	$34,000	$35,000	$30,000	$0
SP14: Air Conditioning MTS#1 & MTS #3	$38,000	$0	$0	$0	$0
SP15: Paint MS Transformers PS North	$39,000	$41,000	$42,000	$44,000	$45,000
SP16: Paint MS Transformers PS South	$31,000	$47,000	$28,000	$90,000	$93,000
SP17: Digital Fault Record Server	$42,000	$0	$0	$0	$0
SP18: Replace RTU & Controllers – John MS	$107,000	$0	$0	$0	$0
SP19: Replace RTU – Baythorn MS	$63,000	$0	$0	$0	$0
SP20: Corporate Connectivity to all TSs	$59,000	$0	$0	$0	$0
SP21: Pave Station Driveways – Barrie	$26,000	$0	$0	$0	$0
SP22: Replace HMI Computer - Markham TS #3.	$34,000	$0	$0	$0	$0
SP23: Transformer Station Vegetation	$0	$39,000	$0	$0	$0
Sub-total	$2,022,000	$761,000	$919,000	$821,000	$1,696,000
Reliability Projects					
R1: Separate Transformer & Breaker SCADA Alarms – MTS #1 & MTS #2	$0	$81,000	$0	$0	$0
R2: **Station Battery Replacement – VTS #1 & VTS #2**	$0	$53,000	$0	$28,000	$0
R3: High Set Instantaneous Feeder Protection – Markham TS #1, #2 & #3	$125,000	$144,000	$190,000	$0	$0
R4: Backup Station Service – Lazenby TS	$0	$26,000	$0	$0	$0
R5: Torstar TS Feeder Protection Replacement	$0	$0	$0	$290,000	$0
R6: Protection upgrade - Richmond Hill TS #2	$0	$0	$431,000	$0	$0
R7: Cooling for VTS #3 Capacitors	$53,000	$0	$0	$0	$0
R8: Spare TS Capacitor Cans	$0	$9,000	$0	$10,000	$0
R9: Lazenby TS #1 – Transformer Sulphur Remediation	$207,000	$0	$0	$0	$0
R10: TS Transformer LV Bushing Replacement	$156,000	$325,000	$335,000	$345,000	$355,000
R11: Replace RHTS#1 Basement Switch Operators	$138,000	$0	$0	$0	$0
R12: Reclosers & 13.8kV Bus - Aurora MS 1	$0	$0	$0	$1,218,000	$0
R13: Station Fence Upgrade PS North	$0	$24,000	$25,000	$0	$0
R14: **MS Battery Replacement – PS South**	$7,000	$0	$7,000	$0	$8,000
R15: **MS Battery Replacement – PS North**	$17,000	$14,000	$16,000	$15,000	$15,000
R16: Spare 46kV S&C Circuit Switcher	$0	$63,000	$0	$0	$0
R17: Rebuild aging MS reclosers	$79,000	$0	$0	$0	$0

Sub-total	$782,000	$739,000	$1,004,000	$1,906,000	$378,000
Capacity Projects					
C1: New transformer station, to be built in Vaughan	$0	$0	$0	$4,159,000	$17,820,000
C2: New Park Place MS, to be built in Barrie	$1,178,000	$0	$0	$0	$0
C3: New Municipal Station, to be built in Aurora	$0	$0	$0	$0	$1,593,000
Sub-total	$1,178,000	$0	$0	$4,159,000	$19,413,000
Unbudgeted Projects	$0	$0	$0	$0	$0
TOTAL DOLLARS	**$3,982,000**	**$1,500,000**	**$1,923,000**	**$6,886,000**	**$21,487,000**

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 2
Schedule 2.3
Appendix B
103 Pages
Filed: August 31, 2012

Distribution Design

Asset Management Plan

2012-1015

Draft Version 3

Compiled By: ____________________________

Irv Klajman, P. Eng.

Director, Distribution Design

April 8, 2011

Distribution Design Asset Management Plan

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This 5 Year Asset Management Plan provides a greater level of detail on how the forecasted numbers were created for the capital budgets created within Distribution Design.

The split between contributed capital and PowerStream rate funded varies depending on the type of work.

Forecasted numbers were based on a combination of historical figures, recent trends and known projects.

There are 4 functional areas within Distribution Design that contribute to the Capital Plan, specifically:

- Residential Subdivisions
- Locates and Inspections
- Capital
- Designer

The summary of the total of all four functional areas over the five year forecast is shown below.

	TOTAL North & South ($M)		
	CONT	RATES	TOTAL
2012	22.60	13.35	35.94
2013	22.92	20.97	43.89
2014	21.50	14.59	36.09
2015	23.62	15.89	39.51
2016	26.07	17.44	43.51
	116.71	**82.24**	**198.94**

1 INTRODUCTION

The ever increasing complexity of the distribution sector, coupled with increased regulatory expectations, results in a need to create solid, defendable documentation on forecasted capital spending.

This 5 Year Asset Management Plan, for Distribution Design, provides a greater level of detail on how the forecasted numbers were created for the capital budgets created.

There are 4 functional areas within Distribution Design that contribute to the Capital Plan, specifically:

- Residential Subdivisions
- Locates and Inspections
- Capital
- Designer

2 SUBDIVISIONS AND NEW SERVICES

a) Layouts

Layouts are a combination of new residential infill services, upgrading of residential services and small commercial services.

The service could be underground or overhead and is the connection from the main plant on the boulevard to the building. 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.

The forecasted spending in 2011 for these three categories is $2.8 million with $1.2 million being contributed from customers.

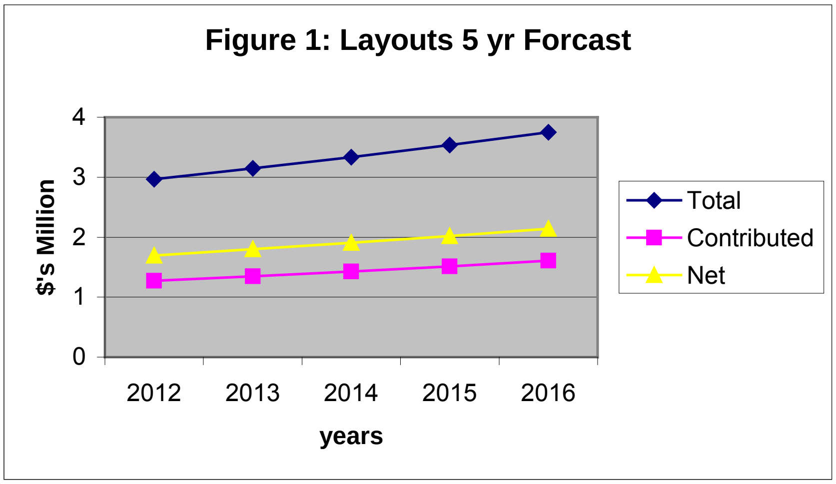
The majority of this work is new Infill residential and upgrading of existing residential services which will continue in a very similar fashion over the next 5 years. With a 6 percent combined inflation/growth rate each year for the next 5 years in 2016 the spend level will be $3.75M with $1.61M being contributed by customers.

The rationale for the forecasting that spending will not decrease is based on the fact that during the recent economic downtown, the volumes in the Layout section remained constant. As such, there is no indication that these numbers will trend downward, and are forecasted to grow as noted above.

See Tables 1, 2 and Figure 1.

TABLE 1: Layouts ($Millions)			
Year	Total	Contributed	Net
2012	2.97	1.27	1.70
2013	3.15	1.35	1.80
2014	3.33	1.43	1.91
2015	3.53	1.51	2.02
2016	3.75	1.61	2.14

TABLE 2: Layout Volumes	
Year	Total
2008	2,901
2009	3,047
2010	3,475



b) Industrial, Commercial and Institutional Services

ICI services (Industrial/Commercial/Institutional) consist of new and/or upgraded primary services normally underground from our existing distribution or sub-transmission system to and including the pad mount transformer on private property for voltages up to 28kV and up to pre-determined kVA sizes.

A review of the nature of the services installed in 2010 indicate a gradual shift from the goods producing sector to the service sector (including education, health care and business services), advanced manufacturing and computer information/communication technologies. As an example, three (3) new large data centres are being proposed in Barrie and the proposed hospital in Vaughan will create many spin off business services.

In accordance with the DSC, these services are considered a connection and are 100% recoverable (deemed as 'Lies Along').

The anticipated total spend in 2011 is 6.3M (1.8 North & 4.5M South) with a predicted 6 percent combined inflation/growth rate for the next 5 years for 8.43M (2.41 North & 6.02 South) in 2016.

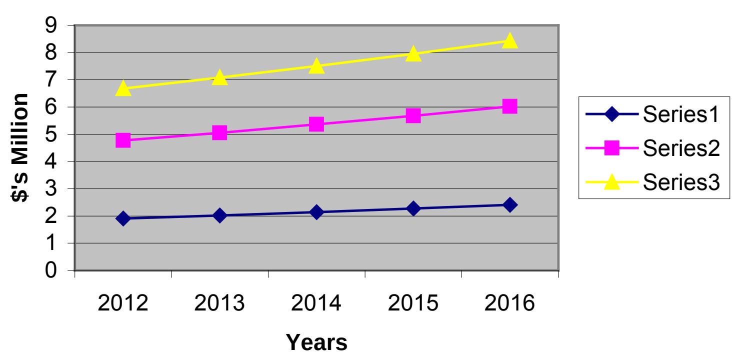
The ICI development in past has remained resilient throughout the global economy downturn and will continue consistent with moderate growth through 2016. Over the years when commercial declines the Institutional through government funding increases filling the void.

See Tables 3 & 4 and Figure 2.

TABLE 3: ICI ($Millions)			
Years	North	South	Total
2012	1.91	4.77	6.68
2013	2.02	5.06	7.08
2014	2.14	5.36	7.50
2015	2.27	5.68	7.95
2016	2.41	6.02	8.43

TABLE 4: ICI Volumes	
Year	Total
2008	146
2009	116
2010	104

Figure 2: ICI 5 yr Forcast



c) <u>Residential Subdivisions</u>

The Subdivision Electrical Distribution System (EDS) consists of new primary and secondary underground cables as well as transformers installed to the street line of each lot within a residential “Greenfield” development.

The North area is predicted to have moderate inflation/growth of 6 percent over the next 5 years with the majority of lots coming from the Bradford and Alliston area. This is based on preliminary discussions with Municipalities.

The South is predicted to start increasing the number of lots significantly in 2013 (400 more each year) when the permit restriction in Markham, Vaughan and Richmond Hill is removed (lot allocation lifted due to Markham water issues and Vaughan & Richmond Hill sewer issues resolved).

The 2011 baseline cost per lot is $3877.

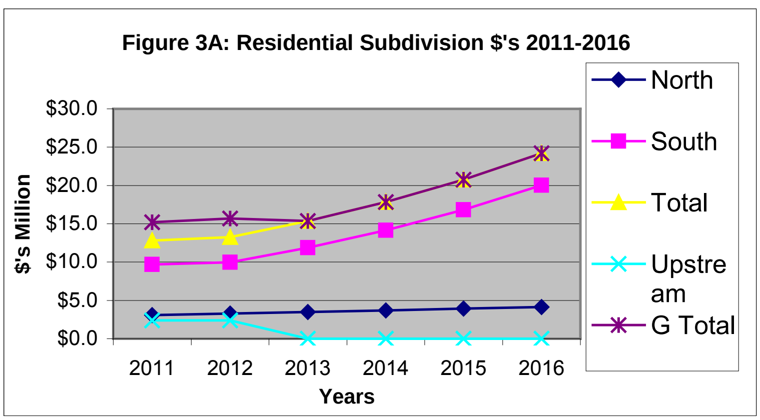
In 2013 PS will be applying for a new rate application and this will mean upstream charges will be removed going forward.

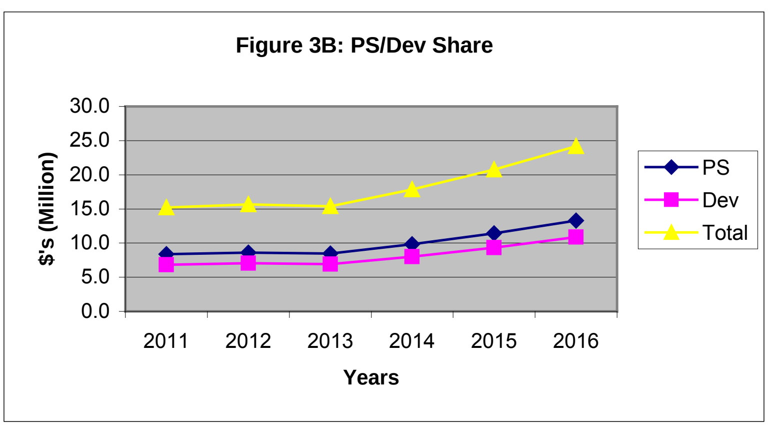
In accordance with the DSC, the development cost is put through an economic model to determine the LDC share and the Developer share based on revenues from the development. Under the current model, the cost sharing is anticipated to be approximately 55% for PowerStream and 45% for the Developer.

See Tables 5a, 5b and Figures 3A and 3B.

TABLE 5a: Residential Subdivision Lots			
Year	North	South	Total
2008			2,755
2009			3,167
2010			4,472
2012	850	2,500	3,350
2013	900	2,900	3,800
2014	950	3,300	4,250
2015	1,000	3,700	4,700
2016	1,050	4,100	5,150

TABLE 5b: PS/Dev % Share in $M			
Year	PS	Dev	Total
2011	8.4	6.8	15.2
2012	8.6	7.1	15.7
2013	8.5	6.9	15.4
2014	9.8	8.0	17.8
2015	11.4	9.3	20.8
2016	13.3	10.9	24.2





d) <u>Secondary Services</u>

Secondary underground services are installed from the service tails at street line to the meter base for each lot. This work will allow for the connection of the secondary service to the pad mount 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 5 years of the EDS being installed.

The growth rate for North and South over the next 5 years is same as the EDS above (ie same number of services as there are lots installed, recognizing the delay in housing construction). An average cost for a service in 2011 is $475.00.

In accordance with the Distribution System Code, these service costs are put through the economic model and shared at time of the OTC. All OTC's signed in the south before 2010 have the developer installing services at his cost. As such, moving toward 2015, PowerStream's funding portion for these services will increase.

The budgeted costs for the services have been included in the Subdivision infrastructure monies above, as they are included in the model run (also part of the $3,877/lot). Consideration from a cash flow perspective still needs to be resolved.

3 DESIGNER

Designer is a software platform that uses ArcGIS as its foundation. It includes tools to simplify the design and planning for the construction of new infrastructure projects.
When fully developed, integrated and deployed with other products, Designer will reduce design times, optimize designs, and speed turnaround for projects.

In 2009, the Designer project within PowerStream was not as effective as was initially envisioned. A Supervisor was hired and dedicated to the development and enhancement of the product, to provide training and to deal with day to day issue resolution.

By the end of 2010, the product had matured in the PowerStream environment, training had been provided, and virtually all new projects were able to be designed using Designer.

The focus on the next 5 years is to integrate with existing platforms to fully leverage the power of the product. The two core systems would be the JDE and the CIS systems.

For the JDE system:

Oracle's JD Edwards Enterprise One (JDE) is the enterprise resource planning system used at PowerStream and is the system of record for financial data, asset lifecycle, work orders, projects etc. Standard costing is also maintained in JDE, including both labor and material costs. ESRI/Telvent mapping software on the other hand is being used by engineering and design groups to digitally maintain and extend PowerStream's electrical distribution network.

PowerStream uses a combination of Designer and AutoCAD for their design work. The Design group maintains a list of Compatible Units (CUs) in Designer which are based on the construction standards supplied by the JDE system. Keeping the CUs up to date with the JDE standard costing is currently done manually and would benefit from some form of automation which could be achieved through the integration of the two systems.

Cost reporting within Designer can also benefit from JDE detail costing so an integration that would bring JDE-owned cost information to Designer would give designers a quick way to validate different design options from an economical/financial perspective.

Work order creation and management would also benefit from a JDE-GIS integration. As the Design group creates CU-based designs and maintains a bill of materials (BOM), that information can be passed over to the JDE when creating the corresponding work order. JDE on the other hand can notify GIS of work order life cycle events.

PowerStream is considering integrating some components of JD Edwards and the GIS system (Designer) in order to leverage some of the synergies between the two products, make better use of each system's strengths, and minimize duplication of effort by automating some of the data exchange. The main business drivers for this integration are:

1. *Minimizing duplication of effort and in return also reducing possibility of data inconsistencies*
2. *Automating some current business processes*
3. *Exchanging data between the two systems more seamlessly*

PowerStream intends to initiate JDE-GIS integration efforts in 1st quarter of 2012 and finish by the 4th quarter 2012. This project will require internal resources from IS, GIS, Design and Standards groups as well as and expertise from ESRI Canada and PowerStream's JDE service provider. IS and GIS involvement will ensure compliance with standards specifically as it relates to systems integration. Information Services (IS) will also help during implementation, testing and go-live phases. Standards and especially Design groups will help detailing the complete functional requirements and will be the immediate beneficiaries of the JDE-GIS integration.

Capital spending reflects the monies required to procure the necessary equipment and software customization to successfully develop Designer.

See Table 6 and Figure 6.

TABLE 6: Designer ($thousands)	
Year	Spending
2012	$267,000
2013	$69,000
2014	
2015	
2016	$40,000

Figure 6: 5 Year Capital Spending for Designer Implementation

	# of Units	Estimated Cost per Unit	Year	Extended Cost	Notes
HARDWARE					
ToughBooks for New Service Techs	4	$6,000	2012	$24,000	To be purchased in 2012
Replacement of ToughBooks for New Service Techs in 4 years	5	$6,000	2016	$30,000	Normal replacement time for Hardware (Laptops)
ToughBooks for Design Techs (North & South)	2	$6,000	2012	$12,000	Shared laptop for all Technicians in the field
GPS units for Design Techs (North & South)	2	$16,000	1 - 2012 1 - 2013	$32,000	With the addition of 2 GPS units, Engineering Design would have access to a total of 4 units.
GPS units for Inspection & Locates (North & South)	2	$16,000	2012	$32,000	With the addition of 2 GPS units, Engineering Locates and Inspection would have access to a total of 2 units.
Replacement of HP T1200 Colour wide body Plotter (South only)	1	$10,000	2016	$10,000	Existing plotter in the South will be 7years old in 2016
Replacement of Colour, wide body Scanner (South only)	1	$20,000	2012	$20,000	Existing scanner in South is over 8 years old in 2011
				$160,000	**SUB-TOTAL**
SOFTWARE					
JDE Integration	lot		2012	$73,000	ESRI work plus JDE work ($63 + $10k)
CIS Integration	lot		2012	$20,000	ESRI work plus CIS work ($15 + $5k)
Designer License purchase	4	$12,000	2 - 2012 2 - 2013	$48,000	Designer requires both a Designer & an ArcEditor License to operate
ArcEditor License purchase	4	$13,000	2 - 2012 2 - 2013	$52,000	
AutoCAD Map 3D License purchase (Upgrade from AutoCAD 2010)	8	$2,500	2012	$20,000	
				$213,000	**SUB-TOTAL**
MISCELLANEOUS					
Additional Paper storage and Drawing layout cabinet	1	$3,000	2013	$3,000	To store all roll paper safely in the print room
				$3,000	**SUB-TOTAL**
				$376,000	**TOTAL CAPITAL COST**

4 LOCATES AND INSPECTIONS

The Inspection and Locates department's mission statement is:

To provide excellent service to all PowerStream customers by supplying timely and accurate Inspection and Locates.

Inspection's main functions involve inspecting and documenting the installation of new underground hydro infrastructure, ensuring it gets installed to PowerStream's approved drawings and standards.

The Cable Locators locate existing underground hydro plant focusing on safety and damage prevention.

Both are responsible for the safety of the public, contractors, and PowerStream customers when dealing with underground facilities.

a) Inspection

The Inspection department ensures all underground distribution installations follow PowerStream's Construction Verification Program (CVP), in order to be compliant with the Ontario Regulation 22/04 and the Electrical Distribution Act.

The proposed CSA S250 standard, Mapping of Underground Utilities Infrastructure is expected to be approved in 2011. This standard covers the recording of underground infrastructure and related appurtenance below, at, or near grade and those that are abandoned or for future needs.

CSA will formally recommend to utilities that they implement all or part of CSA S250. Although it is at each utility's discretion to implement this standard, the regional and local municipalities within PowerStream's service territory are currently supporting its implementation. Although it has not been determined to what level of accuracy they would like Utilities to submit proposed plans for access agreements and road occupancy permits. Table 7 indicates the five levels of accuracy.

Table 7: Mapping Record Accuracy

Accuracy level	Description	Reference
1	Accurate to within +/- 25mm in the x, y, and z coordinates, and referenced to an accepted geodetic datum with a 95% confidence level.	Absolute
2	Accurate to within +/- 100mm in the x, y, and z coordinates, and referenced to an accepted geodetic datum with a 95% confidence level.	Absolute
3	Accurate to within +/- 300mm in the x, y, and z coordinates, and referenced to an acceptable geodetic datum or topographical and cadastral features with a 95% confidence level.	Absolute or relative
4	Accurate to within +/- 1000mm in the x, y, and z coordinates, and referenced to an acceptable geodetic datum or topographical and cadastral features with a 95% confidence level.	Absolute or relative
0	No information available related to spatial accuracy.	

Levels 1 through 4 requires a Z coordinate. Not to be confused with depth of cover, the Z coordinate is an elevation measurement that does not change with cuts or fills. To provide this information, a tool that captures and records this data is required. Working with the GIS and Designer departments, the Inspection and Locates department will jointly implement a trial project this spring to test GPS equipment that will capture the X, Y & Z components of the underground distribution system installations.

Based on the results of this pilot, subsequent pilots may be done on other GPS units with the ultimate goal of the Inspection and Locates department purchasing appropriate GPS units for each Inspector that will capture all the required coordinates. See Figure 7 for the five year purchase plan.

b) Locates

PowerStream, as a Local Distribution Company under Ontario Regulation 22/04 Section 10 (4), is required to provide reasonable information with respect to the location of its underground distribution lines and associated plant within a reasonable time.

Sub-section 2.6 of the ESA's Guideline for Excavation in the Vicinity of Utility Lines states:

“Except in cases of emergency, or where the response for the locate request has been agreed with the Excavator, the utility shall make every reasonable effort to respond to notification requests and provide locates within 4 working days of receiving the notification, and 5 working days during peak times.”

Based on the review of previous years’ data, PowerStream Inc. has defined, for a calendar year, the periods as follows:

4 Day Non-Peak Period	Jan, Feb, Dec
5 Day Peak Period	Mar - Nov

The Operations, Maintenance and Administration annual budget captures cost of locating PowerStream’s underground distribution system. Service quality indicators (SQI), Ontario Electricity Board (OEB) minimum standard of 90%.

To manage locate requests and to be compatible based on future ArcGIS updates, a new ticket and field analyzers will need to be purchased. Staff will investigate the various analyzers to ensure that they fit with PowerStream’s GIS system. Refer to Figure 7.

To ensure that the locating equipment used by the Locator is the up to date with current technology, plans are to annually replace one set of locating equipment. With current staffing numbers, the equipment will be replaced every 6 years. Refer to Figure 7.

Additionally, extra equipment, such as a full body scanner, will be procured to assist with efficient processing of the inspection process, including issued for construction and as-built drawings.

Figure 7: Inspection & Locates 2012 to 2016 Asset Management Plan

	Estimated Cost per Unit	# of Units	Year 2012	# of Units	Year 2013	# of Units	Year 2014	# of Units	Year 2015	5 Year Extended Cost	Notes
HARDWARE											
ToughBooks Replacement for Inspectors and Locators	$6,000	2	$12,000	2	$12,000	2	$12,000	2	$12,000	$48,000	To replace existing expired units
Locating Equipment	$6,000	2	$12,000	1	$6,000	1	$6,000	0	$0	$24,000	Normal replacement time for Hardware (Laptops)
GPS units for Inspection	$16,000	2	$32,000	2	$32,000	2	$32,000	0	$0	$96,000	To GPS X,Y&Z coordinates during the as built process, to meet the proposed CSA S250 Standard. The plan is to have a unit for each Inspector. Currently, there is 7 Inspectors, therefore a unit would be used from the Designer Group.
Replacement of Ink Jet HP 800 Colour wide body Plotter (Addiscott Location)	$10,000	0	$0	1	$10,000	0	$0	0	$0	$10,000	This plotter was removed from service from the Eng. Dept. and was repaired in 2009, with hopes that it will stay in service for additional two years.
Purchase of Colour, wide body Scanner (Addiscott Location)	$20,000	1	$20,000	0	$0	0	$0	0	$0	$20,000	Presently, staff are ultizing the scanning in Construction, with the new Electronic Work Order Filenexus system, and the Red-Line As-Built procedure, drawings need to be scanned and filed electronically.
			$0		$0		$0		$0	$0	
										$198,000	**SUB-TOTAL**
SOFTWARE											
Replacement of DigSmart Analizer	$80,000	1	$80,000		$0		$0		$0	$80,000	The current DigSmart Analyzer is presently operating on ArcFm 9.0. When the GIS Dep't upgrades to ArcFm 10.x, this may cause an incompatible issue.
Replacement of DigSmart Field Drawing Tools	$500	7	$3,500		$0		$0		$0	$3,500	Covers the license cost of Multiviewer
			$0		$0		$0		$0	$0	
			$0		$0		$0		$0	$0	
			$0		$0		$0		$0	$0	
										$83,500	**SUB-TOTAL**
MISCELLANEOUS											
										$0	
										$0	**SUB-TOTAL**
	Yearly Cost		$159,500		$60,000		$50,000		$12,000	$281,500	TOTAL CAPITAL COST

5 CAPITAL

The Capital division is responsible for forecasting:

- Non-controllable Capital Projects as dictated by Road Authorities;
- Emerging Customer Initiated Projects;
- Capital purchases.

a) Road Authorities

Tables 8 and 9 indicate the historical spending on Road Authority projects in the South and North territories.

TABLE 8: SOUTH ROAD AUTHORITY HISTORICAL SPENDING

PS South History Year	Budget Gross	Actual Gross	Difference (under budget)	# of Known Projects
2006	Not available were combined with planned projects			
2007	Not available were combined with planned projects			
2008	2,582,000	1,219,000	(1,363,000)	1
2009	2,736,000	3,884,000	1,148,000	3
2010	2,834,693	873,591*		12
2011	9,116,652			6

TABLE 7: NORTH ROAD AUTHORITY HISTORICAL SPENDING

Emerging Capital Initiated Projects

TABLE 9: NORTH ROAD AUTHORITY HISTORICAL SPENDING

PS North History Year	Budget Gross	Actual Gross	Difference (under budget)
2006	2,700,000	1,204,148	(1,495,852)
2007	2,993,550	3,548,564	555,014
2008	2,435,100	2,791,118	356,018
2009	3,860,000	1,882,000	(1,978,000)
2010	3,035,276	2,321,584*	
2011	3,500,000		

* Actual Gross is Based on June 30/10 YTD, 2010 Forecast Actual Gross - $3.3M
2011 Budget Number does not include Ontario Stimulus Funding

The forecasts for Road Authority projects are based on an assessment of previous years volumes, combined with known Municipal or Regional projects.

The forecasted numbers do not take any future YRRT or TYSSE projects into account, given that although is likely there will be some YRRT projects within the next five years, the timing is uncertain.

The forecast from York Region and the Cities/Towns do not provide much visibility in 2015/16. The amount of unknown projects was increased to compensate for this.

The project scopes for some of the Road Projects were unclear and it was difficult to determine if there would be any required hydro relocation work.

The forecast from the Simcoe County and the Cities/Towns do not provide much information for 2014 - 2016. The amount of unknown projects was increased to compensate for this.

The projects identified in 2012/13 are dependent on EA or are on hold by the Town/City. Timing is uncertain on these projects.

Tables 10, 11 and 12 summarize the forecasted spending. Supporting details can be found in Appendix 1.

TABLE 10: SOUTH ROAD AUTHORITY FORECASTED SPENDING

PS-South Year	Budget Gross			Contributed Capital	Net Budget
	Known Projects	Unknown Projects	Total		
2012	$1,408,640	$1,500,000	$2,908,640	$878,862	$2,029,778
2013	$13,376,806	$750,000	$14,126,806	$4,238,042	$9,888,764
2014	$2,626,943	$750,000	$3,376,943	$1,013,083	$2,363,860
2015	$1,205,300	$2,000,000	$3,205,300	$961,590	$2,243,710
2016	$442,960	$2,500,000	$2,942,960	$882,888	$2,060,072
5-Year Total	$19,060,649	$7,500,000	$26,560,649	$7,974,465	$18,586,184

TABLE 11: NORTH ROAD AUTHORITY FORECASTED SPENDING

PS-North Year	Budget Gross			Contributed Capital	Net Budget
	Known Projects	Unknown Projects	Total		
2012	$1,600,000	$1,500,000	$3,100,000	$930,000	$2,170,000
2013	$1,610,000	$1,500,000	$3,110,000	$933,000	$2,177,000
2014	$0	$3,000,000	$3,000,000	$900,000	$2,100,000
2015	$0	$3,000,000	$3,000,000	$900,000	$2,100,000
2016	$0	$3,000,000	$3,000,000	$900,000	$2,100,000
5-Year Total	$3,210,000	$12,000,000	$15,210,000	$4,563,000	$10,647,000

TABLE 12: Road Authority Summary

Year	Total	Cont	Net
2012	$6.01	$1.81	$4.20
2013	$17.24	$5.17	$12.07
2014	$6.38	$1.91	$4.46
2015	$6.21	$1.86	$4.34
2016	$5.94	$1.78	$4.16

b) Emerging Customer Initiated Projects

The 2012-2016 Budget is based on the same level of activity as the 2010 budget adjusted for a 5% increase. 2012 reflects the known Southeast Collector Sewer Project ($700K). The contributed is estimated at 80% of the Gross amount.

Tables 13 summarizes the south and north historical figures.

Tables 14, 15 and 16 summarize the south and north forecasts.

TABLE 13: SOUTH EMERGING CUSTOMER INITIATED HISTORY

Year	Gross	Contributed	Net
2006	1,392,000	1,047,000	345,000
2008	349,491	229,559	119,932
2009	1,084,397	864,441	219,956
2010 South	828,811	428,214	400,597
2010 North	188,724	32,518	156,205
2011 South	659,358		
2011 North	719,426		

TABLE 14: SOUTH EMERGING CUSTOMER INITIATED PROJECTS

PS-South Year	Gross	Contributed	Net Budget
2012	$1,392,326	$1,113,861	$278,465
2013	$726,942	$581,554	$145,388
2014	$763,289	$610,631	$152,658
2015	$801,454	$641,163	$160,291
2016	$841,526	$673,221	$168,305
5-Year Total	$4,525,538	$3,620,430	$905,108

TABLE 15: NORTH EMERGING CUSTOMER INITIATED PROJECTS

PS-North Year	Gross	Contributed	Net Budget
2012	$3,183,547	$3,126,838	$56,709
2013	$297,725	$238,180	$59,545
2014	$312,611	$250,089	$62,522
2015	$328,241	$262,593	$65,648
2016	$344,653	$275,723	$68,931
5-Year Total	$4,466,778	$4,153,422	$313,356

TABLE 16: Emerging Summary

Year	Total	Cont	Net
2012	$4.58	$4.24	$0.34
2013	$1.02	$0.82	$0.20
2014	$1.08	$0.86	$0.22
2015	$1.13	$0.90	$0.23
2016	$1.19	$0.95	$0.24

c) Capital Purchases

There is a need to invest in Structural Analysis software. Although the development of the Canadian Telvent Designer integrated package is slated for eventual development, it is deemed prudent to acknowledge the need for monies within the budget, at an assumed value of the previously recommended software package.

Software Licensing	# Units	Unit Price	Total
SPIDACalc, Full License	1	$2,500.00	$2,500.00
SPIDACalc, Additional Users	12	$830.00	$9,960.00
2012 - Initial Total Investment			**$12,460.00**
OM&A : 2013-2016 Annual Maintenance & Support			$15,060.00

6

SUMMARY

The 2012-2016 Summary is detailed below.

Non-Controllable Capital Summary

	PREVIOUS CATEGORY	*NEW CATEGORY*	TOTAL North & South CONT	TOTAL North & South RATES	TOTAL North & South TOTAL	2011 BUDGET TOTAL North & South CONT	2011 BUDGET TOTAL North & South RATES	2011 BUDGET TOTAL North & South TOTAL
	New Residential Subdivision Infrastructure	Res Subdivisions	8.600	7.100	15.700	7.644	5.096	12.740
	New Residential Subdivision Services					0.275	0.183	0.458
	New Industrial/Commercial Subdivision Infrastructure					0.800	0.000	0.800
2012	Industrial/Commercial 3 Phase Projects	ICI	6.680	0.000	6.680	6.900	0.000	6.900
	New O/H & U/G Secondary Residential					0.303	0.131	0.434
	O/H & U/G Secondary Upgrades	Layouts	1.270	1.700	2.970	0.352	0.151	0.503
	Small New & Upgraded Commercial Projects					1.004	0.000	1.004
	Road Authority Projects		1.810	4.200	6.010	1.644	4.187	5.831
	Emerging Customer Initiated Projects		4.240	0.340	4.580	0.586	0.296	0.882
	Capital Purchases & Projects			0.012		0.000	0.000	0.040
		Designer Related		0.267	0.267			
		Locates & Inspection Related		0.160	0.160			
	TOTALS		**$22.600**	**$13.352**	**$35.940**	**$20.688**	**$14.951**	**$35.639**

	CATEGORY		TOTAL North & South CONT	TOTAL North & South RATES	TOTAL North & South TOTAL
	New Residential Subdivision Infrastructure	Res Subdivisions	8.500	6.900	15.400
	New Residential Subdivision Services				
	New Industrial/Commercial Subdivision Infrastructure				
2013	Industrial/Commercial 3 Phase Projects	ICI	7.080	0.000	7.080
	New O/H & U/G Secondary Residential				
	O/H & U/G Secondary Upgrades	Layouts	1.350	1.800	3.150
	Small New & Upgraded Commercial Projects				
	Road Authority Projects		5.170	12.070	17.240
	Emerging Customer Initiated Projects		0.820	0.200	1.020
	Capital Purchases & Projects				
		Designer Related		0.069	0.069
		Locates & Inspection Related		0.060	0.060
	TOTALS		**$22.920**	**$20.970**	**$43.890**

	CATEGORY		TOTAL North & South CONT	TOTAL North & South RATES	TOTAL North & South TOTAL
	New Residential Subdivision Infrastructure	Res Subdivisions	9.800	8.000	17.800
	New Residential Subdivision Services				
	New Industrial/Commercial Subdivision Infrastructure				
2014	Industrial/Commercial 3 Phase Projects	ICI	7.500	0.000	7.500
	New O/H & U/G Secondary Residential				
	O/H & U/G Secondary Upgrades	Layouts	1.430	1.910	3.340
	Small New & Upgraded Commercial Projects				
	Road Authority Projects		1.910	4.460	6.370
	Emerging Customer Initiated Projects		0.860	0.220	1.080
	Capital Purchases & Projects				
		Designer Related			
		Locates & Inspection Related		0.050	0.050
	TOTALS		**$21.500**	**$14.590**	**$36.090**

	CATEGORY ↓		TOTAL North & South CONT	RATES	TOTAL
2015	New Residential Subdivision Infrastructure	Res Subdivisions	11.400	9.300	20.700
	New Residential Subdivision Services				
	New Industrial/Commercial Subdivision Infrastructure				
	Industrial/Commercial 3 Phase Projects	ICI	7.950	0.000	7.950
	New O/H & U/G Secondary Residential				
	O/H & U/G Secondary Upgrades	Layouts	1.510	2.020	3.530
	Small New & Upgraded Commercial Projects				
	Road Authority Projects		1.860	4.340	6.200
	Emerging Customer Initiated Projects		0.900	0.230	1.130
	Capital Purchases & Projects				
		Designer Related			
		Locates & Inspection Related		0.012	0.012
	TOTALS		$23.620	$15.890	$39.510

	CATEGORY ↓		TOTAL North & South CONT	RATES	TOTAL
2016	New Residential Subdivision Infrastructure	Res Subdivisions	13.300	10.900	24.200
	New Residential Subdivision Services				
	New Industrial/Commercial Subdivision Infrastructure				
	Industrial/Commercial 3 Phase Projects	ICI	8.430	0.000	8.430
	New O/H & U/G Secondary Residential				
	O/H & U/G Secondary Upgrades	Layouts	1.610	2.140	3.750
	Small New & Upgraded Commercial Projects				
	Road Authority Projects		1.780	4.160	5.940
	Emerging Customer Initiated Projects		0.950	0.240	1.190
	Capital Purchases & Projects				
		Designer Related		0.040	0.040
		Locates & Inspection Related			
	TOTALS		$26.070	$17.440	$43.510

	TOTAL North & South ($M) CONT	RATES	TOTAL
2012	22.60	13.35	35.94
2013	22.92	20.97	43.89
2014	21.50	14.59	36.09
2015	23.62	15.89	39.51
2016	26.07	17.44	43.51
	116.71	**82.24**	**198.94**

APPENDIX 1

2012 - South

						Comments	Estimate	Contribution
York Region						Comments	Estimate	Contribution
86860	16th Avenue and Reesor Road Jog Elimination	16th Avenue	Town of Markham	2012	Details	Relocation in 2011, design in progress		
96020	Bathurst St Green Lane West to Yonge Street	Bathurst Street	Town of East Gwillimbury	2012	Details	Not in our service territory		
		Bathurst Street	Township of King	2012				
82680	Hwy 404 Crossing north of Hwy 7	Highway 7	Town of Markham	2012	Details	No impact		
		Highway 7	Town of Richmond Hill	2012				
96770	Keele St Steeles Ave to Hwy 407	Keele Street	City of Vaughan	2012	Details	1.2 KM, 2cct, 27.6kV	$604,246	$181,274
81320	Major Mackenzie Dr Hwy 27 to Pine Valley Dr	Major Mackenzie Drive	City of Vaughan	2012	Details	No impact		
85660	Major Mackenzie Drive from Pine Valley Drive to Weston Road	Major Mackenzie Drive	City of Vaughan	2012	Details	No impact		
83940	Teston Road East of Pine Valley Dr	Teston Road	City of Vaughan	2012	Details	Relocation in 2011, design in progress		
82690	Vaughan Corporate Centre Hwy 400/Hwy 7 Interchange work	Highway 7	City of Vaughan	2012	Details	No impact/Relocation in 2011 for TTC Station		
85710	Yonge Street from Davis Drive to Green Lane		Town of East Gwillimbury	2012	Details	Not in our service territory		
TRH								
	Olde Bayview Ave / Sunset Beach Road					WO 303352, Designed in 2010	$174,100	$58,500
	Snively Street / Drynoch Ave						$63,550	$19,065
	Bond Crescent					No impact		
	Iredale Road / Gretel Drive					No impact		
	Talmage Avenue					No impact		
Markham								
	Main Street Markham - Part 1					900m, 2cct, 27.6kV	$462,497	$138,749
	Main Street Markham - Part 2					900m, 2cct, 27.6kV	$104,247	$31,274
	Old Woodbine Ave					Relocation completed in 2010		

2012 - North

- 50% Lab&Equip&Contract, estimated at 30% of the project budget

- 2012 Known Projects (Timing dependent on the City/Town):
- Barrie – Mapleview Drive Ph.1 – Bayview to Huronia ($500K)
- Barrie – Mapleview Drive Ph.2 – Huronia to Country Lane ($500K)
- Bradford – Melbourne – Holland South ($600K)

2013 - South

Project No.	Project Name	Road	Municipality	Year	Comments	Estimate	Contribution
84860	Bathurst Street and Highway 9		Town of Newmarket	2013 Details	Not in our service territory		
83890	Hwy 50 Castlemore Rd/Rutherford Rd to Countryside Dr/Nashville Rd		City of Vaughan	2013 Details	4km, 1cct, 27.6kV	$4,000,000	$1,200,000
			Peel Region	2013			
			York Region	2013			
98180	Hwy 7 Warden Ave to Sciberras	Highway 7	Town of Markham	2013 Details	1.7km, 4cct, 27.6kV	$3,000,000	$900,000
85730	Jane Street and Rutherford Road	Jane Street	City of Vaughan	2013 Details	No impact		$0
		Rutherford Road	City of Vaughan	2013			$0
85780	Jog elimination at 9th Line & Stouffville Road		Town of Whitchurch-Stouffville	2013 Details	Not in our service territory		$0
85650	Major Mackenzie Drive from CPR to Highway 27		City of Vaughan	2013 Details	No impact		$0
86800	Queensville Sideroad from Leslie Street to Woodbine Avenue		Town of East Gwillimbury	2013 Details	Not in our service territory		$0
85570	Rutherford Road from Jane Street to Keele Street	Rutherford Road	City of Vaughan	2013 Details	2.1km, 2cct, 27.6kV	$1,261,789	$378,537
85560	Rutherford Road from Keele Street to Dufferin Street	Rutherford Road	City of Vaughan	2013 Details	2.1km, 2cct, 27.6kV	$1,361,051	$408,315
99880	Vivian Rd from Hwy 48 to York Durham line	Vivian Road	Durham Region	2013 Details	Not in our service territory		$0
		Vivian Road	Town of Whitchurch-Stouffville	2013			$0
82720	Weston Rd Hwy 7 to Rutherford Rd	Weston Road	City of Vaughan	2013 Details	2.1km, 4cct, 27.6kV	$3,753,966	$1,126,190

TRH		
	Puccini Drive, Poplar Drive, Aida Place	No impact
	Maple Avenue	No impact
Markham		
	Commerce Valley Drive Widening	No impact
Vaughan		
	No info provided	

- 50% Lab&Equip&Contract, estimated at 30% of the project budget

- 2013 Known Projects (Timing dependent EA or on the City/Town):
- Barrie – Ferndale ($750K)
- Barrie – Boulton Court – Pumping Station Feed, 6 poles ($60K)
- Barrie – Essa Rd – Ferndale to Coughlin ($600K)
- Barrie – Essa Rd – Brynne to Anne ($200K)

2014 - South

Project No	Project Name	Road	Municipality	Year		Comments	Estimate	Contribution
99180	16th Ave Bayview Ave to Leslie St	16th Avenue	Town of Richmond Hill	2014	Details	2.1km, 2cct, 27.6kV	$1,261,789	$378,537
85610	16th Avenue from Leslie Street to Highway 404	16th Avenue	Town of Richmond Hill	2014	Details	900m, 2cct, 27.6kV	$423,965	$127,190
85600	16th Avenue from Yonge Street to Bayview Avenue	16th Avenue	Town of Markham	2014	Details	No impact		
85620	2nd Concession from Green Lane to Mount Albert Road	2nd Concession	Town of East Gwillimbury	2014	Details	Not in our service territory		
85740	Highway 7 and Keele Street		City of Vaughan	2014	Details	No impact		
85720	Jane Street and Major Mackenzie Drive		City of Vaughan	2014	Details	No impact		
83020	King Rd from Hwy 400 to Hwy 27	King Road	Township of King	2014	Details	Not in our service territory		
85670	Major Mackenzie Drive from Highway 400 to Jane Street		City of Vaughan	2014	Details	No impact		
98700	Markham Bypass Extension to Morningside Ave	Markham Bypass	Town of Markham	2014	Details	No impact		
97100	St John's Sdrd Bayview Ave to Woodbine Ave	St. John's Sideroad	Town of Aurora	2014	Details		$233,000	$69,900
		St. John's Sideroad	Town of Whitchurch-Stouffville	2014		Not in our service territory		
83410	Warden Ave from Apple Creek Blvd to 16th Ave	Warden Avenue	Town of Markham	2014	Details	1.6km, 2cct, 27.6kV	$708,189	$212,457
86810	York Durham Line from Highway 407 to Highway 7	Highway 407	Town of Markham	2014	Details	No impact		
		Highway 7	Town of Markham	2014				
		York/Durham Line	Town of Markham	2014				
TRH								
	Sunset Beach Road, Dunn Drive					No impact		
	Boisdale Avenue					No impact		
Markham								
	No impacts identified at this time							
Vaughan								
	No info provided							

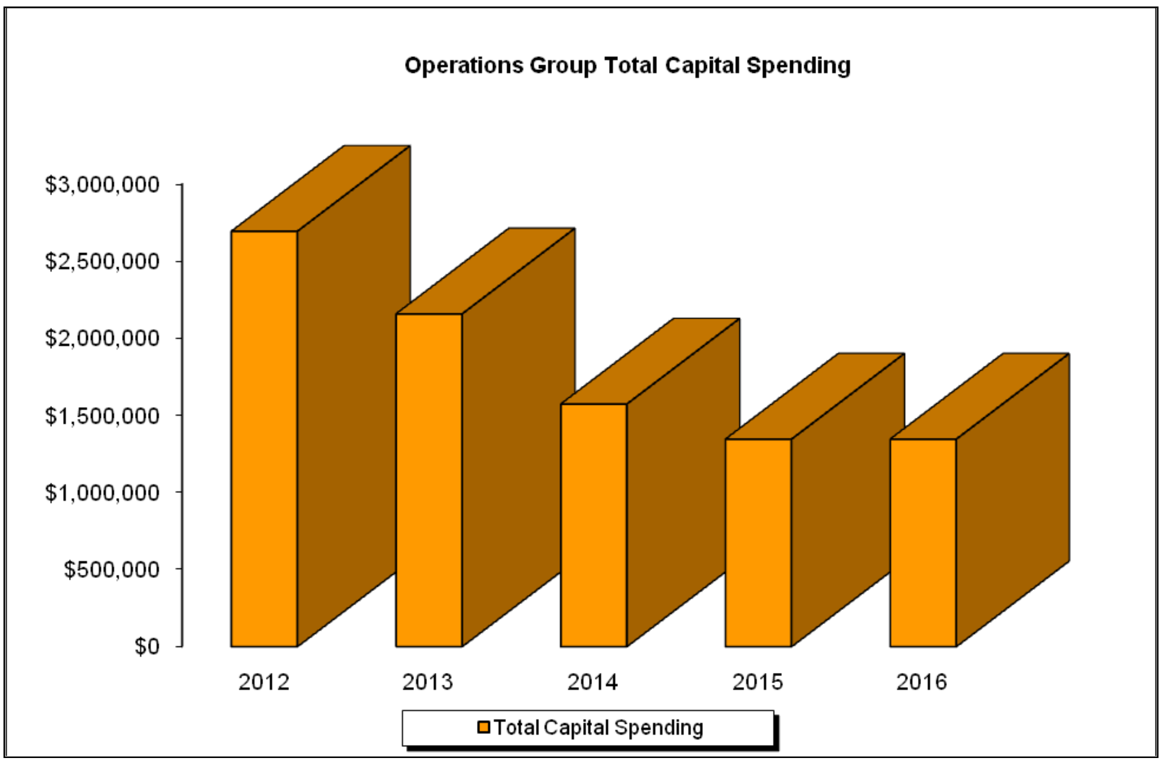
Project No	Project Name	Road	Municipality	Year		Comments	Estimate	Contribution
97000	Bayview Ave Hwy 407 to 16th Ave	Bayview Avenue	Town of Markham	2015	Details	Plant is u/g		
		Bayview Avenue	Town of Richmond Hill	2015				
		Bayview Avenue	York Region	2015				
84200	Doane Road Improvements	Doane Road	Town of East Gwillimbury	2015	Details	Not in our service territory		
86740	Doane Road bridge at Highway 404		Town of East Gwillimbury	2015	Details	Not in our service territory		
80590	Leslie St. Wellington to 500m northerly	Leslie Street	Town of Aurora	2015	Details	No impact		
84190	Leslie Street St John's to Mulock	Leslie Street	Town of Aurora	2015	Details	No impact		
		Leslie Street	Town of Newmarket	2015		Not in our service territory		
84180	Leslie Street Wellington to St. John's	Leslie Street	Town of Aurora	2015	Details	1.3km, 2cct, 1x13.8kV, 1x44kV	$676,995	$203,099
85760	Leslie Street and 16th Avenue		Town of Richmond Hill	2015	Details	No impact		
98650	Major Mackenzie Dr New Markham Bypass to Ninth Line	Major Mackenzie	Town of Markham	2015	Details	No impact		
83450	Major Mackenzie Dr from Hwy 50 to CPR		City of Vaughan	2015	Details	775m, 1cct, future 2cct, 27.6kV	$307,955	$92,387
99780	McCowan Rd 14th Ave to HWY 7	McCowan Road	Town of Markham	2015	Details	No impact		
TRH								
	Lakeland Crescent					No impact		
	Anzac Road					No impact		
	Alsace Road, Ashlar Road					No impact		
Markham								
	Miller Ave - Woodbine to Rodick					570m, 1cct, future 2cct, 27.6kV	$220,350	$66,105
Vaughan								
	No info provided							

2016 - South

Project No	Project Name	Road	Municipality	Year		Comments	Estimate	Contribution
98210	14th Ave Ninth Line to Reesor Rd incl. Connect to Markham Scarb. Link	14th Avenue	Town of Markham	2016	Details	830m, 1cct, future 2 cct, 27.6kV	$342,960	$102,888
84160	Hwy 404 Mid Block Crossing north of Major Mackenzie Dr		Town of Markham	2016	Details	No impact		
			Town of Richmond Hill	2016				
86920	Keele Street and King-Vaughan Road	Keele Street	City of Vaughan	2016	Details	No project scope provided		
		Keele Street	Township of King	2016				
99540	Langstaff Rd Dufferin St to Keele St	Langstaff Road	City of Vaughan	2016	Details	No impact		
83360	Leslie St from Hwy 7 to 16th Ave	Leslie Street	Town of Richmond Hill	2016	Details	No impact		
83370	Leslie Street from 16th Ave to Major Mackenzie Dr	Leslie Street	Town of Richmond Hill	2016	Details	No impact		
85680	Major Mackenzie Drive from Jane Street to Keele Street		City of Vaughan	2016	Details	No impact		
85580	Rutherford Road from Dufferin Street to Bathurst Street	Rutherford Road	City of Vaughan	2016	Details	No impact		
86830	York Durham Line from Bloomington Road to Main Street		Town of Whitchurch-Stouffville	2016	Details	Not in our service territory		
TRH								
	No info provided							
Markham								
	Old Woodbine Ave					Relocation completed in 2010		
	Old Kennedy Road Improvement							
	Midland Ave Extension (Steeles Ave to Old Kennedy)						$100,000	$30,000
Vaughan								
	No info provided							

2012-2016

Operations Group 5 Year Asset Management Plan



April 26, 2011

John McClean

Director, Operations

Summary

The Operations area in PowerStream encompasses the Business Units of (565) System Control, (485) Protection and Control, and (475 & 335) Station Sustainment. The simplified functions of each business unit are the following:

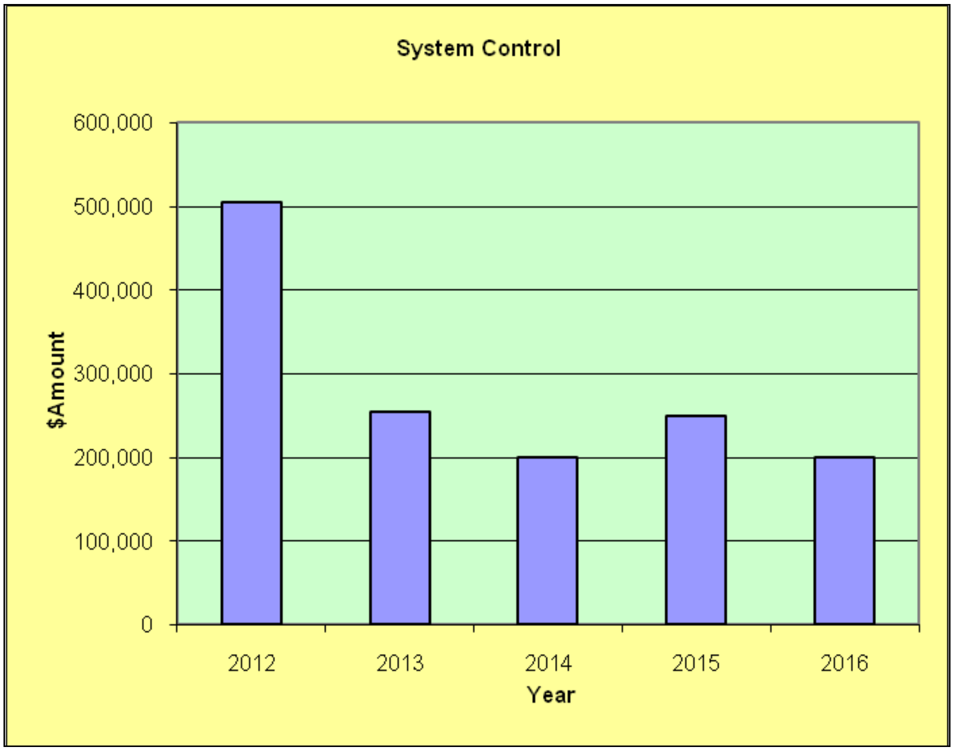
- 565: Monitor, operate, and control the PowerStream distribution network from the take-off point at Hydro One (transmission or sub-transmission points) to the customer service entrance within equipment limits and ratings. Direct the restoration of power for unplanned events via remote and manual efforts.
- 485: Maintain the protection, communication, and SCADA assets used by PowerStream to manage its assets. Test according to schedules and requirements.
- 475/335: Maintain the substation electrical and facility assets to maximize lifespan and in-service availability. Locate cable faults in the field to efficiently to reduce equipment outage time.

The proposed five year Capital Plan for the Operations area exhibits continued spending to build on existing platforms and maximize the lifespan of assets.

System Control

The focus in System Control is for continued spending to enhance unique application tools currently used in the control room and provide outage information to customers more efficiently and accurately. System outage and performance data collection and management is an important function that requires spending support as technology changes. There is a drop in capital spending as we look out past two years. This is due to the fact that many post-merge/formation technologies are in production mode and spending is in the OM&A arena. Key projects such as OMS, IVR, and Website outage information should be completed at some point in 2011/12. Minor upgrades due to technology changes are expected. OMS/GIS upgrades are foreseen towards the end of the five year timeframe but this is a project that could be a moving target. Custom Environment features include furniture and appliance capital spending to accommodate ergonomic or technology needs. Due to the nature of a 24/7 room, it is expected that the lifecycle of furniture and fixtures is reduced and requires earlier replacement than normal office fixtures.

At some point beyond 2016, consideration may be given to a new SCADA/DMS application. This decision would be based on the ability of the current vendor to meet ever-changing technology and the needs of any smart-grid applications. Integration of SCADA into the corporate landscape given potential NERC cyber requirements is an unknown at this time. PowerStream is a direct-connect entity but the feeling at the moment is that NERC Cyber-Security requirements may not apply to us in their entirety.



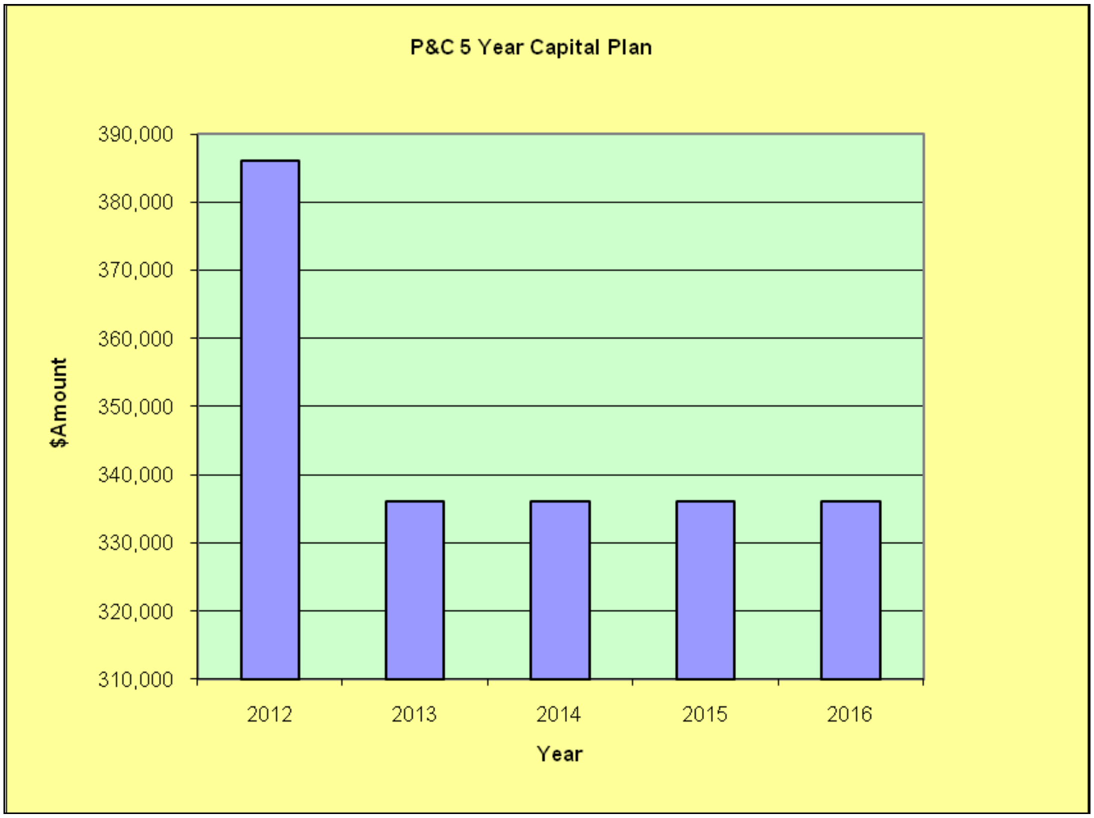
Protection & Control (P&C)

The spending strategy in P&C focuses on maintaining the SCADA system, replacing legacy field remote units, and Transformer Station Human – Machine – Interface (HMI) upgrades. Key and critical spare part purchases by Station Sustainment and P&C are planned to ensure maximum in-service availability of PowerStream substation assets.

Typical program type expenditures include:

Replacement of SCADA Workstation PC's
RTU Replacement Program
P&C Specific Tools and Testing Equipment
Purchase of Spare Relays –   Critical Spares and to Enable a Test Environment in New Operations Centre
PMH RTU Conversion to SEL (2)
HMI Upgrade MTS#1

As the schedule moves out to 2016, spending levels out and focuses on recurring program expenditures to keep our assets functioning.



Station Sustainment

The Station Sustainment spend plan is to support their approach to a Reliability –Centred - Maintenance regimen and documented Asset Management Plan. A concerted effort is underway to identify all components in the Computerized Maintenance Management System (CMMS) as well as collect as much information as possible to provide guidance on maintenance efforts and frequency for each of our substation assets. Spending is broken down into the following categories:

TS
MS
Both
Tools
Spare Parts (both MS/TS)
Information Technology/Infrastructure
Consulting/testing

In addition to this project, efforts are underway to catalog all spare parts. The long term focus of the department is to utilize technology to ensure maximum asset availability while ensuring the maximum life cycle.

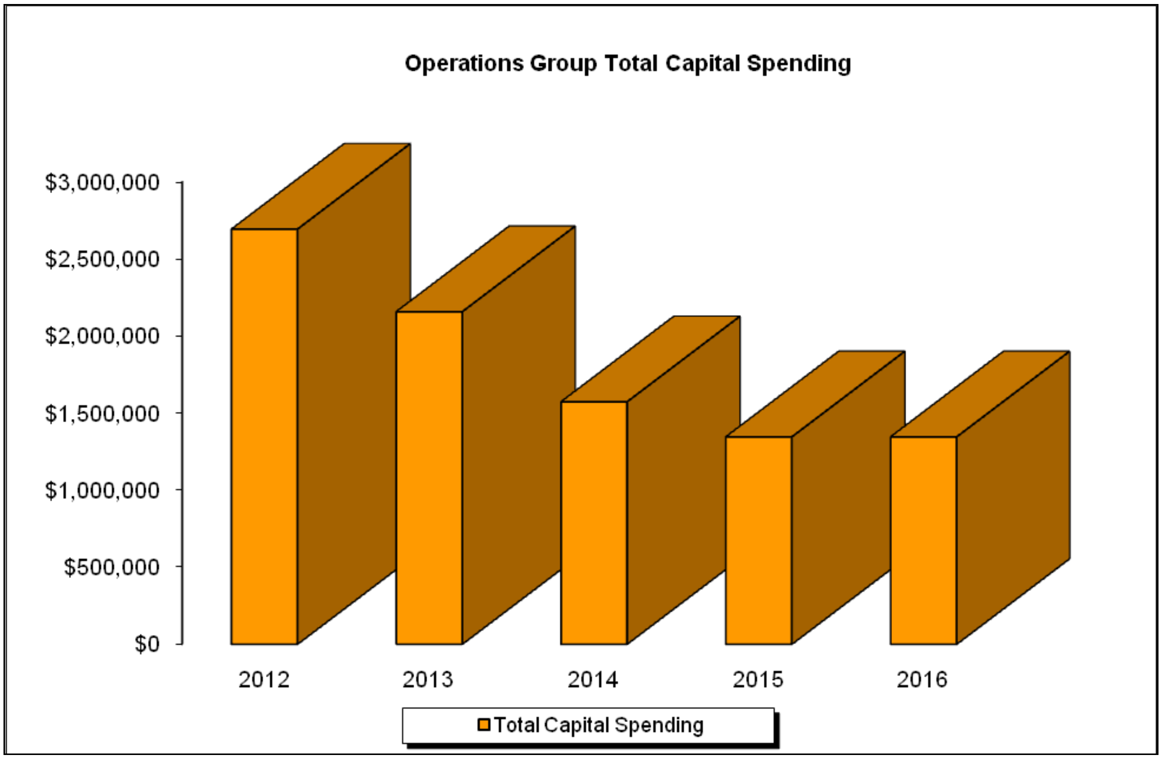
2012 to 2013 exhibit higher spending levels as efforts are made to tool up the department and address immediate needs at our facilities. Emerging patterns of vandalism, graffiti, and thefts require some additional spending at certain asset locations.

Some projects within the P&C and Station Sustainment folders will be forwarded to the Station Design and Construction group for consideration, editing, and project development. There may be projects transferred to the Operations Group from SD&C if there is deemed to be minimal engineering or project oversight.

Operations Group Trend

Trending of capital spending for the collective group is projected to level out towards 2013. Many of the programs and technology currently underway will be in place and efforts will fall under the OM&A portfolio. Strong spending levels in years 2012-2013 focus on specific station projects and resemble a catch-up philosophy to ensure our assets are performing at a maximum level now and in the future. Near term spending addresses some identified existing shortcomings at facilities that need to be resolved. Spending continues in the near term to support the build of technology and interfaces (OSISoft PI software for example) to serve the needs of various internal customers from Eng - Planning to Corporate Communications and others. There will be a need to grow some technology platforms annually to meet internal needs.

Business Unit	2012	2013	2014	2015	2016
565 System Control	$505,000	$255,003	$200,004	$250,005	$200,006
485 P&C	$386,000	$336,000	$336,000	$336,000	$336,000
335 & 475 SMD	$1,803,500	$1,567,500	$1,037,500	$760,000	$810,000
Totals	**$2,694,500**	**$2,158,503**	**$1,573,504**	**$1,346,005**	**$1,346,006**



Expanded granularity for each business unit sub-category group is shown in the attached detailed spreadsheets for the 2012-2013 proposed spends.

The majority of the spending for all groups is controllable with many proposals supporting Smart Grid initiatives and PowerStream's vision to be a leader in our industry in all aspects of our business.

PowerStream Inc.

Lines

Asset Management Plan

2012-2016

Compiled By: Phil Hoover

Director, Lines

April, 2011

Lines Asset Management Plan

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This 5 Year Asset Management Plan provides a greater level of detail on how the forecasted numbers were created for the capital budget created within Lines.

The following plan addresses the capital expenditures required to maintain our distribution system consisting of the following equipment servicing 329,000 customers.

Overhead circuit wires	2,824 km
Underground cable	4,751 km
Transformers	40, 682
Switchgears	1,772
Poles and Pole Structures	43,575

1.0 INTRODUCTION

The ever increasing complexity of the distribution sector, coupled with increased regulatory expectations, results in a need to create solid, defendable documentation on forecasted capital spending.

This 5 Year Lines Asset Management Plan provides a greater level of detail on how the forecasted numbers are created for the Lines capital budget.

The 8 functional areas within Lines that contribute to the Capital Plan are as follows:

1. Replacement of Failed (end of useful life) Distribution Equipment
2. Replacement of Distribution Equipment due to Storm events
3. Recoverable replacement of Distribution Equipment due to Accidents
4. Non Recoverable replacement of Distribution Equipment due to Accidents
5. Joint use Pole removal
6. Fault indicator installation & replacement program
7. Mobile technology projects
8. Tool & Equipment purchases

2.0 Sustainable Capital

i) Replacement of Failed (end of useful life) Distribution Equipment

a) This expenditure covers the emergency replacement of all failed equipment within our 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. These costs are tracked by the following categories: poles and fixtures, conductors and devices, services and transformers.

   With the introduction of Asset Condition Assessment (ACA) program in 2010 for planned replacements of some distribution equipment (such as Switch Gears/Poles) it is expected that failures should be reduced in several years. To date, this has not been the case as the program is just in the second year.

b) The 2010 total spending in this category was $6,418,992. The 2012 budget projections are an estimated total of $7,901,775. Please refer to Table 1.

c) For years 2012 through 2016 this expenditure will be divided into the following 5 headings:

   - Poles
   - Transformers
   - Conductors & Devices
   - U/G Switchgears
   - LIS Switches

Table 1: Replacement of Failed Distribution Equipment

Project Title	2012	2013	2014	2015	2016	Remarks
Emergency Pole Replacements	573,877	591,094	608,827	627,091	645,904	
Emergency Transformer Replacements	4,036,834	4,157,939	4,282,677	4,411,158	4,543,492	
Emergency Conductors & Devices	1,785,355	1,838,915	1,894,083	1,950,905	2,009,432	2012 - 2016 Switchgears & LIS budgeted separately
Emergency U/G Switchgears	1,040,000	1,071,200	1,103,336	1,136,436	1,170,529	Estimated 20 units per year
Emergency LIS Switch Replacement	600,000	618,000	636,540	655,636	675,305	Estimated 20 units per year

ii) Replacement of Distribution Equipment due to Storm Events

This expenditure is for 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 safely working conditions. The projection for this capital budget item is estimated based on the past 5 years of historical spending due to the year over year variability in annual severe weather patterns. The average annual spending for the years of 2007-2011 is $700,000. Please refer to Table 2.

Table 2: Replacement of Distribution Equipment due to Storm Events

Project Title	2012	2013	2014	2015	2016	Remarks
Storm Damage, Replacement of Distribution Equipment due to Storm	700,000	700,000	700,000	700,000	700,000	Based on previous 5 years average

iii) Recoverable Replacement of Distribution Equipment due to Accidents

This expenditure tracks the cost associated with replacement of major equipment damaged by vehicle accidents and foreign interference when we are able to identify the third party and appropriately collect information at the time of the damage. The replacement costs are tracked and collection is made from the party causing the damage to our distribution equipment. This budget tracks the contributed capital spending and will net at 0 with 50% of funds being collected during each budget year. Please refer to Table 3.

Table 3: Recoverable Replacement of Distribution Equipment due to Accidents

Project Title	2012	2013	2014	2015	2016	Remarks
Recoverable Replacement of Distribution Equipment due to Accident/Vandalism	402,248	425,000	430,000	440,000	450,000	This budget Nets at 0 with 50% collected in the actual budget year

iv) Non Recoverable Replacement of Distribution Equipment due to Accidents

This expenditure tracks the cost associated with replacement of major equipment damaged by vehicle accidents and foreign interference when we are **not** able to identify or collect costs from the third party causing damage to our distribution equipment and therefore bear the replacement costs ourselves. Please refer to Table 4.

Table 4: Non Recoverable Replacement of Distribution

Equipment due to Accidents

Project Title	2012	2013	2014	2015	2016	Remarks
Non Recoverable Replacement of Distribution Equipment due to Accident/Vandalism	203,523	400,000	412,000	424,360	437,000	2011 Actuals are higher than expected

v) Fault Indicator Installation and Replacement Program

As we operate our system the installation of fault indicators are crucial to improving our trouble shooting capability when system events occur and reduce the number of times we subject our plant to fault currents. There are several types of fault indicators currently in our system due to the mergers that have taken place. Some areas have a limited number installed and some areas have no fault indicators. As we complete our annual inspection of equipment we have an opportunity to check existing installations and install new fault indicators standardizing our underground and overhead network. The new areas for installation will be established by consulting with the control room and system planning. This expenditure will benefit our reliability by reducing outage duration times. This budget did not make it through the optimizer process for 2011. Please refer to Table 5.

Table 5: Fault Indicator Installation and Replacement Program

Project Title	2012	2013	2014	2015	2016	Remarks
Fault Indicator Replacement Program	400,000	500,000	500,000	500,000	500,000	Did not make optimizer 2011

3.0 Operational Capital

i) Joint Use Pole Removal

During the process of pole replacements in our service area there is a lag time for joint use parties to relocate their attachments to our new pole. Historically, this time has taken several months or years. The costs associated with removal of poles that have been left for joint use utilities to relocate to new poles is estimated at the completion of any work order for new pole installations. Please refer to Table 1. A flat rate per pole cost is calculated for the removal of each pole and applied to the work order being closed and when the poles are removed we charge the removal cost to a standing work order.

Table 1: Joint Use Pole Removal

Project Title	2012	2013	2014	2015	2016	Remarks
Joint Use Pole Removal	449,398	449,398	449,398	449,398	449,398	

ii) Mobile Technology Projects

As technology advances we have made an attempt to leverage the latest in mobile equipment. This has assisted our department with data collection and inspection of distribution equipment, viewing system maps and tracking time records electronically in our effort to gain efficiencies, reduce duplication of work and be more environmentally responsible. Please refer to Table 2. This budget will allow for future requirements in the area of equipment purchases and programming required to meet our needs.

Table 2: Lines Mobility

Project Title	2012	2013	2014	2015	2016	Remarks
Lines Mobility	80,000	80,000	82,400	82,400	84,872	

iii) Tool & Equipment Acquisitions

This expenditure is for purchases of all major tools for the Lines department with an individual value greater than $1000 with a life expectancy of more that 1 year.

Day to day line work operations requires a variety of specialty tools that wear out, become damaged or become obsolete. This budget item covers the replacement costs with similar items or to upgrade obsolete tools. Please refer to Table 3.

The tools purchased include but are not limited to:

(i) barriers used in live line operations
(ii) hoisting equipment
(iii) temporary grounding devices
(iv) temporary secondary service jumpers and hydraulic presses
(v) high voltage Rubber cover up
(vi) high voltage switch sticks

(vii) tension stringing equipment including replacement ropes, travelers, brackets,
(viii) ladders, test meters, manhole entry systems & gas detectors. etc.

Table 3: Tools & Equipment

Project Title	2012	2013	2014	2015	2016	Remarks
Tools & Equipment	374,000	362,000	362,000	373,663	375,000	

All equipment purchased allows our staff to safely and efficiently maintain our system. Providing and maintaining equipment, materials and protective devices is mandated in section 25(1) of the OH&SA.

4.0 Summary Table

Project Title	2012	2013	2014	2015	2016	Remarks
Emergency Pole Replacements	573,877	591,094	608,827	627,091	645,904	
Emergency Transformer Replacements	4,036,834	4,157,939	4,282,677	4,411,158	4,543,492	
Emergency Conductors & Devices	1,785,355	1,838,915	1,894,083	1,950,905	2,009,432	2012 - 2016 Switchgears & LIS budgeted separately
Emergency U/G Switchgears	1,040,000	1,071,200	1,103,336	1,136,436	1,170,529	Estimated 20 units per year
Emergency LIS Switch Replacement	600,000	618,000	636,540	655,636	675,305	Estimated 20 units per year
Storm Damage, Replacement of Distribution Equipment due to Storm	700,000	700,000	700,000	700,000	700,000	Based on previous 5 years average
Recoverable Replacement of Distribution Equipment due to Accident/Vandalism	402,248	425,000	430,000	440,000	450,000	This budget Nets at 0 with 50% collected in the actual budget year
Non Recoverable Replacement of Distribution Equipment due to Accident/ Vandalism	203,523	400,000	412,000	424,360	437,000	2011 Actuals are higher than expected
Fault Indicator Replacement Program	400,000	500,000	500,000	500,000	500,000	Did not make optimizer 2011
Joint Use Pole Removal	449,398	449,398	449,398	449,398	449,398	
Lines Mobility	80,000	80,000	82,400	82,400	84,872	
Tools & Equipment	374,000	362,000	362,000	373,663	375,000	
TOTALS	10,645,235	11,193,546	11,461,261	11,751,047	12,040,932	

Supply Chain Services

Five Year Asset Management Plan

2012-2016

Supply Chain Services Five Year Asset Management Plan

2012-2016

1 Executive Summary

Supply Chain Services is composed of the following functional areas: Procurement, Inventory Management, Fleet Services and Facilities Management. Our mission is to "*create, develop and maintain effective alliances and partnerships to support the internal business units in the acquisition and distribution of goods and services, providing a safe and first class fleet and workplace environment*." In order to achieve this capital funds are accordingly allocated on a yearly basis. They are distributed as follows:

Procurement:	B/U 745
Inventory Management:	B/U 755
Fleet Services:	B/U 495
Facilities Management:	B/U's 307, 625, 635

The most capital intensive areas are Fleet Services and Facilities management.

The Fleet Services group presently manages approximately $30M in Fleet assets. These assets are composed of three vehicle classifications:

$23M - H (Heavy Duty - Lines aerial devices)

$7M - L/M (Light/Medium - Vans, pickups, and automobiles)

- M (Miscellaneous - trailers, tension machines, fork lifts)

Facilities Management is responsible for the oversight of the two Operations and Administrative facilities. The 55 Patterson Rd. (built 1990) and Cityview Blvd. (built 2008) locations are owned by PowerStream while the Addiscott Crt. (built 2010) location is a leased facility.

The following is a five year capital plan based on the parameters outlined in each area. The capital requirement for the Procurement area is nil. A total of $150K has been allotted for potential Inventory Management warehouse automation enhancements. It is also important to note that a portion of the annual capital plan from both the Fleet Services and Facilities Management teams is based on B/U requests (i.e. organic growth). This plan does not allow for Fleet Services Fleet inventory growth contribution as it is part of the annual Equipment Schedule that is submitted by the B/U's. Provision for increased Facilities utilization has been included. In addition, there may be the opportunity for the rationalization or non-replacing of assets based on changes in business needs (i.e. contraction). This is also determined on a yearly basis and does not form part of this plan.

2 Fleet Services Capital Program

3

- ***Total Fleet Net Present Value approx. $30M***
- ***Lines Inventory $23.3M, $20.3M H-Classification (Double/Single bucket and RBD's)***
- ***Ideally replacement $ = surplus $ in any one given year***

- ***Due to M&A and resulting Fleet inventory mergers this balance is going to take several years to achieve.***
- ***Delivery time from order date approx 18 months making forecasting difficult.***

3.1

4 Replacement Plan

4.1

5 Expected Life Replacement

5.1.1

- **Replacement determined based on achieving years of use, mileage or hours as per manufacturers recommendations (replacement guideline).**

5.1.2

6 Expected Life Replacement Considerations

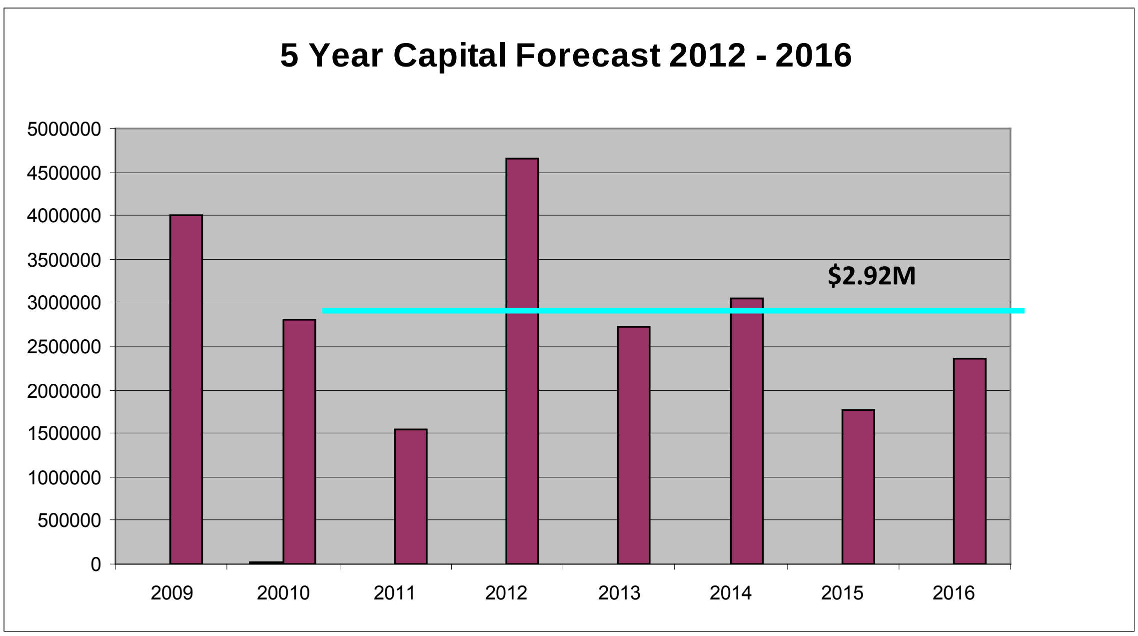
- **Ability to forecast (balanced approach)**
- **Lower risk of catastrophic vehicle failure (vehicles are replaced prior to cost -vs- asset value intersect point)**
- **Ability to negotiate long term procurement contracts with vendors and realize savings.**
- **Approach currently used throughout industry including Toronto Hydro, Hydro Ottawa and City of Vaughan.**

Replacement Guideline

Heavy Class	
Single Axle Cab and Chassis (i.e. small single bucket trucks)	150,000 km OR 8 years
Single Axle (Trouble single bucket trucks)	200,000 km OR 10 years
Tandem Axle (Double bucket trucks)	250,000 km/12000 hrs OR 10 yr.
Radial Boom Device (RBD)	10 years
Light & Medium Class	
Compact Pickup Truck	100,000 km OR 5 years
Full Size Pickup Truck 1/2 or 3/4 ton(2 wheel Drive)	120,000 km OR 6 years
Full Size Pickup Truck 1 ton (4X4)	150,000 km OR 8 years

Compact or Full Size Van	120,000 km OR 6 years
Cube Van	120,000 km OR 6 years
Automobiles / Mini-vans / SUV's	100,000 km OR 5 years
Miscellaneous Class	
Pole Trailer	20 years
Cargo Trailer	10 years
Tension Machine	15 years
Reel Trailer	15 years

5 Year Fleet Capital Plan



7 Fleet Services Capital Plan Summary

- ***Annual capital spend of $2.92M be allocated for 5 year period (2012 – 2016)***
- ***Assist with capital forecasting***
- ***Plan to be reviewed by capital optimization committee on an annual basis***

- ***Life cycle cost analysis to be conducted on a regular basis to update replacement guideline as needed***

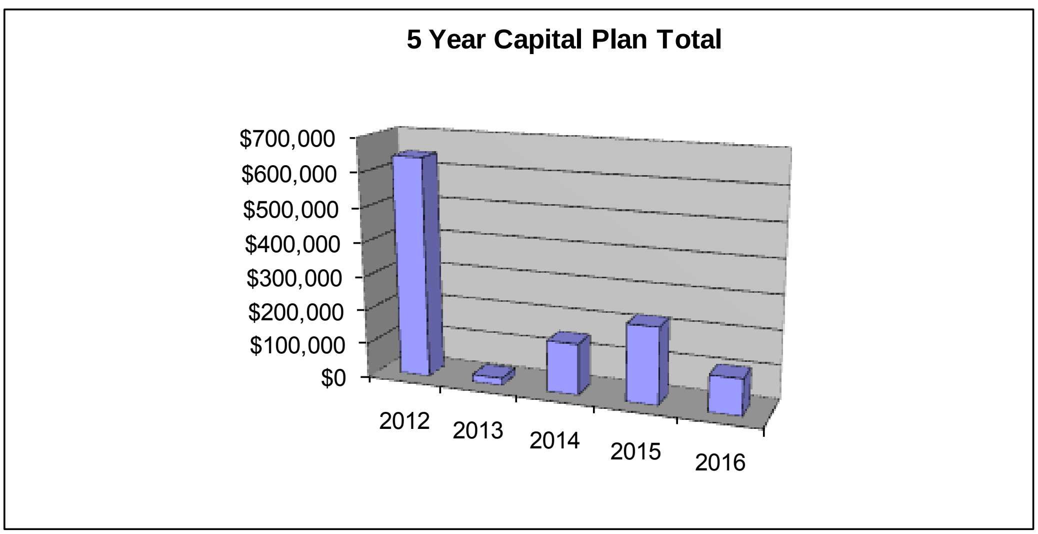
- ***Joint Fleet/BU vehicle utilization and job demand analysis to be conducted on yearly basis and considered as part of annual optimization process***

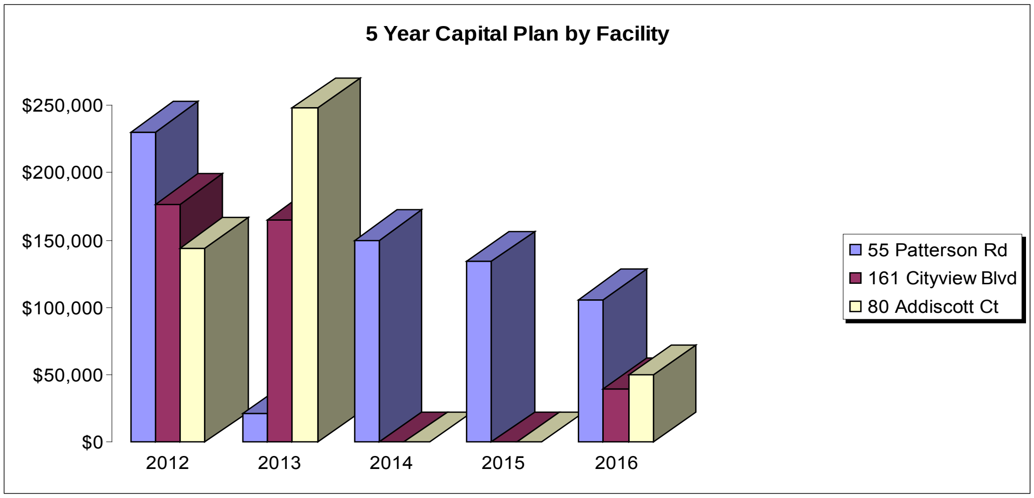
Facilities Management Capital Program

The Facilities Management capital plan is based on a life cycle analysis of relevant facility components that are categorized as follows:

- Exterior (i.e. pavement, fencing, lighting, stores yard)
- Interior (i.e. furniture)
- Mechanical (i.e. Plumbing)
- Structural (i.e. windows, doors, wall partitions)
- HVAC (Heating & air conditioning)
- Equipment (major tools, lifts)

As the PowerStream south facilities are relatively new we do not anticipate major capital replacement expenditures within the next 5 years. The PowerStream north facility is in relatively good condition but some components will require replacement as a result of aging. Anticipated increased utilization of the 55 Patterson Rd facility will require significant capital allocation in 2012. Lease hold improvements at the 80 Addiscott Ct facility will also result in increased capital requirements.





CAT.	ITEM	Rep. Yr.	CURRENT COST	FUTURE COST	2012	2013	2014	2015	2016
	55 Patterson Rd								
Interior	Increased Utilization:Upfitting Floors, Relocation & New Furniture	2012	180,000	180,000					
Exterior	Storage Shed	2012	50,000.00	50,000.00					
TOTAL			**230,000.00**	**230,000.00**	**230,000.00**				
Exterior	Exterior Lighting	2013	4,000.00	5,000.00					
Exterior	Gates & Operators - Yard	2013	6,500.00	8,000.00					
Exterior	Landscaping	2013	6,500.00	8,000.00					
TOTAL			**17,000.00**	**21,000.00**		**21,000.00**			
Exterior	Gates & Operators - Main	2014	7,000.00	8,250.00					

Exterior	Signage	2014	8,500.00	10,000.00		
Struct.	Caulking - Ph 1	2014	20,000.00	25,000.00		
Mech.	Heat Pumps (Compressor)	2014	15,000.00	15,000.00		
Mech.	Transformer	2014	27,000.00	31,250.00		
Mech.	Air Sensors	2014	15,000.00	18,750.00		
HVAC	Cooling Tower Sand Filter	2014	5,000.00	6,000.00		
HVAC	BAS - Upgrade Ph1	2014	3,000.00	3,750.00		
Interior	Flooring-broadloom	2014	15,000.00	18,750.00		
Interior	Ceiling Tile - Ph 2	2014	10,000.00	12,500.00		
TOTAL			**125,500.00**	**149,250.00**	**149,250.00**	
HVAC	Roof Exhaust Fans Ph 1	2015	24,000.00	33,000.00		
Struct.	Windows Atrium	2015	13,000.00	15,000.00		
Struct.	Over Gar Doors - Ph 1	2015	32,000.00	50,000.00		
HVAC	BAS-Upgrade Ph 2	2015	10,000.00	10,000.00		
Interior	Sinks	2015	2,400.00	2,700.00		
Interior	Doors & Hardware	2015	18,000.00	22,950.00		
TOTAL			**99,400.00**	**133,650.00**		**133,650.00**
Struct.	Windows - Ph 1	2016	20,000.00	26,500.00		
Struct.	Exterior doors - Service	2016	7,200.00	9,360.00		
Struct.	Caulking - Ph 2	2016	20,000.00	22,500.00		
HVAC	Water Treatment	2016	1,200.00	2,000.00		

	Pumps/Motors				
Interior	Flooring- broadloom - Ph 5	2016	35,000.00	45,500.00	
TOTAL			**83,400.00**	**105,860.00**	**105,860.00**
HVAC	Storage Tank Removal	2017	10,000.00	12,000.00	
Struct.	Windows - Ph 2	2017	20,000.00	22,000.00	
Struct.	Exterior doors - Public	2017	6,000.00	6,600.00	
Struct.	Gar Door Hardware - Ph 1	2017	20,000.00	24,000.00	
HVAC	Roof Exhaust Fans Ph 2	2017	24,000.00	33,500.00	
Mech.	Elevators - Upgrade	2017	25,000.00	33,125.00	
TOTAL			**105,000.00**	**131,225.00**	
Struct.	Caulking - Ph 3	2018	20,000.00	27,000.00	
TOTAL			**20,000.00**	**27,000.00**	
Exterior	Landscaping - Ph 3	2019	6,000.00	8,000.00	
TOTAL			**6,000.00**	**8,000.00**	

161 Cityview Blvd

Interior	Lighting re-lamping	2012	35,000.00	35,000.00		
exterior	Parking lot upgrade	2012	100,000.00	100,000.00		
project	Records Storage	2012	30,000.00	30,000.00		
Total			**165,000.00**	**165,000.00**	**165,000.00**	
Interior	Kitchen Equipment	2015	36,000.00	40,000.00		
Total			**36,000.00**	**40,000.00**		**40,000.00**

80 Addiscott Ct

Equip.	Scissor lift	2012	18,000.00	18,000.00	
Exterior	Parking lot upgrade	2012	50,000.00	50,000.00	
HVAC	BAS	2012	80,000.00	80,000.00	
	Emergency lighting	2012	10,000.00	10,000.00	
	CO Warning System	2012	15,000.00	15,000.00	
	Fire alarm system	2012	25,000.00	25,000.00	
	Microwave Security System	2012	50,000.00	50,000.00	
Total			**248,000.00**	**248,000.00**	**248,000.00**

Interior	Overhead doors	2015	50,000.00	50,000.00					
Total			**50,000.00**	**50,000.00**				**50,000.00**	
Totals					**643,000.00**	**21,000.00**	**149,250.00**	**223,650.00**	**105,860.00**

Facilities Capital Program – Detail

Facilities Management Capital Plan Summary

- Total 5 year capital allocation as follows:
  - 55 Patterson Rd. $670K
  - 161 Cityview Blvd. $381K
  - 80 Addiscott Ct. $442K

- Projected increase in 55 Patterson Rd. facility utilization has been identified for 2012. ($230K)
- Lease hold improvements at the 80 Addiscott Crt. facility has been identified. ($230K)

Supply Chain Services Capital Plan Summary

- Procurement capital requirements nil over five year period (2012-2016)

- Inventory Management capital requirements ($50K in 2012, 2013, 2014 for warehouse automation)

- Fleet Services
  - $3M capital allocation each year (2012 – 2016)
  - To be reviewed annually

- Facilities Management
  - Varied capital allocation
  - 55 Patterson Rd 2012 Capital due to Increased utilization $230K
  - 80 Addiscott Ct 2012 Capital due to Lease hold improvements $230K

Supply Chain Services Overall Capital Allocation 2012-2016

	2012	2013	2014	2015	2016
Fleet Services	$3M	$3M	$3M	$3M	$3M
Facilities Management	$.64M	$.02M	$.15M	$.22M	$.11M
Inventory Management	$.05M	$.05M	$.05M	-	-
Procurement	-	-	-	-	-
TOTAL	$3.69M	$3.07M	$3.2M	$3.22M	$3.11M

Smart Grid and Metering

Five Year Capital Plan

2012 – 2016

Prepared by: E. Chatten, J. Mulrooney & R. Lapp

April 15th, 2011

Table of Contents

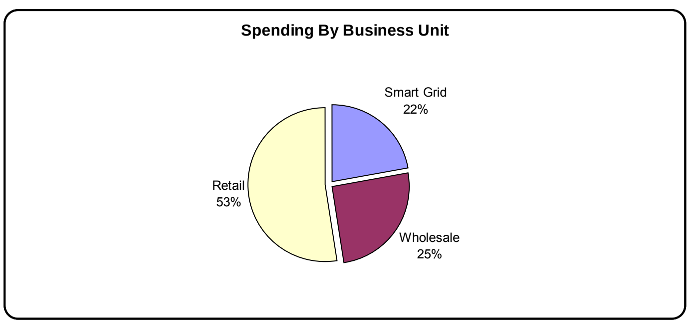
Executive Summary

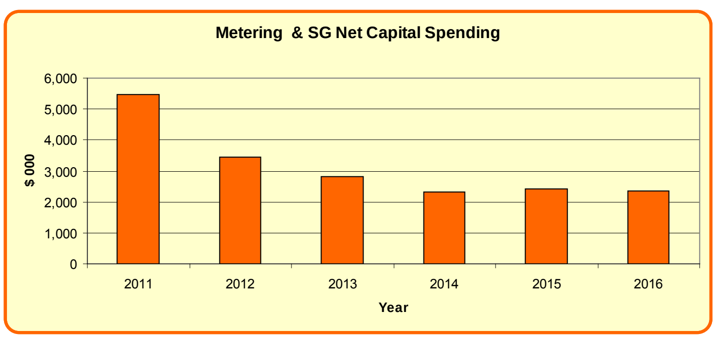
The Meter and Smart Grid departments estimate of capital expenditures for the five period 2012 – 2016 is a total of $13.35 million, shown in the table below.

There is no contributed capital in the Metering and Smart Grid capital program (100% chargeable to rates).

Summary - SG & Metering 21012 - 2016 Capital Planning

	$ 000						
Section	**2011 Net**	**2012 Net**	**2013 Net**	**2014 Net**	**2015 Net**	**2016 Net**	**TOTAL**
Smart Grid	603	1,250	650	350	350	350	**2,950**
Wholesale Metering	1,354	707	662	707	662	662	**3,400**
Retail & Suite Metering	3,510	1,500	1,500	1,250	1,400	1,350	**7,000**
` **TOTAL**	5,467	` 3,457	2,812	2,307	2,412	2,362	**13,350**





1. Overview of Smart Grid and Metering Department

The Smart Grid and Metering department comprise three business units:

Smart Grid

Wholesale Metering

Retail Metering

The Smart Grid business unit was former in 1Q 2010 and PowerStream's Smart Grid Strategy and Plan was developed thereafter with Board of Director approval in September 2010. Development of Smart Grid within the company is directed by the Smart Grid Task Force, a group of senior management department heads that provides consensus and prioritization of SG initiatives.

The Wholesale Metering business unit is responsible for metering the electricity supply points to PowerStream distribution system, including meter re-verifications (i.e. regulatory testing of meter accuracy) and the newly commissioned (2011) smart meter test facility which tests smart meter functionality.

Retail Metering manages the installation and maintenance of revenue meters to all customers. In 2011, PowerStream will complete installation of its $1 billion Smart meter installation program begun in 2006.

2. 2011 Capital Budget and Forecast (end of Q1)

Q1 2011 Metering Capital Forecast

Work Order	Description	Net 2011 Budget $	Net 2011 Actual $	Forecasted Gross & Net at Year End 2011
W.00301078	PUR/INSTALL OF NEW SUITE METER	638,858.00	73,804.61	639,000
W.00300849	Retrofit bulk metered premises	115,050.00	0.00	115,000
W.00305036	Purc/Install Suite Metering	118,877.00	1,255.84	118,000
W.00305037	Retrofit Bulk Metered Premises	109,501.00		110,000
W.00201224	Replmnt failed Meter Equip	36,305.00	3,231.57	36,000
W.00201226	Meter Reverifications	132,893.00	13,221.53	133,000
W.00305042	Revenue meter re-verifications	25,985.00	0.00	26,000
W.00301992	Cont. install. of Smart Meters	1,290,080.00	510,665.76	1,900,000
W.00301994	Proj. Mgmt. Smart Meters		14,397.53	
W.00302840	MDMR costs for SMART meters		8,280.00	
W.00305096	Smart Meter Replacements		9,578.21	
W.00305104	PURC SM 1& 3 PHASE		128,296.84	
W.00305098	Cont-Staff Install. - SMeters	361,900.00	75,507.27	500,000
W.00305101	PROJ MANAGMNT FOR SMART METER		-3,102.85	
W.00305102	PURCH SMART METERS -1&3 PHASE		78,134.09	
W.00301995	sub-metering system data		127.44	
W.00301993	Purchase of Smart meters		16,478.88	
W.00306457	UPGRADE 2.5 ELEMENT METERS	126,874.00		127,000
W.00306458	BUTTONVILLEMETERING UPGRADE	995,269.00		995,000
W.00306459	FAILED METER REPLACEMENT	15,726.00		16,000
W.00306460	REPL MURRAY JENSEN METER BASES	6,133.00	1,299.60	6,000
W.00306461	TOOL & EQUIPMENT NORTH	16,500.00	7,116.00	17,000
W.00306462	TOOL AND EQUIPMENT SOUTH	55,000.00		55,000
	SUBTOTAL	4,044,951.00	938,292.32	4,793,000
W.00122974	Wholesale Meter Upgragde (Carryover from 2010)		3,266.01	70,000
W.00305040	Wholesale metering upgrade (Carryover from 2010)		-9,606.71	0
	SUBTOTAL	4,044,951	931,952	4,863,000

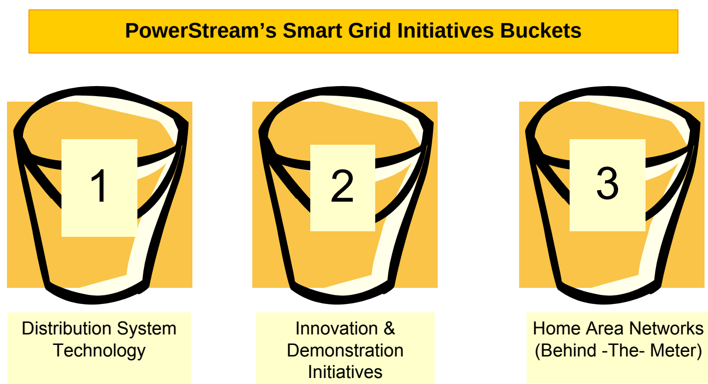
Q1 2011 Smart Grid Capital Forecast

Status Comment	Net Budget	Net Actual	Forecasted Gross & Net at Year End 2011
Digital Fault Indicators	Deferral Acct	29,618	29,618
Electric Vehicle Trial - South	Deferral Acct	0	143,000
Electric Vehicle Trail - North	Deferral Acct	0	0
GRID ENERGY MANAGEMENT	459,706	0	460,000
Total to Rate Base	459,706	0	460,000
Total to Deferral Accounts			172,618

3. Smart Grid 2012 – 2016

In 2010, staff issued PowerStream's Smart Grid Strategy and Plan titled "Creating Tomorrow's Reality Today" in which it proposed five year capital spending program for the period 2011 – 2015.

Simply put, Smart Grid inare technologies available to the LDC to enhance its performance in each of the following three areas:



1. Distribution System Technology – using technology to modernize, control, coordinate, and optimize the performance of the distribution grid.

2. Innovation and Demonstration Projects – covering initiatives dealing with new emerging technologies that impact the distribution system and designed to give the LDC a better understanding of the technology and whether or not it could be applied to larger portions or the distribution system. These initiatives are usually small in scale.

3. Home area Networks – cover "behind-the-meter" technology applications that involve the customer and usually involve third party technology providers. The objective of these initiatives is to enabling the customer to take advantage of Smart Grid technologies to develop a smarter electric energy usage in the home and office areas.

Over the 2012 – 2016 period, PowerStream expects to continue prudently optimizing distribution m technology, continue to carry out trial and demonstration of technology application projects, and increase it efforts to advance Smart Grid technology downstream of the meter.

Electric Vehicle Trial

In 2010, PowerStream undertook a Electric Vehicle (EV) Smart Charger demonstration trial in partnership with Better Place Inc., a world 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 and PowerStream has leased one EV to operate between these centres. Two additional vehicles have been order from Nissan Canada and will be delivered later in 2011.

Working with Better Place (and possibly Georgian College), develop insight into the potential impact of PEV technology and its associated centrally managed charging network on PowerStream's distribution system. 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.

Over the next five year period, 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.

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.

i. identify power diversion (theft) by reconciling loads connected to transformer.

ii. provide alarm and indication of low voltage and outage conditions

iii. provides transformer energy loading profile (kwhrs versus time of day)

iv. measure and report line losses from transformer to residential meter

v. power factor of the total transformer load

vi. provide KVA loading of transformer (KVA versus time)

vii. transformer loading profile (KVA versus time of day). This will 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. provide phase current balancing to three phase feeder supply to subdivision.

ix. provides feeder load reconciliation to the station feeder. This will permit calculation of feeder losses, feeder power factor, feeder phase balance, feeder load profiling,

x. will reduce latency and increase AMI operational performance of the OMS by reducing AMI traffic by 88 to 90 % of present traffic volumes.

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. It is expected that expansion of this technology application past 2013 will be achieved via PowerStream's rate-based capital expenditure program.

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. A recent initiative that provided actual consumption data for a project evaluating the impact of EVs on PowerStream's distribution system generated additional requests form planning engineers for more data access tools to assist in system planning and analysis.

Over the five year plan period, PowerStream, with the assistance of contract personnel, will develop user friendly GUI type database queries to provide easy access to those personnel requiring this data. Have 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 is currently stored in an Operational Data Store (ODS) provided by Savage Data located in Thunder bay, ON..

Staff believe that development of this application technology will continue throughout the five year period of this plan.

Home Energy Management (HEM) Trials (Behind the Meter SG Applications)

Previously in its Smart Grid plans, PowerStream elected to not develop Smart Grid downstream of the Smart Meter, but to act as an enabler of third party technologies, choosing to leave this development to the numerous retail and service providers offering home energy management products. PowerStream did participate in a number of “behind-the-meter” applications in its energy conservation and demand management programs such as the residential PeakSaver program.

The provincial government, the Ontario Energy Board and the IESO SG Forum are placing an increased emphasis on HEM applications and to have LDC’s participate in some meaningful way. LDC’s will find increasing pressure by these groups to be encouraged to behind the meter activities.

Over the next five year period, monies have been budgeted to provide SG information and opportunities to the customer and to provide in-home demonstration initiatives to demonstrate this technology.

Feasibility of Storage Technologies

As renewable energy sources continue to be developed throughout PowerStream’s service territory and as Electric Vehicles continue their entrance into the southern Ontario marketplace, there is an increased need to better understand the electricity storage options opened to LDC’s. There have been significant technical advances in electricity energy storage systems such as inertial flywheels, pneumatic storage, hydraulic storage and advanced battery systems.

PowerStream believes that as part of its SG strategy, it should investigate specific applications some of these storage technologies and, where thought to be 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.

The SGTF supports the allocation of capital monies to investigate and report on these technologies with greater sending in the first two years of the plan and reduced spending in the latter years of the plan.

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.

Coupling the Sensus Flexnet AMI communications technology with Horstmann line fault indicator technology, this project will install twenty for 3-phase fault indicators on PowerStream's distribution system and one 3-phase 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.

While this project is scheduled for completion in 2011, it is planned that additional development work will necessary in 2012. 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.

4. Wholesale Metering 2012 - 2016

Wholesale Meter Upgrade (Finch, Leslie & Fairchild)

This project is required to make the PowerStream’s wholesale meter systems located at Finch, Leslie and Fairchild transformer stations compliant with the IESO Rules for Wholesale Metering. Installations and thereby satisfy OEB licensing requirements

This project would install new two current and voltage transformers for installation in the three HONI owned transformer stations located in Markham.

When completed, the metering installation would be similar to the 230 kV metering setup at both Greenwood TS and Markham TS#4.

This capital work will be completed in 2011.

Buttonville Wholesale Metering Upgarde

This one-time project, required to make the PowerStream’s wholesale meter systems located at Buttonville transformer station compliant with the IESO Rules for Wholesale Metering. Installations and thereby satisfy OEB licensing requirements, will be completed in 2011.

Failed Meter/Transformer Replacement

Periodically revenue billing meter systems fail in-service for a number of reason beyond PowerStream's control. When a billing meter or associated components such as metering transformer fail, replacement must take place as soon as possible to minimize the time that customer energy consumption data is lost. Replacement would include labour and parts for metering to replace all meters, wire, instrument transformers and associated test equipment. Based on past experience, approximately 50 units are expected to fail in the South and 20 units in the North throughout the year.

Tools and Equipment

The periodic replace of small tools and test equipment is essential to the safe and efficient operation of metering staff. Often new tools have to be added to accommodate new equipment and new testing requirements. These tools are used by staff to install, maintain, repair, test any new, existing or removed meter installations. Typical tools in that require replacement under this program include:

- hydraulic cable cutters - cut cables to install instrument transformers

- hydraulic crimpers - crimping tool equipment

- voltage, amperage and measurement device for service analyzing.

- power quality analysis equipment

Meter Reverifications

This project is a Federal Government requirement under the Electricity and Gas Inspection Act enforced by Measurement Canada) required to ensure that all revenue meters meeting 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.

All revenue meters are sealed upon installation and each meter seal is tracked for age. Seals have an expiry date ranging from 4 to 12 years depending on the type of meter. To comply with Measurement Canada's requirements, meters are removed from service after their seal date exceeds the specified age and are tested. Each year, PowerStream determines which meters require re-verification. Typical meter life for electromechanical meters is 40 years while the new smart meters range from 15 - 18 years..

Re-verification involves removal of the old meter to be tested, and replacing it with a new meter with a valid seal. The removed meter is delivered to a Measurement Canada certified test facility (in PowerStream case, it is E-caliber at Erie Thames Hydro). If the meter passes its tests, in is returned to PowerStream's inventory for future use. If the mete fails testing, then it is scrapped and the value is written-off the finance ledgers.

At this point in time, smart meters do not require re-verification. This project only applies to the approximately 14,000 electromechanical and electronic meters remaining on PowerStream's system, mostly on ICI services. In 2011, some 2,500 meters will be re-verified. Re-verification costs included meter removal and replacement, transportation to and from the testing facility and the cost of testing itself.

As a condition of its operating license, PowerStream must comply with Measurement Canada's requirements to test revenue meters for accuracy and proper operation. This process ensures that customers are billed fairly and accurately.

5. Retail & Suite Metering 2012 – 2016

AMI/MDMR/TOU Program

The metering department primary focus since 2006 was to satisfy the Provincial Government mandate to replace the electromechanical billing meters with the new Smart Meter and AMI (advanced meter infrastructure) two –way communication system. PowerStream completes this program in 2011 meeting the government target deadlines. The major capital spending focus associated with Smart Meters (AMI,MDM/R (Meter Data Repository) and TOU (Time-of-Use)) will focus on maintaining the newly installed system .

Over the plan period, to accommodate the additional customers associated with load growth, it is expected that two new TGB (Tower Gateway Base) stations will be needed to accommodate this growth. Each TGB can manage up to 25,000 meters.

The Remote Disconnect project looks to installing a number of Smart Meters on customer accounts having payment problems. This technology will allow the control room to disconnect and re-connect customers remotely. Over the plan period, it is estimated that some 2,500 meters will be installed at a cost of $200 per meter.

The RNI (Regional Network Interface) is a data management computer system that interfaces the TGB to the Sensus, the meter supplier. It is expected that this computer system software will require two upgrade over the plan period to accommodate improvements in operational effectiveness.

AMI/MDMR/TOU Spending Breakdown	2012	2013	2014	2015	2016
TGB	0	150	0	150	0
Remote Disconnect	200	200	200	200	200
RNI	0	100	0	0	100
Total	200	450	200	350	300
South @ 80%	160	360	160	280	240
North @ 20%	40	90	40	70	60

Suite Metering

This program identifies residential condominiums or commercial/retail buildings in which PowerStream negotiates the cost of installing a new suite metering system or for PowerStream to install a Bulk Meter.

Presently, builders/developers of residential/condominium housing and industrial/commercial/institutional 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 objective is to secure our business, promote organic growth and increase our customer base.

Consistent with past years, staff expect about $700,000 per year capital spending over the plan period.

Retrofit Bulk to Suite Meters

This program replaces bulk billing meter systems totalizing energy consumption for the entire condo/apartment building with individual unit metering through negotiation and agreements with building owners. For 2012 we estimate the conversion of 100 units. We do not have historical data for the north. This initiative supports PowerStream’s objective is to secure our business and promote organic growth of its customer base.

Upgrade 2.5 Element Meters

Upgrade existing two and one half (2.5) element meters to the more modern three (3) element meters. Also replace all fuse linked Test Blocks with current standard Test Blocks. All current digital type meters, including Smart Meters, are 3 element meters.

The older fuse link test blocks often have fuses operate or blow 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 unti a meter inspection reveals the blow fuse.

The meter upgrading will was completed in the North in 2011. It is planned to complete the one-time meter upgrading program in the South in 2012.

6. 2012- 2016 Planned Capital Spending

Smart Grid and Metering Five Year Capital Budget (Rev 2)

Department	ProjectLeader	Project Title	2011 Net	2012 Net	2013 Net	2014 Net	2015 Net	2016 Net
			$ 000					
Strategy	Ed Chatten							
Smart Grid	John Mulrooney	Electric Vehicle Smart Charger Trial	143	200	200	100	100	100
		Grid Energy Management	460	500	0	0	0	0
		Data Mining	0	100	100	100	100	100
		Home Energy Management Trial	0	250	250	50	50	50
		Feasibility of Storage Technologies	0	100	100	100	100	100
		Digital Fault Indicators	0	100	0	0	0	0
Metering								
	Roger Ersil	Wholesale Meter Upgrade(Finch, Fairchild, Leslie)	70	0	0	0	0	0
	Roger Ersil	Buttonville Metering Upgrade	995	0	0	0	0	0
	Roger Ersil	Failed Transformer Replacement - South	36	36	36	36	36	36
	Roger Ersil	Failed Transformer Replacement - North	16	16	16	16	16	16
	Roger Ersil	Replace Murray Jensen Meter Bases	6	0	0	0	0	0
	Roger Ersil	Tools & Equipment - South	55	85	50	85	50	50
	Roger Ersil	Tools & Equipment - North	17	30	20	30	20	20
	Roger Ersil	Meter Reverifications - South	133	430	430	430	430	430
	Roger Ersil	Meter Reverifications - North	26	110	110	110	110	110
	Andy Cartwright	Suite Metering - South	639	550	550	550	550	550
	Andy Cartwright	Suite Metering - North	119	150	150	150	150	150
	Andy Cartwright	Retrofit Bulk to Suite Meters - South	115	200	200	200	200	200
	Andy Cartwright	Retrofit Bulk to Suite Meters - North	110	150	150	150	150	150
	Andy Cartwright	Upgrade 2.5 Element Meters - South	0	250	0	0	0	0
	Andy Cartwright	Upgrade 2.5 Element Meters - North	127	0	0	0	0	0
	Rick Lapp	AMI/MDMR/TOU Program - South	1,900	160	360	160	280	240
	Rick Lapp	AMI/MDMR/TOU Program - North	500	40	90	40	70	60
		Total	5,467	3,457	2,812	2,307	2,412	2,362

Notes to the above:
1. computers and vehicles are budgetted through IS and Fleet depatments respectively.
2. meters costs for new services and new subdivisions are included in Engineering Design projects.

AMI/MDMR/TOU Spending Breakdown	2012	2013	2014	2015	2016
TGB	0	150	0	150	0
Remote Disconnect	200	200	200	200	200
RNI	0	100	0	0	100
Total	200	450	200	350	300
South @ 80%	160	360	160	280	240
North @ 20%	40	90	40	70	60

PowerStream Inc.

Information Services Department

Asset Management Plan 2012 - 2016

1 Executive Summary

After seven years of steady growth, PowerStream's Information Services Department is shifting its focus from Infrastructure and Operations to Business Solutions and Strategy. PowerStream engaged the services and expertise of KPMG to facilitate the development of a business driven 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 Leadership Team. The result was a five year Information Services Roadmap and investment plan.

PowerStream is proposes to invest $40 million dollars over the next five years to achieve the strategic initiatives outlined in Figure 1.

Strategic Initiative	2012	2013	2014	2015	2016	Total Cost
Developing Information Capital	$250	$120	$120	$120	$3,220	**$3,830**
Delivering Outstanding Customer Services	$7,610	$7,060	$150	$0	$500	**$15,320**
Achieving Operational Excellence	$150	$130	$1,070	$3,510	$60	**$4,920**
Building a Foundation for Innovation	$120	$30	$0	$0	$0	**$150**
Maintaining our infrastructure	$3,340	$3,010	$3,010	$3,010	$3,120	**$15,490**
Total ($ Thousands)	**$11,470**	**$10,350**	**$4,350**	**$6,640**	**$6,900**	**$39,700**

Figure 1 – PowerStream's Proposed IS Investments

The largest single investment proposed is the replacement of the existing Customer Information System (CIS), commencing in 2011 at an estimated cost of $14.6 million over the two year (2012-2013) period. This will be a large undertaking for PowerStream and will consume a significant number of resources from multiple business units.

Spending on infrastructure and system sustainment will remain consistent with traditional levels at just over $3 million per year, making this the second largest investment during the next five years. Figure 2 shows the comparison.

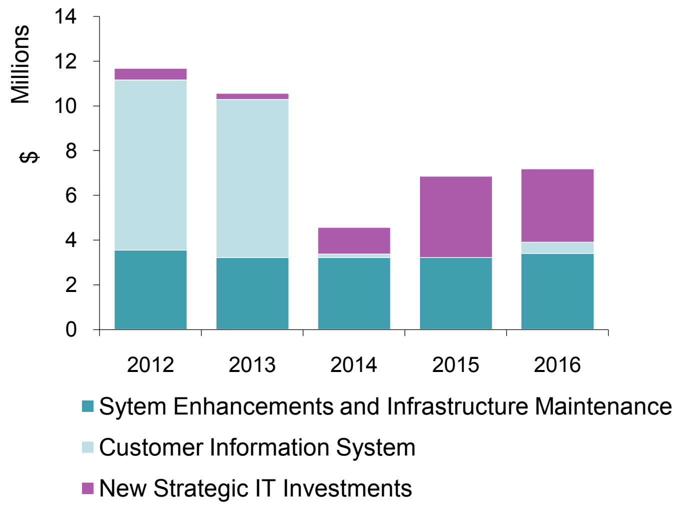


Figure 2 - Spend Level Comparison

In parallel with the CIS replacement project, Information Services will establish a corporate IS governance framework and also begin to develop an Enterprise data model, which will support all the proposed initiatives. These initiatives are expected to be relatively small and driven by Information Services with limited resource requirements for other business units.

Once the CIS project is complete, PowerStream will begin planning the implementation of an Enterprise Asset Management system. This project is expected to take two years and will provide tools to automate many of the processes currently in place. The project will also result in a single repository of asset information which will also improve the quality of data, and potentially the cost associated with asset management.

Subsequent to completing the Asset Management project, PowerStream proposes to implement an Enterprise Content Management (ECM) system to provide a tool to automate paper-based processes and forms. An ECM system will also provide a tool to automate retention policies and the overall Records Management function.

The development of Business Intelligence beginning in 2016 will provide staff with access to a wealth of information. The ability to relate data from multiple sources (including operational networks) will provide staff up-to-date information about business operations faster and with less effort. The result will be business decisions based on a wider variety of more current information. The tools will also enable the creation of relevant “Dashboard” style reports for all level of management.

Figure 3 shows PowerStream’s proposed investments over the next five years.

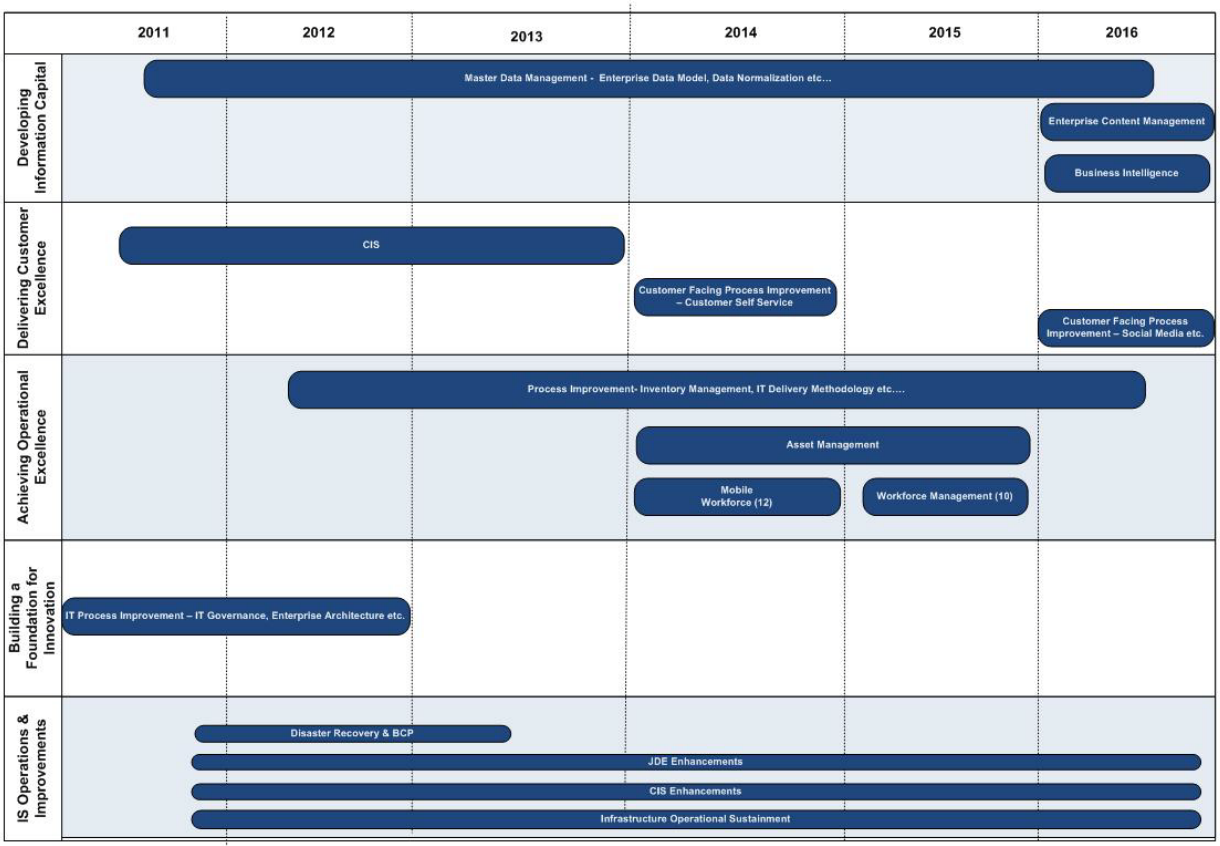


Figure 3 - PowerStream IS Investment Roadmap

2 Table of Contents

3 Introduction

3.1 *Department Overview*

The Information Services Department consists of 20 staff lead by a Vice President. The department is currently arranged into two lines of Business; 1) Operations & Support and 2) Strategic Planning & Administration

The Operations & Support group maintains “back-office” and network infrastructure equipment such as servers, routers and phone systems. They also handle first level technical support and user requests.

The Strategic Planning and Administration team is focused on planning, both strategic and short term. This team also helps business units implement technology based business solutions, with a predominant focus on Project Management.

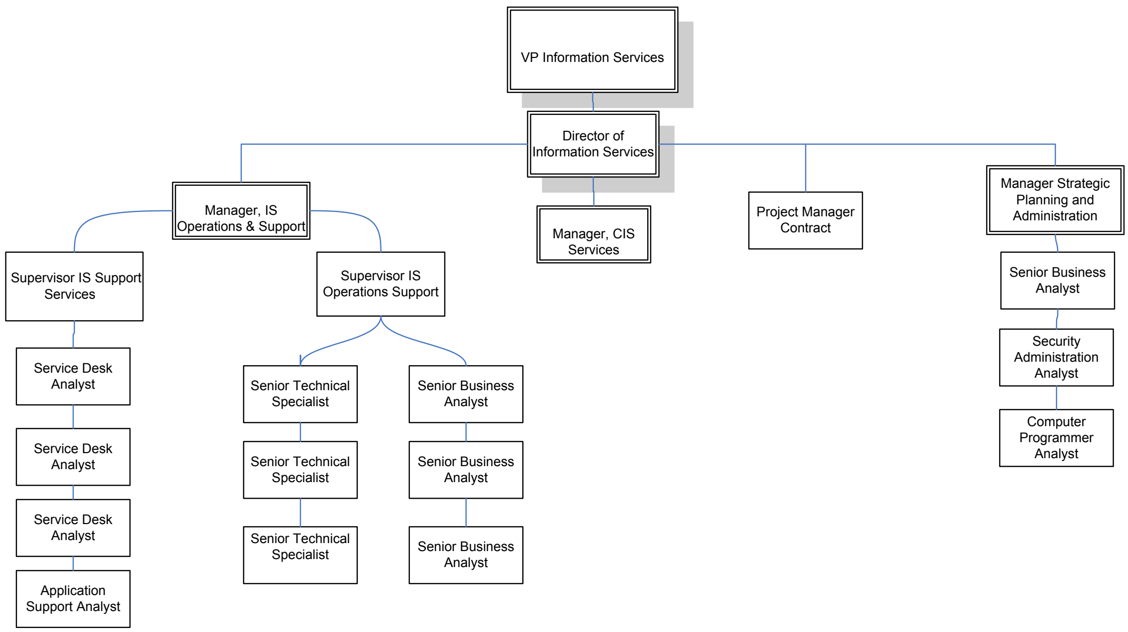


Figure 4 - IS Organizational Chart - April 2011

Maintenance and Support of PowerStream’s Customer Information System (CIS) is contracted out with oversight provided by an IS Manager. A committee of cross functional PowerStream Staff, chaired by the IS Manager provides Governance. First level user support of the CIS is provided by IS.

3.2 *IS Vision*

We will be catalyst in developing new business opportunities, delivering innovative, timely, and technically sound solutions, building strategic partnerships with our customers to support the future growth of PowerStream.

3.3 *IS Mission*

We provide reliable services and solutions, enabling our customers to leverage information and technology, aligned with corporate strategies and goals.

3.4 *Network Design*

Beginning in 2004, Information Services has developed a robust enterprise class network infrastructure. IBM blade servers, EMC Storage Area Network (SAN) and CISCO switches are the core of the IS infrastructure. Industry standards and best practices are employed with respect to the implementation and management of PowerStream's computing infrastructure.

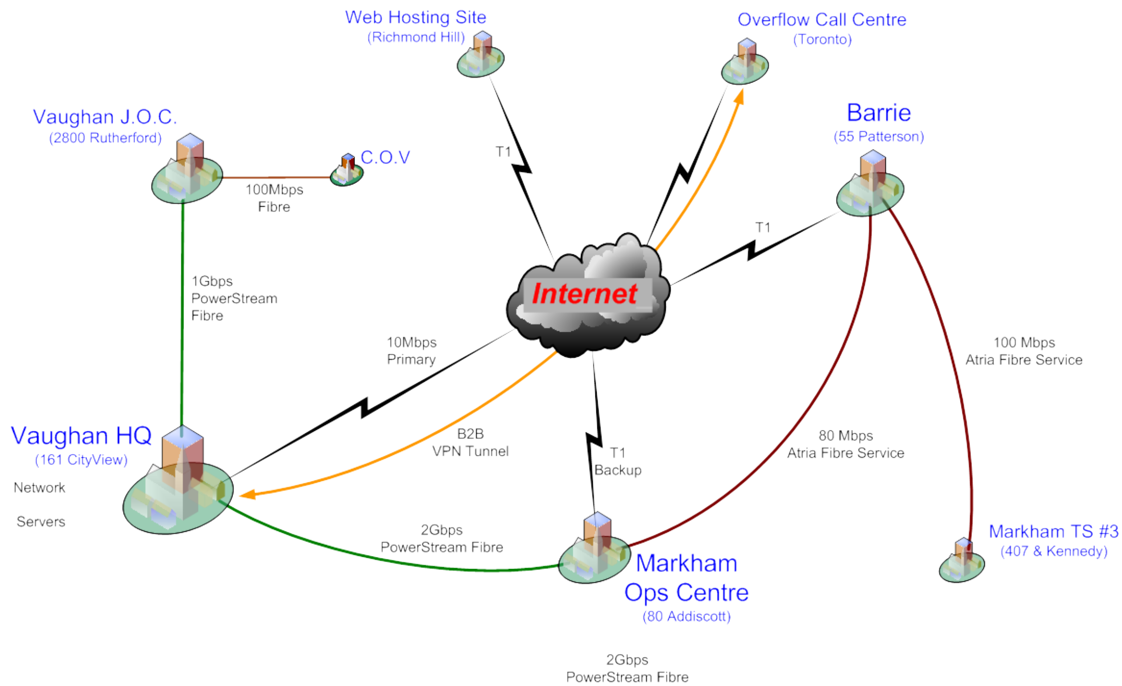


Figure 5 - Network Overview

PowerStream's head office at 161 Cityview Blvd. houses the main data centre for the corporate network. Two branch offices are connected via a private fibre-optic circuit. PowerStream's corporate website is hosted at a vendor's site. PowerStream is currently migrating Disaster Recovery capabilities from a third party to its own backup data centre at one of its branch offices.

PowerStream's telephone system utilizes Voice over IP (VOIP) technology, and is extended to all branch offices via the data network.

3.5 *Current IS Computing Platforms*

Typically, data is produced, manipulated and stored to meet the requirements of the line of business most closely served. The result is multiple computing platforms with point-to-point data connections as shown in Figure 6.

PowerStream's data architecture consists of three main "pillars":

- Enterprise Resource Planning (ERP) – JD Edwards
- Customer Information System (CIS) – Proprietary IBM Unix based Billing system
- Windows – E-mail and unstructured Data (documents)

Traditionally in the utility sector, there has been a clear delineation between the corporate Local Area Network and the Supervisory Control and Data Acquisition (**SCADA**) network. PowerStream's SCADA system is managed and operated by the Operations department. The evolution of Smart Metering technology and the Smart Grid is driving a business need for convergence. As a result, the demand for data exchange between Operational networks and IS LAN continues to grow.

GIS combines the elements of map or location based visual information with traditional textural data. PowerStream uses an Enterprise GIS system developed and maintained by ESRI. While Information Services assumes responsibility for Support and Maintenance of the GIS system, capital development and enhancements are planned and carried out by PowerStream's Engineering Services group.

As PowerStream continues to grow new applications will be added to meet business requirements. The requirement to exchange data between systems is also expected to grow. In addition, the evolution of Smart Metering has resulted in the introduction another key component in PowerStream's data architecture. The Automated Meter Reading Infrastructure will collect data from all smart meters and store it in the Provincially run Meter Data Management Repository (MDM/R). Although this infrastructure is outside of PowerStream's data centre, much of the data will ultimately flow through, or be consumed by PowerStream's systems. While the MDM/R is primarily a "Billing" data repository, a tremendous amount of "operational" data will become available, and will be stored in an Operational Data Store (ODS).

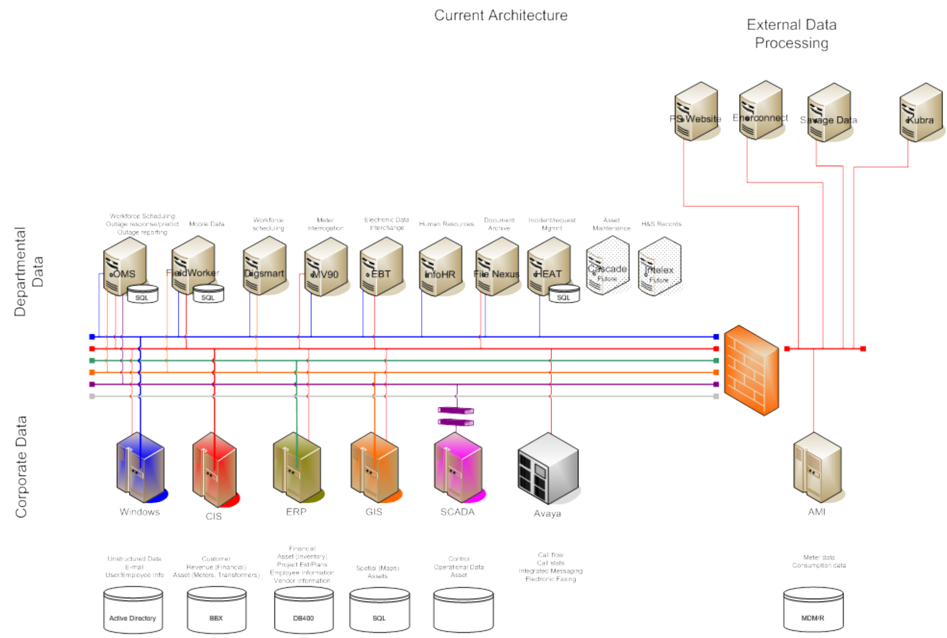


Figure 6 - IS Computing Platforms

4 Five Year Capital Plan

In 2011, PowerStream developed a business-driven five year technology strategy and roadmap. The process was facilitated by KPMG and involved extensive input from the PowerStream's Senior Leadership Team (typically VP's) as well as the Executive Management Team (C-level executives). 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 the development of 5 strategic initiatives which will guide IS investments to ensure alignment with overall business direction. Figure 7 describes Information Services' strategic initiatives.

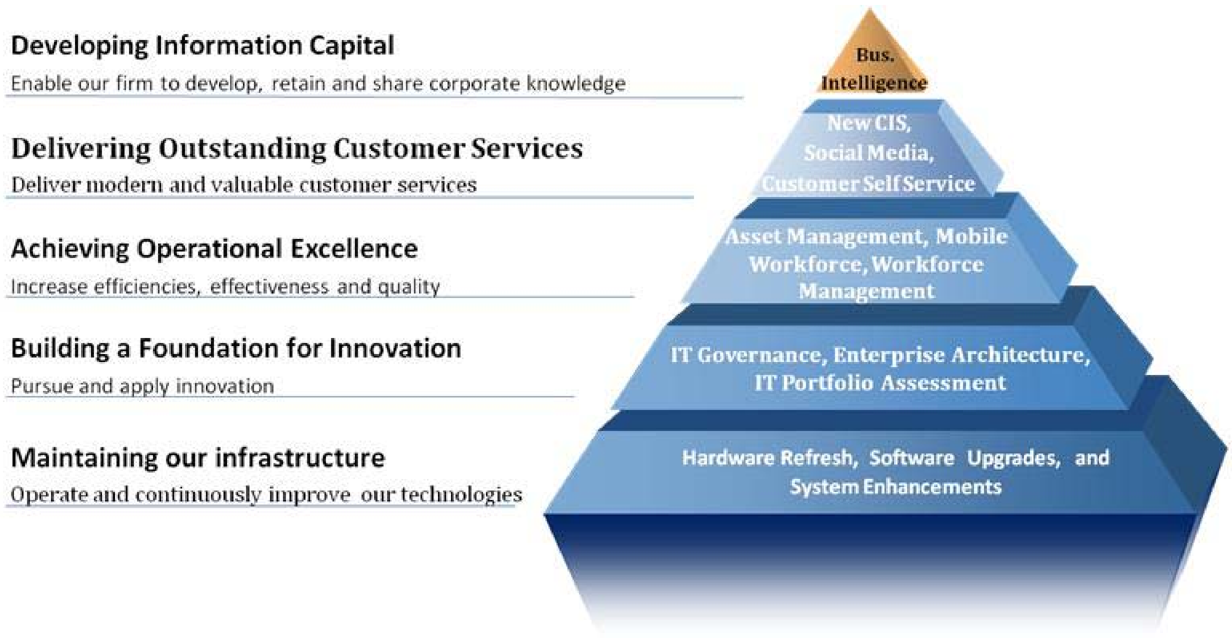


Figure 7 - IS Strategic Initiatives

Over the next five years PowerStream proposes to invest approximately $40 million in its Information and Technology systems. The overarching objective of investments is to support the achievement of the strategic initiatives, which in turn support the corporation's strategy.

A collaborative approach was adopted to arrive at a prioritized list of initiatives which make up PowerStream's five year roadmap. Initiatives were prioritized based on the following five criteria:

1. Customer (External) Satisfaction (weight x3)
2. Compliance Improvement / Requirement (weight x2)
3. Cost Savings & Operational Excellence: efficiency, quality, productivity (weight x2)
4. Cost of Implementation (weight x1)
5. Implementation Risk & Change Impact (weight x1)

Figure 8 summarizes the estimated capital investment required over the next 5 years in each of the five areas to achieve the strategic objectives.

Strategic Initiative	2012	2013	2014	2015	2016	Total Cost
Developing Information Capital	$250	$120	$120	$120	$3,220	**$3,830**
Delivering Outstanding Customer Services	$7,610	$7,060	$150	$0	$500	**$15,320**
Achieving Operational Excellence	$150	$130	$1,070	$3,510	$60	**$4,920**
Building a Foundation for Innovation	$120	$30	$0	$0	$0	**$150**
Maintaining our Infrastructure	$3,340	$3,010	$3,010	$3,010	$3,120	**$15,490**
Total ($ Thousands)	**$11,470**	**$10,350**	**$4,350**	**$6,640**	**$6,900**	**$39,710**

Figure 8

4.1

4.2 Developing Information Capital

This category of spending 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.

Develop Information Capital	2012	2013	2014	2015	2016	Total
Business Intelligence System	$0	$0	$0	$0	$1,580	**$1,580**
Enterprise Content Management System	$0	$0	$0	$0	$1,510	**$1,510**
Master Data Management Program	$250	$120	$120	$120	$130	**$740**
Total ($ Thousands)	**$250**	**$120**	**$120**	**$120**	**$3,220**	**$3,830**

Figure 9

4.2.1

4.2.2 Business Intelligence

The amount of corporate data produced by new initiatives is expected to grow exponentially in the coming years. The growing use of Smart Meters will result in vast amounts of data which can benefit many lines of business. Translating data into meaningful business information will improve the quality of business decisions. Making the information available in or near real-time, without the need of numerous staff and hours of manipulation will improve efficiencies.

This project will leverage the efforts around data management, and result in a series of applications and systems which will enable the aggregation of large volumes of data from numerous sources. A data warehouse may be required to house the extracted data and enable automated manipulation to provide unique views and insight into all aspects of business operations.

4.2.3 Enterprise Content Management (ECM)

Enterprise Content Management integrates a variety of different technologies to manage an organization's unstructured information, wherever it exists.

Figure 10

Benefits of an ECM system can impact three interlocking factors: compliance/litigation, IT efficiency, and business efficiency. PowerStream initially proposes to leverage features of an ECM to automate existing paper-based processes requiring forms and approvals or other work-flow. Improving search capabilities and reducing hardcopy storage requirements will also provide tangible benefits to PowerStream.

4.2.4 Master Data Management

PowerStream's data architecture has evolved in an ad hoc fashion in response to then current business requirements. This approach was effective and facilitated the integration of multiple companies, however it is not sustainable. There are multiple instances of identical data, and multiple interconnections between systems. Furthermore, a number of systems are "owned" by different business units, resulting in "silos" of information, with no common standards for data management.

PowerStream's approach to Master Data Management will be broken into four distinct components as follows:

1. Data Needs Analysis – Identification and analysis of data and reporting requirements from the enterprise and business unit perspective.

2. Enterprise Data Model – Documentation of existing data model and design of a to-be state which articulates authoritative sources for a given data set.

3. Data Normalization – Identification and correction of data duplication and redundancies.

4. Data Integration Strategy – Determination of the best method and solution for integrating existing and future systems.

Providing staff with access to up-to-date and accurate information in a timely manner will contribute to better performance. Improved data architecture along with Master Data Management will:

- Facilitate management of significantly increasing volumes of data
- Enable better Decision Support
- Eliminate data duplication
- Support business process improvement initiatives

This initiative will also support business processes improvement to take full advantage of existing systems and automation.

4.3 Customer Service Excellence

PowerStream is committed to providing its customers, the rate payers, with 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, and customer facing impact. These projects are aimed to provide modern and valuable customer services.

4.4

Customer Service Excellence	2012	2013	2014	2015	2016	Total
New CIS Implementation	$7,610	$7,060	$0	$0	$0	**$14,670**
Customer Facing Process Improvements	$0	$0	$150	$0	$500	**$650**
Total ($ Thousands)	**$7,610**	**$7,060**	**$150**	**$0**	**$500**	**$15,320**

Figure 11

4.4.1 New Customer Information System (CIS) Implementation

PowerStream's existing CIS is the result of combining three similar systems subsequent to the merger of Hydro Vaughan, Markham Hydro and Richmond Hill Hydro in 2004. The system has been modified to accommodate the subsequent integration of Aurora Hydro and Barrie Hydro. While the system continues to meet functional requirements, the risks associated with supportability and further scalability is becoming less tolerable. PowerStream is the only customer (user) of this application in the world, and the future of the company which developed and continues to support it is uncertain. This risk is further increased due to the lack of expertise generally available in the application's outdated development platform known as BBX.

4.4.2 Customer Facing Process Improvements

PowerStream strives to provide its customers with the best possible customer service. Keeping customers informed and educated about issues related to electricity distribution is seen a key component of good service.

Over the next five years, PowerStream will invest in initiatives such as Social Media, Customer Self Service and a new web site to provide its customers with modern and convenient choices to interact with the utility.

4.5

4.6 Achieving Operational Excellence

Investments in this category are aimed to applications and initiatives to improve business processes primarily through automation. During the past 7 years of rapid growth through mergers and acquisitions, PowerStream's processes 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.

The breakdown of spending in this strategic category is shown in Figure 12.

Achieving Operational Excellence	2012	2013	2014	2015	2016	Total
Enterprise Asset Management System	$0	$0	$220	$2,400	$0	**$2,620**
Workforce Management	$0	$0	$0	$660	$0	**$660**
Mobile Workforce	$0	$0	$820	$0	$0	**$820**
Process Improvement Initiatives	$150	$130	$30	$450	$60	**$820**
Total ($ Thousands)	**$150**	**$130**	**$1,070**	**$3,510**	**$60**	**$4,920**

Figure 12

4.6.1 Enterprise Asset Management System

PowerStream manages nearly one billion dollars of assets. Effectively managing an asset throughout its life cycle requires knowledgeable people and relevant processes. It also requires technology to automate the administrative part of the processes and to manage the information about the asset. Maintaining assets in optimal condition will reduce long term replacement cost, and potentially reduce failure and unplanned outages.

Currently, PowerStream utilizes a combination of applications and manual processes brought together as a result of mergers and acquisitions to manage various asset classes. It also relies heavily on the knowledge of senior staff. The introduction of IFRS places additional demands on information about asset lifecycle, which is currently addressed with additional manual, paper based processes.

An integrated asset management system can provide staff at various levels of the organization with up-to-date information to support strategic and operational decisions.

4.6.2 Workforce Management

A Workforce Management Solution (WFMS) is an application that covers all the processes needed to forecast labour needs, schedule and deploy the workforce, track the nature and amount of time worked, and manage the total cost of labour. Figure 10 shows a list of potential processes which may be automated and managed by an enterprise WFMS.

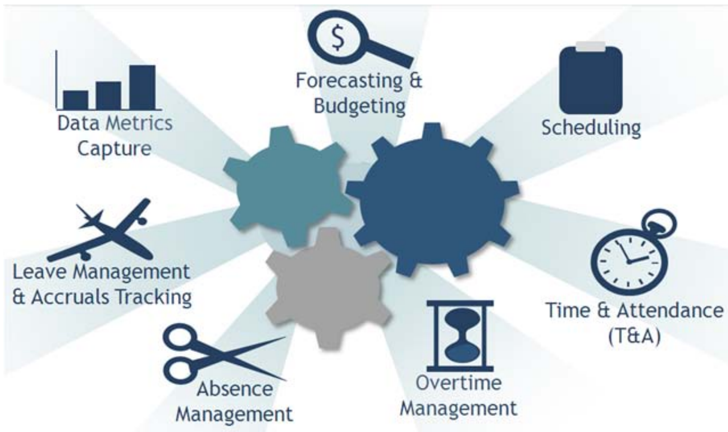


Figure 13 - WFMS Components

PowerStream proposes to implement a system to enable managers to allocate and forecast resource utilization. With the growing work force, and a desire to provide the best customer service possible, the ability to better manage and allocate resources for projects and maintenance is required. While the greatest benefit is anticipated to be found in the Operations (construction and Maintenance) areas, Metering, Customer Service and engineering may also benefit from an enterprise Workforce Management application.

4.6.3

4.6.4 Mobile Workforce

Providing staff with tools (hardware and software) to create and consume information in the field will simplify process by eliminating steps involving the manual transfer of information. This will also reduce the potential for errors and information loss. PowerStream proposes to investigate opportunities to extend existing business processes to field staff. Current research suggests customer connection, disconnection and asset inspection related processes will benefit greatly by equipping field staff with mobile computing capabilities. This initiative will also greatly support the previously discussed Asset Management and Workforce Management initiatives.

4.6.5 Process Improvement Initiatives

PowerStream recognizes that Information Systems and Technology have the potential to automate many existing processes. It is also recognized that simply applying technology to a process without analyzing to optimize the overall efficiency of the process can lead to disappointing results. It is further recognized that failing to review a process with a broad end-to-end (enterprise) view, may lead to missed opportunities to maximize efficiencies. As a result, selected processes will be reviewed and where applicable will be modified to take full advantage of new or existing systems.

4.7 *Building a Foundation for Innovation*

The Information Services department strives to be a strategic enabler for PowerStream. Disciplined management processes and governance are the foundation for future success. Establishing and adhering to technology standards will also help control costs.

Building a Foundation for Innovation	2012	2013	2014	2015	2016	Total
IT Process Improvements	$120	$30	$0	$0	$0	**$150**
Total ($ Thousands)	**$120**	**$30**	**$0**	**$0**	**$0**	**$150**

Figure 14

Investments in this category are geared toward improving how Information Services serves the corporation. Initiatives include development of an Information Services Governance framework to ensure alignment with business units remains strong. PowerStream also proposes to develop Enterprise Architecture Standards to help manage the growing requirement to add and integrate new systems and data sources.

4.8 *Maintaining our Infrastructure*

Spending in this category is generally required to maintain PowerStream's computer assets reasonably current and in good working order.

In 2010 PowerStream reviewed its asset life cycle management practices and aligned its practices with future IFRS (useful life) standards. Figure 15 outlines the useful life of various IS asset classes.

Asset Class	Useful Life (years)
Desktops/Laptops (includes immaterial monitors)	4
Servers (including servers and SAN)	5
MFP's (including all printers)	5
Switches/Routers	6
Computer Software Application	4
Computer Software Operations (Operating Systems)	3

Figure 15

While Figure 15 serves as a guideline for planning and budget purposes, other factors such as reliability and the impact (cost) of failure remain the primary factors considered in the decision to replace. Disposal of computer assets is carried out in accordance with corporate procedure # ITS-10.

Figure 16 outlines PowerStream's proposed spending to maintain its infrastructure.

Maintaining our Infrastructure	2012	2013	2014	2015	2016	Total Cost
Client Hardware & OS	$510	$550	$450	$440	$800	**$2,750**
Server & Infrastructure (hw & sw)	$1,350	$690	$840	$1,380	$970	**$5,230**
Application Software	$220	$360	$110	$30	$120	**$840**
Telecom	$100	$250	$450	$0	$0	**$800**
CIS Enhancements	$510	$510	$510	$510	$540	**$2,580**
ERP Enhancements	$650	$650	$650	$650	$690	**$3,290**
Total ($ Thousands)	**$3,340**	**$3,010**	**$3,010**	**$3,010**	**$3,120**	**$15,490**

Figure 16

4.8.1 Client Hardware and Operating Systems

PowerStream currently has a total of 630 personal computers (PC's) distributed amongst three locations including selected field personnel. Form factors include desktop PC's, laptops and rugged laptops for field use. In addition, selected field staff also utilizes a total of 24 hand held devices for specialized applications such as work force management and data collection. Annual funding is required to replace 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 utilizes a centralized printing model as much as possible. A total of 22 high capacity multi function printers (MFP) are located throughout the various offices. The majority of these units were installed in 2005 and 2006, and will be replaced in 2010 and 2011. There continues to be a need for stand-alone or small workgroup printers to meet specific needs. As a result, 68 units are currently part or PowerStream's printer fleet.

4.8.2 Server and Infrastructure Hardware and Software

PowerStream's current server inventory consists of a total of 138 servers. While server consolidation remains part of a strategy, it remains a challenge. Typically all server based applications require dedicated servers to comply with manufactures specifications. Combining applications on a single server will limit PowerStream's ability to obtain technical support, and increase operational stability.

PowerStream continuously looks for opportunities to extend the lifecycle of hardware and software. The introduction of virtualization, both on the client and server side, has the potential to reduce the dependency on physical hardware. PowerStream began a virtualization program for Servers in 2008 and in 2010 will begin a pilot project to evaluate virtualization for client applications.

4.8.3 Application Software

PowerStream strives to maintain software as current as practical. Software is only upgraded once all reasonable options are considered and deemed inadequate to meet current business needs. Reasons to upgrade include:

- Lack of vendor support
- Lack of compatibility with versions used by business partners and customers
- New features which provide additional functionality to improve efficiency
- Lack of compatibility with new software or hardware

Starting in 2011, PowerStream will upgrade the existing 2003 version of Microsoft Office suite. A number of server applications including Exchange Email and SharePoint will also be upgraded starting in 2011.

4.8.4 Telecom

PowerStream's Avaya voice over Internet Protocol (VOIP) telephone system extends to all three branch offices. Unlike traditional PBX phone systems, VOIP systems are largely based on server based software. As a result, the development lifecycle is now much shorter, with new versions and functionality being released more frequently. The option to integrate voice communication with electronic mail also requires phone system software version to be relatively current.

4.8.5 Customer Information System (CIS) System Enhancements

PowerStream's CIS system produces electricity and water bills for upwards to 320,000 customers. The system maintains all customer information including financial transactions, consumption and metering records. The CIS application consists of numerous programs developed specifically for PowerStream (including its predecessors) in Business Basic (BBX) programming language, and runs on an IBM UNIX server. The system was developed, and continues to be supported and maintained by a company called T&W Information Systems. T&W employs a team of programmers who work closely with PowerStream staff.

As a regulated company, PowerStream must comply with directives set forth by its regulating body, the OEB. In many cases, the directives require changes to customer bills and/or billing process. In order to implement such changes, programmers are required to modify existing, or create new files within the application. In addition to regulated changes, PowerStream strives to improve organizational performance by improving and automating business processes. In many cases, a change to a business process requires changes to the supporting CIS applications.

All projects and initiatives proposed and submitted are evaluated and approved by a steering committee consisting of cross-functional stakeholders within PowerStream. This process provides oversight to ensure that investments are aligned with overall business requirements.

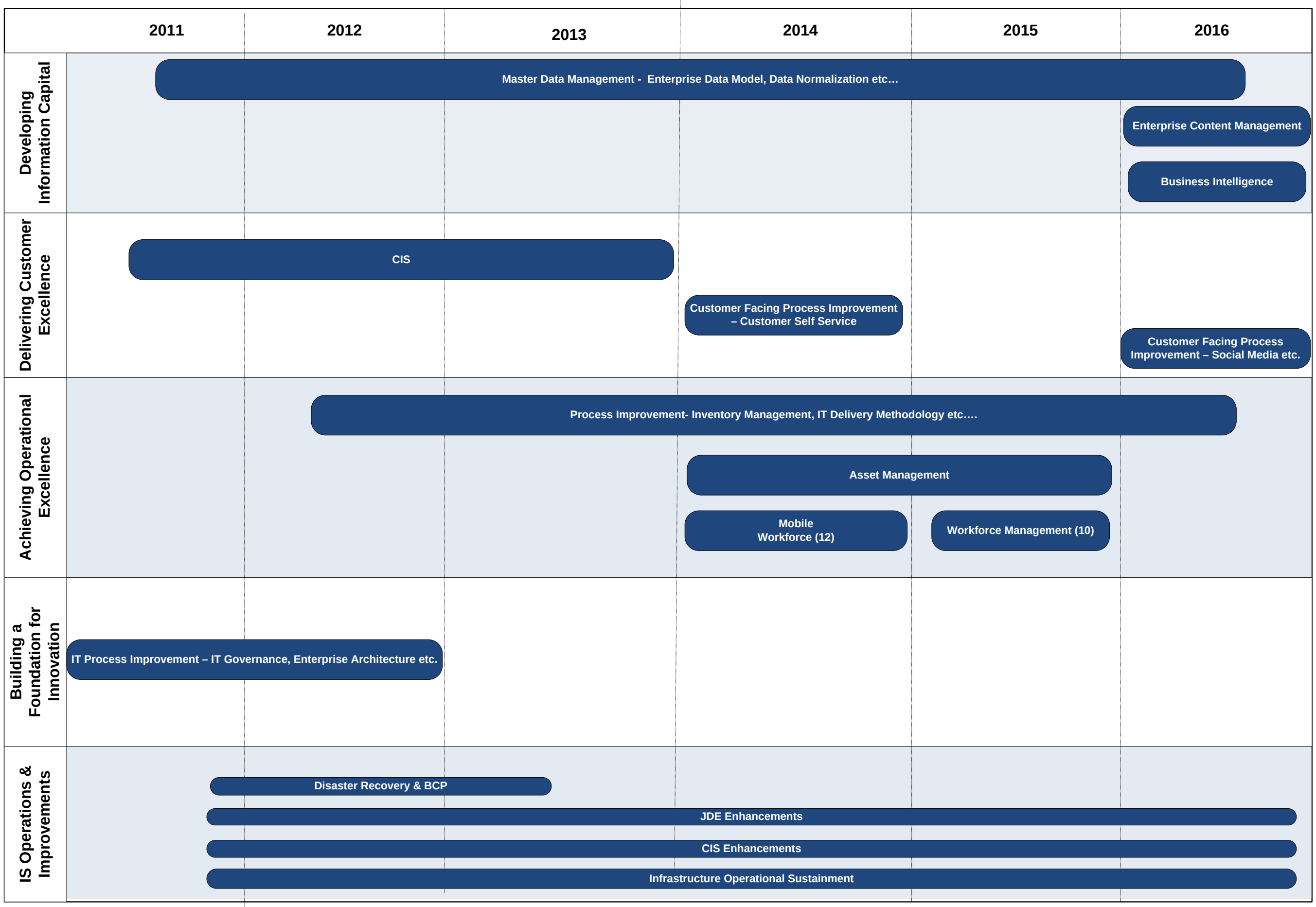
PowerStream is planning to replace the existing CIS within the coming 3 to 4 years. As a result, spending in this category is expected to fall as new investments will be carefully scrutinized and limited to regulatory and other uncontrollable modifications. The CIS replacement project is discussed in detail later in this document.

4.8.6 Enterprise Resource Planning (ERP) system Enhancements

PowerStream utilizes JD Edwards Enterprise One, version 8.12 as its ERP system. The system is primarily used to manage the corporation’s financial information. However, this enterprise class system is based on a tightly integrated set of modules which offer a wide range of applications. PowerStream recognizes the potential to improve and automate processes through the use of additional modules and feature of this system. As a result, PowerStream is proposing to implement modules to manage its fleet of vehicles as well as its buildings and facilities.

PowerStream continues to implement the mandatory accounting practice known as International Financial Reporting Standards (IFRS). This is a multi-year project with completion targeted in 2012.

5 Appendix A – Information Services Investment Roadmap



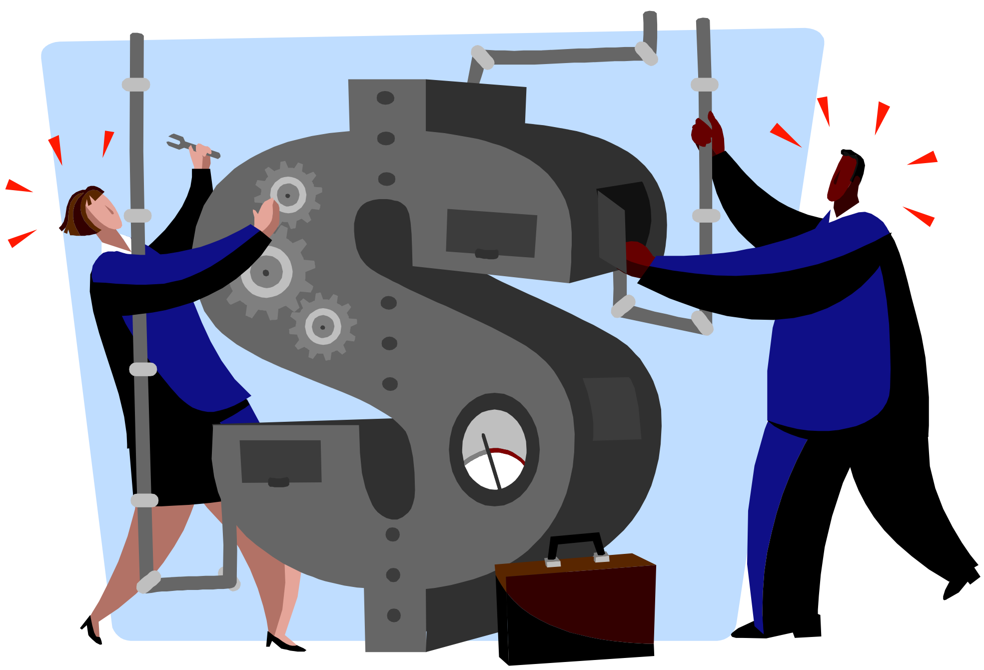
6 Appendix B – Five Year Project List

Initiative	Project	Group Category	2012	2013	2014	2015	2016	Total
Achieving Operational Excellence	Asset Management (Procurement)	Asset Management	$0	$0	$125	$125	$0	$250
Achieving Operational Excellence	Asset Management (Implementation)	Asset Management	$0	$0	$25	$2,271	$0	$2,296
Achieving Operational Excellence	Asset Management (Requirements)	Asset Management	$0	$0	$65	$0	$0	$65
Achieving Operational Excellence	Financial Needs Analysis	Process Improvement	$22	$0	$0	$0	$0	$22
Achieving Operational Excellence	Inventory Management (Implementation)	Process Improvement	$0	$0	$0	$446	$0	$446
Achieving Operational Excellence	Inventory Management (Requirements)	Process Improvement	$0	$0	$32	$0	$0	$32
Achieving Operational Excellence	IT Delivery Methodology	Process Improvement	$0	$0	$0	$0	$58	$58
Achieving Operational Excellence	Mobile Workforce	Mobile Workforce	$0	$0	$818	$0	$0	$818
Achieving Operational Excellence	Process Improvement	Process Improvement	$130	$130	$0	$0	$0	$259
Achieving Operational Excellence	Workforce Management	Workforce Management	$0	$0	$0	$664	$0	$664
Building a Foundation for Innovation	Enterprise Architecture	IT Process Improvement	$0	$0	$0	$0	$0	$0
Building a Foundation for Innovation	IT Cost Optimization	IT Process Improvement	$25	$25	$0	$0	$0	$50
Building a Foundation for Innovation	IT Evaluation Methodology	IT Process Improvement	$34	$0	$0	$0	$0	$34
Building a Foundation for Innovation	IT Governance	IT Process Improvement	$0	$0	$0	$0	$0	$0
Building a Foundation for Innovation	IT Portfolio Assessment	IT Process Improvement	$58	$0	$0	$0	$0	$58
Delivering Customer Excellence	CIS (Implementation)	New CIS Implementation	$3,758	$3,758	$0	$0	$0	$7,517
Delivering Customer Excellence	CIS (Procurement)	New CIS Implementation	$3,850	$3,300	$0	$0	$0	$7,150
Delivering Customer Excellence	CIS (Requirements)	New CIS Implementation	$0	$0	$0	$0	$0	$0
Delivering Customer Excellence	Knowledge Management	Customer Facing Process Improvements	$0	$0	$0	$0	$225	$225
Delivering Customer Excellence	Self Service	Customer Facing Process Improvements	$0	$0	$151	$0	$0	$151
Delivering Customer Excellence	Social Media	Customer Facing Process Improvements	$0	$0	$0	$0	$180	$180
Delivering Customer Excellence	Website Redesign	Customer Facing Process Improvements	$0	$0	$0	$0	$96	$96
Developing Information Capital	Business Intelligence	Business Intelligence	$0	$0	$0	$0	$1,434	$1,434
Developing Information Capital	Data Needs Analysis	Master Data Management Program	$0	$0	$0	$0	$0	$0
Developing Information Capital	Data Normalization	Master Data Management Program	$124	$124	$124	$124	$131	$629
Developing Information Capital	Document Management	Enterprise Content Management	$0	$0	$0	$0	$1,387	$1,387
Developing Information Capital	E-Learning	Master Data Management Program	$0	$0	$0	$0	$120	$120
Developing Information Capital	Enterprise Data Model	Master Data Management Program	$0	$0	$0	$0	$0	$0
Developing Information Capital	Integration Strategy	Master Data Management Program	$121	$0	$0	$0	$0	$121
Developing Information Capital	Performance Dashboards	Master Data Management Program	$0	$0	$0	$0	$144	$144
IS Operations & Improvement	CIS (Enhancements)	CIS Enhancements	$510	$510	$510	$510	$538	$2,578
IS Operations & Improvement	Disaster Recovery & BCP	Disaster Recovery & BCP	$333	$0	$0	$0	$0	$333
IS Operations & Improvement	Infrastructure: Maintenance and Improvem	Infrastructure Operational Sustainment	$1,849	$1,849	$1,849	$1,849	$1,892	$9,288
IS Operations & Improvement	JDE Enhancements	JDE Enhancements	$653	$653	$653	$653	$690	$3,303
	Total ($ Thousands)		$11,466	$10,350	$4,354	$6,643	$6,894	$39,708

Departmental Five Year Capital Plan

Department: Capital Budget

2012 - 2016



Prepared by: Tony D'Onofrio

Capital Budget Supervisor

June, 2011

Table of Contents

1 GENERAL SUMMARY

The role of the capital budget department is to establish total capital budget process of generating, evaluating, selecting and following up on capital expenditures. It has been arranged that the capital budget department prepare a five year capital report for its expenditures and also include a five year capital report for six other departments within PowerStream. Due to the expected low capital activity for these departments it was agreed that compiling the information in one document will be more efficient.

This report describes the five year capital plan recommended by the following departments:

1. **Capital Budget**
2. **Accounting**
3. **Communications**
4. **Corporate Finance**
5. **Corporate Performance**
6. **Environmental Office**
7. **Support and Customer Care**

All expenditures mentioned in this report will correlate to capital main and sub categories established for easy classification of capital portfolio. Below are the main categories with definition. **Refer to page 4 for list of capital sub categories.**

Sustainment:	**Infrastructure capital carried out to sustain reliability of the distribution system**
Development:	**System expansion and relocation due to growth, external demands**
Operations:	**Capital that supports the day to day operation of the distribution system**

1. Sustainment Capital	
1a	Replacement Program
1b	Sustainment Driven Lines Projects
1c	Emergency / Restoration
1d	Transformer / Municipal Stations
1e	Emerging Sustainment Capital
1f	Sustainment Work In Progress Projects (carried over from previous year)
2. Development Capital	
2a	Subdivision / Services
2b	Road Authority Projects
2c	Additional Capacity (Transformer / Municipal Stations)
2d	Growth Driven Lines Projects
2e	Emerging Development Capital
2f	Development Additional Capacity Work In Progress Projects (carried over from previous year)
2g	Connections to customer initiated Renewable Generation projects not allowable in deferral account
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
3h	Operations Work In Progress Projects (carried over from previous year)
3i	Interest Capitalization
3j	Burden Clearing

2 FIVE YEAR CAPITAL PLAN

The five year capital plan will cover years 2012 through 2016. In addition to categorizing projects into main and sub categories as mentioned on page 3 and 4 projects will also be broken down by PowerStream service territory and project type. We presently have 2 territories, PowerStream North and PowerStream South. The identification of two territories assists in the project management of jobs.

PowerStream North is comprised of projects in the following municipalities: Barrie, Bradford W.G., New Tecumseth, Penetanguishene and Thornton.

PowerStream South is comprised of projects in the following municipalities: Aurora, Markham, Richmond Hill and Vaughan.

PowerStream North and South comprises of projects which encompass both service territories.

Project types identify a project as controllable and non-controllable. The definitions are as follows:

Controllable: Projects driven by Corporate Objectives and Distribution System Code requirements to maintaining a reliable electrical distribution system. Drivers of these projects include Distribution System Reliability, Capacity Operational Efficiency and Effectiveness and Health and Safety. These projects have one or more reasonable alternative. Selected controllable projects are deemed to be in the best interest of our customers and employees.

Non-controllable: Projects that are considered must be done as a result of PowerStream's legal obligation as set by Provincial and Federal Legislations. Not complying will place PowerStream in a position to face fines or possibly lose its distribution license. Also includes Work in Progress that was initially approved as a controllable project. These projects have no reasonable alternatives.

2.01 CAPITAL BUDGET DEPARTMENT CAPITAL EXPENDITURES

The capital budget department prepares budgets for carry over, emerging issues operation, and expenditures related to budgeting software tools.

2.01.1 CARRY OVER (WORK IN PROGRESS)

PowerStream's capital portfolio consists of monies to be spent in fiscal year from previous approved projects that did not complete by year end. The capital portfolio ONLY considers carry over on controllable non-programmed projects. These types of projects are deemed to be 100% under our control and expected to be started and completed in fiscal year. Budgeting carry over is challenging because budgets are being prepared much earlier in the year and

during that time most project leaders are optimistic that their projects will be completed by year end. We use historical figures in determining carry over spending and have encouraged project leaders to truly evaluate the start and completion of a project and have implemented a practice to budget the design/investigation of a project in one year and budget the construct/implement in the following year to minimize carry over costs. It is our intention in the near future to work towards reducing carry over spending to a level acceptable to PowerStream.

CARRY OVER FORECAST SPENDING

POWERSTREAM NORTH						
Year	**Main Category**	**Sub Category**	**Type**	**Gross Budget (000)**	**Contributed Budget (000)**	**Net Budget (000)**
2012	Sustainment	Work In Progress	Non-controllable	100	0	100
2013	Sustainment	Work In Progress	Non-controllable	100	0	100
2014	Sustainment	Work In Progress	Non-controllable	100	0	100
2015	Sustainment	Work In Progress	Non-controllable	100	0	100
2016	Sustainment	Work In Progress	Non-controllable	100	0	100

POWERSTREAM SOUTH						
Year	**Main Category**	**Sub Category**	**Type**	**Gross Budget (000)**	**Contributed Budget (000)**	**Net Budget (000)**
2012	Sustainment	Work In Progress	Non-controllable	2,000	0	2,000
2013	Sustainment	Work In Progress	Non-controllable	1,000	0	1,000
2014	Sustainment	Work In Progress	Non-controllable	500	0	500
2015	Sustainment	Work In Progress	Non-controllable	500	0	500
2016	Sustainment	Work In Progress	Non-controllable	500	0	500

POWERSTREAM NORTH						
Year	**Main Category**	**Sub Category**	**Type**	**Gross Budget (000)**	**Contributed Budget (000)**	**Net Budget (000)**
2012	Development	Work In Progress	Non-controllable	100	0	100
2013	Development	Work In Progress	Non-controllable	100	0	100
2014	Development	Work In Progress	Non-controllable	100	0	100
2015	Development	Work In Progress	Non-controllable	100	0	100
2016	Development	Work In Progress	Non-controllable	100	0	100

POWERSTREAM SOUTH						
Year	**Main Category**	**Sub Category**	**Type**	**Gross Budget (000)**	**Contributed Budget (000)**	**Net Budget (000)**
2012	Development	Work In Progress	Non-controllable	1,500	0	1,500
2013	Development	Work In Progress	Non-controllable	1,000	0	1,000
2014	Development	Work In Progress	Non-controllable	750	0	750
2015	Development	Work In Progress	Non-controllable	750	0	750
2016	Development	Work In Progress	Non-controllable	750	0	750

POWERSTREAM NORTH						
Year	**Main Category**	**Sub Category**	**Type**	**Gross Budget (000)**	**Contributed Budget (000)**	**Net Budget (000)**
2012	Operation	Work In Progress	Non-controllable	10,000	0	10,000
2013	Operation	Work In Progress	Non-controllable	10,000	0	10,000
2014	Operation	Work In Progress	Non-controllable	10,000	0	10,000
2015	Operation	Work In Progress	Non-controllable	10,000	0	10,000
2016	Operation	Work In Progress	Non-controllable	10,000	0	10,000

POWERSTREAM SOUTH						
Year	**Main Category**	**Sub Category**	**Type**	**Gross Budget (000)**	**Contributed Budget (000)**	**Net Budget (000)**
2012	Operation	Work In Progress	Non-controllable	200	0	200
2013	Operation	Work In Progress	Non-controllable	100	0	100
2014	Operation	Work In Progress	Non-controllable	100	0	100
2015	Operation	Work In Progress	Non-controllable	100	0	100
2016	Operation	Work In Progress	Non-controllable	100	0	100

2.01.2 EMERGING ISSUES OPERATIONS

PowerStream's capital portfolio consists of monies for expenditures that are unforeseen and fall into the operation section of capital categorization. Projects in this category typically require to be performed due to emergency situation or was missed during budget preparation but if not completed would have a negative impact our day to day operation of the distribution system. Project leaders requesting to tap into these funds are to receive approval by completing an expenditure form prior to work commencing. Departments that typically request these funds are Customer Service, Information Services, Station Design, System Control, Protection & Control and Station Maintenance. This budget is prepared by analyzing historical spending pattern. It is important to note that commencing in 2012 the Station Maintenance department will be including in their department budget expenditure to cover emergency replacements in transformer or municipal stations. This should decrease future spending in Emerging Issues Operation budget.

EMERGING ISSUES OPERATION SPENDING

POWERSTREAM NORTH						
Year	**Main Category**	**Sub Category**	**Type**	**Gross Budget (000)**	**Contributed Budget (000)**	**Net Budget (000)**
2012	Operation	Emerging	Controllable	60	0	60
2013	Operation	Emerging	Controllable	60	0	60
2014	Operation	Emerging	Controllable	60	0	60
2015	Operation	Emerging	Controllable	60	0	60
2016	Operation	Emerging	Controllable	60	0	60

POWERSTREAM SOUTH						
Year	**Main Category**	**Sub Category**	**Type**	**Gross Budget (000)**	**Contributed Budget (000)**	**Net Budget (000)**
2012	Operation	Emerging	Controllable	60	0	60
2013	Operation	Emerging	Controllable	60	0	60
2014	Operation	Emerging	Controllable	60	0	60
2015	Operation	Emerging	Controllable	60	0	60
2016	Operation	Emerging	Controllable	60	0	60

2.01.3 SOFTWARE TOOLS FOR BUDGETING APPLICATION

The capital budget department budgets annual expenditures pertaining to the enhancement of the Capital Budget Management System (CBMS) database which involve computer programming. In 2011 we moved the CBMS from a stand alone based system to a web based system incorporating the database into PowerStream's intranet site called InFlow.

Main Category: Operation

Sub Category: Information / Communication Systems

Type: Controllable

POWERSTREAM NORTH & SOUTH (000)					
Title	**2012**	**2013**	**2014**	**2015**	**2016**
PowerStream CBMS installation to InFlow	0	0	0	0	0
Programming enhancements to CBMS **(includes Integration pieces to other systems for years 2012 - 2016)**	50	50	50	50	50
Enhancements to Project Schedule Database	0	0	0	0	0
Comcast presentation software development	40	0	0	0	0
TOTAL	**90**	**50**	**50**	**50**	**50**

2.02 ACCOUNTING DEPARTMENT CAPITAL EXPENDITURES

The accounting department's inclusion of projects in the capital budget primarily deals with systems enhancements or new installation of various software systems such as JD Edwards's financial system. In addition the accounting department annually budget interest capitalization.

Main Category: Operation

Sub Category: Information / Communication Systems with exception of Interest Capitalization

Type: Controllable

POWERSTREAM NORTH & SOUTH (000)					
Title	**2012**	**2013**	**2014**	**2015**	**2016**
Transform AP / AP module "bolt on" software	190	0	0	0	0
Improvement for the payment of US$ invoices	0	10	0	0	0
JDE improvements	63	0	0	0	0
Expense module implementation	5	20	0	0	0
Interest Capitalization	1,100	1,100	1,600	1,600	1,600
TOTAL	**1,358**	**1,130**	**1,600**	**1,600**	**1,600**

2.03 COMMUNICATIONS DEPARTMENT CAPITAL EXPENDITURES

The communications department's inclusion of projects in the capital budget primarily deals with enhancements to the corporate web site.

Main Category: Operation

Sub Category: Information / Communication Systems

Type: Controllable

POWERSTREAM NORTH & SOUTH (000)					
Title	**2012**	**2013**	**2014**	**2015**	**2016**
Website Enhancements	50	50	50	50	50
TOTAL	**50**	**50**	**50**	**50**	**50**

2.04 CORPORATE FINANCE DEPARTMENT CAPITAL EXPENDITURES

The corporate finance department's inclusion of projects in the capital budget primarily deals with systems enhancements or new installation of various software systems such as JD Edwards's financial system.

Main Category: Operation

Sub Category: Information / Communication Systems

Type: Controllable

POWERSTREAM NORTH & SOUTH (000)					
Title	**2012**	**2013**	**2014**	**2015**	**2016**
Purchase of Executive Console Software License	50	0	0	0	0
Developing OM&A web based database on InFlow	50	50	0	0	0
TOTAL	**100**	**50**	**0**	**0**	**0**

2.05 ORGANIZATIONAL EFFECTIVENESS DEPARTMENT CAPITAL EXPENDITURES

The organizational effectiveness department's inclusion of projects in the capital budget primarily deals with systems enhancements or new installation of various software systems such as JD Edwards's financial system. The Organizational Effectiveness department does not plan on submitting a capital budget in 2012 - 2016. The implementation of IFRS is moving most cross-functional process improvement initiatives that don't involve new software in the OM&A budget rather than capital.

Main Category: Operation

Sub Category: Information / Communication Systems

Type: Controllable

POWERSTREAM NORTH & SOUTH (000)					
Title	**2012**	**2013**	**2014**	**2015**	**2016**
Process improvement initiatives	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**

2.06 ENVIRONMENTAL OFFICE DEPARTMENT

The environmental office department's inclusion of projects in the capital budget primarily deals with environmental initiatives.

Main Category: Sustainment

Sub Category: Emergency / Restoration

Type: Controllable

POWERSTREAM NORTH & SOUTH (000)					
Title	**2012**	**2013**	**2014**	**2015**	**2016**
Reduce in-service low level (<50 ppm) PCB transformers	0	0	0	0	0
Decommission PCB Storage site **JOC Vaughan Yard**	0	0	0	0	0
Decommission PCB Storage site **Barrie Yard**	0	0	0	.40	0
TOTAL	**0**	**0**	**0**	**.40**	**0**

2.07 SUPPORT AND CUSTOMER CARE DEPARTMENT

The support and customer care department's inclusion of projects in the capital budget primarily deal with enhancement to computer systems.

Main Category: Operation

Sub Category: Information / Communication Systems

Type: Controllable

POWERSTREAM NORTH & SOUTH (000)					
Title	**2012**	**2013**	**2014**	**2015**	**2016**
Customer Care database	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 2
Schedule 2.3
Appendix C
28 Pages
Filed: August 31, 2012

PowerStream
IT Strategy

2011

PowerStream

2011

PowerStream
IT Strategy

Contents

Executive **Summary**

The local distribution company industry in Ontario reflects a decade of amalgamations, consolidations and acquisitions. Moving forward, the landscape will continue to change, and increased competition will emerge through the use of new technologies and changing regulations. As such, we clearly see an opportunity to leverage information technology in order to grow, innovate, and deliver outstanding quality to our customers, employees and shareholders. These opportunities are encapsulated in our IT Strategy and enable our vision of a Social Energy Network.

The PowerStream IT Strategy is to achieve business excellence in a progressive manner that balances continuous improvement and the use of innovation. To achieve this objective, we need to change the organizational behaviour and business processes for managing IT. Ultimately, we need to adopt the belief that business needs drive IT. As such, the research, design and implementation of IT solutions requires a collaborative approach with business and technology managers.

At the core of our strategy are five strategic imperatives that prescribe a suite of people, process and technology oriented solutions. These imperatives are:

1. **Maintaining our infrastructure** to ensure we continuously improve our existing and core IT assets;
2. **Building a foundation for innovation** by aligning our IT governance and IT management procedures to promote an enterprise culture for innovation;
3. **Delivering outstanding customer service** by implementing scalable and leading IT solutions;
4. **Achieving operational excellence** that will increase efficiencies, quality and reduce our environmental footprint; and
5. **Developing information capital** in order to retain and share corporate knowledge as a competitive asset.

The outcome of this strategy will enhance our IS department to include business analysis and advisory skills that will strengthen our ability to identify synergies and IT sharing opportunities. From a technology perspective, we will modernize our consolidated and ageing systems to scale to future increased customer demands. Our data will be integrated and enabled by powerful business intelligence tools that will tie information between our customers, smart meters, smart grid, and our operations. Finally, we will integrate and automate the back-office to the front office (customers). The sum of these outcomes will reflect people, process and technologies that support business agility and increasing demands.

Our implementation plan spans six years and encapsulates a suite of projects grouped by strategic imperative. In order to support this strategy, PowerStream will need to hire between twelve and seventeen full time equivalents (FTE). The total cost for external labour, software and hardware is $47 million and is detailed in the following table.

STRATEGIC IMPERATIVES	Q3-Q4 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	TOTAL COST
Developing Information Capital	280,908	245,016	124,416	124,416	124,416	3,216,328	4,115,500
Achieving Operational Excellence	–	151,200	129,600	1,065,600	3,506,600	57,600	4,910,600
Delivering Customer Excellence	4,001,200	7,608,400	7,058,400	151,200	–	500,800	19,320,000
Building a Foundation for Innovation	177,800	117,000	25,200	–	–	–	320,000
IS Operations & Improvement	1,829,796	3,548,092	3,215,592	3,215,592	3,215,592	3,394,236	18,418,900
TOTAL ($)	**6,289,704**	**11,669,704**	**10,553,208**	**4,556,808**	**6,846,608**	**7,168,964**	**47,085,000**

Our IT Strategy supports our corporate mission, vision and growth objectives. We have designed an aggressive plan that will require additional resources and skills. However we firmly believe it is achievable and appropriate for a company of our size. Our strategy is consistent with industry peers and trends. We have intentionally balanced continuous improvement and innovation in a manner that reflects our corporate culture and capabilities.

The PowerStream IT Strategy is a living document that will be reviewed periodically, and updated to reflect changing business needs and emerging technology trends. Underpinning the overall success of this strategy will be a robust IT Governance model that will prescribe processes for aligning our business and technology needs, while balancing continuous improvement and innovation.

About The Strategy

Multiyear strategy driven by the SLT

Vendor agnostic

Supported and validated by market research

Reflects leading practices within the utilities industry

Aligned with the Corporate Strategy, Vision and Mission

Consistent with industry peers and industry trends

Ambitious, however, achievable

The PowerStream IT Strategy was developed by the Senior Leadership Team (SLT) and reflects careful alignment to our corporate strategy, vision and mission. Spanning three months, the process and framework was provided and facilitated by KPMG. With their help, we developed an IT Strategy that sets a direction for IT, defines our principles and establishes a roadmap of initiatives.

At a high level, the SLT developed the IT Strategy by identifying the underlying technology requirements for a set of business drivers that were defined by the Executive Operating Committee (EOC). The technology requirements were analysed and converted into initiatives: people, process or technology. Each initiative was reviewed and prioritized, whereby the collection of initiatives was categorized into five strategic themes – described in the following page. Once prioritized, the SLT sequenced the initiatives in order to produce a multi-year roadmap. KPMG compared the roadmap to industry peers both in Canada and the USA. The outcome of this analysis revealed consistency with our industry peers and trends.

This strategy describes the initiatives we will undertake, their proposed timing and estimated costs. As we move towards execution, each initiative will require a more detailed business case that will quantify the initial benefits we have identified. The cost estimates must be refined and a work force planning exercise should be undertaken to convert our preliminary estimation of effort into actual people and positions within PowerStream, as well as external resources via procurement and contracts. We have recognized that commitment of internal resources as well as external resources is critical to implementation success and sustainability of the new IT capabilities that will result from this strategy.

The following diagram illustrates our approach for converting and tracing business drivers into strategic imperatives.

DRIVERS

- Customers and competition
- Regulatory requirements
- Market consolidation
- Rate pressures
- Green initiatives
- Aging workforce
- Technology innovation

SPECIFIC BUSINESS PRIORITIES

TECHNOLOGY SOLUTION TO SUPPORT

SET THE PRIORITY FOR EACH INITIATIVE

STRATEGIC THEMES FOR IT

Developing information capital
Enterprise Data Model (blueprint)
Integration Strategy
Business Intelligence

Achieving operational excellence
IT Delivery Methodology
Workforce Management
Mobile Workforce

Delivering customer excellence
CIS
Self Service
Social Media

Building a foundation for innovation
IT Governance
Enterprise Architecture (blueprint)
IT Portfolio Assessment

Maintain our Infrastructure
IS operations
GIS extensions
JDE enhancements

Strategic **Mission**

Our IT strategy takes us from a period of consolidating technology through a period of evolving technology and driving business performance

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.

This mission and the initiatives we define in this strategy will fundamentally change how IT works at PowerStream. To help visualize that change, the table below compares the characteristics of IT today and at the successful execution of this strategy.

In recent years, we have focused predominately on consolidating systems from our acquisitions. Looking forward our IT strategy focuses on enhancing our capabilities, driving innovation and increasing our internal efficiency.

	Today	In the Future
People	IS core competency is primarily infrastructure based	IS will complement their infrastructure skills with business analysis and advisory capabilities
	Unclear accountabilities for pursuing technology innovation	Well defined accountabilities for identifying, evaluating and applying innovation
Process	Business-unit approach for raising and evaluating IT investments	Enterprise portfolio approach for optimizing our systems and identifying new investment opportunities (IT Governance)
Technology	Fragmented data model (patch quilt) that constrains our business	Enterprise data model and repository that enables business agility
	Consolidated and ageing systems	Modernized and scalable systems based on leading technologies
	Standalone and paper based processe	Integrated and automated processes that focus on quality, efficiency, and reducing our environmental footprint

Guiding Principles

The following principles provide a set of guidelines that will assist us to make decisions about IT investments.

The list below represents the principles developed at the outset of our strategic planning process. As we developed our strategy, these principles were continuously applied.

Technology must enable integration and interoperability

Eliminate information and processing duplication and redundancy

Enable information sharing and seamless interoperability with partners and customers

Technology must be agile and enable the business to adapt to change

Technology is an enterprise-wide asset

The full life cycle of technology assets must be managed

Technology must be leveraged across the enterprise

Decisions must be based on full life cycle cost

Technology must be scalable to increasing demand

Enterprise-wide technology standards enable optimization

Share and re-use technology assets

Adopt industry standards where possible

Research emerging technologies for consideration, however favour proven technologies to support core business processes

Re-use before buy, buy before build

Business Plans and Strategies drive technology investments

Technology investments support and enable the realization of business strategies

Technology investments are aligned with business improvement initiatives

Technology investments are based on business cases (benefits and costs), and benefits realization is measured

The business implications of technology decisions must be clearly articulated

Key Principles:

Business needs drive IT investments

Technology must enable information integration

Leverage technology across the enterprise

Use industry standards, where feasible

Research emerging, however favour proven technologies

Re-use before buy, buy before build

Strategic Imperatives

Our strategy is to pursue a progressive use of technology that will benefit our customers, employees and shareholders. Through this strategy, we will support our company in addressing key business drivers such as rate pressures, market consolidation, aging workforce, emerging competition, and changing customer needs.

In order to achieve our strategy, we have categorized over thirty initiatives by strategic imperative. Each imperative reflects a level of IT maturity that is balanced and aligned with our internal capacity and risk tolerance. These imperatives are aligned to our 2011 Corporate Strategy Map and encapsulate initiatives that satisfy key business drivers and the underlying business requirements. Although ambitious, this strategy is achievable. The IT Strategy is visually represented as a pyramid that has five levels of maturity and focus.

- At the bottom level is a focus on maintaining our infrastructure. The underlying initiatives are largely multi-year and represent maintenance and enhancements to our core systems and IT infrastructure assets (networks, servers, desktops, etc). This foundational level is the physical underpinning of our strategy.
- The second level represents new strategic initiatives that build upon our infrastructure and focus on people and process initiatives that prescribe and enforce a more strategic use of technology. At the core of this level, and integral to our strategy, is IT Governance; a decision model that clearly defines the accountabilities for governing and managing IT throughout the organization. These initiatives are prioritized early in our roadmap.
- The central (third) layer of our strategy focuses on the customer; ensuring we provide valued and reliable services that are consistent with industry trends. Included within this imperative is the modernization of our CIS.
- In the fourth level of our strategy, we have included a series of operational investments that will drive efficiencies, increase quality and reduce our environmental footprint. The key investments include Asset Management, Mobile Workforce and Workforce Management.
- The tip of the pyramid represents the pinnacle of IT maturity, where we have enterprise wide system and data integration that enables our company to harness information. The following pages describe each of these strategic imperatives.

Strategic Imperative

Maintaining Our Infrastructure

Over the last eight years, we have acquired and merged multiple utility companies. Throughout this period, we have developed a mature discipline in the deployment, migration and consolidation of infrastructure technologies.

Moving forward, we will build on this strength to pursue strategic technology investments that will require a scalable and agile infrastructure. This IT Strategy requires a technology infrastructure that enables our core business to pursue innovation, respond to growing demands, and enable business agility. As such, we believe that "maintaining our infrastructure" is a key imperative that must be included as part of this strategy.

Furthermore, including this stream of work provides us with a full view of our strategic and operational investments. As such, we are better positioned to plan our resources, prioritize, and balance risk. Aligned with the Foundation component of our 2011 Corporate Strategy Map, this strategic imperative supports two key business drivers:

Market Consolidation – ensuring our infrastructure is adaptable and can support our growth targets

Technology Innovation – ensuring our infrastructure can interoperate and leverage innovative technologies.

The underlying initiatives for this imperative are operations related and technology-centric. For the most part, the initiatives are multi-year and address routine system enhancements to GIS, CIS, JDE and Cascade, as well as desktop, server and network upgrades to name a few. The following outlines major initiatives addressed by this strategic imperative:

This strategic imperative is aligned with the Foundation component of our 2011 Strategy Map

Key Benefits:

Physically underpins our strategy

Enables our business to pursue innovation

Maintains value of our existing investments

GIS Enhancements

Extend the use of GIS technology to a broader community, and

Leverage advanced features of integrated GIS technology.

CIS Enhancements

Customizations to the legacy CIS in response to changing business requirements, and

Prepare for the implementation of a new CIS and the related integrations.

Infrastructure: Maintain and Improve

Enable IS to continue its maintenance and improvement of PowerStream's current IT infrastructure, which

Includes sustaining the desktop computing environment, IT servers, peripherals and business productivity tools.

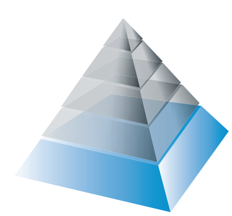
JD Edwards Enhancements

Aligned with process improvement initiatives,

To improve our business processes, and

Increase the value from our existing investments.

MAINTAINING OUR INFRASTRUCTURE



Strategic Imperative

Building a Foundation for Innovation

This strategic imperative is aligned with the Foundation component of our 2011 Strategy Map

Key Benefits:

Enterprise approach for portfolio management

Reduce redundancies by optimizing existing investments

Promotes and focuses on innovation through governance

As mentioned earlier, we have focused and developed significant maturity with integrating companies (people, process and technology). Moving forward, we must complement our tactical strength with strategic planning and decision making processes.

In order to elevate the use of technology as a strategic enterprise asset, we fundamentally need to change the behaviours and processes for governing and managing IT. Unlike the previous imperative, which focused on foundational technology solutions, this imperative outlines five key initiatives that will “build a foundation for innovation” through people and processes.

To keep our organization innovative, while supporting the “core”, we need to change our organizational behaviours and processes. Underpinning this major change is IT Governance; a decision model that outlines the responsibilities and accountabilities for managing IT at all organizational levels.

Specifically related to innovation, we will outline the tasks, process, roles and frequency for managing innovation.

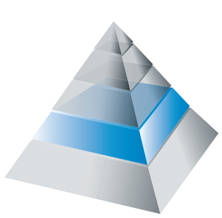
Aligned with the Foundation component of our 2011 Corporate Strategy Map, this strategic imperative supports the following key business driver:

Technology Innovation – ensuring our people and processes are designed to identify, evaluate and apply innovation

The underlying initiatives will enable us to increase the return on our technology investments, reduce redundancies, promote innovation, and establish clear roles and accountabilities for governing technology.

In order to achieve these benefits, we will need to review our existing organizational structure and determine the appropriate level of IT leadership throughout the enterprise. The following outlines major initiatives addressed by this strategic imperative:

BUILDING A FOUNDATION FOR INNOVATION



IT Governance

Defines a model for making key IT decisions

Articulates responsibilities and accountabilities

Promotes and focuses on innovation at all organizational levels

Sustains the IT Strategy

Enterprise Architecture

Defines a target blueprint of our business, systems, and data

Helps inform and evaluate future IT investment decisions

Ensures alignment between our strategy, business, systems, and data

IT Portfolio Assessment

Formalizes a recurring process for assessing our technology portfolio

Rationalizes our portfolio by determining what should be kept, updated, or retired

Identifies synergies across the enterprise

IT Evaluation Methodology

Prescribes a method and criteria for evaluating information technology (either procured or through merger and acquisition)

Ensures consistency and alignment of initiatives within the overall IT Strategy

Strategic Imperative

Delivering Excellent Customer Service

The current regional industry structure may not last forever. New sources of energy and competing services will emerge. As such, we need to firmly demonstrate the value of our brand and services today, so that we can retain and continue to "deliver excellent customer service" in the face of emerging competition.

At the core of our strategy is a focus on "customer service" through the use of technology. Under this strategic imperative, modernization of the current CIS is the first initiative to be rolled out. This also happens to be the largest investment proposed under this strategy; representing approximately 40% of the IT Strategy budget.

The underlying driver for modernizing CIS is the risk of business continuity: high vendor reliance, aging technology, and limited growth capabilities. Furthermore, there may be an opportunity to leverage our effort by partnering with an industry peer.

Aligned with the Customers component of our 2011 Corporate Strategy Map, this strategic imperative supports the following key business drivers:

Customer & Competition – delivering valued and reliable services by using technology to gain customer insight

Technology & Innovation – providing modern communication channels to increase our corporate and social connection with customers

The following outlines major initiatives addressed by this strategic imperative:

This strategic imperative is aligned with the Customers component of our 2011 Strategy Map

Key Benefits:

Gain customer insight

Increased customer satisfaction (retention)

Modern customer experience

Customer Information System

Replaces the existing CIS with a modern and scalable system that is based on leading technologies

Supports our growth targets and increasing customer base

Customer Self Service

Enables our customers to interact and request services through modern communication channels

Reduces calls to our service desk

Allows PowerStream to track customer behaviours

Knowledge Management

Enables customers to access online knowledge artefacts such as How-Tos and FAQs

Reduces calls to our service desk

Improves service quality index through reduced wait times

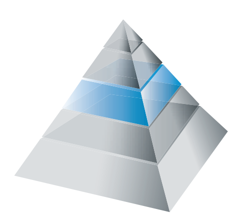
Social Media

Enables PowerStream to connect and interact with our customers

Increases brand awareness and drives interest to our corporate website

Gains customer insight through conversations, polls, opinions

DELIVERING EXCELLENT CUSTOMER SERVICE



Strategic Imperative

Achieving Operational Excellence

This strategic imperative is aligned with the Processes component of our 2011 Strategy Map

Key Benefits:

Increases employee and customer satisfaction

Increases quality and efficiencies

Reduces our environmental footprint

Today, many of our current processes are standalone and paper based. Our workforce, for instance, still uses paper forms for capturing field information. The field workers and the front line staff are not connected or integrated and therefore unable to provide our customers with meaningful information in a timely manner.

This lack of integration and automation impacts our customers and is also reflective of our operational technology. In the future, we want to exceed our industry peers by “achieving operational excellence” by designing and implementing integrated and leading processes that better serve our customers and our employees.

Secondly, rate pressures will squeeze our margins, forcing us to do more with less. The proactive solution is to routinely analyse our business for improvement opportunities and to seek technology solutions that can streamline and automate our core business processes.

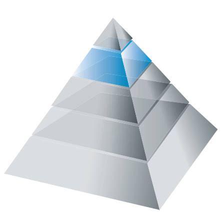
Aligned with the Processes component of our 2011 Corporate Strategy Map, this strategic imperative supports the following key business drivers:

Rates Pressures & Regulatory Requirements – gaining operational efficiencies through process automation and optimization

Green Initiatives – reducing our environmental footprint by using digital assets in lieu of paper

The recommended approach for this imperative is to first initiate a needs analysis and process improvement initiatives. The outcome of these initiatives may identify investment opportunities beyond what is already recommended as part of this strategy. As such, these opportunities will be evaluated as part of a defined IT Governance model. The following outlines major initiatives addressed by this strategic imperative:

ACHIEVING OPERATIONAL EXCELLENCE



Process Improvements

Defines a method and recurring process to analyze our business and identify operational improvements

Automates and streamlines our business

Yields productivity gains and cost reductions

Asset Management

Enterprise solution that manages the lifecycle and maintenance of an asset from cradle-to-grave (drawings, fleet, computers, etc)

Links to Inventory Management

Increases investment longevity and contains cost

Mobile Workforce

Automates and modernizes field operations

Integrates with the front office

Increases data quality and reduces paper

Increases employee satisfaction

Workforce Management

Automates work assignment, scheduling, forecasting and resource utilization

Optimizes resource utilization and planning

Strategic Imperative

Developing Information Capital

Information Capital is a broad industry term used to encapsulate the concept of "knowledge". In today's economy, managing knowledge is a critical success factor for gaining competitive advantage, making strategic decisions, and preserving corporate memory.

This strategic imperative addresses all three of these factors and outlines a gradual process that will enable PowerStream to develop and share "information capital". Today, our current systems and the underlying data structure are fragmented and not well integrated. Generating a regulatory report, for example, requires significant manual effort and is dependent on multiple departments in order to extract, aggregate and verify data accuracy. In the future, we will have an enterprise data model and repository that will enable our business to generate financial, corporate and regulatory reports, to name a few.

Secondly, our current workforce is aging and presents a potential risk to business continuity and the lack of corporate memory.

To mitigate this risk, we must design solutions that improve the capture and sharing of information capital in order to maintain the level of quality delivered to our clients. Aligned with the Foundation, Processes, Customers, and Financial component of our 2011 Corporate Strategy Map, this strategic imperative supports the following key business drivers:

Customers & Competition – leverage the Smart Grid, Smart Meter, and CIS to gain customer insight (data)

Policy & Regulatory Requirements – improve our reporting capabilities through data normalization and increased integration

Aging Workforce – enable our staff to create, share and access information capital (policies, procedures, tips, on boarding, off boarding, etc)

The following outlines major initiatives addressed by this strategic imperative:

This strategic imperative is aligned with the Foundation, Customers, and Financial components of our 2011 Strategy Map

Key Benefits:

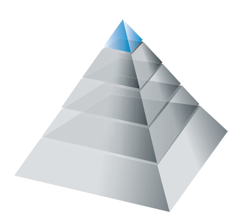
Agile reporting (financial, corporate and regulatory)

Data accuracy (sources of truth)

Information access and sharing

Enterprise Data Model	Integration Strategy	Data Normalization	Business Intelligence
Designs a normalized data structure that articulates the authoritative source for a given data set	Defines an approach and standards for integrating our current and future systems	Defines a recurring process for repairing data quality issues, duplication, and redundancies	Centralizes reporting solution for corporate, financial and regulatory reporting
Enables improved data quality and reduced data duplication	Enables business agility via system interoperability	Improves data reporting / reliability	Aggregates data from various sources
			Reduces manual efforts to compile and reconcile information

DEVELOPING INFORMATION CAPITAL



Implementation Plan

We have designed an ambitious implementation plan that reflects a balance of internal capacity, risk tolerance, and logical priority.

The following principles guided the design of our implementation plan:

- The sequencing of initiatives should reflect a gradual increase in the risk level of associated technology projects. This is evident by the earlier prioritization of smaller people and process centric initiatives, followed by larger and more innovative technology projects later in the roadmap.
- Foundational projects and dependant initiatives should begin early. This is reflected by the early prioritization of solutions such as IT Governance, Data Needs Analysis and Enterprise Data Model.
- Avoid running large investments in parallel. This is illustrated by the sequencing of the CIS renewal prior to asset management and mobile workforce technology.
- Spread the yearly internal effort (and external costs) evenly in order to yield a relatively consistent annual investment of people and external costs.
- Defer lower priority initiatives to 2016 onwards.

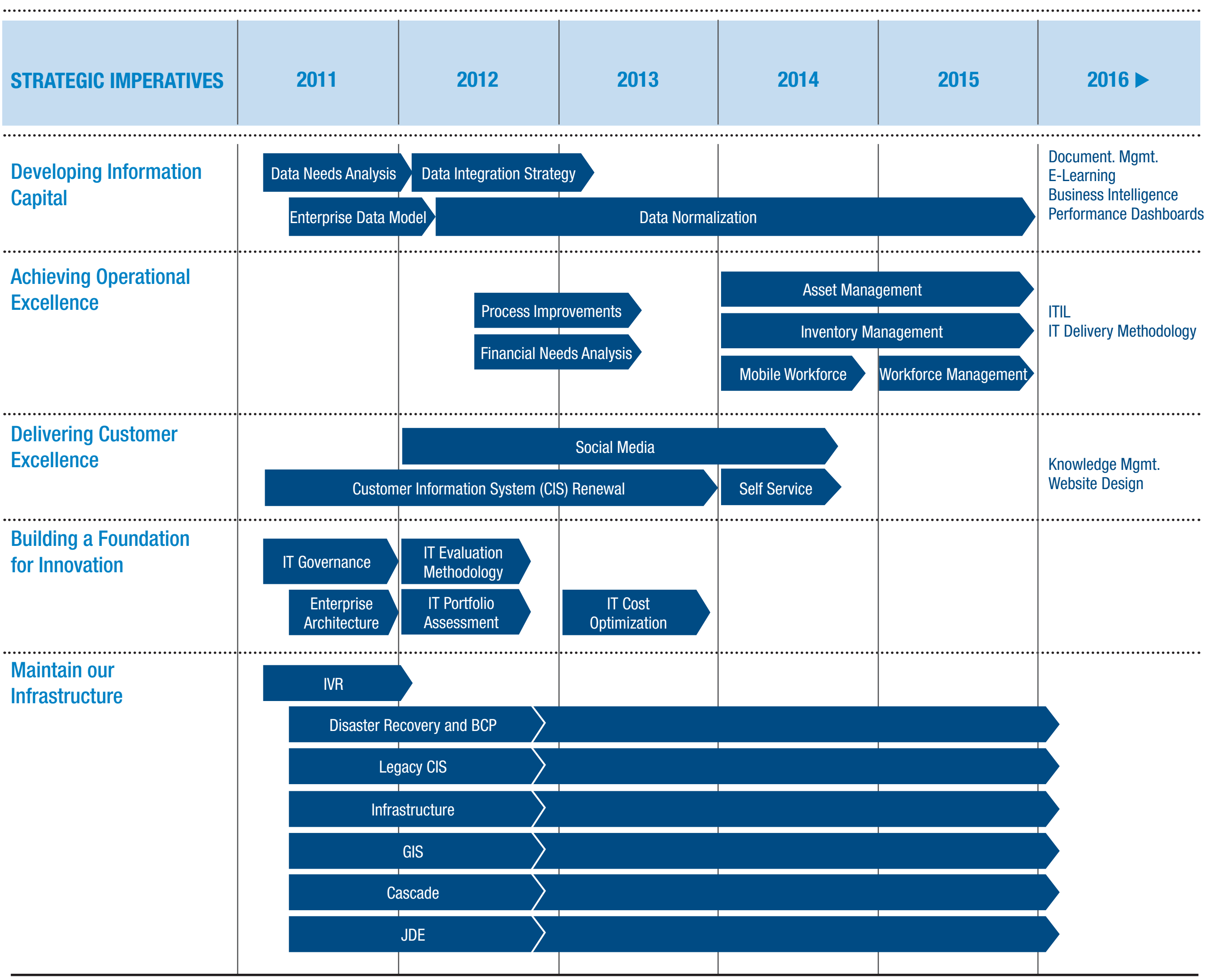
Our implementation plan has three phases.

- In the first phase (2011 – 2013), the plan is to invest in foundational IT projects, process improvements and a renewal of the CIS.
- The second phase (2014-2015) of the strategic plan focuses on operational technology initiatives such as asset management, mobile workforce and workforce management.
- The third phase (2016 onwards) consists of lower priority initiatives that will need to be planned and sequenced in 2015.

We have developed a staffing model, but more work is required as we begin to execute the strategy.

- Resource estimates for each of the initiatives are based on a high-level scoping exercise that identified the roles, effort, duration, and resource type (internal vs. external). Moving forward, these estimates must be refined with additional information that may change the scope and assumptions.
- PowerStream needs to conduct a workforce planning exercise in order to determine how to proceed with back-filling, the number of hires required and the balance of contract resources.

IT Strategy Roadmap



Each initiative is described in Appendix A – Definition of Strategic Initiatives

Financial Cost Estimates

Total IT Spend is $47.1 million and includes external labor, hardware and software

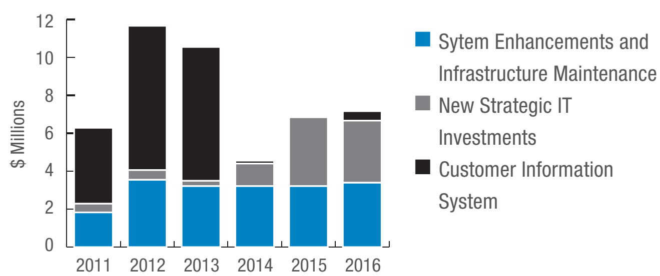
Excluding CIS, this is an additional $10 million above our historic spending on IT, over the next six years

Our preliminary cost estimate, for all solutions and initiatives selected to be part of the IT strategy, is $47.1 million.

Excluding CIS, the incremental IT spend for new strategic IT investments is $10 million over and above our historic expenditure level. The grey sections of the chart below shows this new expenditure.

- The average yearly cost for system enhancements and infrastructure maintenance is $3.1 million and is consistent with previous spending periods.
- The CIS investment spans 2011, 2012 and 2013. In these years, new strategic initiatives are estimated to cost an average of just under $0.5 million annually.
- For the period 2014-2016, estimated costs for new strategic IT investments are $8.2 million. During this period, the continued IT investment on system enhancements and infrastructure are consistent with previous years spending.

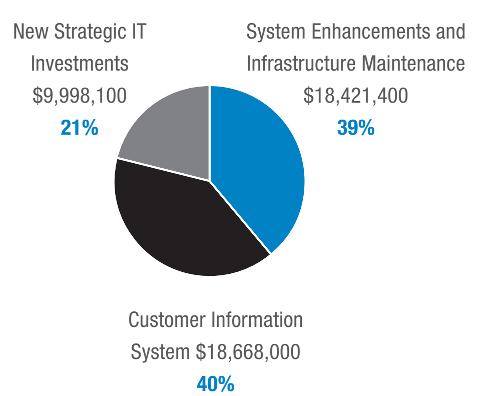
Annual IT Cost Estimates 2011 – 2016



This estimated spend is split into three categories.

- $18.4 million represents the cost for ongoing system enhancements and infrastructure maintenance.
- $18.7 million represents the cost for replacing the CIS.
- $10 million is the additional funding request for addressing strategic IT investments such as asset management, data integration and mobile workforce.

IT Cost Categories 2011 – 2016



Internal Resource Requirements

The resource estimates for this IT Strategy Roadmap indicate an internal FTE requirement beyond the organization's current resource capacity. In order to deliver this IT Strategy, PowerStream will need additional resources.

The table below shows internal labour costs as FTEs by Business Unit (Corporate Services, Finance, and Operations). These are the estimated internal FTE resources required to execute our strategy. Internal FTE resource requirement estimates are driven by the solution scope and logical resource mix required to execute each of the initiatives planned in the IT Strategy Roadmap.

Internal FTE resources will be complemented by external labour resources. The average ratio of internal to external resources is 1:1.04 (or 49% internal, and 51% external).

Our strategy requires between 12 and 17 internal resources to execute it

BU	DEPARTMENT	2011	2012	2013	2014	2015	2016
CORPORATE SERVICES	Communications	0.1	0.3	0.3	0.1	0.1	0.3
	Human Resources	0.1	0.2	0.1	0.1	0.1	2.1
	Information Services	1.2	3.5	2.9	1.7	1.4	5.6
	Procurement	0.1	0.2	0.2	0.6	0.9	0.3
	Total (FTE range)	**1 to 3**	**3 to 5**	**3 to 5**	**2 to 4**	**1 to 3**	**6 to 10**
FINANCE	Customer Services	3.5	7.4	7.3	3.2	0.6	1.1
	Finance	0.2	0.5	0.2	0.1	0.1	2.5
	Rates	–	0.1	0.1	–	–	0.1
	Total (FTE range)	**3 to 5**	**6 to 10**	**6 to 10**	**1 to 4**	**1 to 2**	**3 to 5**
OPERATIONS	Operations	0.1	0.9	0.9	0.7	0.7	1.1
	Engineering	0.2	0.3	0.2	4.1	7.2	0.5
	Total (FTE range)	**1 to 2**	**1 to 2**	**1 to 2**	**3 to 7**	**6 to 10**	**1 to 3**
In Year Internal FTE's Required		**5 to 9**	**10 to 16**	**10 to 16**	**8 to 14**	**8 to 14**	**11 to 17**

Critical Success Factors

IT Governance is a core component for sustaining the strategic use of IT at PowerStream

Progress towards achieving the IT Strategy must be measured annually by the SLT

The IT Strategy is a living document that should reflect current strategies, objectives and business drivers

There are two factors that will help ensure PowerStream is able to sustain the strategy and successfully execute: IT governance and periodic reviews of progress against our plan.

The governance of IT is the process of making key decisions on the application of and the investment in technology. A governance model defines the key decisions, who gets to make the decision and the process we follow to make the decision. IT governance does not live in isolation from other governing bodies within a corporation.

- PowerStream needs to design and implement an IT Governance model that clearly articulates the responsibilities and accountabilities for managing information technology
- IT should be governed at all organizational levels, however the SLT must drive the use and application of IT
- The IS department needs to increase its competencies to include business analysis, project delivery, and promoting the use of innovative technologies

At a minimum, the **IT Strategy should be reviewed annually** to:

- Assess our progress
- Confirm our objectives continue to reflect our business priorities
- Adjust the plan and strategy as required

Performance against the IT Strategy needs to be measured annually by the SLT.

Performance gaps or deficiencies may require an update to the IT Strategy.

At the end of this review process we will update the IT Strategy to reflect changes to the corporate strategies, objectives and business drivers.

Every five years we will undertake a more fulsome strategy development exercise.

In a similar manner to the way this IT strategy was developed, we will inspect the business strategy, the business unit priorities and our current state of IT, to develop a renewed IT strategy. The current strategy defines a full complement of initiatives for the coming periods, with our annual reviews confirming we have the correct priorities at that time.

This full review after five years will focus on defining the needs of the organization for IT in the coming years.

We Require Three Committees to Execute this Model

Executive Technology Committee
The executive committee will have final decision making responsibility for the specific role of IS within PowerStream, for the IT strategy and for the annual investment level in technology.

The membership of this committee will be consistent with the Executive Operating Committee. Decisions from this committee would typically be required annually, and the committee should initially meet twice a year.

IT Steering Committee
The IT steering committee is responsible for coordinating the identification of business needs and for monitoring progress against the strategy and priorities. The primary membership will be the senior leadership team, with representation across all lines of business. The committee will meet once a month with a typical agenda including:

- **IT project progress** – are we on track, are there contentions between projects for resources
- **Benefits realization** – are we receiving the benefits we expected from our investments, should we change anything to increase the benefits
- **IT operational performance** – are we achieving the operational service levels we desire with IT, do we need to make changes to achieve these service levels

In addition, annually, the IT steering committee will gather business needs and prioritize for the coming year. As a starting point, the steering committee will review the IT strategy to assess whether the documented priorities remain relevant and to add any new needs for technology. The output of this session will be input into the annual capital process.

Architecture Committee
The architecture committee is responsible for defining the technology standards and the target technology architecture, and ensuring the technology architecture is aligned with the business strategy and business architecture of the organization. The committee will also have oversight on technology solutions developed within IT projects, helping ensure they align with the enterprise architecture and standards.

Continued on next page

Three committees will make the decisions we describe in the governance model

We Require Three Committees to Execute this Model

The primary membership will be the IS architect, representatives from other technology teams including GIS and SCADA, and representatives from the other lines of business who have specific interests in the technology architecture. An example may include the communications team who wish to influence the web technologies. The committee will meet on a quarterly basis, with an initial agenda including:

- **Changes in technical standards** - through new business needs or solutions selected by projects, request to deviate from the technical standards will occur. The committee will review the request and decide on whether or not it represents an acceptable deviation

- **Opportunity for emerging technologies** – assess if a new technology has potential for Power Stream and define when may be the appropriate time to investigate its application

- **Maintain the architecture** – review the current architecture and documentation to ensure it is up to date and reflects the optimum use of technology within Power Stream

The committee's starting reference point will be the PowerStream technology standards and enterprise architecture, which will be developed in one of the projects commissioned by this strategy.

The IS architect, as representative of this committee, will have oversight on all proposed technology solutions within projects. His role is to assess solution compliance with PowerStream's standards and architecture and to recommend adjustments to align the proposed solution with the standards and architecture.

Endorsement
by Senior Leadership

The following PowerStream individuals, along with members of their respective teams, worked collaboratively to prepare and endorse this IT Strategy

Ed Benvenuto
VP, Customer Service

Ed Chatten
SVP, Smart Grid & Strategic Support

Shelly Cunningham
SVP, Engineering Services

Barb Gray
SVP, Human Resources &
Organizational Effectiveness

Basil Henriques
Manager, Strategic Planning
& Administration

Lucy Lombardi
VP, Finance

Colin Macdonald
VP, Rates & Corporate Accounting

Mike Matthews
SVP, Operations & Construction

William Schmidt
VP, Information Services

Ted Wojcinski
VP, Engineering Planning

Appendix A
Definition of Strategic Initiatives

Asset Management: Technology solution that manages the asset lifecycle from acquisition, maintenance, repair to disposal. The scope of this solution includes all corporate assets (fleet, computers, materials, etc).

Disaster Recovery and BCP: Project to develop and implement a Disaster Recovery and Business Continuity Planning (BCP) strategy.

Business Intelligence: Technology solution that aggregates and/or centralizes data for the purposes of 1) financial, management and operational reporting, 2) ad-hoc reporting, and 3) analytics.

Cascade: Project to implement a Computer Maintenance Management System (CMMS) that will improve Transformer Station equipment reliability through condition based maintenance.

CIS Renewal: Project to procure, design, and implement a modernized CIS. The solution will cater to the end-to-end customer care and billing process.

Data Integration Strategy: Project to develop an enterprise strategy for data and system integrations, both internally and externally. The scope of this strategy includes all enterprise systems (existing and planned), operational data stores, and data from smart grid infrastructure developments.

Data Needs Analysis: Project that identifies data and reporting requirements from an enterprise and business unit perspective. The project will capture the current state and outline a high level strategic plan to fulfill the business needs for data and reporting.

Data Normalization: Project that identifies and repairs data quality issues, data duplication, and data redundancy issues.

Document Management: Technology that provides a mechanism to digitize, classify, tag, search, control and link both electronic and hardcopy documents. The scope includes the development of a records management policy (includes retention schedule and storage), automating the process of archiving and a process to deal with the digitization and classification of historic records.

E-Learning: Technology that manages the creation, and delivery of training content to PowerStream employees through digital mediums. Training areas include Health and Safety, Field Operations, and Corporate Services.

Enterprise Architecture: Project to develop a business and technology blueprint that ensures business agility, scalability, and alignment with business strategy. The blueprint should address the following four architectural layers: Business, Application, Information, and Infrastructure.

Enterprise Data Model (EDM): Project that documents the existing enterprise data model and designs a normalized structure that articulates the authoritative sources for a given data set. This project should outline an As-Is and To-Be data model. This solution will lay the foundation for Data Integration, Business Intelligence, Asset Management and CIS solutions, to name a few.

Financial Needs Analysis: Project that identifies the financial needs as it relates to regulatory and non-regulatory financial reporting. This project covers the IT requirements as they relate to future revenue models, M & A activity, and financial implications of new enterprise systems such as asset management, inventory management and workforce management. This project includes the analysis of finance needs with respect to our ERP system, data, processes and related business systems.

GIS: Project to analyze, identify and implement opportunities for extending Geographic Information System technology capabilities to other parts of the business and enhancing current investments in underlying technologies and applications. Sample scenarios where GIS could be extended are visualizing outages for customer service, integration with material management, and overlaying asset location information. This project will consider the extension of GIS applications and data to the field operators as PowerStream invests in related mobile workforce technology.

Infrastructure: Project that maintains and improves our current IT infrastructure. The scope includes desktop computing, corporate network, IT servers, hardware peripherals, business productivity software, IS applications and communications technology.

Inventory Management: Technology that enables inventory management, forecasting, planning and automated procurement. This involves leveraging planned maintenance and asset management to optimize inventory levels and supply chain management. Solution scope includes the use of advanced and integrated inventory management technology that encompasses field assets, equipment and tools, as well as corporate inventory assets.

IT Cost Optimization: Project to determine IT cost optimization opportunities such as technology consolidation, shared services, and outsourcing. Scope is enterprise wide.

IT Delivery Methodology: Project to design a project delivery methodology that includes tools, templates, and procedures for planning, developing, testing, training, and supporting the implementation or enhancement of IT solutions. E.g. a PowerStream System Development Lifecycle (SDLC) methodology.

Appendix A

Definition of Strategic Initiatives

IT Evaluation Methodology: Project to develop a framework for assessing and evaluating technology assets and investments. Particular attention should be placed on compliance with PowerStream standards and compatibility with existing or planned IT investments. Common elements to review include: data migration, interoperability, workflow and hardware compatibility, scalability, functionality, and currency. This solution should result in a defined and repeatable process for evaluation and compatibility assessment.

IT Governance: Project to develop a new governance model that clearly articulates the roles, accountabilities and responsibilities of IS and the business units for making technology decisions. The governance model will also identify new entities and processes such as 1) establishing an architecture committee for managing the architecture of PowerStream's IT Infrastructure, Applications, and Data, and 2) an innovation forum for both the business units and IS to co-chair to discuss leading and emerging technologies.

IT Portfolio Assessment: Project to assess our portfolio of IT applications and related technology investments. The objective is to capture the current state, gaps and determine future potential of business technology investments. This exercise includes a review of current and future needs as they relate to IT applications enabling business functions. The output of this exercise should determine whether an IT asset is to be Replaced, Upgraded, Maintained, or Decommissioned.

ITIL: Project that builds discipline and maturity with regards to IT management (Help desk, configuration management, release management, etc). ITIL is the Information Technology Infrastructure Library, a set of industry best practices widely adopted to improve IT service management.

IVR: Project to implement a new Integrated Voice Response system to improve customer service through the use of automated account inquiry and outage information.

JDE: Project that implements routine system enhancements and maintenance to JD Edwards. Scope includes the implementation of new modules and software releases. The scope includes the following planned enhancements: G/L executive console rollout, On line-On time, Fleet, Integrate with bar-coding, Improve and automate work order process, and ongoing system security maintenance.

Knowledge Management: Technology solution that enables customers to access online knowledge artefacts (How-To, Tips, Initiatives, FAQs). This also includes the customer content management and usage monitoring.

Legacy CIS: Project to apply routine improvements to the existing CIS. These enhancements are based on evolving business requirements, such as modifications required for integrating smart meter data for billing.

Mobile Workforce: Project to identify and implement solutions for automating the field staff through the use of mobile technology. The scope of this project includes meter reading and the reduction of paper forms for field operations, as well as integrating the front line staff or customer with the field.

Performance Dashboards: Project to design, identify, collect, and report a mix of financial and non financial performance measures. This solution is linked with the Business Intelligence project.

Process Improvements: Project to periodically identify, analyze, and prioritize process improvement opportunities through the use of technology. This touches all parts of the business, internal and external. Current list of opportunities include: Time Entry (HR), Field operations, Purchase Orders, Work Orders, Approvals, Locate Requests, Customer Power Connections.

Self Service: Technology solution that provides greater communication channels and self-service features to customers on a 24x7 basis (e.g. scheduling moves, outage updates). Sample communication mediums include the web, mobile computing, interactive phone, chat, and email to name a few. The scope may include the integration with our IVR system and the possibility of on-line chatting with CSR's.

Social Media: Technology that supports the PowerStream Social Media Strategy. This technology will create a social communication channel(s) whereby individuals can discuss, share and interact with our brand.

Website Design: Project to redesign the existing public facing website using modern technology platforms. This solution will align with the social media strategy as well as the digital communications and customer segmentation strategy. The scope of this project includes improving navigation, branding and general static content.

Workforce Management: Technology that enables resource managers to allocate, schedule and assign work to resources. This solution includes the ability to capture actual time and resources expended, forecast resource utilization and deliver co-ordination and optimization via automation of the Resource Management process (includes people and equipment). Scope includes Operations, Engineering Services, Customer Services (for collections), Information Services, Fleet, and Facilities management.

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 2
Schedule 2.3
Appendix D
111 Pages
Filed: August 31, 2012

Business Case

Project Title:	Cable Replacement Program (ACA) - Locations
Location:	Various Locations
Capital Budget Year:	2013
Project Lead:	Quan Tran
Submission Date:	7/27/2011
Net Capital Amount:	2,627,223
Annual OM&A Expense (if applicable):	0
Controllable Expenditure:	☑ Yes ☐ No
Planned Project:	Yes
Project ID:	100389

Objective:

Describe the reason why you are undertaking this project.

To improve reliability of supply and customer service to the various locations throughout PowerStream North by replacing primary cable candidates. It is recommended to replace 9,400 m of cable in 2013.

Background:

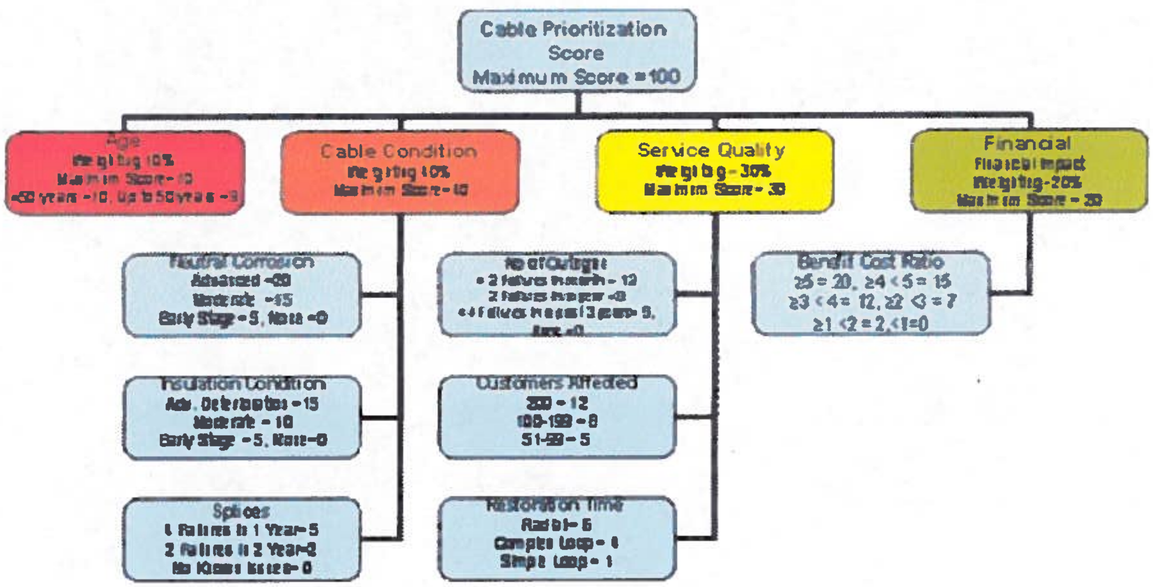
Describe the current situation and conditions in detail.

PowerStream's Underground Cable Replacement and Cable Injection Prioritization Methodology

PowerStream's approach to manage the cable population is summarized below:

- 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 20 years initially and continue at the similar rate afterward
- The cable injection program will last for 10 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.

Underground Cable Replacement

PowerStream has approx. 7,957 km of underground primary cable length, the vast majority of which is direct buried and the rest is in duct.

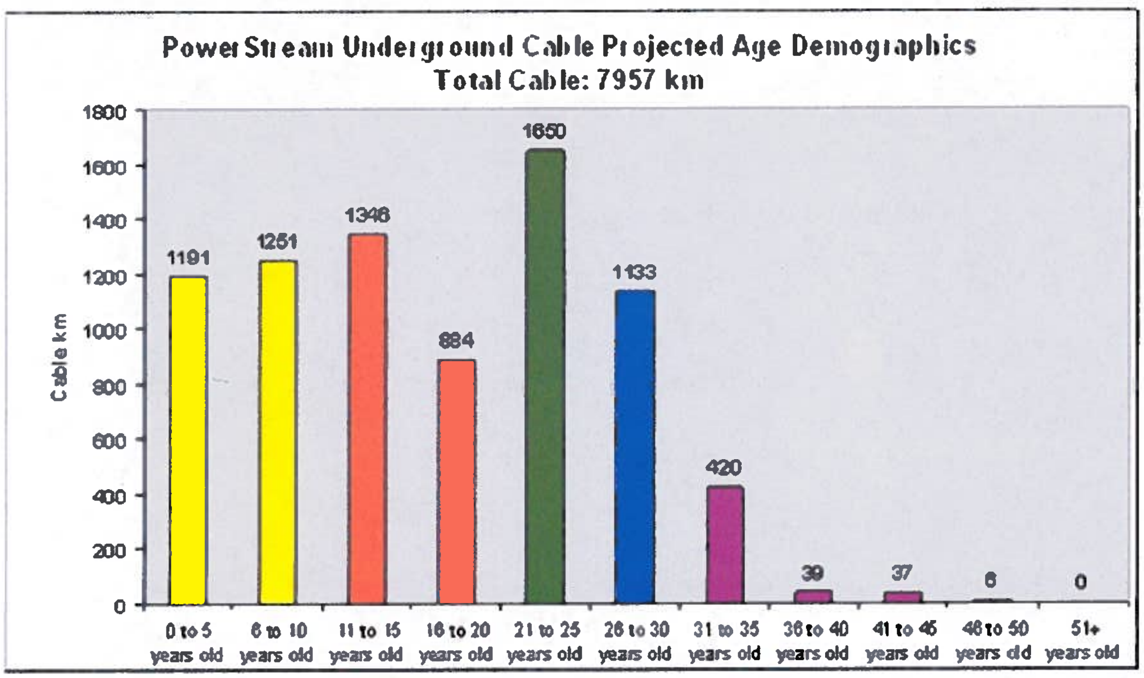
According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**, the useful lives of various types of underground cable are listed below.

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 35 years is used for pre-1987 cable and a useful life of 45 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.
The current 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 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 conducting field trial 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.

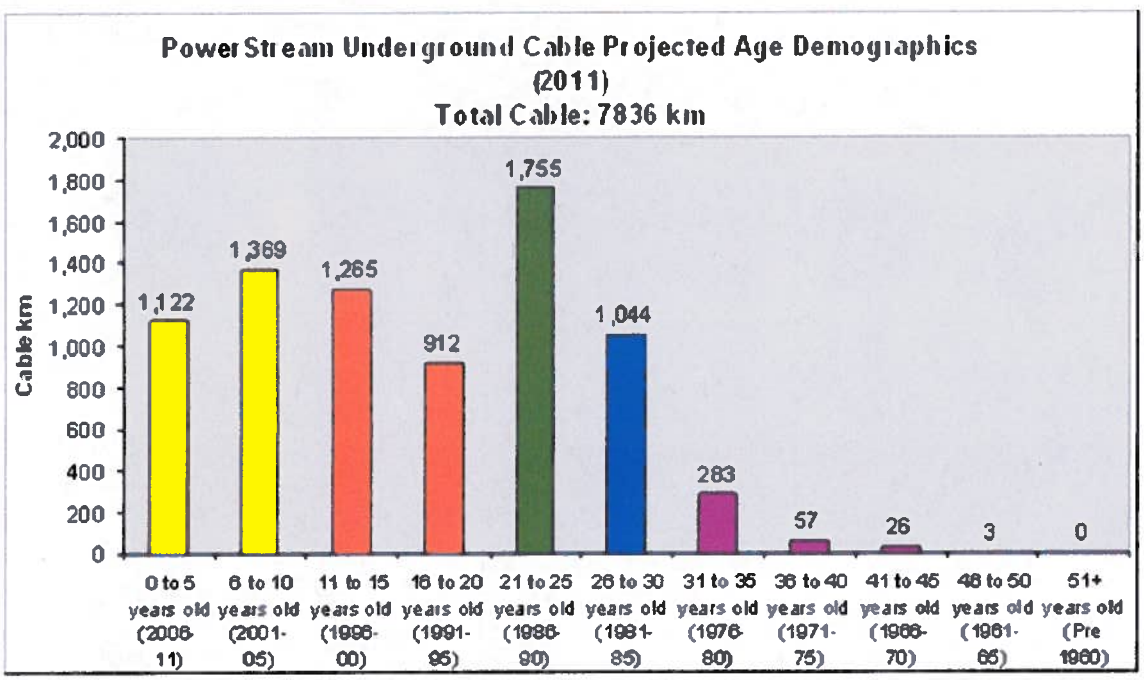
PowerStream will address its Underground Cable assets by using a combination of Cable Replacement and Cable Injection as means of intervention. The Cable Replacement plan (discussed later in this Section) will be ongoing as we will continually need to replace cable as it gets older. This report will cover the first 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 (discussed in the next Section - Cable Injection) will take place over a period of 10 years. After 10 years all suitable candidates for injection will be exhausted, therefore this plan will not be ongoing.

20-Year Cable Replacement Plan:

In 2011, a general plan to address the cable issue (a 20 year plan for cable replacement, and a 10 year plan for cable injection) was developed and approved by PowerStream management. To develop the cable plan, the 2011 cable age demographics was used to divide the cable population into the following 5 groups:

- Group 1: 31 years and older (1980 and older)
- Group 2: Between 26 – 30 years (1981-1985)
- Group 3: Between 21 – 25 years (1986 – 1990)
- Group 4: Between 11 – 20 years (1991 – 2000)
- Group 5: Between 1 – 10 years (2001 and younger)

The 2011 cable age demographics and age groups are described below.



Group 1: 31 years and older (1980 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 (1981 – 1985):
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 (1986 – 1990):
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 (1991 – 2000):
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 (2001 and younger):
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.

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 47 km per year from 2013 - 2031

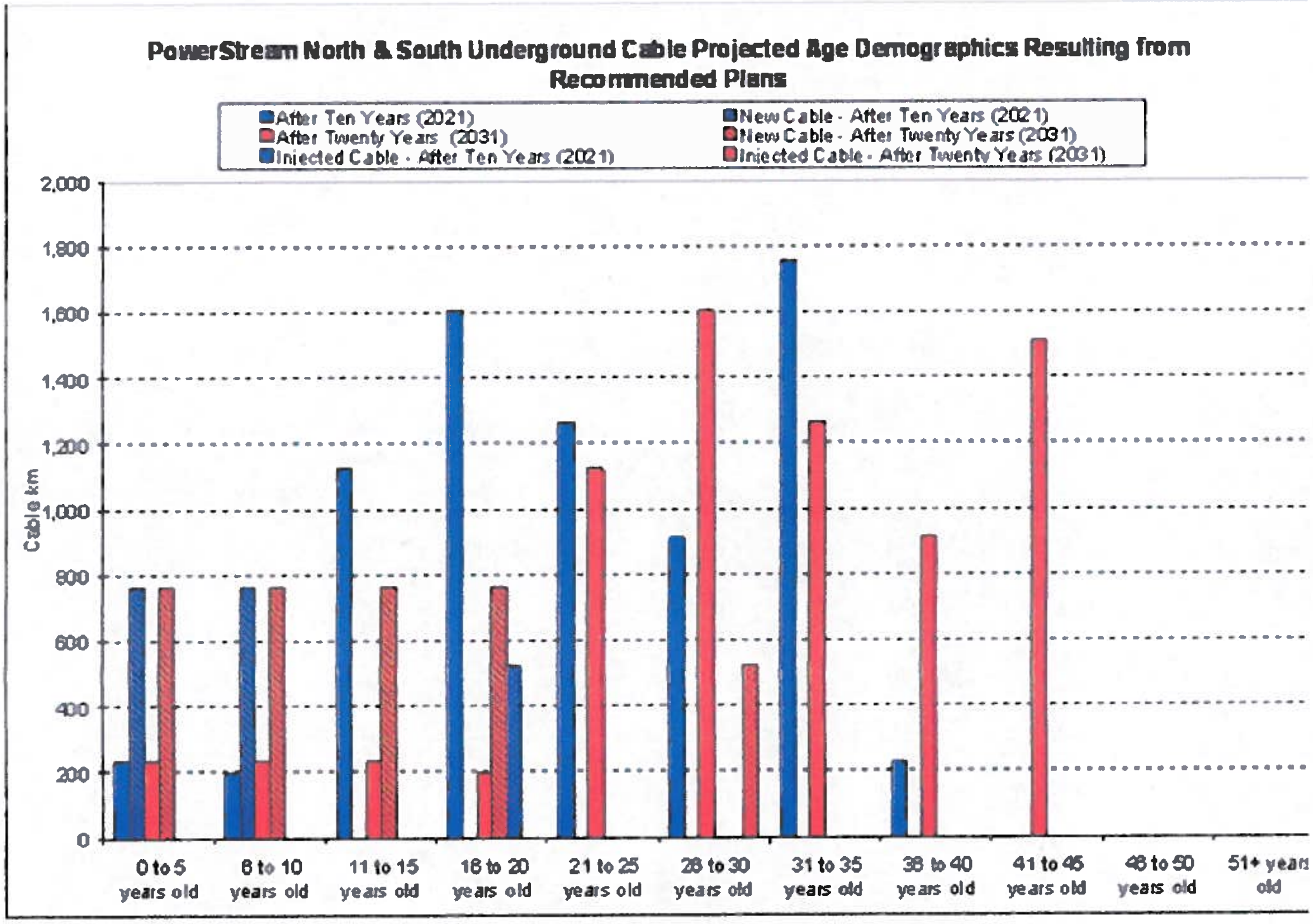
At this rate, all of the 892 km will have been replaced by 2032.
Currently, PowerStream does not have sufficient physical condition and test data to determine the degree of deterioration and to estimate the remaining life of the cable population.

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.



Based on the above chart, after 20 years PowerStream will have 1,745km 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.

Cost of Cable Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2013	2014	2015	2016	2017	5 Yr. Total
2.1	Cable Replacement	$17,399,485	$18,695,752	$17,895,044	$15,519,644	$15,543,026	$85,042,95

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 (approx. 26 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 (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.
In 2011 PowerStream completed 2 cable injection projects using two different contractors.
In 2012 PowerStream will proceed with 2 cable injection projects to continue to gain experience.

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 gaining experience 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 57 km per year 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.

Cost of Cable Injection

PowerStream - Capital Work Plan from Planning and Stations							
Category		2013	2014	2015	2016	2017	5 Yr. Total
22	Cable Injection	$4,060,942	$4,074,566	$4,088,187	$4,101,812	$4,115,437	$20,440,94

Alternative One: Status Quo

Describe the status quo.

The status quo is to do nothing, not replace existing cable, and respond to failures and outages under emergency.

Provide details of the cost of the status quo, if applicable.

N/A

*Describe the **health and safety** risk of the status quo.*

Because the cables are at end-of-life, failures may occur which under rare but not improbable circumstances may cause injuries to operations staff and the public.

*Describe the **business excellence** risk to the Status quo.*

Leaving the cable in its deteriorated conditions will cause cable failures and negatively impact PowerStream's effort to achieve operation excellence. Inefficiencies are created when operations staff perform repairs and replacements under emergency situations.

*Describe the **customer satisfaction** risk to the Status quo.*

When old deteriorated cable is not injected or replaced, failures will occur resulting in customer outages which will have a negative impact to system reliability and customer service. Based on the estimate of 2 failures per year per subdivision, there would be 21,600 CMI (Customer Minutes of Interruption) per subdivision of 4,000 m cable, or 50,760 CMI for 9,4000 m cable.

*Describe **financial risk** of the status quo.*

The financial risk calculations are based on the following assumptions and estimates (per 4,000 m of cable or 1 subdivision):
- Frequency of interruption: 2 failures/year
- Duration of interruption: 3 hours
- Number of transformers: 12 transformers
- Number of customers in the loop: 120 customers
- Number of customers affected in an outage: 120/2 = 60 customers (half loop)
- Customer load: 120 customers x 3 kW = 360 kW
- Customer load affected in an outage: 360 kW/2 = 180 kW (half loop)
- Customer Interruption Cost (Frequency): $2.00/kW (Residential)
- Customer Interruption Cost (Duration): $4.00/kWh (Residential)
- Emergency Response/Repair Cost: $10,000/event
- Delivery Charge, etc. for loss of revenue calculation: $0.024/kWh

The financial risk cost is estimated as follows:
Cost to PowerStream:
- Emergency Response/Repair Cost = $10,000 x 2 failures/year = $20,000
- Loss of Revenue Cost (Delivery Charge, etc.) = 180 kW x 3 hrs x $0.024/kWh x 2 failures/year = $26

Total Cost to PowerStream = $20,000 + $26 = $20,026

Cost to Customers:
- Customer Interruption Cost (Frequency) = 180 kW x $2/kW x 2 failures/year = $720
- Customer Interruption Cost (Duration) = 180 kW x 3 hrs x $4/kWh x 2 failures/year= $4,320

Total Cost to Customers (Interruption) = $720 + $4,320 = $5,040

Total Risk Cost per subdivision = $20,026 (PowerStream) + $5,040 (Customers) = $25,066

Total Risk Cost for 9.4 km of cable length is:
$20,026 x 9400/4000 (PowerStream) + $5,040 x 9400/4000 (Customers) = $47,061 (PowerStream) + $11,844 (Customers) = $58,905

*Describe the **environmental risk** of the status quo.*

Increased risk of cable failures which will have negative impacts on the environment. Trouble response and repair will be required, increasing vehicle emissions and disruption to land (e.g. digging up the boulevard to expose the faulted direct buried cable).

Alternative 2 :

Replace cable at various locations over a period of 20 years

Describe the alternative.

Replace the underground primary cable at various locations in PowerStream over a period of 20 years. Continuing with 8.5 km in 2012 then 47 km (including 9.4 km in the North and 37.6 km in the South) per year from 2013 - 2032. The details are outlined in the proposed 20 year plan below:

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 more 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 from 2013 – 2032, of which 9.4 km is in PowerStream North and 37.6 km is in PowerStream South

At this rate, all of the 892 km will have been replaced by 2032.

After 20 years PowerStream will have 1,746 km of cable that is 41 to 45 years old. While this is a higher amount of cable in the age range as compared to the amount 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 future 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.

Provide details of the cost of this alternative.

$2,627,223
See Project 100389 Budget Form for details.

Recommended Alternative:

Alternative 2: Replace cable at various locations over a period of 20 years

Describe the recommended alternative.

Replace the underground primary cable at various locations in PowerStream over a period of 20 years. Continuing with 8.5 km in 2012 then 47 km (including 9.4 km in the North and 37.6 km in the South) per year from 2013 - 2032. The details are outlined in the proposed 20 year plan below:

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 more 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 from 2013 – 2032, of which 9.4 km is in PowerStream North and 37.6 km is in PowerStream South

At this rate, all of the 892 km will have been replaced by 2032.

After 20 years PowerStream will have 1,746 km of cable that is 41 to 45 years old. While this is a higher amount of cable in the age range as compared to the amount 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 future 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.

Why did you choose the recommended alternative?

The recommended alternative was chosen for the following reasons;
1. Resolves the operations and safety concerns.
2. Improves reliability of supply and customer satisfaction.
3. Replace assets that are at end-of-life.

Is this project dependent on any other project(s)? Identify Project ID(s).

This project is dependent on one other project:
- Project ID 100385: Cable Replacement Program (ACA) - Locations TBD, DESIGN ONLY - North

*What is the **health and safety** value of the recommended alternative to the organization?*

Deteriorated cables are replaced with new cables, resulting in fewer cable failures and reduction in the risk of injuries for staff and the public.

*What is the **business excellence** value of the recommended alternative to the organization?*

Improve reliability within the subdivision. Improve efficiency because operations staff will perform fewer repairs and replacements under emergency situations.

*What is the **customer satisfaction** value of the recommended alternative to the organization?*

Replacement deteriorated cables will result in more reliable service to customers. Based on the estimate of 2 failures per year and 60 customers affected (half of 120 customers), a reduction of 21,600 CMI (Customer Minutes of Interruption) can be achieved. The CMI is estimated as

follows:
CMI per subdivision = 60 customers x 3 hours x 60 minutes x 2 failures/year = 21,600 CMI
CMI for 9.4 km of cable length = 21,600 x (9400/4000) = 50,760 CMI

*What is the **financial** value of the recommended alternative to the organization?*

Customer outages will be reduced, resulting in a saving of customer interruption cost, equipment repair cost, and revenue loss cost, totaling $25,066 per year, of which $20,026 is attributed to PowerStream cost, and $5,040 is attributed to Customer Interruption cost (per subdivision).
Financial value for 9.4 km of cable length is: $47,061 (PowerStream) + $11,844 (Customers) = $58,905

*What is the **environmental** value of the recommended alternative to the organization?*

Reducing cable failures will have positive impacts on the environment. Fewer trouble response and repair will reduce vehicle emission. Fewer cable repair will reduce disruption to land (e.g. digging up the boulevard to expose the faulted direct buried cable).

Implementation Timeline:

Provide planned timelines for project completion.

2012 - Complete Cable Replacement projects approx. 8.5 km at various locations.
2013 - 2032 - Complete Cable Replacement projects approx. 47 km per year, of which approx. 9.4 km at various locations in the North and 37.6 km at various locations in the South.

Reviewed By:

POWERSTREAM\doug.fairchild

Title	Name	Signature	Date
Project Leader	Quan Tran	POWERSTREAM\quan.tran	7/27/2011 2:26:23 PM
Project Sponsor	Doug Fairchild	POWERSTREAM\doug.fairchild	7/28/2011 11:51:50 AM
Department Director	Ted Wojcinski	POWERSTREAM\ted.wojcinski	7/28/2011 3:10:11 PM
Department VP	Shelly Cunningham	POWERSTREAM\shelly.cunningham	8/3/2011 1:53:47 PM
VP Rates & Regulatory	Colin MacDonald	POWERSTREAM\colin.macdonald	8/24/2011 1:28:52 PM
Executive VP	Mark Henderson	POWERSTREAM\mark.henderson	8/24/2011 2:19:55 PM

Executive VP & CFO	John Glicksman	POWERSTREAM\john.glicksman	8/29/2011 10:13:18 AM
President & CEO			

Additional Attachments

File Attachment

Sign off and approval required by

Department Director, Department VP, VP Rates & Regulatory, EVP, EVP&CFO

CCC #15 - Attachment 2 (BC237)

Business Case

Project Title:	Cable Replacement Program (ACA) - Locations TBD - South
Location:	Various Locations
Capital Budget Year:	2013
Project Lead:	Quan Tran
Submission Date:	7/27/2011
Net Capital Amount:	10,508,894
Annual OM&A Expense (if applicable):	0
Controllable Expenditure:	☑ Yes ☐ No
Planned Project:	Yes
Project ID:	100390

Objective:

Describe the reason why you are undertaking this project.

To improve reliability of supply and customer service to the various locations throughout PowerStream South by replacing primary cable candidates. It is recommended to replace 37,600 m of cable in 2013.

Background:

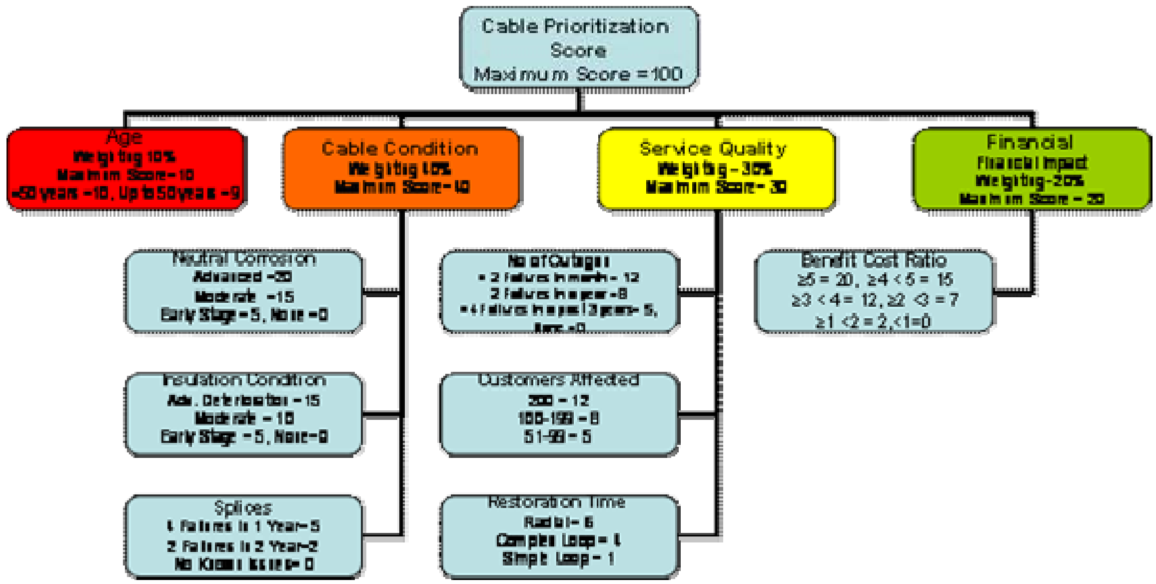
Describe the current situation and conditions in detail.

PowerStream's Underground Cable Replacement and Cable Injection Prioritization Methodology

PowerStream's approach to manage the cable population is summarized below:

- 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 20 years initially and continue at the similar rate afterward
- The cable injection program will last for 10 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.

Underground Cable Replacement

PowerStream has approx. 7,957 km of underground primary cable length, the vast majority of which is direct buried and the rest is in duct.

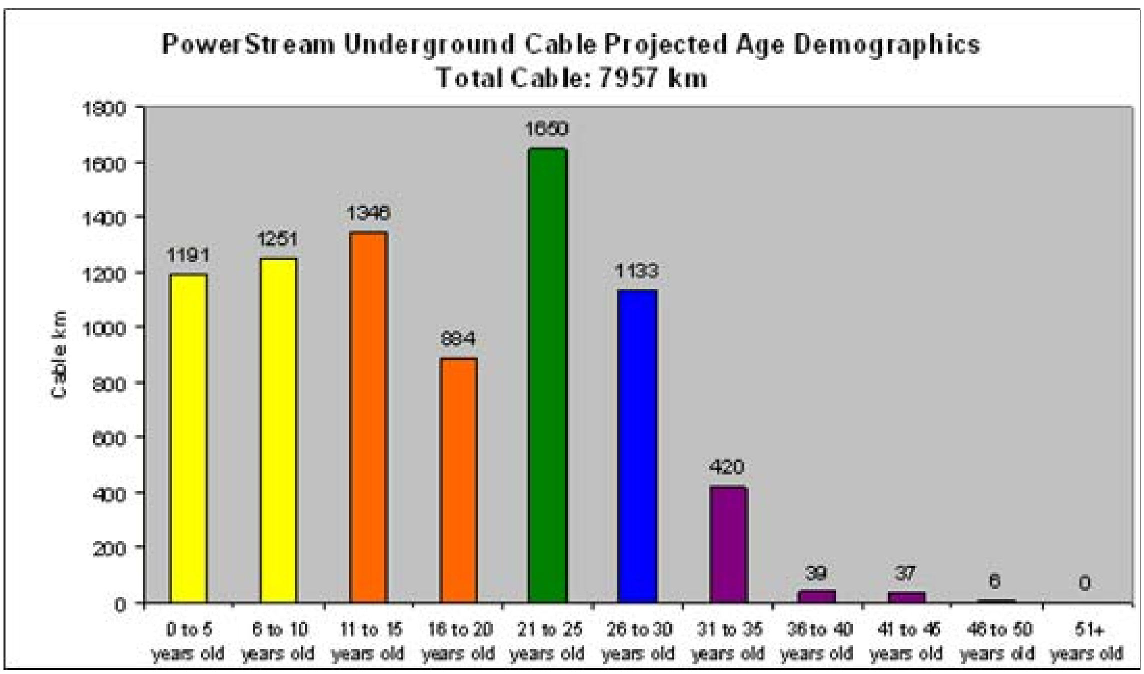
According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**, the useful lives of various types of underground cable are listed below.

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 Retandant XLPE - Direct Buried	25 Years	30 Years	35 Years
Primary Tree Retandant XLPE - In Duct	35 Years	40 Years	55 Years

At PowerStream, for IFRS purposes, a useful life of 35 years is used for pre-1987 cable and a useful life of 45 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.
The current 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 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 conducting field trial 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.

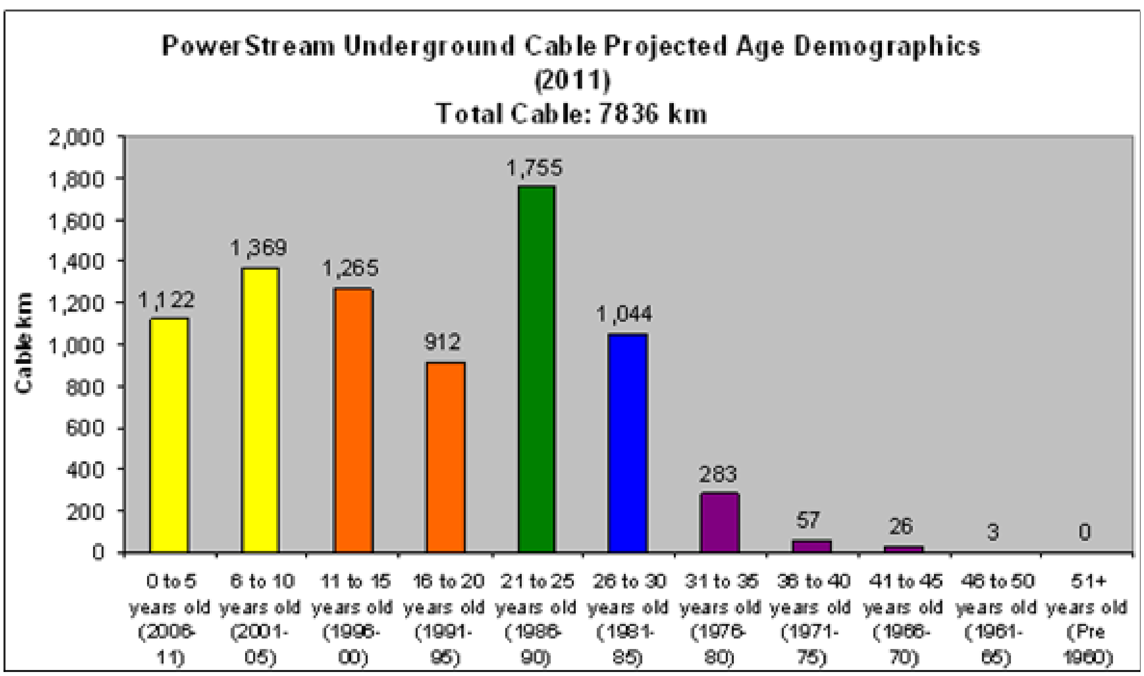
PowerStream will address its Underground Cable assets by using a combination of Cable Replacement and Cable Injection as means of intervention. The Cable Replacement plan (discussed later in this Section) will be ongoing as we will continually need to replace cable as it gets older. This report will cover the first 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 (discussed in the next Section - Cable Injection) will take place over a period of 10 years. After 10 years all suitable candidates for injection will be exhausted, therefore this plan will not be ongoing.

<u>20-Year Cable Replacement Plan:</u>

In 2011, a general plan to address the cable issue (a 20 year plan for cable replacement, and a 10 year plan for cable injection) was developed and approved by PowerStream management. To develop the cable plan, the 2011 cable age demographics was used to divide the cable population into the following 5 groups:

- Group 1: 31 years and older (1980 and older)
- Group 2: Between 26 – 30 years (1981-1985)
- Group 3: Between 21 – 25 years (1986 – 1990)
- Group 4: Between 11 – 20 years (1991 – 2000)
- Group 5: Between 1 – 10 years (2001 and younger)

The 2011 cable age demographics and age groups are described below.



Group 1: 31 years and older (1980 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 (1981 – 1985):

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 (1986 – 1990):

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 (1991 – 2000):

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 (2001 and younger):

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.

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 47 km per year from 2013 – 2031

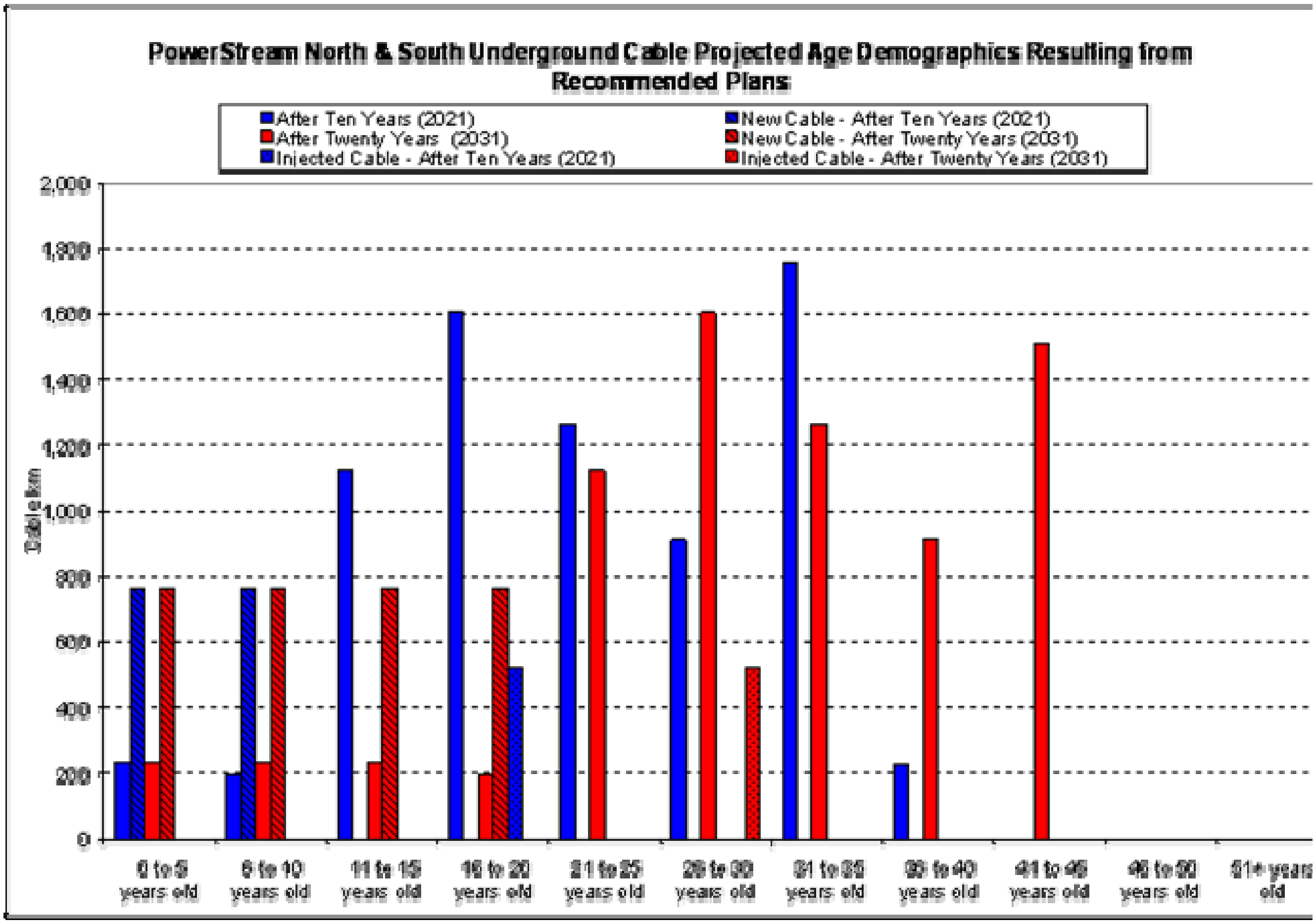
At this rate, all of the 892 km will have been replaced by 2032.
Currently, PowerStream does not have sufficient physical condition and test data to determine the degree of deterioration and to estimate the remaining life of the cable population.

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.



Based on the above chart, after 20 years PowerStream will have 1,745km 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.

Cost of Cable Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2013	2014	2015	2016	2017	5 Yr. Total
2.1	Cable Replacement	$17,399,485	$18,695,752	$17,885,044	$15,519,644	$15,543,026	$85,042,95

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 (approx. 26 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 (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.
In 2011 PowerStream completed 2 cable injection projects using two different contractors.
In 2012 PowerStream will proceed with 2 cable injection projects to continue to gain experience.

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 gaining experience 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 57 km per year 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.

Cost of Cable Injection

PowerStream - Capital Work Plan from Planning and Stations							
Category		2013	2014	2015	2016	2017	5 Yr. Total
22	Cable Injection	$4,060,942	$4,074,566	$4,088,187	$4,101,812	$4,115,437	$20,440,94

Alternative One: Status Quo

Describe the status quo.

The status quo is to do nothing, not replace existing cable, and respond to failures and outages under emergency.

Provide details of the cost of the status quo, if applicable.

N/A

*Describe the **health and safety** risk of the status quo.*

Because the cables are at end-of-life, failures may occur which under rare but not improbable circumstances may cause injuries to operations staff and the public.

*Describe the **business excellence** risk to the Status quo.*

Leaving the cable in its deteriorated conditions will cause cable failures and negatively impact PowerStream's effort to achieve operation excellence. Inefficiencies are created when operations staff perform repairs and replacements under emergency situations.

*Describe the **customer satisfaction** risk to the Status quo.*

When old deteriorated cable is not injected or replaced, failures will occur resulting in customer outages which will have a negative impact to system reliability and customer service. Based on the estimate of 2 failures per year per subdivision, there would be 21,600 CMI (Customer Minutes of Interruption) per subdivision of 4,000 m cable, or 203,040 CMI for 37,600 m cable.

*Describe **financial risk** of the status quo.*

The financial risk calculations are based on the following assumptions and estimates (per 4,000 m of cable or 1 subdivision):
- Frequency of interruption: 2 failures/year
- Duration of interruption: 3 hours
- Number of transformers: 12 transformers
- Number of customers in the loop: 120 customers
- Number of customers affected in an outage: 120/2 = 60 customers (half loop)
- Customer load: 120 customers x 3 kW = 360 kW
- Customer load affected in an outage: 360 kW/2 = 180 kW (half loop)
- Customer Interruption Cost (Frequency): $2.00/kW (Residential)
- Customer Interruption Cost (Duration): $4.00/kWh (Residential)
- Emergency Response/Repair Cost: $10,000/event
- Delivery Charge, etc. for loss of revenue calculation: $0.024/kWh

The financial risk cost is estimated as follows:
Cost to PowerStream:
- Emergency Response/Repair Cost = $10,000 x 2 failures/year = $20,000
- Loss of Revenue Cost (Delivery Charge, etc.) = 180 kW x 3 hrs x $0.024/kWh x 2 failures/year = $26

Total Cost to PowerStream = $20,000 + $26 = $20,026

Cost to Customers:
- Customer Interruption Cost (Frequency) = 180 kW x $2/kW x 2 failures/year = $720
- Customer Interruption Cost (Duration) = 180 kW x 3 hrs x $4/kWh x 2 failures/year= $4,320

Total Cost to Customers (Interruption) = $720 + $4,320 = $5,040

Total Risk Cost per subdivision = $20,026 (PowerStream) + $5,040 (Customers) = $25,066

Total Risk Cost for 37.6 km of cable length is:
$20,026 x 37,600/4,000 (PowerStream) + $5,040 x 37,600/4,000 (Customers) = $188,244 (PowerStream) + $47,376(Customers) = $235,620

*Describe the **environmental risk** of the status quo.*

Increased risk of cable failures which will have negative impacts on the environment. Trouble response and repair will be required, increasing vehicle emissions and disruption to land (e.g. digging up the boulevard to expose the faulted direct buried cable).

Alternative 2 :

Replace cable at various locations over a period of 20 years

Describe the alternative.

Replace the underground primary cable at various locations in PowerStream over a period of 20 years. Continuing with 8.5 km in 2012 then 47 km (including 9.4 km in the North and 37.6 km in the South) per year from 2013 - 2032. The details are outlined in the proposed 20 year plan below:

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 more 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 from 2013 – 2032, of which 9.4 km is in PowerStream North and 37.6 km is in PowerStream South

At this rate, all of the 892 km will have been replaced by 2032.

After 20 years PowerStream will have 1,746 km of cable that is 41 to 45 years old. While this is a higher amount of cable in the age range as compared to the amount 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 future 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.

Provide details of the cost of this alternative.

$10,508,894
See Project 100390 Budget Form for details.

Recommended Alternative:

Alternative 2: Replace cable at various locations over a period of 20 years

Describe the recommended alternative.

Replace the underground primary cable at various locations in PowerStream over a period of 20 years. Continuing with 8.5 km in 2012 then 47 km (including 9.4 km in the North and 37.6 km in the South) per year from 2013 - 2032. The details are outlined in the proposed 20 year plan below:

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 more 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 from 2013 – 2032, of which 9.4 km is in PowerStream North and 37.6 km is in PowerStream South

At this rate, all of the 892 km will have been replaced by 2032.

After 20 years PowerStream will have 1,746 km of cable that is 41 to 45 years old. While this is a higher amount of cable in the age range as compared to the amount 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 future 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.

Why did you choose the recommended alternative?

The recommended alternative was chosen for the following reasons;
1. Resolves the operations and safety concerns.
2. Improves reliability of supply and customer satisfaction.
3. Replace assets that are at end-of-life.

Is this project dependent on any other project(s)? Identify Project ID(s).

This project is dependent on one other project:
- Project ID 100386: Cable Replacement Program (ACA) - Locations TBD, DESIGN ONLY - South

*What is the **health and safety** value of the recommended alternative to the organization?*

Deteriorated cables are replaced with new cables, resulting in fewer cable failures and reduction in the risk of injuries for staff and the public.

*What is the **business excellence** value of the recommended alternative to the organization?*

Improve reliability within the subdivision. Improve efficiency because operations staff will perform fewer repairs and replacements under emergency situations.

*What is the **customer satisfaction** value of the recommended alternative to the organization?*

Replacement deteriorated cables will result in more reliable service to customers. Based on the estimate of 2 failures per year and 60 customers affected (half of 120 customers), a reduction of 21,600 CMI (Customer Minutes of Interruption) can be achieved. The CMI is estimated as

follows:
CMI per subdivision = 60 customers x 3 hours x 60 minutes x 2 failures/year = 21,600 CMI
CMI for 37.6 km of cable length = 21,600 x (37,600/4,000) = 203,040 CMI

*What is the **financial** value of the recommended alternative to the organization?*

Customer outages will be reduced, resulting in a saving of customer interruption cost, equipment repair cost, and revenue loss cost, totaling $25,066 per year, of which $20,026 is attributed to PowerStream cost, and $5,040 is attributed to Customer Interruption cost (per subdivision).
Financial value for 37.6 km of cable length is: $188,244 (PowerStream) + $47,376 (Customers) = $235,620

*What is the **environmental** value of the recommended alternative to the organization?*

Reducing cable failures will have positive impacts on the environment. Fewer trouble response and repair will reduce vehicle emission. Fewer cable repair will reduce disruption to land (e.g. digging up the boulevard to expose the faulted direct buried cable).

Implementation Timeline:

Provide planned timelines for project completion.

2012 - Complete Cable Replacement projects approx. 8.5 km at various locations.
2013 - 2032 - Complete Cable Replacement projects approx. 47 km per year, of which approx. 9.4 km at various locations in the North and 37.6 km at various locations in the South.

Reviewed By:

POWERSTREAM\riaz.shaikh

Title	Name	Signature	Date
Project Leader	Quan Tran	POWERSTREAM\quan.tran	7/27/2011 2:26:43 PM
Project Sponsor	Doug Fairchild	POWERSTREAM\doug.fairchild	7/28/2011 11:54:00 AM
Department Director	Ted Wojcinski	POWERSTREAM\ted.wojcinski	7/28/2011 3:09:53 PM
Department VP	Shelly Cunningham	POWERSTREAM\shelly.cunningham	8/3/2011 1:53:53 PM
VP Rates & Regulatory	Colin MacDonald	POWERSTREAM\colin.macdonald	8/24/2011 1:29:21 PM
Executive VP	Mark Henderson	POWERSTREAM\mark.henderson	8/24/2011 2:20:30 PM

Executive VP & CFO	John Glicksman	POWERSTREAM\john.glicksman	8/29/2011 10:13:35 AM
President & CEO	Brian Bentz		

Additional Attachments

File Attachment

Sign off and approval required by

Department Director, Department VP, VP Rates & Regulatory, EVP, EVP&CFO, President&CEO

CCC #15 - Attachment 3 (BC231)

Business Case

Project Title:	Cable Rehabilitation Romfield Phase 3 Markham
Location:	Romfield Subdivision Phase 3, west of Bayview & south of Hwy 7, Markham
Capital Budget Year:	2013
Project Lead:	Quan Tran
Submission Date:	7/26/2011
Net Capital Amount:	1,885,952
Annual OM&A Expense (if applicable):	0
Controllable Expenditure:	☑ Yes ☐ No
Planned Project:	Yes
Project ID:	100371

Objective:

Describe the reason why you are undertaking this project.

To improve reliability of supply and customer service to the Romfield Subdivision area. Replacing the 8.32 kV primary cable that is over 40 years old and at end-of-life with new 27.6 kV primary cable, and replacing obsolete submersible transformers with new padmount transformers. This is Phase 3 of a five-phase project. Phase 1 was completed in 2011. Phase 2 is being completed in 2012. Phase 3 is recommended for 2013. Phase 4 is recommended for 2014. Phase 5 is recommended for 2015.

Background:

Describe the current situation and conditions in detail.

The Romfield Subdivision supply area is supplied at 8.32 kV level. The underground cable is over 40 years old and is at end-of-life. The submersible transformers are obsolete and cannot be switched while energized due to safety reasons.

The proposed rehabilitation work in the Romfield area includes the replacement of approx. 127 transformers and 13,000 meters of underground cable, and is divided into five phases as follows:

1. **Romfield Phase 1 (2011):** includes the replacement of approx. 27 transformers and 3,865 meters of underground cable.
2. **Romfield Phase 2 (2012):** includes the replacement of approx. 26 transformers and 3,864 meters of underground cable.
3. **Romfield Phase 3 (2013):** includes the replacement of approx. 18 transformers and 1,009 meters of underground cable.
4. **Romfield Phase 4 (2014):** includes the replacement of approx. 28 transformers and 2,187 meters of underground cable.
5. **Romfield Phase 5 (2015):** includes the replacement of approx. 28 transformers and 2,187 meters of underground cable.

The underground cable is over 40 years old and have failed numerous times in the last few years as shown by the following outage reports:

-
    - 1999-0068
    - 1999-0069
    - 2003-0005
    - 2003-0012
    - 2004-0138
    - 2005-0375
    - 2005-0537 (defective underground submersible transformer)
    - 2007-0427
    - 2008-0014 (defective underground equipment - elbow)
    - 2010-0312 (defective underground submersible transformer)
    - 2010-0348 (defective underground submersible transformer)
    - 2011-0136 (defective underground submersible transformer)
    - 2011-0316 (defective underground submersible transformer)

A non-destructive Partial Discharge (PD) cable test completed by DTE/Probyn Energy Solutions in December 1999 indicated that 62 cable sections (out of 458 cable sections tested) showed a PD Level 4 (Medium probability of failure in 2 years). Consideration should be given to replacement of the cable. A report summary is attached.

In addition to the age and condition of the cable, the subdivision has submersible distribution transformers which because of the design, installation, and safety reasons, cannot be switched while the transformers are energized. As a result, any switching operation needed within the subdivision will require an outage to de-energize the transformers first. This will cause outages to the customers within the subdivision.

Alternative One: Status Quo

Describe the status quo.

The status quo is to do nothing, not replace existing transformers and cable, and respond to failures and outages as required. The status quo means leaving the subdivision operated under two different supply systems.

Provide details of the cost of the status quo, if applicable.

N/A

*Describe the **health and safety** risk of the status quo.*

Because the transformers are obsolete and the cables are at end-of-life, failures may occur which under rare but not improbable circumstances may cause injuries to operations staff and the public.

*Describe the **business excellence** risk to the Status quo.*

Because of the design and installation limitations of the submersible transformers, the operations staff cannot perform the switching when the units are energized. This creates inefficiency when operations staff perform maintenance and trouble response work.
Because this is phase 3 of a five-phase five-year project, if phase 3 is not completed, there will be inconsistent system design against the Phase 1 & Phase 2. Old asset left in the deteriorated conditions will negatively impact PowerStream's effort to achieve operational excellence.

*Describe the **customer satisfaction** risk to the Status quo.*

A high rate of failures will continue to occur resulting in customer outages which will have a negative impact to system reliability and customer satisfaction. Based on the estimate of 3 failures per year in the subdivision, there would be 48,600 CMI (Customer Minutes of Interruption).

*Describe **financial risk** of the status quo.*

The financial risk calculations are based on the following assumptions and estimates:
- Frequency of interruption: 3 failures/year (2 cable failures and 1 transformer failure)
- Duration of interruption: 3 hours
- Number of transformers: 18 transformers
- Number of customers: 180 customers
- Number of customers affected in an outage: 180/2 = 90 (half loop)
- Customer load: 180 customers x 3 kW = 540 kW
- Customer load affected in an outage: 540 kW/2 = 270 kW (half loop)
- Customer Interruption Cost (Frequency): $2.00/kW
- Customer Interruption Cost (Duration): $4.00/kWh
- Emergency Response/Repair Cost: $10,000/event
- Delivery Charge, etc. for loss of revenue calculation: $0.024/kWh

The financial risk cost is estimated as follows:
<u>Cost to PowerStream:</u>
- Emergency Response/Repair Cost = $10,000 x 3 failure/year = $30,000
- Loss of Revenue Cost (Delivery Charge, etc.) = 270 kW x 3 hrs x $0.024/kWh x 3 failures/year = $58

Total Cost to PowerStream = $30,000 + $58 = $30,058
<u>Cost to Customers:</u>
- Customer Interruption Cost (Frequency) = 270 kW x $2/kW x 3 failures/year = $1,620
- Customer Interruption Cost (Duration) = 270 kW x 3 hrs x $4/kWh x 3 failures/year= $9,720

Total Cost to Customers (Interruption) = $1,620 + $9,720 = $11,340
Total Cost = $30,058(PowerStream) + $11,340(Customers) = $41,398

*Describe the **environmental risk** of the status quo.*

Risk of transformer oil discharge to the environment due to transformer failure. A number of existing submersible transformers within the area have a PCB (Polychlorinated Biphenyl) level of more than 2 PPM (parts per million) and less than 50 PPM.

Alternative 2 :

Cable Injection

Describe the alternative.

Cable Injection was considered but is not recommended.
The reasons are:

1. The cable is over 40 years old and is at end-of-life.
2. The unjacketed concentric neutral of the cable has likely corroded significantly.

Provide details of the cost of this alternative.

N/A

Alternative 3 :

Replace cable and submersible transformers within the Romfield area over a period of five years, starting with Phase 1 in 2011, Phase 2 in 2012 and continuing with Phase 3 in 2013

Describe the alternative.

Replace the primary cable with 28 kV cable. Replace the submersible transformers with dual primary voltage (8/16 kV) padmount transformers. Convert the supply system from 8.32 kV to 27.6 kV.

The proposed rehabilitation work in the Romfield area is divided into five phases as follows:

1. Romfield Phase 1 (2011): includes the replacement of approx. 3,865 meters of underground cable and 27 transformers.
2. Romfield Phase 2 (2012): includes the replacement of approx. 3,864 meters of underground cable and 26 transformers.
3. **Romfield Phase 3 (2013): includes the replacement of approx. 1,009 meters of underground cable and 18 transformers.**
4. Romfield Phase 4 (2014): includes the replacement of approx. 2,187 meters of underground cable and 28 transformers.
5. Romfield Phase 5 (2015): includes the replacement of approx. 2,187 meters of underground cable and 28 transformers.

Provide details of the cost of this alternative.

$1,885,952
See the Project 100371 Budget Form for details.

Recommended Alternative:

Alternative 3

Describe the recommended alternative.

The recommended alternative is alternative 3, proceed with Phase 3 of the Romfield Subdivision Rehabilitation in 2013.

Why did you choose the recommended alternative?

The recommended alternative was chosen for the following reasons;
1. Resolves the operations and safety concerns.
2. Improves reliability of supply and customer service to the subdivision.
3. Replace assets that are at end-of-life.

Is this project dependent on any other project(s)? Identify Project ID(s).

This project is dependent on two other projects:
- Project ID QTR004: Cable Rehabilitation Romfield Phase 1 Markham (proposed for 2011 budget year - refer to BC207)
- Project ID 100177: Cable Rehabilitation Romfield Phase 2 Markham (proposed for 2012 budget year - refer to BC209)

*What is the **health and safety** value of the recommended alternative to the organization?*

Obsolete and old equipment are replaced with new equipment, resulting in fewer equipment failures and reduction in the risk of injuries for staff and the public.

*What is the **business excellence** value of the recommended alternative to the organization?*

Maintain consistency in system design and operations within the subdivision, making it more efficient and effective for operations staff to perform maintenance and trouble response work.

*What is the **customer satisfaction** value of the recommended alternative to the organization?*

Replacement of obsolete and old equipment will result in more reliable service to customers. Based on the estimate of 3 failures per year in the subdivision, a reduction of 48,600 CMI (Customer Minutes of Interruption) can be achieved. The CMI is estimated as follows:
90 customers x 3 hours x 60 minutes x 3 failures/year = 48,600 CMI

*What is the **financial** value of the recommended alternative to the organization?*

Customer outages will be reduced, resulting in a saving of customer interruption cost, equipment repair cost, and revenue loss cost, totaling $41,398 per year, of which $30,058 is attributed to PowerStream cost, and $11,340 is attributed to Customer Interruption cost.

*What is the **environmental** value of the recommended alternative to the organization?*

Manage the risk of transformer oil discharge to the environment due to transformer failure. A number of existing submersible transformers within the area have a PCB (Polychlorinated Biphenyl) level of more than 2 PPM (parts per million) and less than 50 PPM. Therefore if these transformers are removed and replaced with new transformers, the work will have a positive impact to PowerStream effort to manage PCB.

Implementation Timeline:

Provide planned timelines for project completion.

2011 - Complete Phase 1 portion of the Romfield Subdivision Rehabilitation project.
2012 - Complete Phase 2 portion of the Romfield Subdivision Rehabilitation project.
2013 - Complete Phase 3 portion of the Romfield Subdivision Rehabilitation project.
2014 - Complete Phase 4 portion of the Romfield Subdivision Rehabilitation project.
2015 - Complete Phase 5 portion of the Romfield Subdivision Rehabilitation project.

Reviewed By:

POWERSTREAM\riaz.shaikh

Title	Name	Signature	Date

Project Leader	Quan Tran	POWERSTREAM\quan.tran	7/26/2011 12:07:38 PM
Project Sponsor	Doug Fairchild	POWERSTREAM\doug.fairchild	7/26/2011 4:54:52 PM
Department Director	Ted Wojcinski	POWERSTREAM\ted.wojcinski	7/26/2011 4:27:13 PM
Department VP	Shelly Cunningham	POWERSTREAM\shelly.cunningham	7/27/2011 8:29:53 AM
VP Rates & Regulatory	Colin MacDonald	POWERSTREAM\colin.macdonald	8/23/2011 1:18:02 PM
Executive VP	Mark Henderson	POWERSTREAM\mark.henderson	8/23/2011 1:22:59 PM
Executive VP & CFO	John Glicksman		11/16/2010 10:09:45 AM
President & CEO			

Additional Attachments

Romfield All.pdf
Adobe Acrobat Document
352 KB

romfield1.pdf
Adobe Acrobat Document
966 KB

romfield2.pdf
Adobe Acrobat Document
907 KB

---

romfield3.pdf
Adobe Acrobat Document
861 KB

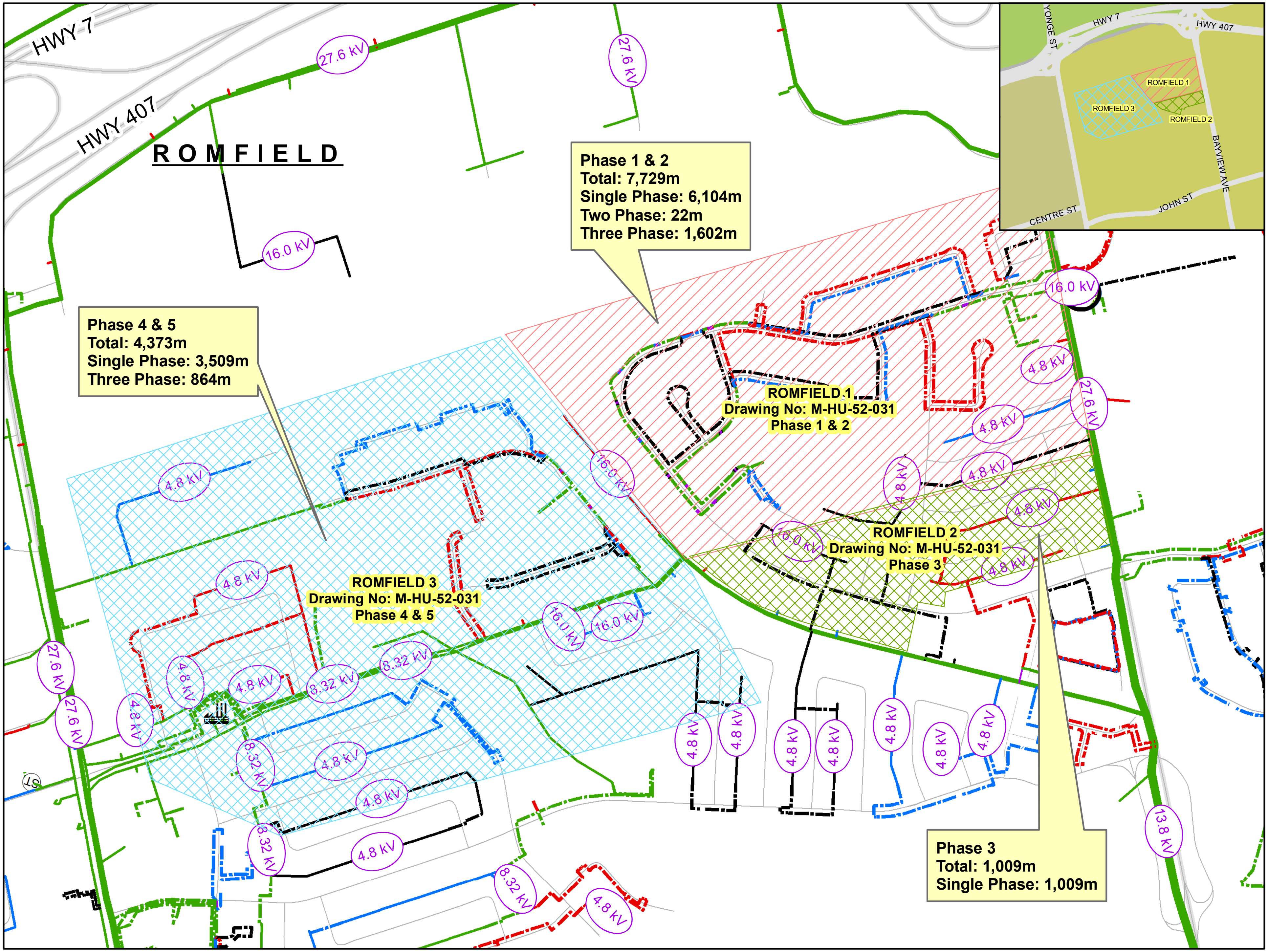
File Attachment

File Attachment

Romfield - Cable Test Report - Summary.pdf
Adobe Acrobat Document
117 KB

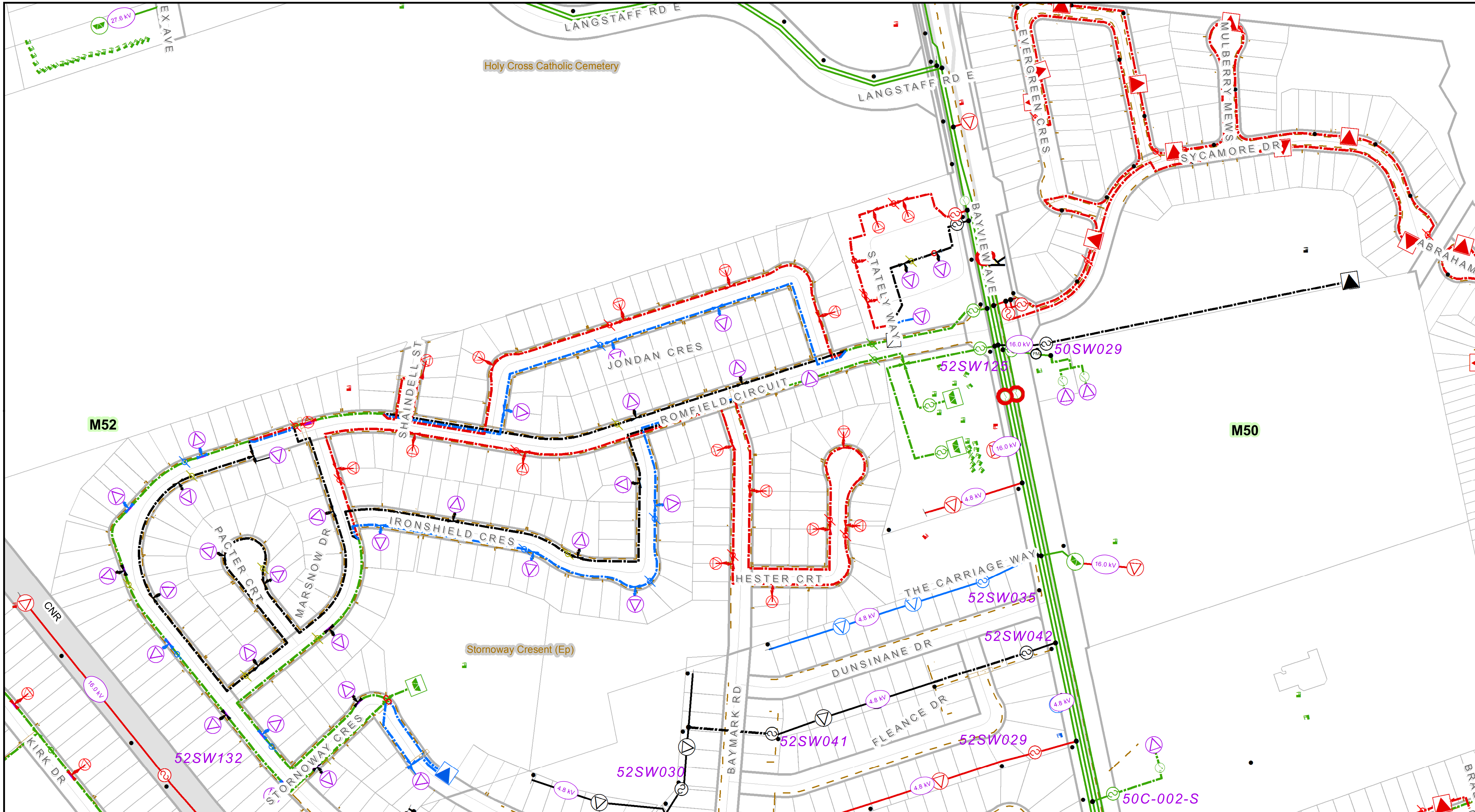
Sign off and approval required by

Department Director, Department VP, VP Rates & Regulatory, EVP, EVP&CFO



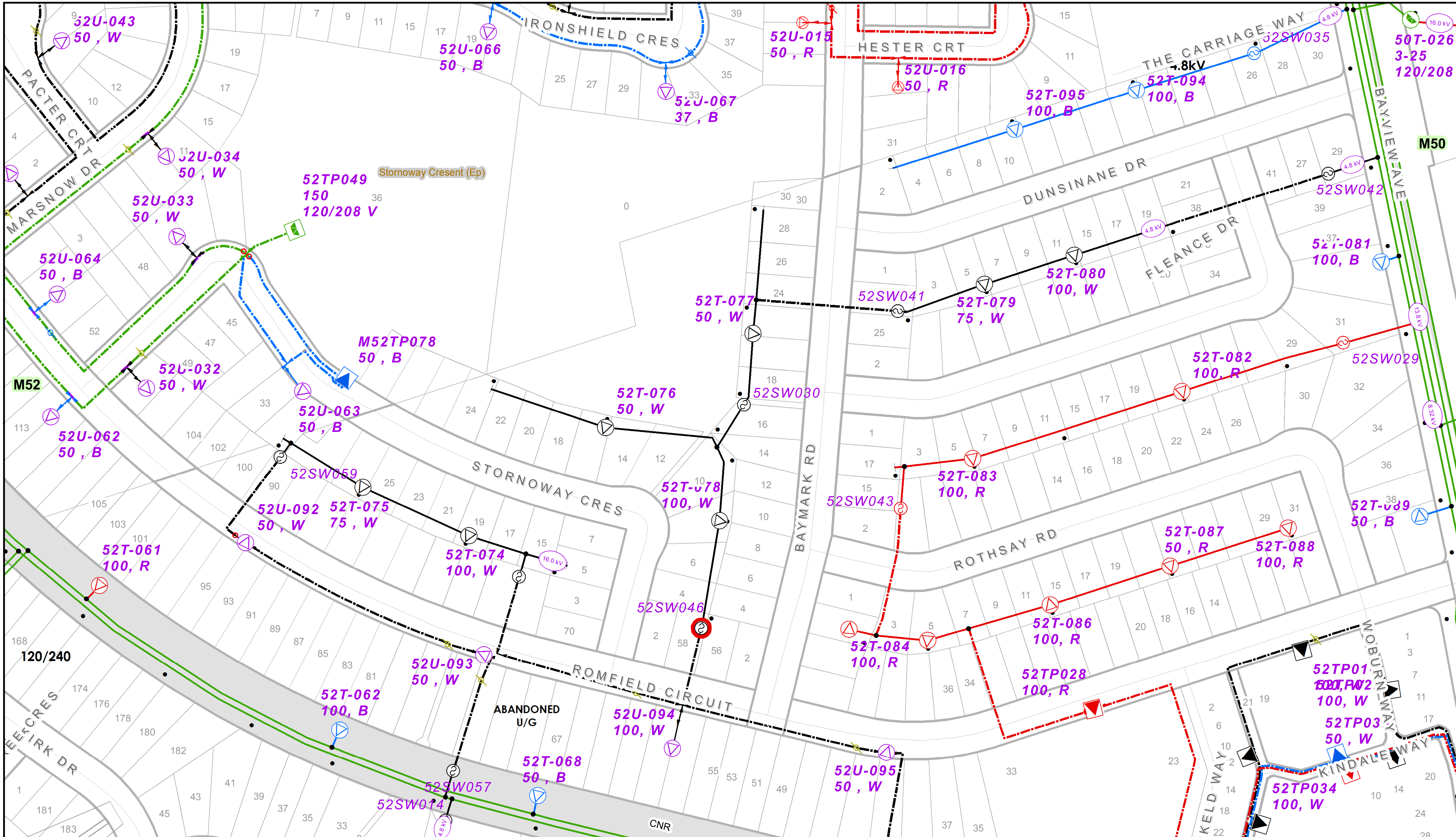
ROMFIELD
HWY 7
HWY 407
Phase 1 & 2
Total: 7,729m
Single Phase: 6,104m
Two Phase: 22m
Three Phase: 1,602m
Phase 4 & 5
Total: 4,373m
Single Phase: 3,509m
Three Phase: 864m
ROMFIELD 1
Drawing No: M-HU-52-031
Phase 1 & 2
ROMFIELD 2
Drawing No: M-HU-52-031
Phase 3
ROMFIELD 3
Drawing No: M-HU-52-031
Phase 4 & 5
Phase 3
Total: 1,009m
Single Phase: 1,009m
27.6 kV
16.0 kV
4.8 kV
8.32 kV
13.8 kV
YONGE ST
HWY 7
HWY 407
ROMFIELD 1
ROMFIELD 3
ROMFIELD 2
BAYVIEW AVE
JOHN ST
CENTRE ST

ROMFIELD 1 - Drawing No: M-HU-52-031 Phase 1, 2



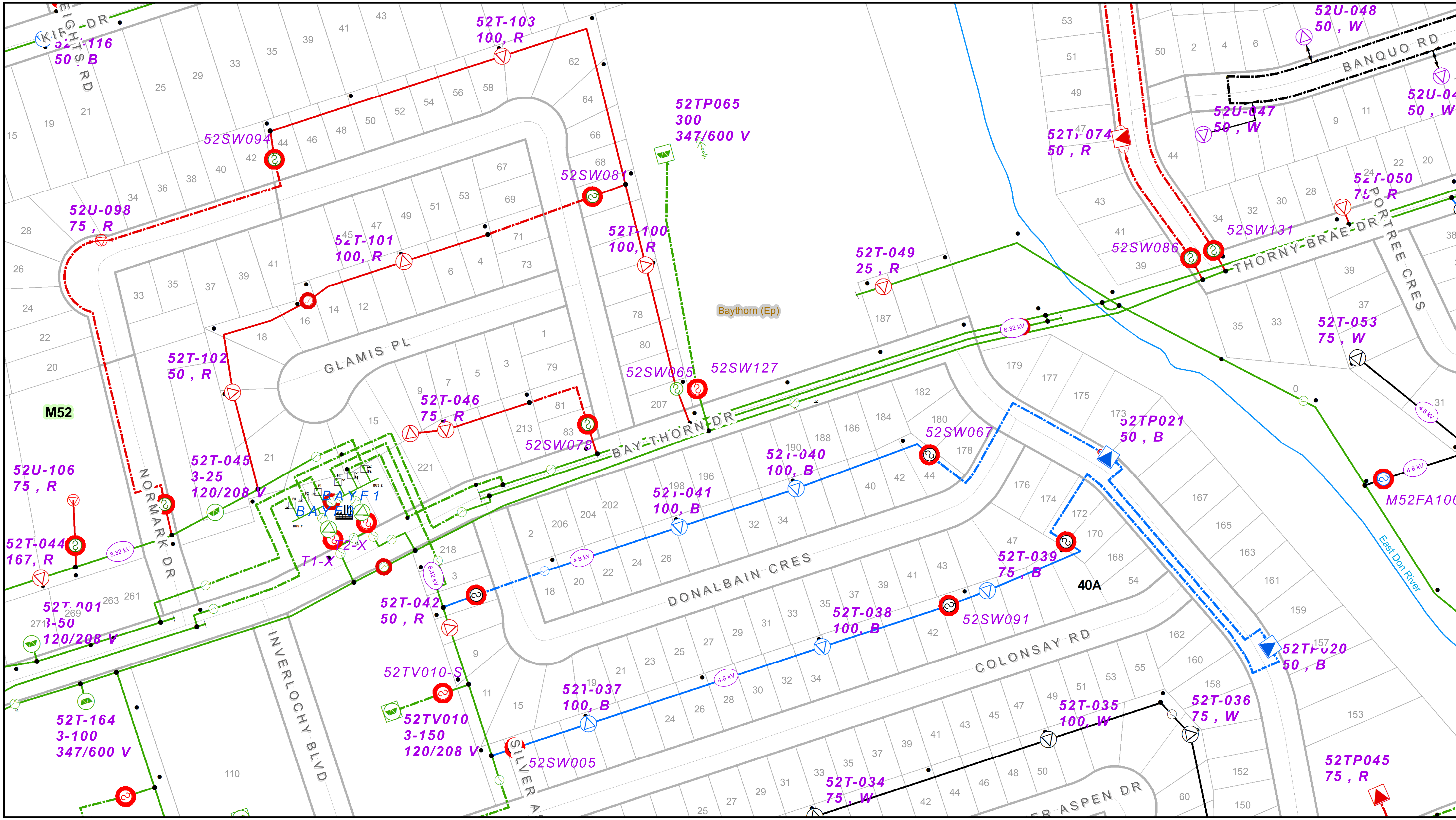
Total: 7,729 m
Single Phase: 6,104 m
Two Phase: 22 m
Three Phase: 1,602 m
January 28, 2010

ROMFIELD 2 - Drawing No: M-HU-52-031 Phase 3



Total: 1,009m
Single Phase: 1,009m
January 28, 2010

ROMFIELD 3 - Drawing No: M-HU-52-031 Phase 4, 5



Total: 4,373 m
Single Phase: 3,509 m
Three Phase: 864 m
January 28, 2010

DTE/Probyn
Energy Solutions

Non-destructive Cable Reliability Tests
Partial Discharge Testing of Underground Cable Systems
December 1999

Markham Hydro

Submitted by: DTE/Probyn Energy Solutions
Head Office (416) 681-9264
Contact: Doug Ryan, Project Manager
(416) 460-5862, anytime

DTE/Probyn Cable Test

Cable testing was carried out by DTE/Probyn Energy Solutions from November 29 through December 23, 1999. During 13 days of on site testing, 458 runs of cable were checked. The total length of cables amounted to 61,354 meters installed between 1965 and 1997.

The Partial Discharge Classifications are as follows:

Level 1	No action to be taken.
Level 2	Consider re testing every 2 years.
Level 3	Low probability of failure in 2 year, consider re testing at 1 year intervals.
Level 4	Medium probability of failure in 2 years, consideration should be given to replacement or other remedial action taken.
Level 5	High probability of failure in 2 years, consideration should be given to replacement.

14% (62 of the 458 cables) tested showed potential discharge of level 4.
46% (212 of 458 cables) tested showed potential discharge of level 3.
40% (184 of 458 cables) tested showed potential discharge of level 2 or lower.

The following are the 62 sites identified as high probability of failure:

1. 52SU14 w-phase cable going to 52SW96
2. 52SU14 cable going to 52U28
3. 52SU14 cable going to 52U100
4. 52U103 cable going to 52U104 (*This cable has subsequently failed)
5. 52U9 cable going to 52U10
6. 52U61 cable going to 52U62
7. 52U35 cable going to 52U36
8. 52SU3 b-phase cable going to 52SW97
9. 52U93 cable going to 52SW57 (*cable adjacent to it has already failed)
10. 52SU15 cable going to 52TP29
11. 52SU15 cable going to 52TP38
12. 52TP60 cable going to 52SW104 (16kV)
13. 52TP56 cable going to 52SW103 (16kV)
14. 52TP56 cable going to 52TP57 (16kV)
15. 52SW11 r-phase cable going to F2 Baythorn (*R-phase arrestor has subsequently failed at this location).
16. 52SW11 w-phase cable going to F2 Baythorn (*W-phase arrestor has subsequently failed at this location).
17. 52SW10 r-phase cable going to F5 Baythorn
18. 52SW10 w-phase cable going to F5 Baythorn
19. 51SW24 w-phase cable going to T2 Morgan (16kV)
20. 51SW75 cable going to 51U45

21. 43TV24 r-phase cable to 43SU23
22. 43TV24 w-phase cable to 43SU23
23. 43TV24 b-phase cable to 43SU23
24. 43SUG1 b-phase cable going to 43TV20
25. 43SUG1 b-phase cable going to 43SW12
26. 43TV17 b-phase cable going to 43TV18
27. 43TV18 b-phase cable going to 43TV19
28. 43TV15 w-phase cable going to 43TV16
29. 43TV15 b-phase cable going to 43SU26
30. 43TV15 w-phase cable going to 43SU26
31. 43SU24 r-phase cable going to 43SW30
32. 43SU24 w-phase cable going to 43SW30
33. 43SU24 b-phase cable going to 43SW30
34. 49SU1 cable going to 49TP46
35. 49SU1 b-phase cable going to 49SW47
36. 49SU1 cable going to 49TP64
37. 49SU1 cable going to 49TP57
38. 49SU1 cable going to 49TP52
39. 49SU7 cable going to 49TP65
40. 49SU7 r-phase cable going to 49SW48
41. 49SU7 b-phase cable going to 49SW48
42. 49SU7 w-phase cable going to 49SW48
43. 49SU7 cable going to 49TP72
44. 49SU6 cable going to 49TP80
45. 22M1 r-phase cable going to terminal pole
46. 22M1 b-phase cable going to terminal pole
47. Amber F2 r-phase cable going to terminal pole
48. Amber F2 b-phase cable going to terminal pole
49. Amber F2 w-phase cable going to terminal pole
50. 49SD3 b-phase cable going to 49SD2
51. John F5 b-phase cable going to terminal pole
52. John F6 r-phase cable going to terminal pole
53. John F6 b-phase cable going to terminal pole
54. John F6 w-phase cable going to terminal pole
55. 24M1 r-phase cable going to terminal pole
56. 24M1 b-phase cable going to terminal pole
57. 24M1 w-phase cable going to terminal pole
58. 24M2 b-phase cable going to terminal pole
59. 24M3 r-phase cable going to terminal pole
60. 24M3 b-phase cable going to terminal pole
61. 24M3 w-phase cable going to terminal pole
62. 24M4 b-phase cable going to terminal pole

CCC #15 - Attachment 4 (BC250)

Business Case

Project Title:	Emerging Cable Replacement Projects
Location:	PowerStream North and South
Capital Budget Year:	2013
Project Lead:	Riaz Shaikh
Submission Date:	9/2/2011
Net Capital Amount:	2,000,000
Annual OM&A Expense (if applicable):	
Controllable Expenditure:	☐ Yes ☑ No
Planned Project:	No
Project ID:	100755

Objective:

Describe the reason why you are undertaking this project.

Cable and splice failures are the leading cause of outages in the Defective Equipment Category. This project will improve reliability of supply and service to customers at various locations throughout PowerStream by replacing primary cable candidates which present significant reliability and operation challenges identified as a result of outages or cable condition.

Background:

Describe the current situation and conditions in detail.

PowerStream has approx. 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

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

Currently we have planned Cable replacement projects for North and South which targets particular subdivisions based on age/outage information. These planned projects are identified and submitted for capital funding during the budget approval cycle.

In some cases cable not identified for replacement in a particular budget year begins to fail to the point where repair is no longer a viable or reliable option and security of customer supply is put at high risk. At this point the cable needs to be replaced immediately and is treated as an emerging project. The projects submitted under this category will be evaluated by Planning in conjunction with System Control, Lines and Customer Services.

Cable and splice failures amount to over 50% of the outages caused within the failed Equipment category (Code 5 Outages) for year 2007-2011. The average contribution to SAIDI for (2007-2011) due to Cable and Splice Failures is 8.3 minutes.

As the cable system gets older we expect that the rate of cable failures will increase and that cabling in some of the residential or industrial sub divisions will have to be addressed in emergency as opposed to planned replacement. For example, in the year 2011 over expenditure requests were submitted for emergency cable replacement totaling to $ 1.1 million which is indicated below.

Date	Feeder	Location	Age	Length (m)	Estimated Cost
Feb 11,2011	80M25	Troyer Court,Vaughan	32	320	$133,451
Feb 18,2011	26M11	Juniper Crescent,Markham	32	170	$53,225

March 7,2011	MS402-F1	Letitia street, Barrie	37	100	$83,557
March 10,2011	MS407-F3	Cundle Road, Barrie	37	130	$122,284
April 14,2011	22M5	JV Fry, Markham	unknown	200	$134,728
August 4,2011	10M1	Centurian Drive, Markham	29	500	$400,000
August 11,2011	MS323-F3	Colborne Street, Bradford	unknown	100	$175,000
				1520	**$1,102,245**

Until June 2012, we have issued projects totaling to $1.2 million under Emerging cable replacement.

Alternative One: Status Quo

Describe the status quo.

The status quo is to do nothing, not replace existing cable, and repair cables on failures as they occur. Repairs in this category would likely result in low-reliability service to affected customers. Cable beyond repair would be left de-energized.

Provide details of the cost of the status quo, if applicable.

n/a

*Describe the **health and safety** risk of the status quo.*

Because the cables are at end-of-life, failures may occur which under rare but not improbable circumstances may cause injuries to operations staff and the public.

*Describe the **business excellence** risk to the Status quo.*

Leaving the cable in its deteriorated conditions will cause cable failures and negatively impact PowerStream's effort to achieve operation excellence. Inefficiencies are created when operations staff perform repairs and replacements under emergency situations.

*Describe the **customer satisfaction** risk to the Status quo.*

When the cable is not replaced, rate of failure will likely accelerate resulting in increased customer outages which will have a negative impact to system reliability and customer service. Based on the estimate of 2 failures per year, there would be 3,600 CMI (Customer Minutes of Interruption) in a industrial loop or 21,600 CMI per residential loop.

*Describe **financial risk** of the status quo.*

T
The financial risk calculations are based on the following assumptions and estimates

For industrial location
Number of customers affected in an outage = 10 customers (half loop)
-Customer load affected in an outage = 10 transformers (10 x 315 kW = 3,150 kW) for 3 hours = 3,150 kW x 3 hrs = 9,450 kWh
-Customer Interruption Cost (Frequency): $20.00/kW (Commercial & Industrial)
-Customer Interruption Cost (Duration): $30.00/kWh (Commercial & Industrial)
-Delivery Charge, etc. for loss of revenue calculation: $0.02/kWh
-Emergency Response/Repair Cost: $10,000/event

Cost to PowerStream:
•Emergency Replacement Cost = $10,000 x 2 failures/year = $20,000 per year
•Loss of Revenue Cost (Delivery Charge, etc.) = 3,150 kW x 3 hrs x $0.02/kWh x 2 failures/year = $ 378
•Total Cost to PowerStream = $20,000 + $378 = $20,378

Cost to Customers:
•Customer Interruption Cost (Frequency) = 3,150 kW x $20/kW x 2 failures/year = $ 126,000
•Customer Interruption Cost (Duration) = 9,450 kW x $30/kWh x 2 failures/year = $ 567,000
•Total Cost to Customers (Interruption) = $126,000 + $567,000 = $ 693,000

Total Risk Cost = $20,378 (PowerStream) + $ 693,000 (Customers) = 713,378

For residential customers:
- Frequency of interruption: 2 failures/year
- Duration of interruption: 3 hours
- Number of transformers: 12 transformers
- Number of customers in the loop: 120 customers
- Number of customers affected in an outage: 120/2 = 60 customers (half loop)
- Customer load: 120 customers x 3 kW = 360 kW
- Customer load affected in an outage: 360 kW/2 = 180 kW (half loop)
- Customer Interruption Cost (Frequency): $2.00/kW (Residential)
- Customer Interruption Cost (Duration): $4.00/kWh (Residential)
- Emergency Response/Repair Cost: $10,000/event
- Delivery Charge, etc. for loss of revenue calculation: $0.02/kWh

The financial risk cost is estimated as follows:
Cost to PowerStream:
- Emergency Response/Repair Cost = $10,000 x 2 failures/year = $20,000
- Loss of Revenue Cost (Delivery Charge, etc.) = 180 kW x 3 hrs x $0.02/kWh x 2 failures/year = $22
Total Cost to PowerStream = $20,000 + $22 = $20,022

Cost to Customers:
- Customer Interruption Cost (Frequency) = 180 kW x $2/kW x 2 failures/year = $720
- Customer Interruption Cost (Duration) = 180 kW x 3 hrs x $4/kWh x 2 failures/year= $4,320
Total Cost to Customers (Interruption) = $720 + $4,320 = $5,040

Total Risk Cost per half loop = $20,022 (PowerStream) + $5,040 (Customers) = $25,062

*Describe the **environmental risk** of the status quo.*

Alternative 2 :

Replace cable at identified locations as verified through the emerging cable replacement process

Describe the alternative.

Replace the identified cable sections in either residential or industrial subdivisions

Provide details of the cost of this alternative.

Cost = 2,000,000. For replacing total of 4 Km of residential subdivision or 2 km of 3 Phase cable in an Industrial subdivision (6 km Total Circuit Length).

Recommended Alternative:

2

Describe the recommended alternative.

Replace the cables

Why did you choose the recommended alternative?

he recommended alternative was chosen for the following reasons;

1. Resolves the operations and safety concerns.
2. Improves reliability of supply and customer satisfaction.
3. Replace assets that are at end-of-life.

Is this project dependent on any other project(s)? Identify Project ID(s).

What is the ***health and safety*** *value of the recommended alternative to the organization?*

Deteriorated cables are replaced with new cables, eliminating cable failures and any potential risk of injuries for staff and the public.

What is the ***business excellence*** *value of the recommended alternative to the organization?*

Improve reliability within the subdivision. Improve efficiency because operations staff will perform fewer repairs and replacements under emergency situations.

What is the ***customer satisfaction*** *value of the recommended alternative to the organization?*

Replacement deteriorated cables will result in more reliable service to customers.

For industrial location:

CMI (Customer Minutes of Interruption):
Based on the estimate of 2 failures per year and 10 customers affected, a reduction of 3600 CMI can be achieved.
The CMI is estimated as follows:
CMI = (10 customers x 3 hours) x 60 minutes x 2 failures/year = 3600 per half loop for industrial location.

For residential location:

Based on the estimate of 2 failures per year and 60 customers affected (half of 120 customers), a reduction of 21,600 CMI (Customer Minutes of Interruption) can be achieved. The CMI is estimated as follows:
CMI per subdivision = 60 customers x 3 hours x 60 minutes x 2 failures/year = 21,600 CMI per half loop.

*What is the **financial** value of the recommended alternative to the organization?*

For Industrial location:

Customer outages will be reduced, resulting in a saving of customer interruption cost, equipment repair cost, and revenue loss cost, totaling $713,453 per year, of which $20,378 is attributed to PowerStream cost, and $693,000 is attributed to Customer Interruption cost (per half loop).

For residential location:

Customer outages will be reduced, resulting in a saving of customer interruption cost, equipment repair cost, and revenue loss cost, totaling $25,062 per year, of which $20,025 is attributed to PowerStream cost, and $5,040 is attributed to Customer Interruption cost (per half loop).

*What is the **environmental** value of the recommended alternative to the organization?*

Reducing cable failures will have positive impacts on the environment. Fewer trouble response and repair will reduce vehicle emission. Fewer cable repair will reduce disruption to land (e.g. digging up the boulevard to expose the faulted direct buried cable).

Implementation Timeline:

Provide planned timelines for project completion.

2013

Reviewed By:

POWERSTREAM\riaz.shaikh

Title	Name	Signature	Date
Project Leader	Riaz Shaikh	POWERSTREAM\riaz.shaikh	9/2/2011 3:59:41 PM

Project Sponsor			
Department Director	Ted Wojcinski	POWERSTREAM\ted.wojcinski	9/6/2011 10:57:54 AM
Department VP			
VP Rates & Regulatory		POWERSTREAM\colin.macdonald	9/6/2011 11:26:08 AM
Executive VP	Mark Henderson	POWERSTREAM\mark.henderson	9/6/2011 11:32:58 AM
Executive VP & CFO	John Glicksman	POWERSTREAM\john.glicksman	9/6/2011 3:24:06 PM
President & CEO			

Additional Attachments

File Attachment

Sign off and approval required by

CCC #15 - Attachment 2 (BC234)

Business Case

Project Title:	Cable Injection Program (ACA) - North
Location:	Locations TBD
Capital Budget Year:	2013
Project Lead:	Quan Tran
Submission Date:	7/27/2011
Net Capital Amount:	788,885
Annual OM&A Expense (if applicable):	0
Controllable Expenditure:	☑ Yes ☐ No
Planned Project:	Yes
Project ID:	100374

Objective:

Describe the reason why you are undertaking this project.

To improve reliability of supply and customer service at various locations throughout the PowerStream North by completing cable injection on primary cable. It is recommended to inject 11,200 m of cable in 2013.

Background:

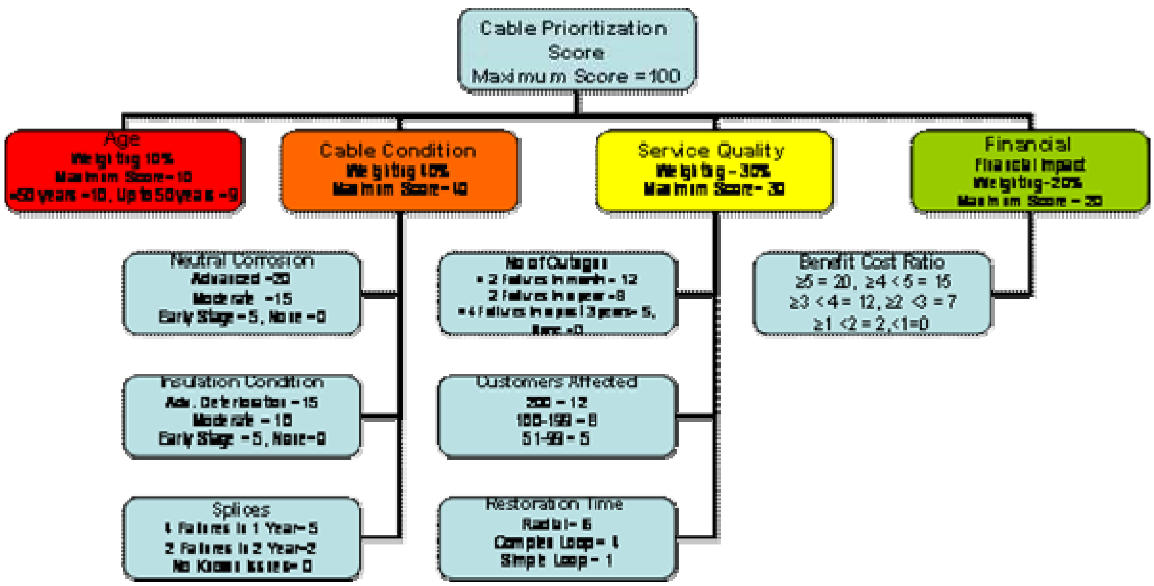
Describe the current situation and conditions in detail.

PowerStream's Underground Cable Replacement and Cable Injection Prioritization Methodology

PowerStream's approach to manage the cable population is summarized below:

- 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 20 years initially and continue at the similar rate afterward
- The cable injection program will last for 10 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.

Underground Cable Replacement

PowerStream has approx. 7,957 km of underground primary cable length, the vast majority of which is direct buried and the rest is in duct.

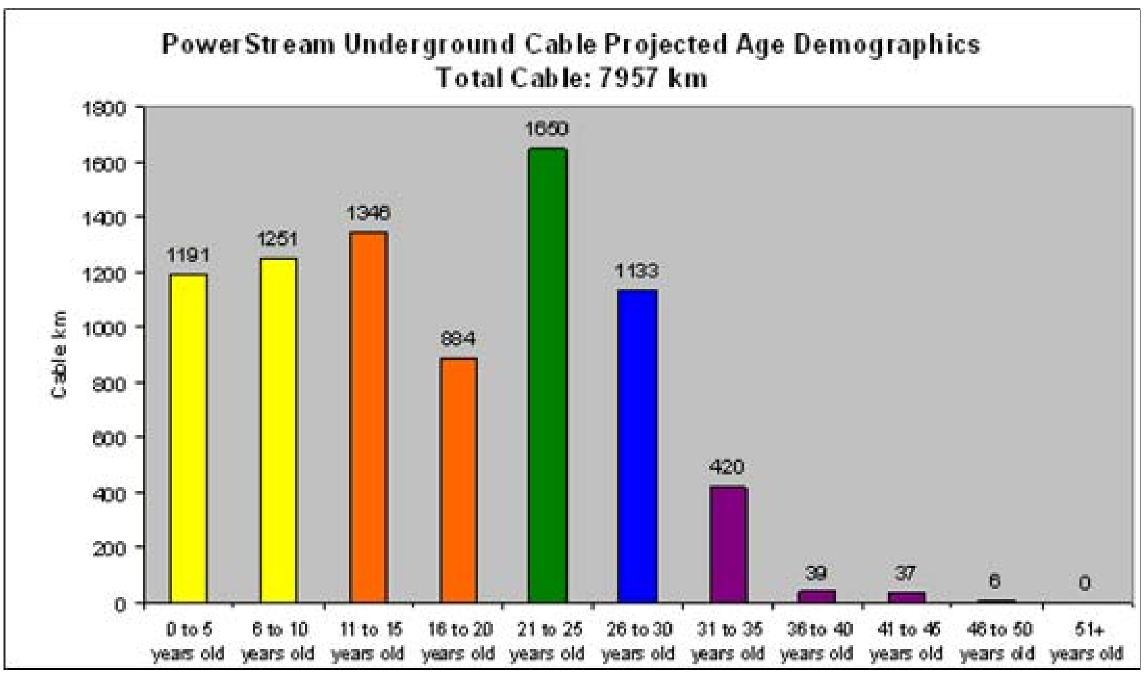
According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**, the useful lives of various types of underground cable are listed below.

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 35 years is used for pre-1987 cable and a useful life of 45 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.
The current 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 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 conducting field trial 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.

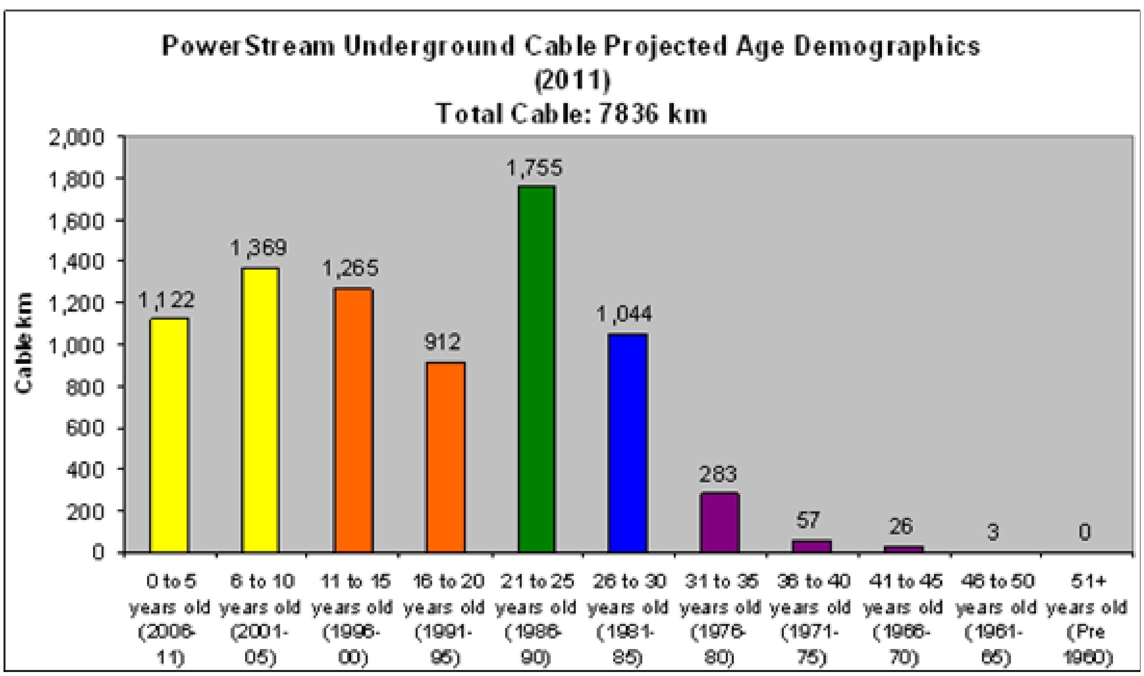
PowerStream will address its Underground Cable assets by using a combination of Cable Replacement and Cable Injection as means of intervention. The Cable Replacement plan (discussed later in this Section) will be ongoing as we will continually need to replace cable as it gets older. This report will cover the first 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 (discussed in the next Section - Cable Injection) will take place over a period of 10 years. After 10 years all suitable candidates for injection will be exhausted, therefore this plan will not be ongoing.

20-Year Cable Replacement Plan:

In 2011, a general plan to address the cable issue (a 20 year plan for cable replacement, and a 10 year plan for cable injection) was developed and approved by PowerStream management. To develop the cable plan, the 2011 cable age demographics was used to divide the cable population into the following 5 groups:

- Group 1: 31 years and older (1980 and older)
- Group 2: Between 26 – 30 years (1981-1985)
- Group 3: Between 21 – 25 years (1986 – 1990)
- Group 4: Between 11 – 20 years (1991 – 2000)
- Group 5: Between 1 – 10 years (2001 and younger)

The 2011 cable age demographics and age groups are described below.



Group 1: 31 years and older (1980 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 (1981 – 1985):
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 (1986 – 1990):
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 (1991 – 2000):
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 (2001 and younger):
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.

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 47 km per year from 2013 – 2031

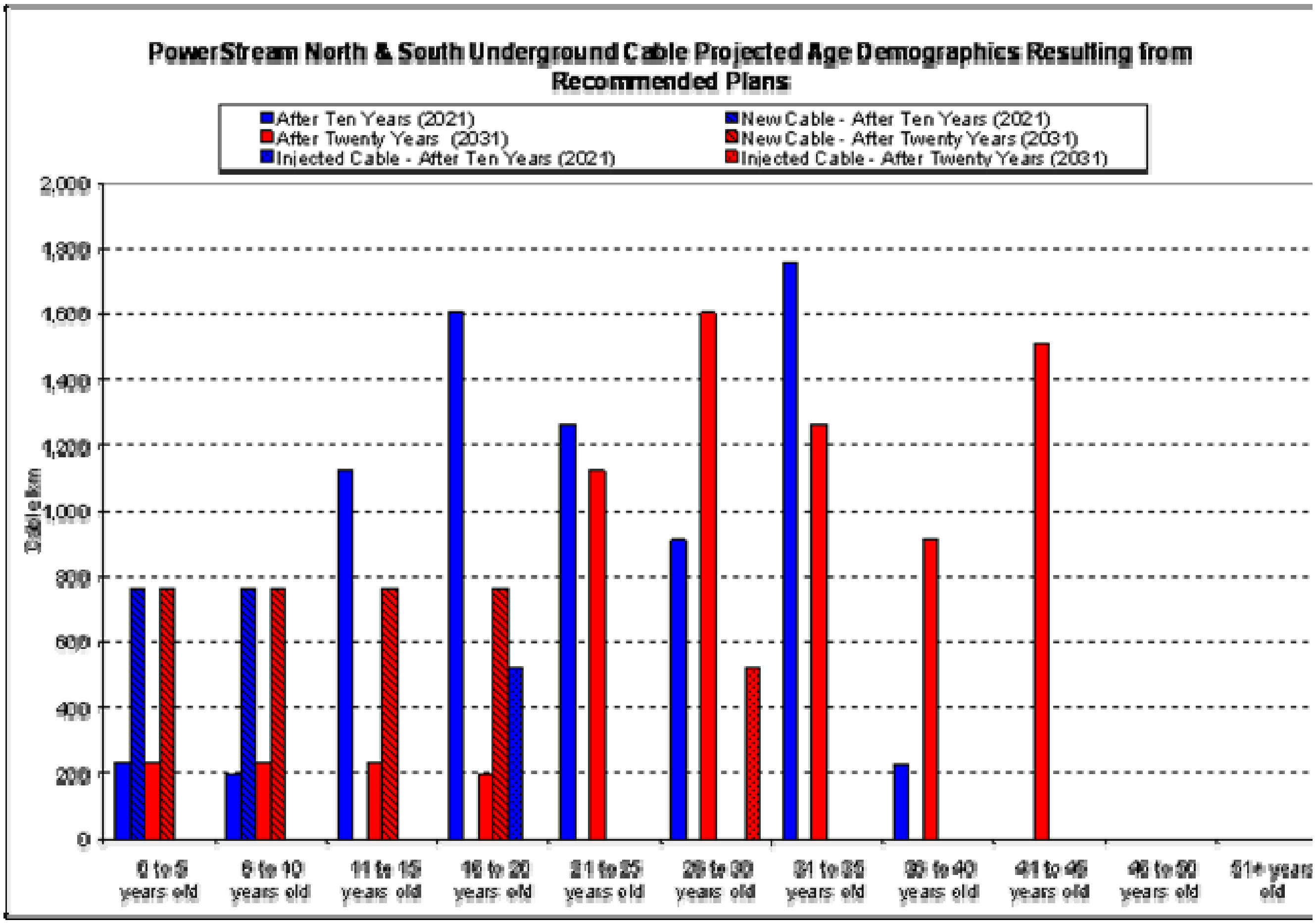
At this rate, all of the 892 km will have been replaced by 2032.
Currently, PowerStream does not have sufficient physical condition and test data to determine the degree of deterioration and to estimate the remaining life of the cable population.

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.



Based on the above chart, after 20 years PowerStream will have 1,745km 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.

Cost of Cable Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2013	2014	2015	2016	2017	5 Yr. Total
2.1	Cable Replacement	$17,399,485	$18,695,752	$17,885,044	$15,519,644	$15,543,026	$85,042,95

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 (approx. 26 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 (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.
In 2011 PowerStream completed 2 cable injection projects using two different contractors.
In 2012 PowerStream will proceed with 2 cable injection projects to continue to gain experience.

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 gaining experience 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 57 km per year 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.

Cost of Cable Injection

PowerStream - Capital Work Plan from Planning and Stations							
Category		2013	2014	2015	2016	2017	5 Yr. Total
2.2	Cable Injection	$4,060,942	$4,074,566	$4,088,187	$4,101,812	$4,115,437	$20,440,94

Alternative One: Status Quo

Describe the status quo.

The status quo is to do nothing, not inject the cable candidates, allowing the cable to run to failure, and respond to outages under emergency.

Provide details of the cost of the status quo, if applicable.

N/A

*Describe the **health and safety** risk of the status quo.*

Cable failures may occur which under rare but not improbable circumstances may cause injuries to operations staff and the public.

*Describe the **business excellence** risk to the Status quo.*

Performing the Injection process on underground primary cable is significantly less expensive than replacing it. Any cable that is not injected in this year will be added to the replacement list and may greatly increase the amount of Capital required to maintain the stability of the underground system. Inefficiencies are created when operations staff perform repairs and replacements under emergency situations.

*Describe the **customer satisfaction** risk to the Status quo.*

When old deteriorated cable is not injected or replaced, failures will occur resulting in customer outages which will have a negative impact to system reliability and customer service. Based on the estimate of 2 failures per year per subdivision, there would be 21,600 CMI (Customer Minutes of Interruption) per subdivision of 4,000 m cable, or 60,480 CMI for 11,200 m cable.

*Describe **financial risk** of the status quo.*

The financial risk calculations are based on the following assumptions and estimates (per 4,000 m of cable or 1 subdivision):
- Frequency of interruption: 2 failures/year
- Duration of interruption: 3 hours
- Number of transformers: 12 transformers
- Number of customers in the loop: 120 customers
- Number of customers affected in an outage: 120/2 = 60 customers (half loop)
- Customer load: 120 customers x 3 kW = 360 kW
- Customer load affected in an outage: 360 kW/2 = 180 kW (half loop)
- Customer Interruption Cost (Frequency): $2.00/kW (Residential)
- Customer Interruption Cost (Duration): $4.00/kWh (Residential)
- Emergency Response/Repair Cost: $10,000/event
- Delivery Charge, etc. for loss of revenue calculation: $0.024/kWh

The financial risk cost is estimated as follows:
Cost to PowerStream:
- Emergency Response/Repair Cost = $10,000 x 2 failures/year = $20,000
- Loss of Revenue Cost (Delivery Charge, etc.) = 180 kW x 3 hrs x $0.024/kWh x 2 failures/year = $26
Total Cost to PowerStream = $20,000 + $26 = $20,026

Cost to Customers:
- Customer Interruption Cost (Frequency) = 180 kW x $2/kW x 2 failures/year = $720
- Customer Interruption Cost (Duration) = 180 kW x 3 hrs x $4/kWh x 2 failures/year= $4,320
Total Cost to Customers (Interruption) = $720 + $4,320 = $5,040

Total Risk Cost per subdivision = $20,026 (PowerStream) + $5,040 (Customers) = $25,066

Total Risk Cost for 11,200 m of cable length is:
$20,026 x 11,200/4000 (PowerStream) + $5,040 x 11,200/4000 (Customers) = $56,073 (PowerStream) + $14,112 (Customers) = $70,185

*Describe the **environmental risk** of the status quo.*

Increased risk of cable failures which will have negative impacts on the environment. Trouble response and repair will be required, increasing vehicle emissions and disruption to land (e.g. digging up the boulevard to expose the faulted direct buried cable).

Alternative 2 :

Inject cable at various locations over a period of 10 years

Describe the alternative.

Perform the cable injection process at various locations in PowerStream Territory over a period of 10 years. Starting with 8 km in 2012 then 57 km (including 11.2 km in the North and 45.8 km in the South) per year for 2013 - 2022. The details are outlined in the proposed 10 year plan below:

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, of which approx. 4 km is in PowerStream North)
- Inject 57 km per year from 2013 – 2022, of which approx. 11.2 km is in PowerStream North and 45.8 km is in PowerStream South.

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.

Provide details of the cost of this alternative.

$788,885
See Project 100374 Budget Form for details.

Recommended Alternative:

Alternative 2: Inject cable at various locations over a period of 10 years

Describe the recommended alternative.

Perform the cable injection at various locations in PowerStream over a period of 10 years. Starting with 8 km in 2012 then 57 km (including 11.2 km in the North and 45.8 km in the South) per year from 2013 - 2022. Details are outlined in the proposed 10 year plan below:

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, of which approx. 4 km is in PowerStream South)
- Inject 57 km per year from 2013 – 2022, of which approx. 11.2 km is in PowerStream North and 45.8 km is in PowerStream South.

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.

Why did you choose the recommended alternative?

The recommended alternative was chosen for the following reasons:
1. Resolves the operations and safety concerns.
2. Improves reliability of supply and customer satisfaction.
3. Rejuvenates assets that are deteriorated.

Is this project dependent on any other project(s)? Identify Project ID(s).

This project is dependent on one other project:
- Project ID 100406: Cable Injection Program (ACA) - Locations TBD, DESIGN ONLY - North

*What is the **health and safety** value of the recommended alternative to the organization?*

Old cables are rejuvenated, resulting in fewer cable failures and reduction in the risk of injuries for staff and the public.

*What is the **business excellence** value of the recommended alternative to the organization?*

Performing the Injection process on underground primary cable is significantly less expensive than replacing it. Any cable that is not injected in this year will be added to the replacement list and may greatly increase the amount of Capital required to maintain the reliability of the underground system.
Improve reliability within the subdivision. Improve efficiency because operations staff will perform fewer repairs and replacements under emergency situations.

*What is the **customer satisfaction** value of the recommended alternative to the organization?*

Cable injection will extend the life of old cables, which will result in more reliable service to customers. Based on the estimate of 2 failures per year and 60 customers affected (half of 120 customers in a loop), a reduction of 21,600 CMI (Customer Minutes of Interruption) can be achieved. The CMI is estimated as follows:
CMI per subdivision = 60 customers x 3 hours x 60 minutes x 2 failures/year = 21,600 CMI
CMI for 11.2 km of cable length = 21,600 x (11,200/4000) = 60,480 CMI

*What is the **financial** value of the recommended alternative to the organization?*

Customer outages will be reduced, resulting in a saving of customer interruption cost, equipment repair cost, and revenue loss cost, totaling $25,066 per year, of which $20,026 is attributed to PowerStream cost, and $5,040 is attributed to Customer Interruption cost (per subdivision).
Financial value for 11,200 m of cable length is: $56,073 (PowerStream) + $14,112 (Customers) = $70,185

*What is the **environmental** value of the recommended alternative to the organization?*

Reducing cable failures will have positive impacts on the environment. Fewer trouble response and repair will reduce vehicle emission. Fewer cable repair will reduce disruption to land (e.g. digging up the boulevard to expose the faulted direct buried cable).

Implementation Timeline:

Provide planned timelines for project completion.

2012 - Complete Cable injection projects approx. 8 km at various locations.
2013 - 2022 - Complete Cable injection projects approx. 57 km per year, of which approx. 11.2 km at various locations in the North and 45.8 km at various locations in the South.

Reviewed By:

POWERSTREAM\riaz.shaikh

Title	Name	Signature	Date
Project Leader	Quan Tran	POWERSTREAM\quan.tran	7/27/2011 2:27:16 PM

Project Sponsor	Doug Fairchild	POWERSTREAM\doug.fairchild	7/28/2011 9:24:24 AM
Department Director	Ted Wojcinski	POWERSTREAM\ted.wojcinski	7/28/2011 2:39:06 PM
Department VP	Shelly Cunningham	POWERSTREAM\shelly.cunningham	8/5/2011 10:38:51 AM
VP Rates & Regulatory	Colin MacDonald	POWERSTREAM\colin.macdonald	8/24/2011 1:28:11 PM
Executive VP	Mark Henderson	POWERSTREAM\mark.henderson	8/24/2011 2:18:58 PM
Executive VP & CFO			
President & CEO			

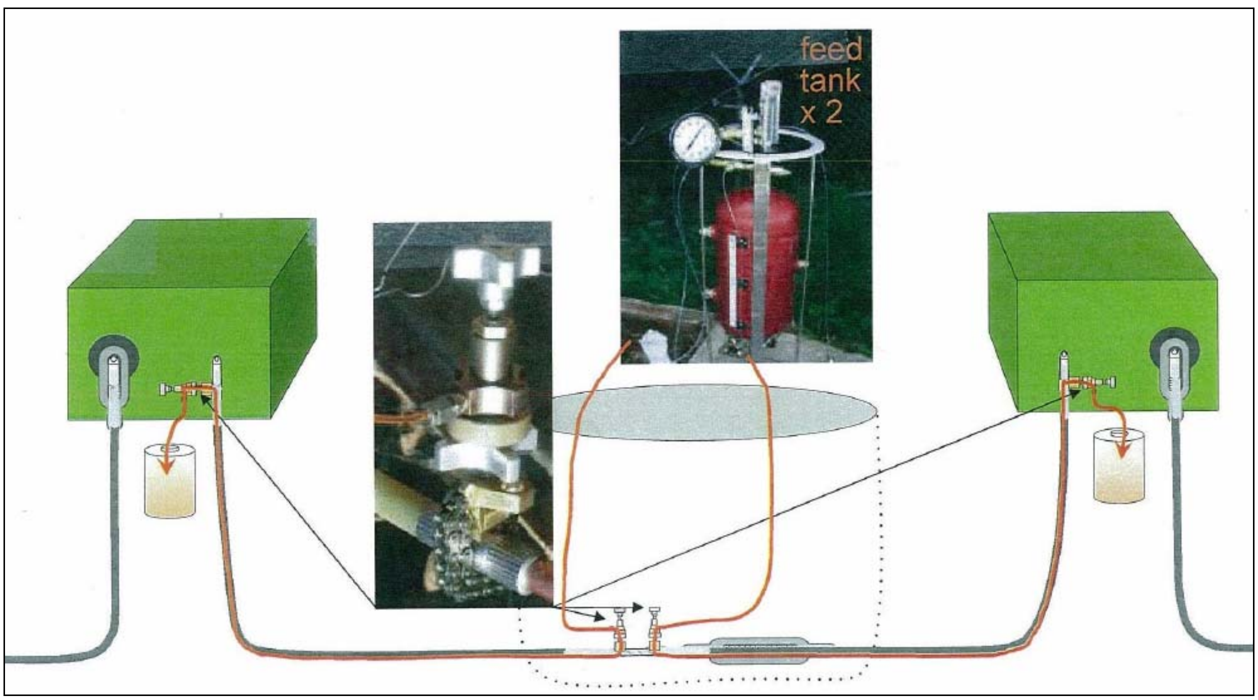
Additional Attachments

Report on Cable Injection Pilot Project _ Nov. 09.pdf
Adobe Acrobat Document
945 KB

Sign off and approval required by

Department Director, Department VP, VP Rates & Regulatory, EVP

PowerStream's Pilot Project on Cable Injection/Rejuvenation



Prepared by:
System Planning
November, 2009

Table of Contents

Summary

Cable injection and cable rejuvenation are two terms commonly used interchangeably to describe the introduction of engineered materials into an aged but still operational cable with the intent of counteracting the effects of cable insulation aging.

Cable injection is the process by which silicone chemicals are injected down the strands of the cable. This chemical fluid diffuses into the insulation, fills the voids, increases the dielectric strength of the cable and thus extends the life of the cable.

Earlier vintages (pre-to-mid1980s) polyethylene cables have experienced a higher than expected failure rate. Water tree growth is the primary aging mechanism of medium voltage cables employing extruded dielectric insulating materials. These cables are a primary candidates for injection.

For injection to be successful there must be a path for the chemical fluid to flow down the cable. This requirement prevents cables with solid core or strand block from being injected. HMWPE (High Molecular Weight Polyethylene), Butyl Rubber, XLPE and TRXLPE all can be successfully rejuvenated. Cable injection extends cable life from 20 to 40 years at 1/3 to ½ of the cable replacement cost.

In 2008, System Planning carried out a detailed assessment of cable injection The results are detailed in the System Planning report titled "*Technical Assessment of Cable Injection*".

The report concluded that cable injection was an economic alternative to cable replacement for earlier vintage (pre-to-mid1980s) polyethylene cables and that PowerStream carry out a Pilot Project to gain experience and determine the actual cost ($/m) of injection.

The subdivision selected for the Pilot Project was " Village in the Valley (Delhi Cres.)" located in Markham near 16th Ave. and Kennedy Rd. It is a residential subdivision consisting of approximately 4,000 meters of 1/0 Al, XLPE, unjacketed, direct buried cable installed in 1982 .

In May 2009 an RFP (*PS-RFP-09-08*) was issued to two qualified contractors namely **Novinium** and **Transelec**. Novinium was the successful contractor based on cost and quality of the injection fluid.

The project was started on September 14th and was completed on September 30th. The work was carried out essentially as planned with the exception of the following:

1) Cable Segment **33TP96 X 33TP97** (Red-Phase, 181m) was found to have four splices. It was decided that this segment should be replaced and not injected. In general if a segment has more than two splices it is not economical to inject.

2) One splice was found to be under the edge of the driveway in cable segment **33TP305 X 33TP102 .** The Line staff decided not to dig up the driveway and therefore this segment (**152m**) was not injected.

3) One splice was found to be in the “roadway crossing” in cable segment **33TP101 X 33SW009** (Red-Phase). Consequently the splice was not dug up and the segment (**246m**) was not injected.

The total cable meters injected was 3,350 at a total cost of $143,000.
The resulting cost per meter was **$43 per meter.** The industry (Canada & USA) standard cost ranges between $45 & $70 per mete depending on the number of splices and the utility internal costs.

Based on the results of the Pilot Project, it is recommended that PowerStream continue with cable injection in lieu of cable replacement for earlier vintage (pre-to-mid1980s) polyethylene cables.

1. Introduction

Cable injection and cable rejuvenation are two terms commonly used interchangeably to describe the introduction of engineered materials into an aged but still operational cable with the intent of counteracting the effects of cable insulation aging.

When a cable is injected, the silicone fluid diffuses out of the strands through the relatively porous strand shields and into the insulation. The fluid then polymerizes with water (or moisture) and the small silicone molecule grows up to seven times its original size and fills all existing water trees and voids. This increases the dielectric strength of the cable and thus extends the life of the cable.

2. Purpose of the Document

The purpose of this document is to:

- Review the Pilot Project from the point of view of “lessons learned” and total cost of cable injection ($/m)
- Based on the findings and experience gained recommend whether to carry on with future cable injection projects.

3. Background

In 2008, System Planning carried out a detailed assessment of cable injection (rejuvenation) including a survey of various utilities both in Canada and USA.
The results are detailed in the System Planning report titled "Technical Assessment of Cable Injection" .

The report concluded that cable injection was an economic alternative to cable replacement for earlier vintage (pre-to-mid1980s) polyethylene cables that have experienced a higher than expected failure rate primarily due to water treeing.
and that PowerStream carry out a Pilot Project to gain experience and determine the actual cost ($/m) of injection.

In May 2009 an RFP (*PS-RFP-09-08*) was issued to two qualified contractors namely **Novinium** and **Transelec**. Novinium was the successful contractor based on cost and quality of the injection fluid. A summary of the Bid Evaluation is shown in **Appendix A .**

Warrantee Offered by the Two Contractors

Transelec (UtilX - CableCure) offers a 20 year warranty.

NOVINIUM offers a 40 year warrantee for Sustained Pressure Process and 20 years for Unsustained Pressure Process

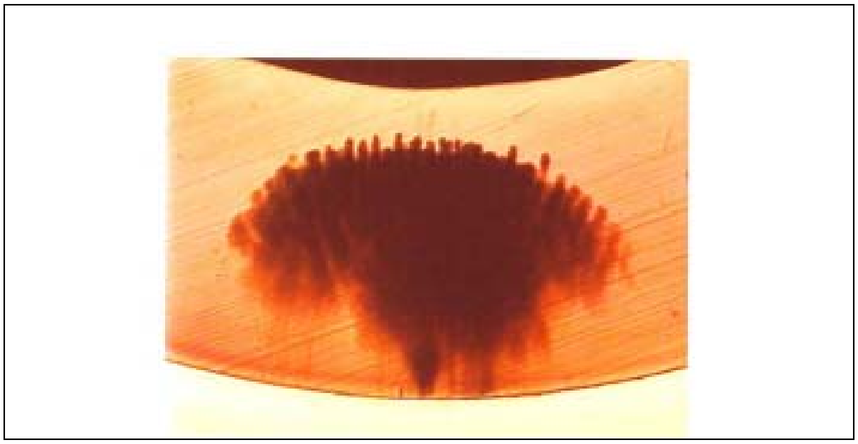
Both warranties provide return of the costs of injection for the failed cable segment.

4. Cable Failure Mechanism

Earlier vintages (pre-to mid1980's) polyethylene cables have experienced a higher than expected failure rate. The degradation of the polyethylene insulation used in most of these cables is by far, the single most important source of cable faults. This premature aging process is caused by a phenomenon known as water treeing. Water tree growth is the primary aging mechanism of medium voltage cables employing extruded dielectric insulating materials.

Water trees start with imperfections (surface irregularities, voids, contaminants, etc.) in the cable insulation. Water trees are named based on their origin. For instance, bow-tie water trees start off as contaminants or imperfections in the insulation. Vented water trees (Figure 1) begin as imperfections on the surface of the insulation.

Figure 1- Example of Vented Water Trees*
(Cable Injection Process, Transelec Common Inc. – Jean Dionne)



Water trees grow in the presence of high AC stress (caused by imperfections) and water. These tree shaped structures are diffuse clouds of microscopic unconnected micro-voids. Water trees are conductive in the presence of water and can be dielectric when dry.

In the initial stage, water trees originate from voids, contaminants and imperfections on the inner and outer surface of the insulation layer. Water trees reduce the AC break down (ACBD) strength of polyethelene-insulated cables. Water trees are influenced by high voltage and water. As water trees grow, the ACBD is reduced. In time the electrical stress exceeds the ACBD and water trees evolve into *electric trees* (Figure 2). This final state of degradation is irreversible and cable failure is imminent. A fault will occur in a short period of time.

Electric trees are micro voids that are the final stage of water trees. They are the consequences of surges, electrical impulses or partial discharge that increase pressure on permeated water trees and alter permanently the insulation. These micro-faults cannot be rejuvenated.

Figure 2 – Electric Trees*
***** (Cable Injection Process, Transelec Common Inc. – Jean Dionne)

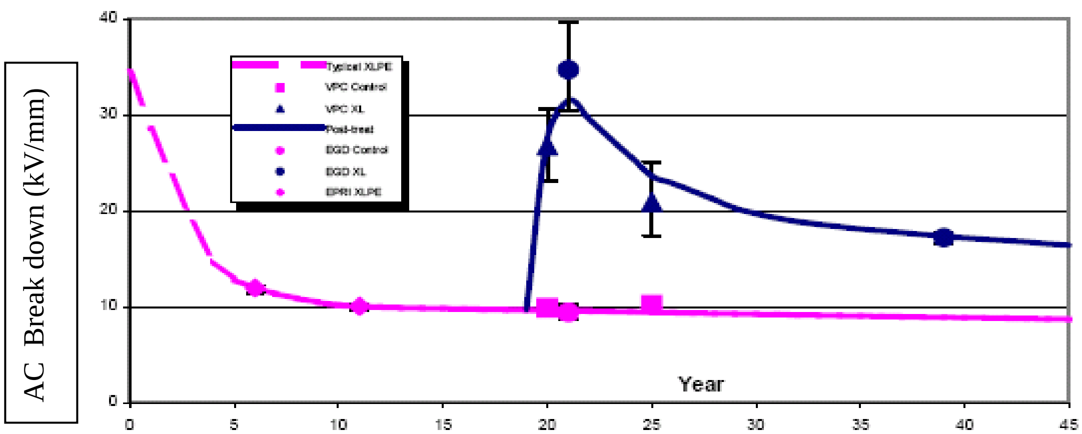
4.1 Pre-1980s Polyethylene Cable Performance

The Electric Power Research Institute (EPRI) has done some work to characterize the reliability of pre-1980 vintage polyethylene cables and the results of that work are summarized in Figure 3. EPRI concluded "the AC breakdown (ACBD) values obtained six to eleven years after installation were at best 1/3 of the level generally regarded as normal for new cable (31.5 kV/mm).

Pre-1980 vintage cables suffer a rapid degradation in AC breakdown performance during the first decade after the cable is installed. The cable then continues to degrade in performance, but at a much slower rate. Figure 3 uses the actual EPRI results and longer-term work done by industry and published in various technical literature.

Figure 3 – Typical performance of pre-1980 vintage PE cables and typical post injection Performance

***(Cable Injection Process, Transelec Common Inc. – Jean Dionne)



5. Cable Rejuvenation Technology

In 1986 silicone injection entered commercial use as a material which when injected into strands of medium and high voltage power cables provided substantial dielectric enhancement and extended cable life.

The silicone fluid must diffuse out of the strands where it is injected through the relatively porous strand shields and into the insulation. The fluid then polymerizes with water and the small silicone molecule grows up to seven times its original size and fills all existing water trees and voids. Movement by diffusion through cable insulation slows by 68,000 times, anchoring cable rejuvenation molecules within insulation. Excess fluid acts as a tree retardant far into the future.

Ultimate performance is realized only after the fluid has had sufficient time to diffuse through the entire width of the insulation. While the time that it takes is dependent upon insulation thickness, the temperature profile of the cable and the amount of water present, peak performance is typically realized about two years after injection is performed.

6. Criteria For Injection

For injection to be successful there must be a path for the chemical fluid to flow down the cable. This requirement prevents cables with solid core or strand block from being injected. The cable industry started using “strand-block” in the late 80’s. Therefore, cables manufactured in the mid 80’s and earlier are good candidates for rejuvenation.

PILC cables do not have a water tree problem, so they are not a candidate for injection. HMWPE (High Molecular Weight Polyethylene), Butyl Rubber, XLPE and TRXLPE all can be successfully rejuvenated.

Another factor to consider for cables with exposed neutrals (unjacketed cable) is neutral corrosion. This can be determined by a non-destructive test (TDR). Generally, if there is an average of 50% of the original neutral remaining, the cable is a candidate for injection. If the neutral corrosion is localized in one portion or segment, it can be locally repaired and then injected.

7. The Injection Process

Both **Novinium** and **Transelec** (Utilx CableCure) generally use a similar process; however, there is a slight variation in their injection steps and procedure.

Procedure used by Novinium

Step 1 - De-energize, test and ground cable with conventional methods. The cable will generally remain grounded for steps 2 - 8 which follow.

Step 2 - Pinpoint all splices, severe cable bends, and neutral corrosion using a high resolution TDR (see Fig. 4 for a typical trace).

Step 3 - Based on results in Step 2, determine if sites identified should be excavated. If not, schedule for replacement. Otherwise, excavate splices, severe bends, and neutral corrosion sites.

Step 4 - Remove and discard all old components including terminations & splices.

Step 5 - Position new compression connectors and injection adaptors.

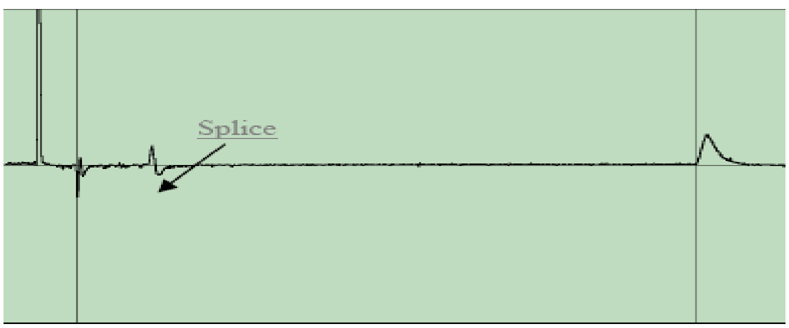
Step 6 - Swage injection adaptors and connectors in a single operation. Compared to standard crimping techniques, this swage provides superior ampacity.

Step 7 - Inject sub-segments at sustained moderate pressure (10-20 psi). Typical lengths and conductors require only a few minutes and are attended. Fluid flows from the feed tank to a rotometer which provides continuous flow measurement. From the rotometer the fluid passes through a ball valve and into the injection tool. The injection tool is mated to the injection adapter and provides leak tight fluid access to the cable.

Step 8 - Complete the installation of Novinium Certified terminations and splices.

Step 9 – Re-energize the cable. Restore any excavations.

Figure 4 – A typical TDR trace locating a splice * (Cable Injection Process, Transelec Common Inc. – Jean Dionne)



8. PowerStream's Pilot Project

8.1 Selection Criteria Used

PowerStream's Pilot Project for Cable Injection was selected based on:

1. **Meet the Criteria for Injection** (as outlined in Section xx)

2. **Operational requests**

a) based on experience from Controllers for assets which limit efficient system operation.

b) **"Cable Failure Analysis Report" by Brosz & Associate.**

(It recommended replacement of the cable based on the number of "water trees" found in the failed cable segment).

3. Field Expert Feedback *(Anecdotal sources) such as field staff, for assets that have* visually or functionally aged (deteriorated) beyond the class visually or functionally aged (deteriorated) beyond the class or unit assessment results of the ACA model.

8.2 Subdivision Selected for Pilot Project

As shown in Appendix B, the subdivision selected for the Pilot Project was " Village in the Valley (Delhi Cres.)" located in Markham near 16th Ave. and Kennedy Rd. It is a residential subdivision consisting of approximately 4,000 meters of 1/0 Al, XLPE, unjacketed, direct buried cable installed in 1982 .

8.3 Injection Process Selected

For any cable injection project there are two Processes available namely;

a) Unsustained Pressure
b) Sustained Pressure

PowerStream selected the "Sustained Process" for the Pilot Project.
There are two major differences between the two Processes, namely injection pressure and time required to complete the injection process.

A detailed comparison of the two processes is shown in Appendix E.

8.4 Project Experience

A Line Crew of two and a supervisor was assigned to the Pilot Project to assist the contractor (Novinium) to carry out the cable injection work. Staff from K-Line and Transpower was also used as required.

The project was started on September 14th and was completed on September 30th. The procedure followed *(9 steps*) is as outlined in Section **xx .**

The work was carried out essentially as planned with the exception of the following:

1) Four splices were found in cable Segment **33TP96 X 33TP97** (Red-Phase). This segment (**181m**) was not injected. In general if a segment has more than two splices it is not economical to inject. It is recommended that this section be replaced.

2) One splice was found to be under the edge of the driveway in cable segment **33TP305 X 33TP102 .** The Line staff decided not to dig up the driveway and therefore this segment (**152m**) was not injected.

3) One splice was found to be in the "roadway crossing" in cable segment **33TP101 X 33SW009** (Red-Phase). Consequently the splice was not dug up and the segment (**246m**) was not injected.

All other splices found were replaced and the cable segments were successfully injected. Segments injected and splice replaced are detailed in Appendix C1 & C2 .

8.5 Customer Complaints

Only one complaint was received within the entire subdivision. One customer objected to the contractor placing "white paint dots" on the apron of his driveway. These dots indicated the location of the splice.

8.6 Project Cost

The total cost of the project including labour and material was **$143,000** of which $29,000 was for internal (labour & material) and $114,000 was for contract forces Including Novinium, K-Line, Transpower & Spring Grove (vacuum truck)

The total cable meters injected was 3,350 (Appendix C2), at a total cost of $143,000, therefore the cost per meter was approximately **$43 per meter.**

According to the contractor (Novinium) the total cost (internal plus external) for injection for both Canada & the USA ranges between **$45 & $70 per meter** depending on the number of splices in the project and the utility's internal costs.

The PowerStream cost of $43/m is therefore slightly below the bottom range of other utilities.

13 Conclusions

The Cable Injection Pilot Project was carried out essentially as planned with the exceptions noted above. There were no issues with the material and equipment used and no issues with the process and procedure used. Both PowerStream staff and the contractor were satisfied with the outcome.

The contractor suggested that in future projects, PowerStream should have a number of "injection elbows" that could be used in areas where it is not economical to dig and replace splices such as outlined above in item's 1) & 2). Novinium will supply the injection elbows at a cost and upon request for particular projects.

If a splice successfully passes a "flow-through" test then an *injection elbow* can be used at the transformer and the cable segment can be injected using the "unsustained" pressure process.

The two cable segments (33TP305 X 33TP102 & 33TP101 X 33SW009) outlined in the previous section [item 2) & 3)] did pass the flow-through test and therefore could have been injected using the "unsustained " pressure process if the injection elbows were available.

Since the injected cable segments have a 40 year warrantee, the injection date and the cable segment identification should be recorded in the GIS primary cable data base. Should a failure occur on any of the injected segment a claim can be made for the failed cable segment. The Operation Staff (control room) should process a warrantee claim.

The project cost of $43 per meter is below industry range of $45 to $70 per meter.

14 Recommendations

Based on the outcome of the Pilot Project, it is recommended that:

a) PowerStream continue with cable injection in lieu of cable replacement for earlier vintage (pre-to-mid 1980's) polyethylene cables.

b) The cable in line segment **33TP96 X 33TP97** (181m) be replaced in 2010

c) The cable in line segment **33TP305 X 33TP102** (152m) and **33TP101 X 33SW009** (246m) be injected using "unsustained " pressure process * .

** (In 2010 Novinium is expected to carry out cable injection for Toronto Hydro. At that time they will notify PowerStream and an arrangement will be made to inject these two sections).*

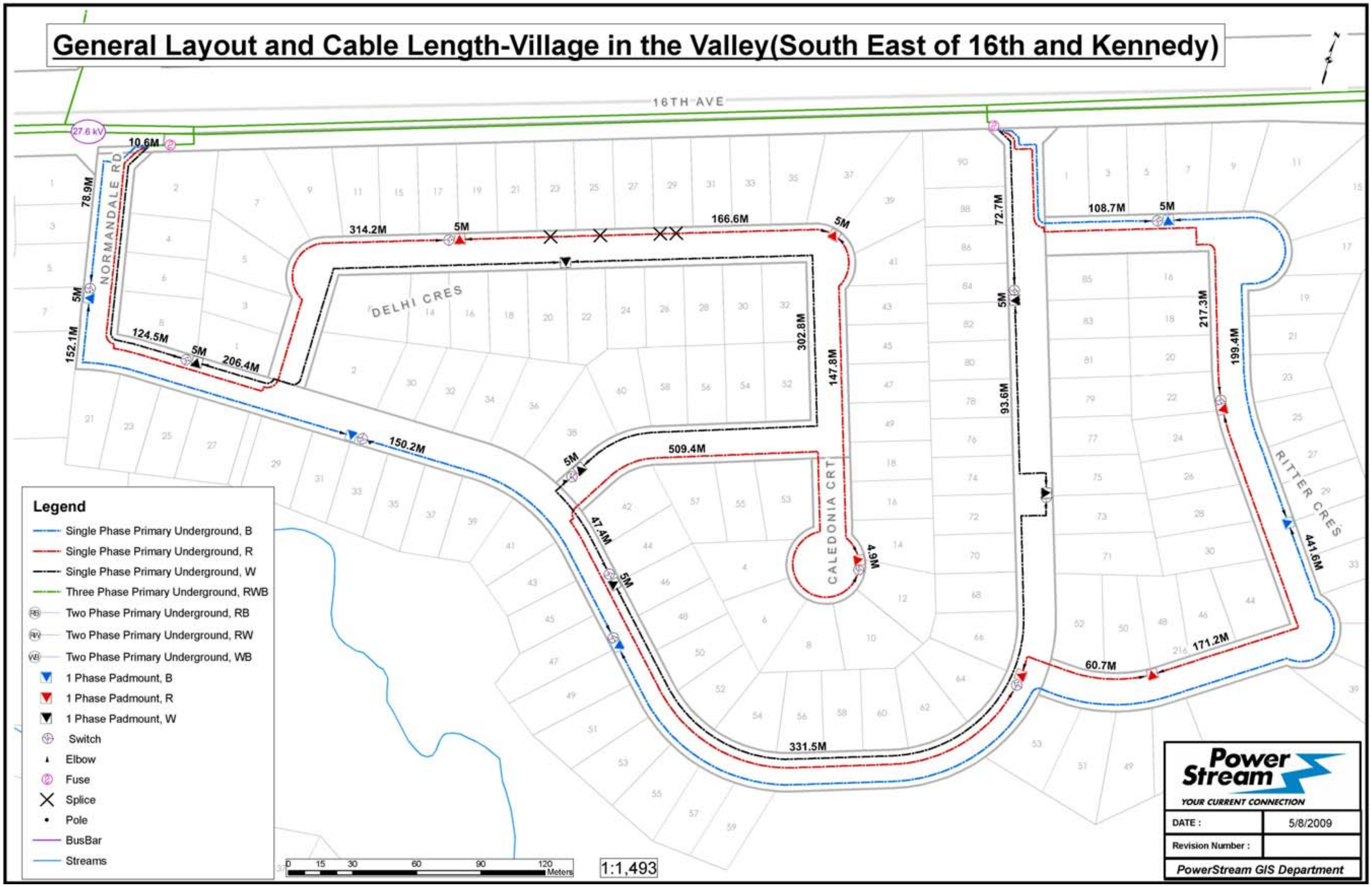
d) The injected cable segments in the subdivision (Village in the Valley (Delhi Cres.) be entered in the GIS primary cable data base with attributes of " *segment ID* " and " *date injected* ".

e) Operation staff (control room) monitor this subdivision for cable faults through the Outage Management System (OMS). Should a cable fault occur in any of the injected segments a claim should be processed by the Operation staff.

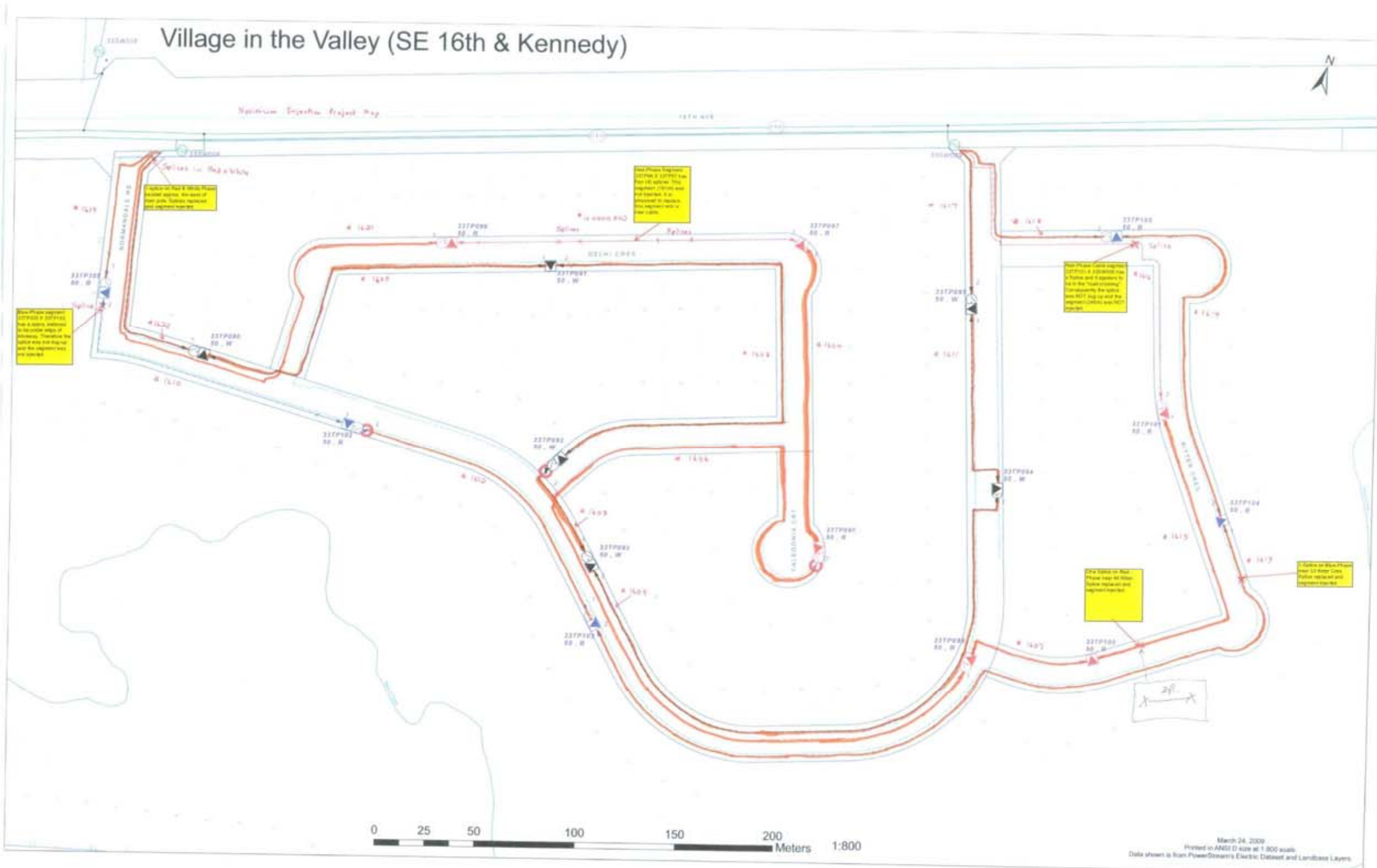
Appendix A – Cable Injection Pilot Project - Bid Evaluation Notes

Cable Injection Pilot Project - Bid Evaluation Notes (Based on 4000m of Cable)			
Item	**Particulars**	**Novinium**	**Transelec**
1	Injection Cost (base bid using "**Perficio 011**" Injection Fluid	$90,160.00	$129,213.75
2	GST (5%)	$4,508.00	$6,460.69
3	PST (8%)	$7,212.80	$7,662.47
4	Total Cost (tax included)	**$101,880.80**	**$143,336.91**
5	Injection Cost (Alternate bid using "**Ultrinium 732**" Injection Fluid	$97,840.00	
6	GST (5%)	$4,892.00	
7	PST (8%)	$7,827.20	
8	Total Cost (tax included)	**$110,559.20**	
	Warranty		
9	For Both Companies Warranty ***applies only to a failed segment (i.e. device-to-device)***		
10	**Novinium:** "Perficio 011" Injection Fluid Using Unsustained Pressure Rejuvenetion (UPR)	20 yrs	
11	**Novinium:**"Perficio 011" Injection Fluid Using Sustained Pressure Rejuvenetion (SPR)	25 yrs	
12	**Novinium:** "Ultrinium 732" Injection Fluid Using Sustained Pressure Rejuvenetion (SPR)	40 yrs	
13	**Transelec**: "CableCURE/XL" Injection Fluid (equivalent to Perficio 011) Using Unsustained Pressure		20 yrs
	EXPLANATION NOTES (some of these notes are from my report (2008) that I compiled on "Cable Injection".		
	1) "Perficio 011" Injection Fluid is comparable to "**CableCURE/X**L" . This is also known as "first generation" fluid.		
	2) Ultrinium 732"- is known as a "second generation" injection fluid introduced by Novinium in 2006. In its website and other published reports, Novinium claims that their chemical fluid (Ultrinium 732) has additional chemicals which provide the rejuvenated cable with stress grading, voltage stabilization, UV stabilization, anti-oxidation, and Partial Discharge (PD) suppression.		
	Process Comparison (Unsustained Pressure vs Sustained Pressure)		
		Unsustained Pressure with Soak	**Sustained Pressure**
	Visits to Site	Three to Four Visits	One Visit
	Soak Tanks	Required for 60-120 days (cable energized)	None Required
	Accessories	Will require special flow-through elbow. May require "flow-through splice" if flow blocked.	Standard Accessories are used. Splice is replaced
	Fluid Contact with Accessories	Accessories soak up fluid. Fluid not compatible with all accessories; may reduce life of accessories..	Fluid does not touch the accessories
	Warranty	20yrs	40yrs
	Pressure Used for Injection	10-20 PSI	100-300 PSI
	Recommendation: Novinium Alternate bid using "Ultrinium 732" Injection Fluid under "Sustained Pressure" is recommended		

Appendix B – Village in the Valley (Delhi Cres.) Subdivision Selected for Pilot Project



Appendix C1 – Village in the Valley (Delhi Cres.), "Cable as Injected by Contractor & Contractor's Notes"



Appendix C2 – Village in the Valley (Delhi Cres.), "Summary of Cable Lengths Injected"

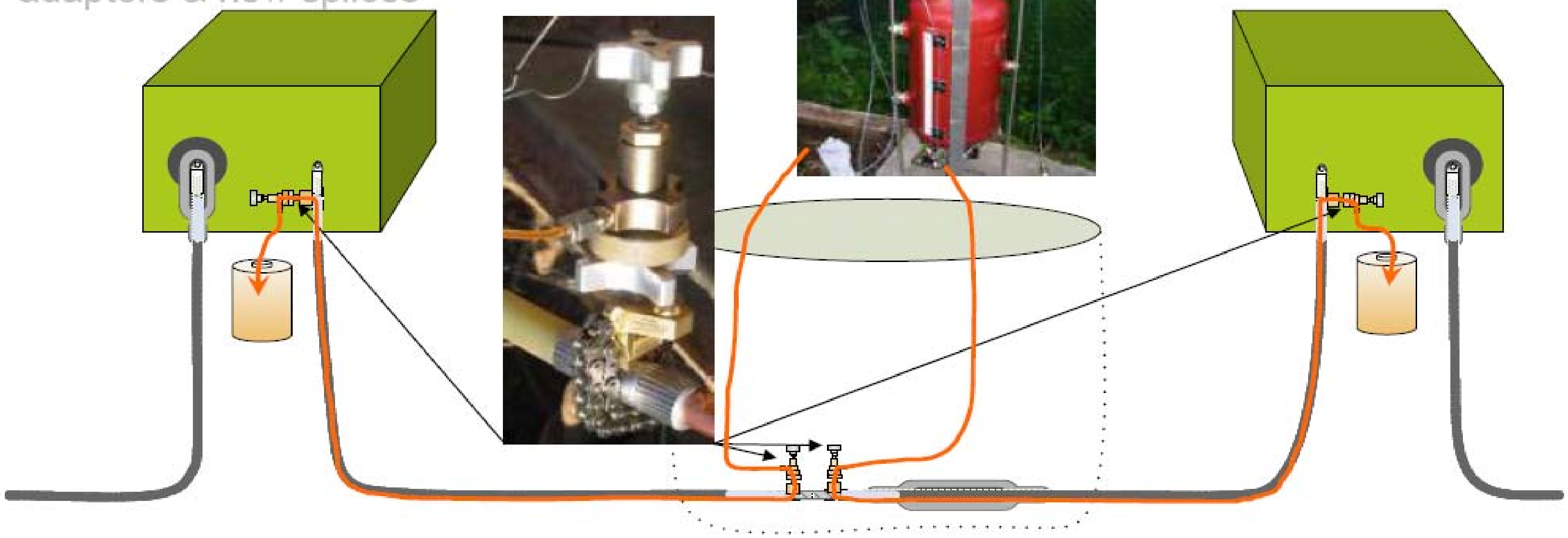
Power Stream Injection Summary Date 9/27/2009

Novinium #	Equpment Numbers	Phase	Tested	Injected	Length Tested in Meters	Length Tested in Feet	Length Injected in Meters	Disposition	Notes
U0000302	33TP96 - 33TP97	Red	9/9/09		181	593		4 Splices	
1604	33TP97 - 33TP98	Red	9/9/09	9/10/09	160	528	160	Injected	
1605	33TP91 - 33TP090	White	9/9/09	9/14/09	221	726	221	Injected	
1606	33TP98 - 33TP099	Red	9/9/09	9/14/09	515	1692	515	Injected	
1608	33TP091 - 33TP092	White	9/9/09	9/14/09	318	1043	318	Injected	
1620	33TP092 - 33TP093	White	9/14/09	9/23/09	62	204	62	Injected	U00000303 Vacuumed out foundation and gained slack in cables 9-23-09
1609	33TP093 - 33TP094	White	9/14/09	9/15/09	344	1130	344	Injected	
1607	33TP099 - 33TP100	Red	9/14/09	9/15/09	77	255	77	Injected	
1610	33TP305 - 33TP102	Blue	9/15/09		168	552		1-Splice	1-splice @ #7 Normandale Rd.
1612	33TP102 - 33TP103	Blue	9/15/09	9/16/09	177	579	177	Injected	
1611	33TP094 - 33TP095	White	9/15/09	9/15/09	108	353	108	Injected	
1613	33TP103 - 33TP104	Blue	9/16/09	9/24/09	456	1495	456	Injected	1-splice @ 33 Ritter Crescent, splice cleared 9-23-09
1614	33TP104 - 33TP105	Blue	9/16/09	9/16/09	209	686	209	Injected	
1615	33TP100 - 33TP101	Red	9/16/09	9/24/09	182	598	182	Injected	1-Splice @ 46 Ritter Crescent, Splice cleared 9-23-09
1616	33TP101 - 33SW009	Red	9/17/09		246	806		1-Splice	1-Splice @ 7 Ritter Crescent
1617	33TP095 - 33SW009	White	9/17/09	10/1/09	105	346	105	Injected	
1618	33TP105 - 33SW009	Blue	9/17/09	10/1/09	137	450	137	Injected	
1619	33TP305 - 33SW008	Blue	9/21/09	9/21/09	129	423	129	Injected	
1621	33TP096 - 33SW008	Red	9/21/09	9/30/09	353	1157	353	Injected	1-splice 18 ft. west of riser pole
1622	33TP090 - 33SW008	White	9/21/09	9/30/09	178	583	178	Injected	1-splice 18 ft. west of riser pole
					Meters	Feet	Meters		
					4326	**14199**	**3350**		**0**

Appendix D – Sustained Cable Injection Process Selected

Sustained Pressure Injection Process

- De-energize, test & ground cable (A-B)
- Pinpoint all splices; vacuum-excavate
- Remove all splices, terminations & connectors
- Position new connectors, injection adaptors & new splices
- Swage injection adaptors & connectors
- Inject sub-segments at moderate pressure



Appendix E – Comparison of Sustained and Unsustained Cable Injection Process

Process Comparison

	Unsustained Pressure with Soak	Unsustained Pressure without Soak	Sustained Pressure
Visits to site	Four visits	Two visits	One visit
Soak Tanks	Required for 60-120 days, potentially energized	Required for 24-48 hours, potentially energized	None
Accessories	Special Flow Though Elbow	Special Flow Though Elbow	Standard Accessories
Fluid Contact with Accessory	Reduces life, soaks up fluid. Fluid not compatible with all accessories	Reduces life, soaks up fluid. Fluid not compatible with all accessories	Fluid does not touch the accessories
Time for Injection Visit	30-60 minutes	30-60 minutes	45-90 minutes

CCC #15 - Attachment 6 (BC235)

Business Case

Project Title:	Cable Injection Program (ACA) - South
Location:	Locations TBD
Capital Budget Year:	2013
Project Lead:	Quan Tran
Submission Date:	7/27/2011
Net Capital Amount:	3,195,951
Annual OM&A Expense (if applicable):	0
Controllable Expenditure:	☑ Yes ☐ No
Planned Project:	Yes
Project ID:	100375

Objective:

Describe the reason why you are undertaking this project.

To improve reliability of supply and customer service at various locations throughout the PowerStream South by completing cable injection on primary cable candidates. It is recommended to inject 45,800 m of cable in 2013 in PowerStream South.

Background:

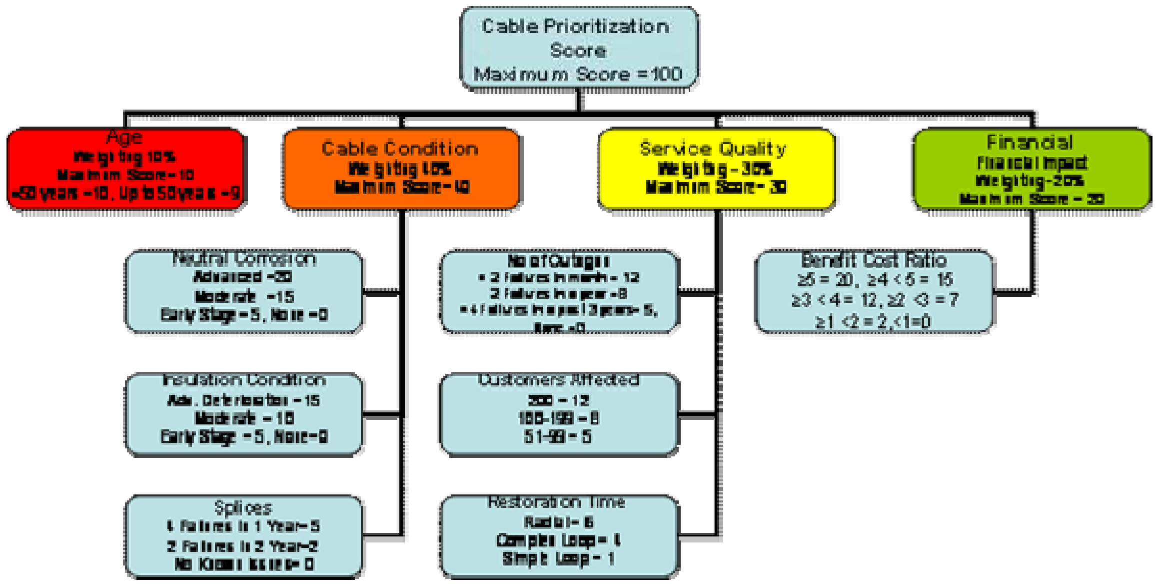
Describe the current situation and conditions in detail.

PowerStream's Underground Cable Replacement and Cable Injection Prioritization Methodology

PowerStream's approach to manage the cable population is summarized below:

- 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 20 years initially and continue at the similar rate afterward
- The cable injection program will last for 10 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.

Underground Cable Replacement

PowerStream has approx. 7,957 km of underground primary cable length, the vast majority of which is direct buried and the rest is in duct.

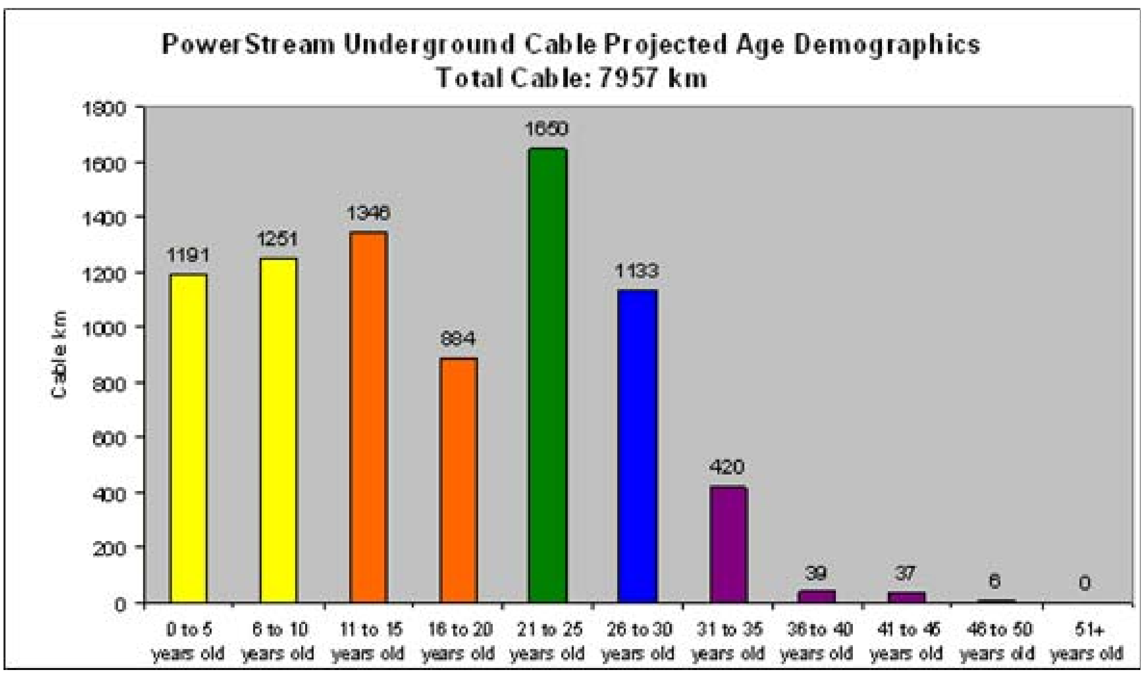
According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**, the useful lives of various types of underground cable are listed below.

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 35 years is used for pre-1987 cable and a useful life of 45 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.
The current 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 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 conducting field trial 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.

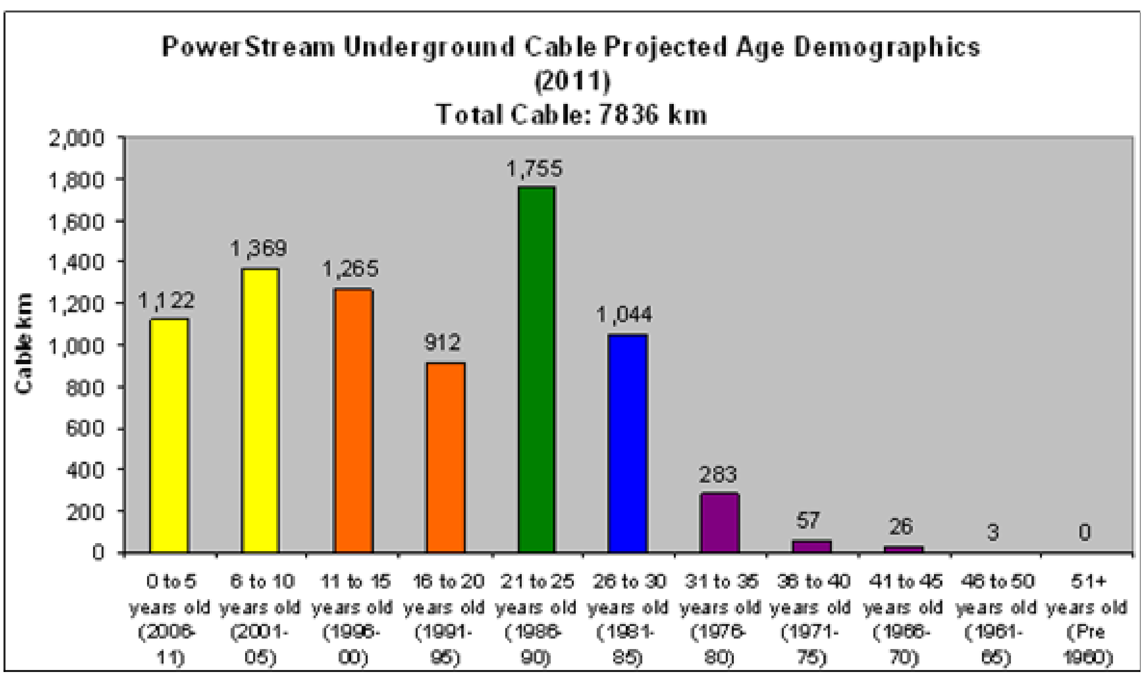
PowerStream will address its Underground Cable assets by using a combination of Cable Replacement and Cable Injection as means of intervention. The Cable Replacement plan (discussed later in this Section) will be ongoing as we will continually need to replace cable as it gets older. This report will cover the first 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 (discussed in the next Section - Cable Injection) will take place over a period of 10 years. After 10 years all suitable candidates for injection will be exhausted, therefore this plan will not be ongoing.

20-Year Cable Replacement Plan:

In 2011, a general plan to address the cable issue (a 20 year plan for cable replacement, and a 10 year plan for cable injection) was developed and approved by PowerStream management. To develop the cable plan, the 2011 cable age demographics was used to divide the cable population into the following 5 groups:

- Group 1: 31 years and older (1980 and older)
- Group 2: Between 26 – 30 years (1981-1985)
- Group 3: Between 21 – 25 years (1986 – 1990)
- Group 4: Between 11 – 20 years (1991 – 2000)
- Group 5: Between 1 – 10 years (2001 and younger)

The 2011 cable age demographics and age groups are described below.



Group 1: 31 years and older (1980 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 (1981 – 1985):

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 (1986 – 1990):

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 (1991 – 2000):

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 (2001 and younger):

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.

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 47 km per year from 2013 – 2031

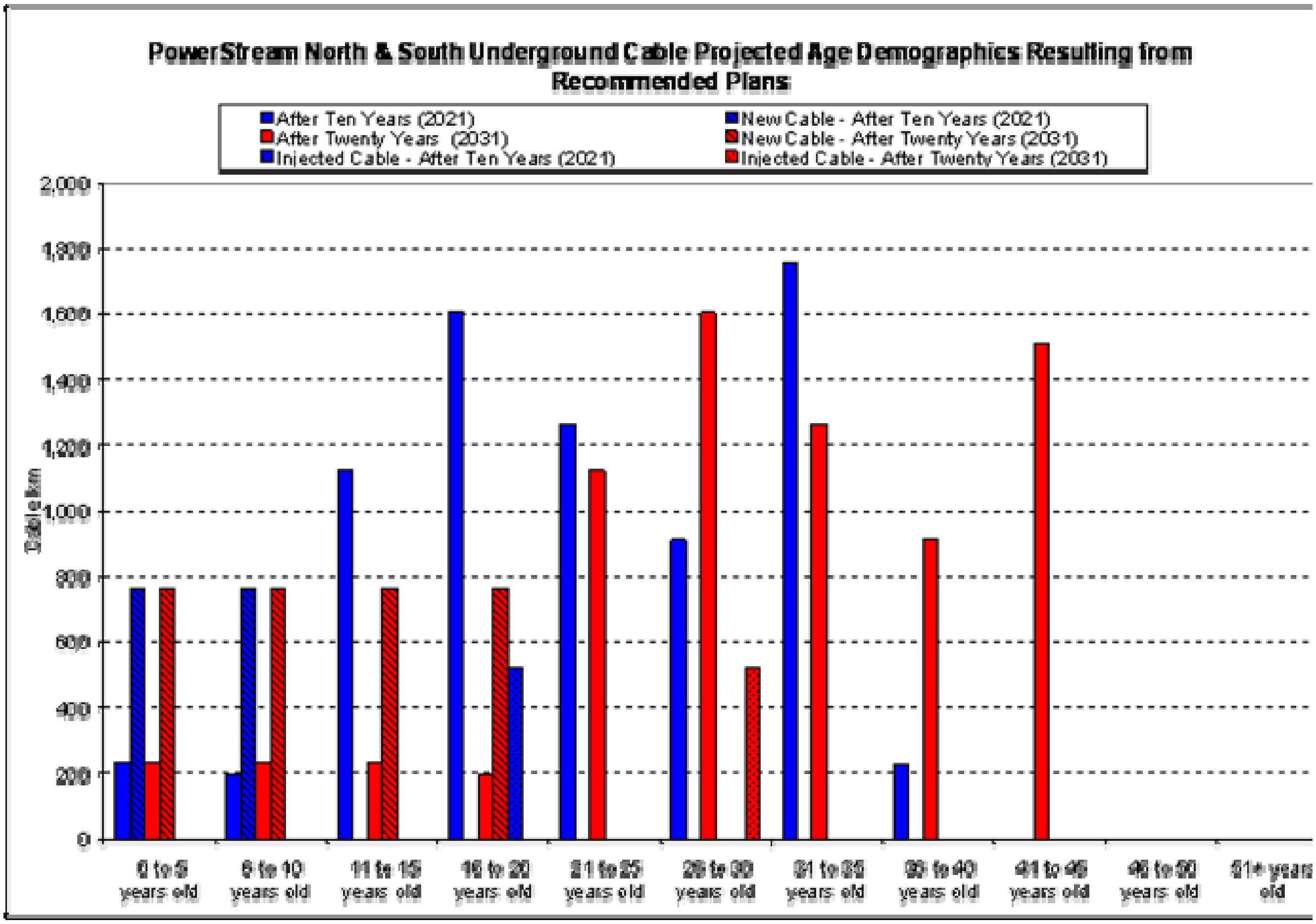
At this rate, all of the 892 km will have been replaced by 2032.
Currently, PowerStream does not have sufficient physical condition and test data to determine the degree of deterioration and to estimate the remaining life of the cable population.

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.



Based on the above chart, after 20 years PowerStream will have 1,745km 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.

Cost of Cable Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2013	2014	2015	2016	2017	5 Yr. Total
2.1	Cable Replacement	$17,399,485	$18,695,752	$17,885,044	$15,519,644	$15,543,026	$85,042,95

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 (approx. 26 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 (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.
In 2011 PowerStream completed 2 cable injection projects using two different contractors.
In 2012 PowerStream will proceed with 2 cable injection projects to continue to gain experience.

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 gaining experience 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 57 km per year 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.

Cost of Cable Injection

PowerStream - Capital Work Plan from Planning and Stations							
Category		2013	2014	2015	2016	2017	5 Yr. Total
22	Cable Injection	$4,060,942	$4,074,566	$4,088,187	$4,101,812	$4,115,437	$20,440,94

Alternative One: Status Quo

Describe the status quo.

The status quo is to do nothing, not inject the cable candidates, allowing the cable to run to failure, and responding to outages under emergency.

Provide details of the cost of the status quo, if applicable.

N/A

*Describe the **health and safety** risk of the status quo.*

Cable failures may occur which under rare but not improbable circumstances may cause injuries to operations staff and the public.

*Describe the **business excellence** risk to the Status quo.*

Performing the Injection process on underground primary cable is significantly less expensive than replacing it. Any cable that is not injected in this year will be added to the replacement list and may greatly increase the amount of Capital required to maintain the stability of the underground system. Inefficiencies are created when operations staff perform repairs and replacements under emergency situations.

*Describe the **customer satisfaction** risk to the Status quo.*

When old deteriorated cable is not injected or replaced, failures will occur resulting in customer outages which will have a negative impact to system reliability and customer service. Based on the estimate of 2 failures per year per subdivision, there would be 21,600 CMI (Customer Minutes of Interruption) per subdivision of 4,000 m cable, or 247,320 CMI for 45,800 m cable.

*Describe **financial risk** of the status quo.*

The financial risk calculations are based on the following assumptions and estimates (per 4,000 m of cable or 1 subdivision):
- Frequency of interruption: 2 failures/year
- Duration of interruption: 3 hours
- Number of transformers: 12 transformers
- Number of customers in the loop: 120 customers
- Number of customers affected in an outage: 120/2 = 60 customers (half loop)
- Customer load: 120 customers x 3 kW = 360 kW
- Customer load affected in an outage: 360 kW/2 = 180 kW (half loop)
- Customer Interruption Cost (Frequency): $2.00/kW (Residential)
- Customer Interruption Cost (Duration): $4.00/kWh (Residential)
- Emergency Response/Repair Cost: $10,000/event
- Delivery Charge, etc. for loss of revenue calculation: $0.024/kWh

The financial risk cost is estimated as follows:
Cost to PowerStream:
- Emergency Response/Repair Cost = $10,000 x 2 failures/year = $20,000
- Loss of Revenue Cost (Delivery Charge, etc.) = 180 kW x 3 hrs x $0.024/kWh x 2 failures/year = $26

Total Cost to PowerStream = $20,000 + $26 = $20,026

Cost to Customers:
- Customer Interruption Cost (Frequency) = 180 kW x $2/kW x 2 failures/year = $720
- Customer Interruption Cost (Duration) = 180 kW x 3 hrs x $4/kWh x 2 failures/year= $4,320

Total Cost to Customers (Interruption) = $720 + $4,320 = $5,040

Total Risk Cost per subdivision = $20,026 (PowerStream) + $5,040 (Customers) = $25,066

Total Risk Cost for 45.8 km of cable length is:
$20,026 x 45,800/4000 (PowerStream) + $5,040 x 45,800/4000 (Customers) = $229,298 (PowerStream) + $57,708 (Customers) = $287,006

*Describe the **environmental risk** of the status quo.*

Increased risk of cable failures which will have negative impacts on the environment. Trouble response and repair will be required, increasing vehicle emissions and disruption to land (e.g. digging up the boulevard to expose the faulted direct buried cable).

Alternative 2 :

Inject cable at various locations over a period of 10 years

Describe the alternative.

Perform the cable injection process at various locations in PowerStream Territory over a period of 10 years. Starting with 8 km in 2012 then 57 km (including 11.2 km in the North and 45.8 km in the South) per year for 2013 - 2022. The details are outlined in the proposed 10 year plan below:

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, of which approx. 4 km is in PowerStream South)
- Inject 57 km per year from 2013 – 2022, of which approx. 11.2 km is in PowerStream North and 45.8 km is in PowerStream South.

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.

Provide details of the cost of this alternative.

$3,195,951
See Project 100375 Budget Form for details.

Recommended Alternative:

Alternative 2: Inject cable at various locations over a period of 10 years

Describe the recommended alternative.

Perform the cable injection at various locations in PowerStream over a period of 10 years. Starting with 8 km in 2012 then 57 km (including 11.2 km in the North and 45.8 km in the South) per year from 2013 - 2022. Details are outlined in the proposed 10 year plan below:

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, of which approx. 4 km is in PowerStream South)
- Inject 57 km per year from 2013 – 2022, of which approx. 11.2 km is in PowerStream North and 45.8 km is in PowerStream South.

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.

Why did you choose the recommended alternative?

The recommended alternative was chosen for the following reasons:
1. Resolves the operations and safety concerns.
2. Improves reliability of supply and customer satisfaction.
3. Rejuvenates assets that are deteriorated.

Is this project dependent on any other project(s)? Identify Project ID(s).

This project is dependent on one other project:
- Project ID 100408: Cable Injection Program (ACA) - Locations TBD, DESIGN ONLY - South

*What is the **health and safety** value of the recommended alternative to the organization?*

Old cables are rejuvenated, resulting in fewer cable failures and reduction in the risk of injuries for staff and the public.

*What is the **business excellence** value of the recommended alternative to the organization?*

Performing the Injection process on underground primary cable is significantly less expensive than replacing it. Any cable that is not injected in this year will be added to the replacement list and may greatly increase the amount of Capital required to maintain the reliability of the underground system.
Improve reliability within the subdivision. Improve efficiency because operations staff will perform fewer repairs and replacements under emergency situations.

*What is the **customer satisfaction** value of the recommended alternative to the organization?*

Cable injection will extend the life of old cables, which will result in more reliable service to customers. Based on the estimate of 2 failures per year and 60 customers affected (half of 120 customers in a loop), a reduction of 21,600 CMI (Customer Minutes of Interruption) can be achieved. The CMI is estimated as follows:
CMI per subdivision = 60 customers x 3 hours x 60 minutes x 2 failures/year = 21,600 CMI
CMI for 45.8 km of cable length = 21,600 x (45,800/4000) = 247,320 CMI

*What is the **financial** value of the recommended alternative to the organization?*

Customer outages will be reduced, resulting in a saving of customer interruption cost, equipment repair cost, and revenue loss cost, totaling $25,066 per year, of which $20,026 is attributed to PowerStream cost, and $5,040 is attributed to Customer Interruption cost (per subdivision).
Financial value for 45.8 km of cable length is: $229,298 (PowerStream) + $57,708 (Customers) = $287,006

*What is the **environmental** value of the recommended alternative to the organization?*

Reducing cable failures will have positive impacts on the environment. Fewer trouble response and repair will reduce vehicle emission. Fewer cable repair will reduce disruption to land (e.g. digging up the boulevard to expose the faulted direct buried cable).

Implementation Timeline:

Provide planned timelines for project completion.

2012 - Complete Cable injection projects approx. 8 km at various locations.
2013 - 2022 - Complete Cable injection projects approx. 57 km per year, of which approx. 11.2 km at various locations in the North and 45.8 km at various locations in the South.

Reviewed By:

POWERSTREAM\riaz.shaikh

Title	Name	Signature	Date
Project Leader	Quan Tran	POWERSTREAM\quan.tran	7/27/2011 2:27:01 PM

Project Sponsor	Doug Fairchild	POWERSTREAM\doug.fairchild	7/28/2011 11:40:54 AM
Department Director	Ted Wojcinski	POWERSTREAM\ted.wojcinski	7/28/2011 2:42:42 PM
Department VP	Shelly Cunningham	POWERSTREAM\shelly.cunningham	8/5/2011 10:39:15 AM
VP Rates & Regulatory	Colin MacDonald	POWERSTREAM\colin.macdonald	8/24/2011 1:28:32 PM
Executive VP	Mark Henderson	POWERSTREAM\mark.henderson	8/24/2011 2:19:28 PM
Executive VP & CFO	John Glicksman	POWERSTREAM\john.glicksman	8/29/2011 10:12:59 AM
President & CEO			

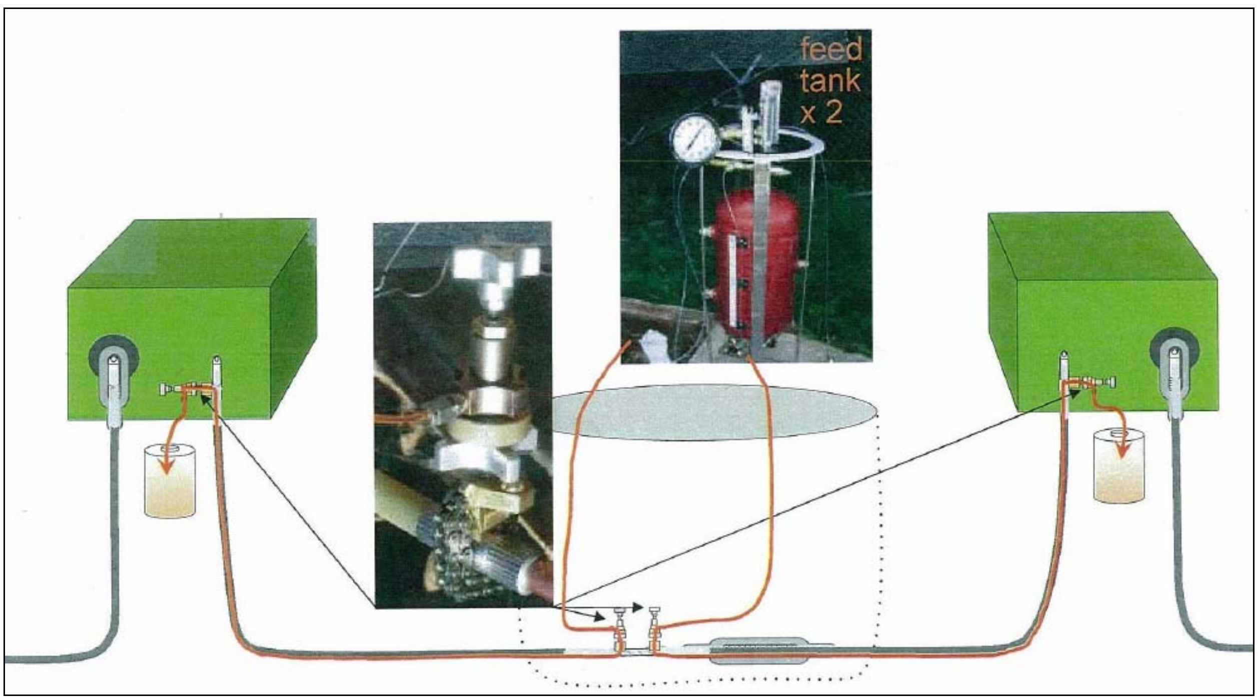
Additional Attachments

Report on Cable Injection Pilot Project _ Nov. 09.pdf
Adobe Acrobat Document
945 KB

Sign off and approval required by

Department Director, Department VP, VP Rates & Regulatory, EVP, EVP&CFO

PowerStream's Pilot Project on Cable Injection/Rejuvenation



Prepared by:
System Planning
November, 2009

Table of Contents

Summary

Cable injection and cable rejuvenation are two terms commonly used interchangeably to describe the introduction of engineered materials into an aged but still operational cable with the intent of counteracting the effects of cable insulation aging.

Cable injection is the process by which silicone chemicals are injected down the strands of the cable. This chemical fluid diffuses into the insulation, fills the voids, increases the dielectric strength of the cable and thus extends the life of the cable.

Earlier vintages (pre-to-mid1980s) polyethylene cables have experienced a higher than expected failure rate. Water tree growth is the primary aging mechanism of medium voltage cables employing extruded dielectric insulating materials. These cables are a primary candidates for injection.

For injection to be successful there must be a path for the chemical fluid to flow down the cable. This requirement prevents cables with solid core or strand block from being injected. HMWPE (High Molecular Weight Polyethylene), Butyl Rubber, XLPE and TRXLPE all can be successfully rejuvenated. Cable injection extends cable life from 20 to 40 years at 1/3 to ½ of the cable replacement cost.

In 2008, System Planning carried out a detailed assessment of cable injection The results are detailed in the System Planning report titled "*Technical Assessment of Cable Injection*".

The report concluded that cable injection was an economic alternative to cable replacement for earlier vintage (pre-to-mid1980s) polyethylene cables and that PowerStream carry out a Pilot Project to gain experience and determine the actual cost ($/m) of injection.

The subdivision selected for the Pilot Project was " Village in the Valley (Delhi Cres.)" located in Markham near 16th Ave. and Kennedy Rd. It is a residential subdivision consisting of approximately 4,000 meters of 1/0 Al, XLPE, unjacketed, direct buried cable installed in 1982 .

In May 2009 an RFP (*PS-RFP-09-08*) was issued to two qualified contractors namely **Novinium** and **Transelec**. Novinium was the successful contractor based on cost and quality of the injection fluid.

The project was started on September 14th and was completed on September 30th. The work was carried out essentially as planned with the exception of the following:

1) Cable Segment **33TP96 X 33TP97** (Red-Phase, 181m) was found to have four splices. It was decided that this segment should be replaced and not injected. In general if a segment has more than two splices it is not economical to inject.

2) One splice was found to be under the edge of the driveway in cable segment **33TP305 X 33TP102 .** The Line staff decided not to dig up the driveway and therefore this segment (**152m**) was not injected.

3) One splice was found to be in the "roadway crossing" in cable segment **33TP101 X 33SW009** (Red-Phase). Consequently the splice was not dug up and the segment (**246m**) was not injected.

The total cable meters injected was 3,350 at a total cost of $143,000.
The resulting cost per meter was **$43 per meter.** The industry (Canada & USA) standard cost ranges between $45 & $70 per mete depending on the number of splices and the utility internal costs.

Based on the results of the Pilot Project, it is recommended that PowerStream continue with cable injection in lieu of cable replacement for earlier vintage (pre-to-mid1980s) polyethylene cables.

1. Introduction

Cable injection and cable rejuvenation are two terms commonly used interchangeably to describe the introduction of engineered materials into an aged but still operational cable with the intent of counteracting the effects of cable insulation aging.

When a cable is injected, the silicone fluid diffuses out of the strands through the relatively porous strand shields and into the insulation. The fluid then polymerizes with water (or moisture) and the small silicone molecule grows up to seven times its original size and fills all existing water trees and voids. This increases the dielectric strength of the cable and thus extends the life of the cable.

2. Purpose of the Document

The purpose of this document is to:

- Review the Pilot Project from the point of view of "lessons learned" and total cost of cable injection ($/m)
- Based on the findings and experience gained recommend whether to carry on with future cable injection projects.

3. Background

In 2008, System Planning carried out a detailed assessment of cable injection (rejuvenation) including a survey of various utilities both in Canada and USA.
The results are detailed in the System Planning report titled "Technical Assessment of Cable Injection" .

The report concluded that cable injection was an economic alternative to cable replacement for earlier vintage (pre-to-mid1980s) polyethylene cables that have experienced a higher than expected failure rate primarily due to water treeing.
and that PowerStream carry out a Pilot Project to gain experience and determine the actual cost ($/m) of injection.

In May 2009 an RFP (*PS-RFP-09-08*) was issued to two qualified contractors namely **Novinium** and **Transelec**. Novinium was the successful contractor based on cost and quality of the injection fluid. A summary of the Bid Evaluation is shown in **Appendix A .**

Warrantee Offered by the Two Contractors

Transelec (UtilX - CableCure) offers a 20 year warranty.

NOVINIUM offers a 40 year warrantee for Sustained Pressure Process and 20 years for Unsustained Pressure Process

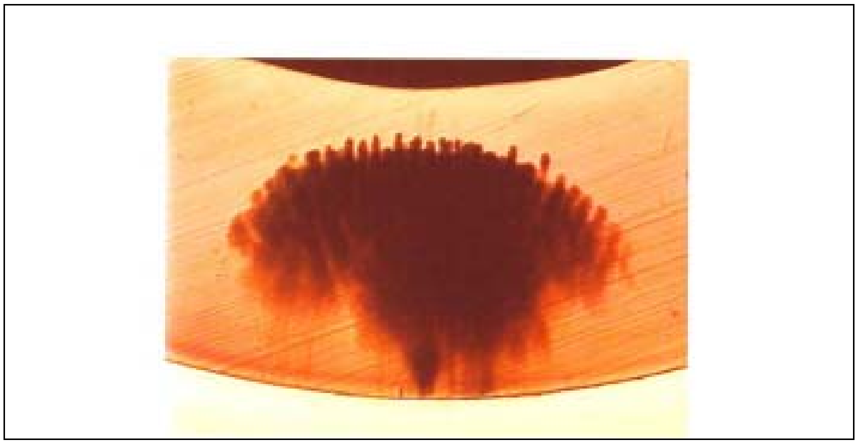
Both warranties provide return of the costs of injection for the failed cable segment.

4. Cable Failure Mechanism

Earlier vintages (pre-to mid1980's) polyethylene cables have experienced a higher than expected failure rate. The degradation of the polyethylene insulation used in most of these cables is by far, the single most important source of cable faults. This premature aging process is caused by a phenomenon known as water treeing. Water tree growth is the primary aging mechanism of medium voltage cables employing extruded dielectric insulating materials.

Water trees start with imperfections (surface irregularities, voids, contaminants, etc.) in the cable insulation. Water trees are named based on their origin. For instance, bow-tie water trees start off as contaminants or imperfections in the insulation. Vented water trees (Figure 1) begin as imperfections on the surface of the insulation.

Figure 1- Example of Vented Water Trees*
(Cable Injection Process, Transelec Common Inc. – Jean Dionne)



Water trees grow in the presence of high AC stress (caused by imperfections) and water. These tree shaped structures are diffuse clouds of microscopic unconnected micro-voids. Water trees are conductive in the presence of water and can be dielectric when dry.

In the initial stage, water trees originate from voids, contaminants and imperfections on the inner and outer surface of the insulation layer. Water trees reduce the AC break down (ACBD) strength of polyethelene-insulated cables. Water trees are influenced by high voltage and water. As water trees grow, the ACBD is reduced. In time the electrical stress exceeds the ACBD and water trees evolve into *electric trees* (Figure 2). This final state of degradation is irreversible and cable failure is imminent. A fault will occur in a short period of time.

Electric trees are micro voids that are the final stage of water trees. They are the consequences of surges, electrical impulses or partial discharge that increase pressure on permeated water trees and alter permanently the insulation. These micro-faults cannot be rejuvenated.

Figure 2 – Electric Trees*
***** (Cable Injection Process, Transelec Common Inc. – Jean Dionne)

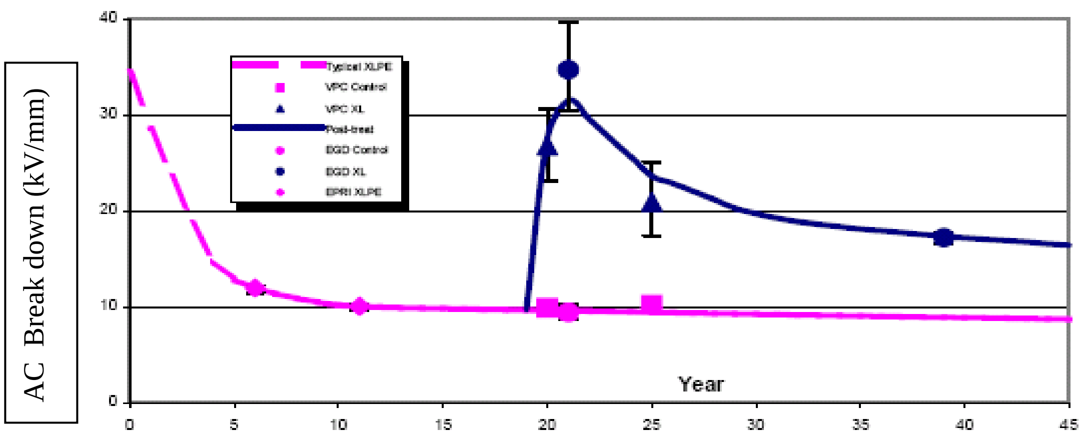
4.1 Pre-1980s Polyethylene Cable Performance

The Electric Power Research Institute (EPRI) has done some work to characterize the reliability of pre-1980 vintage polyethylene cables and the results of that work are summarized in Figure 3. EPRI concluded “the AC breakdown (ACBD) values obtained six to eleven years after installation were at best 1/3 of the level generally regarded as normal for new cable (31.5 kV/mm).

Pre-1980 vintage cables suffer a rapid degradation in AC breakdown performance during the first decade after the cable is installed. The cable then continues to degrade in performance, but at a much slower rate. Figure 3 uses the actual EPRI results and longer-term work done by industry and published in various technical literature.

Figure 3 – Typical performance of pre-1980 vintage PE cables and typical post injection Performance

*(Cable Injection Process, Transelec Common Inc. – Jean Dionne)



5. Cable Rejuvenation Technology

In 1986 silicone injection entered commercial use as a material which when injected into strands of medium and high voltage power cables provided substantial dielectric enhancement and extended cable life.

The silicone fluid must diffuse out of the strands where it is injected through the relatively porous strand shields and into the insulation. The fluid then polymerizes with water and the small silicone molecule grows up to seven times its original size and fills all existing water trees and voids. Movement by diffusion through cable insulation slows by 68,000 times, anchoring cable rejuvenation molecules within insulation. Excess fluid acts as a tree retardant far into the future.

Ultimate performance is realized only after the fluid has had sufficient time to diffuse through the entire width of the insulation. While the time that it takes is dependent upon insulation thickness, the temperature profile of the cable and the amount of water present, peak performance is typically realized about two years after injection is performed.

6. Criteria For Injection

For injection to be successful there must be a path for the chemical fluid to flow down the cable. This requirement prevents cables with solid core or strand block from being injected. The cable industry started using “strand-block” in the late 80’s. Therefore, cables manufactured in the mid 80’s and earlier are good candidates for rejuvenation.

PILC cables do not have a water tree problem, so they are not a candidate for injection. HMWPE (High Molecular Weight Polyethylene), Butyl Rubber, XLPE and TRXLPE all can be successfully rejuvenated.

Another factor to consider for cables with exposed neutrals (unjacketed cable) is neutral corrosion. This can be determined by a non-destructive test (TDR). Generally, if there is an average of 50% of the original neutral remaining, the cable is a candidate for injection. If the neutral corrosion is localized in one portion or segment, it can be locally repaired and then injected.

7. The Injection Process

Both **Novinium** and **Transelec** (Utilx CableCure) generally use a similar process; however, there is a slight variation in their injection steps and procedure.

Procedure used by Novinium

Step 1 - De-energize, test and ground cable with conventional methods. The cable will generally remain grounded for steps 2 - 8 which follow.

Step 2 - Pinpoint all splices, severe cable bends, and neutral corrosion using a high resolution TDR (see Fig. 4 for a typical trace).

Step 3 - Based on results in Step 2, determine if sites identified should be excavated. If not, schedule for replacement. Otherwise, excavate splices, severe bends, and neutral corrosion sites.

Step 4 - Remove and discard all old components including terminations & splices.

Step 5 - Position new compression connectors and injection adaptors.

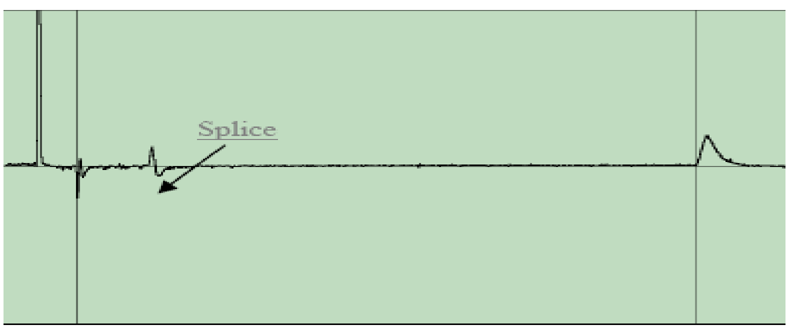
Step 6 - Swage injection adaptors and connectors in a single operation. Compared to standard crimping techniques, this swage provides superior ampacity.

Step 7 - Inject sub-segments at sustained moderate pressure (10-20 psi). Typical lengths and conductors require only a few minutes and are attended. Fluid flows from the feed tank to a rotometer which provides continuous flow measurement. From the rotometer the fluid passes through a ball valve and into the injection tool. The injection tool is mated to the injection adapter and provides leak tight fluid access to the cable.

Step 8 - Complete the installation of Novinium Certified terminations and splices.

Step 9 – Re-energize the cable. Restore any excavations.

Figure 4 – A typical TDR trace locating a splice * (Cable Injection Process, Transelec Common Inc. – Jean Dionne)



8. PowerStream's Pilot Project

8.1 Selection Criteria Used

PowerStream's Pilot Project for Cable Injection was selected based on:

1. **Meet the Criteria for Injection** (as outlined in Section xx)

2. **Operational requests**

a) based on experience from Controllers for assets which limit efficient system operation.

b) **"Cable Failure Analysis Report" by Brosz & Associate.**

(It recommended replacement of the cable based on the number of "water trees" found in the failed cable segment).

3. Field Expert Feedback *(Anecdotal sources) such as field staff, for assets that have* visually or functionally aged (deteriorated) beyond the class visually or functionally aged (deteriorated) beyond the class or unit assessment results of the ACA model.

8.2 Subdivision Selected for Pilot Project

As shown in Appendix B, the subdivision selected for the Pilot Project was " Village in the Valley (Delhi Cres.)" located in Markham near 16th Ave. and Kennedy Rd. It is a residential subdivision consisting of approximately 4,000 meters of 1/0 Al, XLPE, unjacketed, direct buried cable installed in 1982 .

8.3 Injection Process Selected

For any cable injection project there are two Processes available namely;

a) Unsustained Pressure
b) Sustained Pressure

PowerStream selected the "Sustained Process" for the Pilot Project.
There are two major differences between the two Processes, namely injection pressure and time required to complete the injection process.

A detailed comparison of the two processes is shown in Appendix E.

8.4 Project Experience

A Line Crew of two and a supervisor was assigned to the Pilot Project to assist the contractor (Novinium) to carry out the cable injection work. Staff from K-Line and Transpower was also used as required.

The project was started on September 14th and was completed on September 30th. The procedure followed *(9 steps*) is as outlined in Section **xx .**

The work was carried out essentially as planned with the exception of the following:

1) Four splices were found in cable Segment **33TP96 X 33TP97** (Red-Phase). This segment (**181m**) was not injected. In general if a segment has more than two splices it is not economical to inject. It is recommended that this section be replaced.

2) One splice was found to be under the edge of the driveway in cable segment **33TP305 X 33TP102 .** The Line staff decided not to dig up the driveway and therefore this segment (**152m**) was not injected.

3) One splice was found to be in the "roadway crossing" in cable segment **33TP101 X 33SW009** (Red-Phase). Consequently the splice was not dug up and the segment (**246m**) was not injected.

All other splices found were replaced and the cable segments were successfully injected. Segments injected and splice replaced are detailed in Appendix C1 & C2 .

8.5 Customer Complaints

Only one complaint was received within the entire subdivision. One customer objected to the contractor placing "white paint dots" on the apron of his driveway. These dots indicated the location of the splice.

8.6 Project Cost

The total cost of the project including labour and material was **$143,000** of which $29,000 was for internal (labour & material) and $114,000 was for contract forces Including Novinium, K-Line, Transpower & Spring Grove (vacuum truck)

The total cable meters injected was 3,350 (Appendix C2), at a total cost of $143,000, therefore the cost per meter was approximately **$43 per meter.**

According to the contractor (Novinium) the total cost (internal plus external) for injection for both Canada & the USA ranges between **$45 & $70 per meter** depending on the number of splices in the project and the utility's internal costs.

The PowerStream cost of $43/m is therefore slightly below the bottom range of other utilities.

13 Conclusions

The Cable Injection Pilot Project was carried out essentially as planned with the exceptions noted above. There were no issues with the material and equipment used and no issues with the process and procedure used. Both PowerStream staff and the contractor were satisfied with the outcome.

The contractor suggested that in future projects, PowerStream should have a number of "injection elbows" that could be used in areas where it is not economical to dig and replace splices such as outlined above in item's 1) & 2). Novinium will supply the injection elbows at a cost and upon request for particular projects.

If a splice successfully passes a "flow-through" test then an *injection elbow* can be used at the transformer and the cable segment can be injected using the "unsustained" pressure process.

The two cable segments (33TP305 X 33TP102 & 33TP101 X 33SW009) outlined in the previous section [item 2) & 3)] did pass the flow-through test and therefore could have been injected using the "unsustained " pressure process if the injection elbows were available.

Since the injected cable segments have a 40 year warrantee, the injection date and the cable segment identification should be recorded in the GIS primary cable data base. Should a failure occur on any of the injected segment a claim can be made for the failed cable segment. The Operation Staff (control room) should process a warrantee claim.

The project cost of $43 per meter is below industry range of $45 to $70 per meter.

14 Recommendations

Based on the outcome of the Pilot Project, it is recommended that:

a) PowerStream continue with cable injection in lieu of cable replacement for earlier vintage (pre-to-mid 1980's) polyethylene cables.

b) The cable in line segment **33TP96 X 33TP97** (181m) be replaced in 2010

c) The cable in line segment **33TP305 X 33TP102** (152m) and **33TP101 X 33SW009** (246m) be injected using "unsustained " pressure process * .

* *(In 2010 Novinium is expected to carry out cable injection for Toronto Hydro. At that time they will notify PowerStream and an arrangement will be made to inject these two sections).*

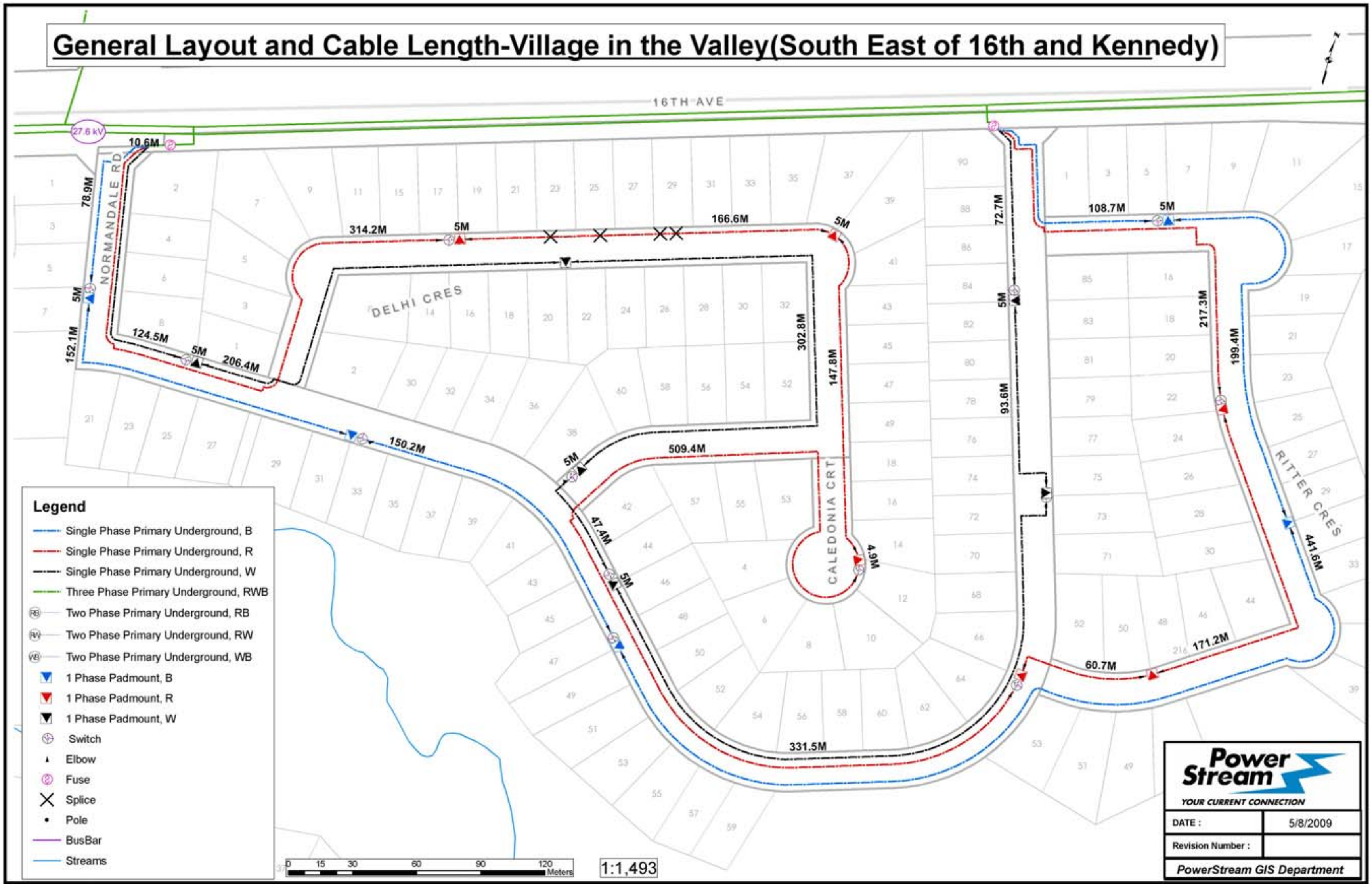
d) The injected cable segments in the subdivision (Village in the Valley (Delhi Cres.) be entered in the GIS primary cable data base with attributes of " *segment ID* " and " *date injected* ".

e) Operation staff (control room) monitor this subdivision for cable faults through the Outage Management System (OMS). Should a cable fault occur in any of the injected segments a claim should be processed by the Operation staff.

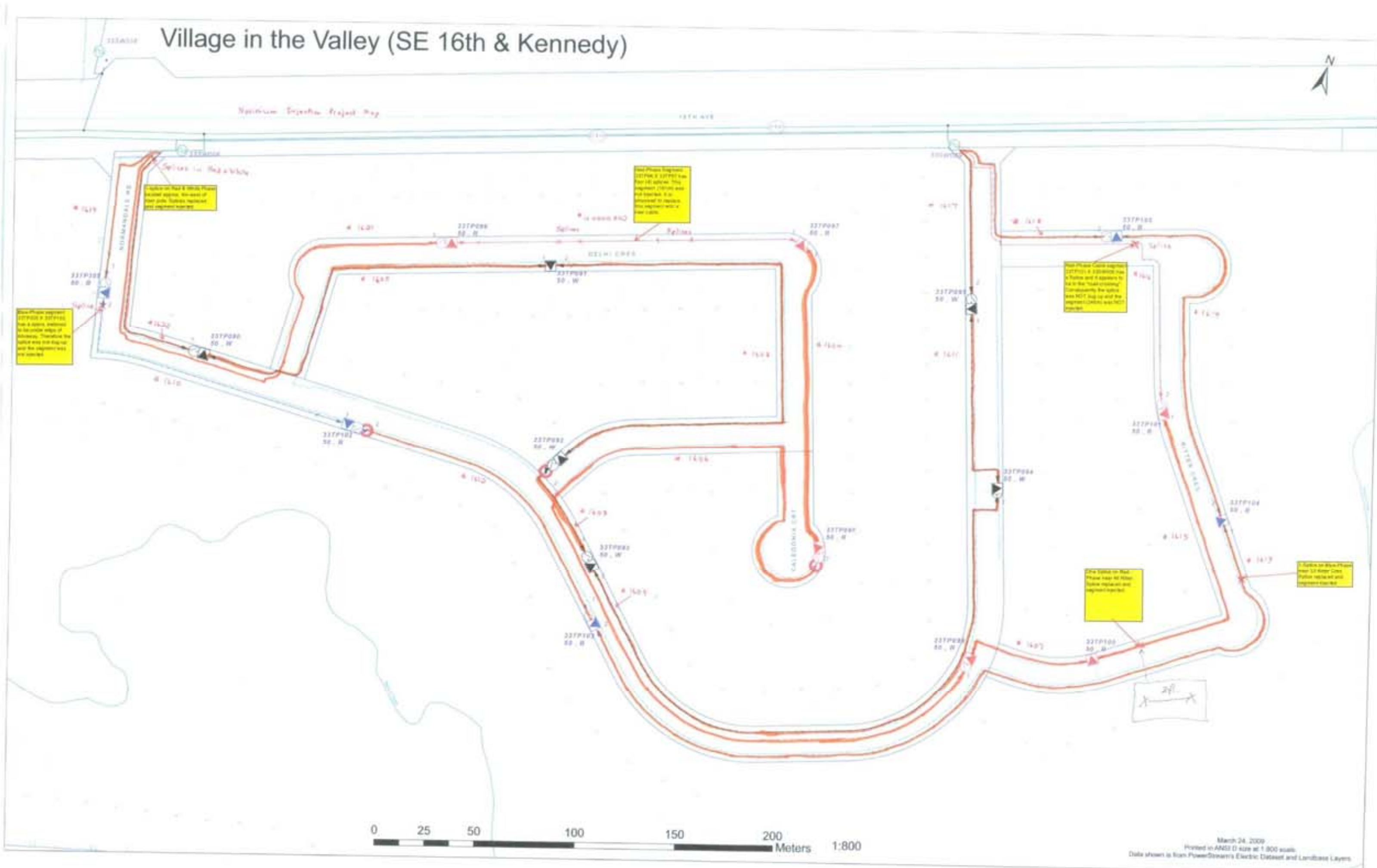
Appendix A – Cable Injection Pilot Project - Bid Evaluation Notes

Cable Injection Pilot Project - Bid Evaluation Notes (Based on 4000m of Cable)			
Item	**Particulars**	**Novinium**	**Transelec**
1	Injection Cost (base bid using "**Perficio 011**" Injection Fluid	$90,160.00	$129,213.75
2	GST (5%)	$4,508.00	$6,460.69
3	PST (8%)	$7,212.80	$7,662.47
4	Total Cost (tax included)	**$101,880.80**	**$143,336.91**
5	Injection Cost (Alternate bid using "**Ultrinium 732**" Injection Fluid	$97,840.00	
6	GST (5%)	$4,892.00	
7	PST (8%)	$7,827.20	
8	Total Cost (tax included)	**$110,559.20**	
	Warranty		
9	For Both Companies Warranty ***applies only to a failed segment (i.e. device-to-device)***		
10	**Novinium:** "Perficio 011" Injection Fluid Using Unsustained Pressure Rejuvenetion (UPR)	20 yrs	
11	**Novinium:**"Perficio 011" Injection Fluid Using Sustained Pressure Rejuvenetion (SPR)	25 yrs	
12	**Novinium:** "Ultrinium 732" Injection Fluid Using Sustained Pressure Rejuvenetion (SPR)	40 yrs	
13	**Transelec**: "CableCURE/XL" Injection Fluid (equivalent to Perficio 011) Using Unsustained Pressure		20 yrs
	EXPLANATION NOTES (some of these notes are from my report (2008) that I compiled on "Cable Injection".		
	1) "Perficio 011" Injection Fluid is comparable to "**CableCURE/X**L" . This is also known as "first generation" fluid.		
	2) Ultrinium 732"- is known as a "second generation" injection fluid introduced by Novinium in 2006. In its website and other published reports, Novinium claims that their chemical fluid (Ultrinium 732) has additional chemicals which provide the rejuvenated cable with stress grading, voltage stabilization, UV stabilization, anti-oxidation, and Partial Discharge (PD) suppression.		
	Process Comparison (Unsustained Pressure vs Sustained Pressure)		
		Unsustained Pressure with Soak	**Sustained Pressure**
	Visits to Site	Three to Four Visits	One Visit
	Soak Tanks	Required for 60-120 days (cable energized)	None Required
	Accessories	Will require special flow-through elbow. May require "flow-through splice" if flow blocked.	Standard Accessories are used. Splice is replaced
	Fluid Contact with Accessories	Accessories soak up fluid. Fluid not compatible with all accessories; may reduce life of accessories..	Fluid does not touch the accessories
	Warranty	20yrs	40yrs
	Pressure Used for Injection	10-20 PSI	100-300 PSI
	Recommendation: Novinium Alternate bid using "Ultrinium 732" Injection Fluid under "Sustained Pressure" is recommended		

Appendix B – Village in the Valley (Delhi Cres.) Subdivision Selected for Pilot Project



Appendix C1 – Village in the Valley (Delhi Cres.), "Cable as Injected by Contractor & Contractor's Notes"



Appendix C2 – Village in the Valley (Delhi Cres.), "Summary of Cable Lengths Injected"

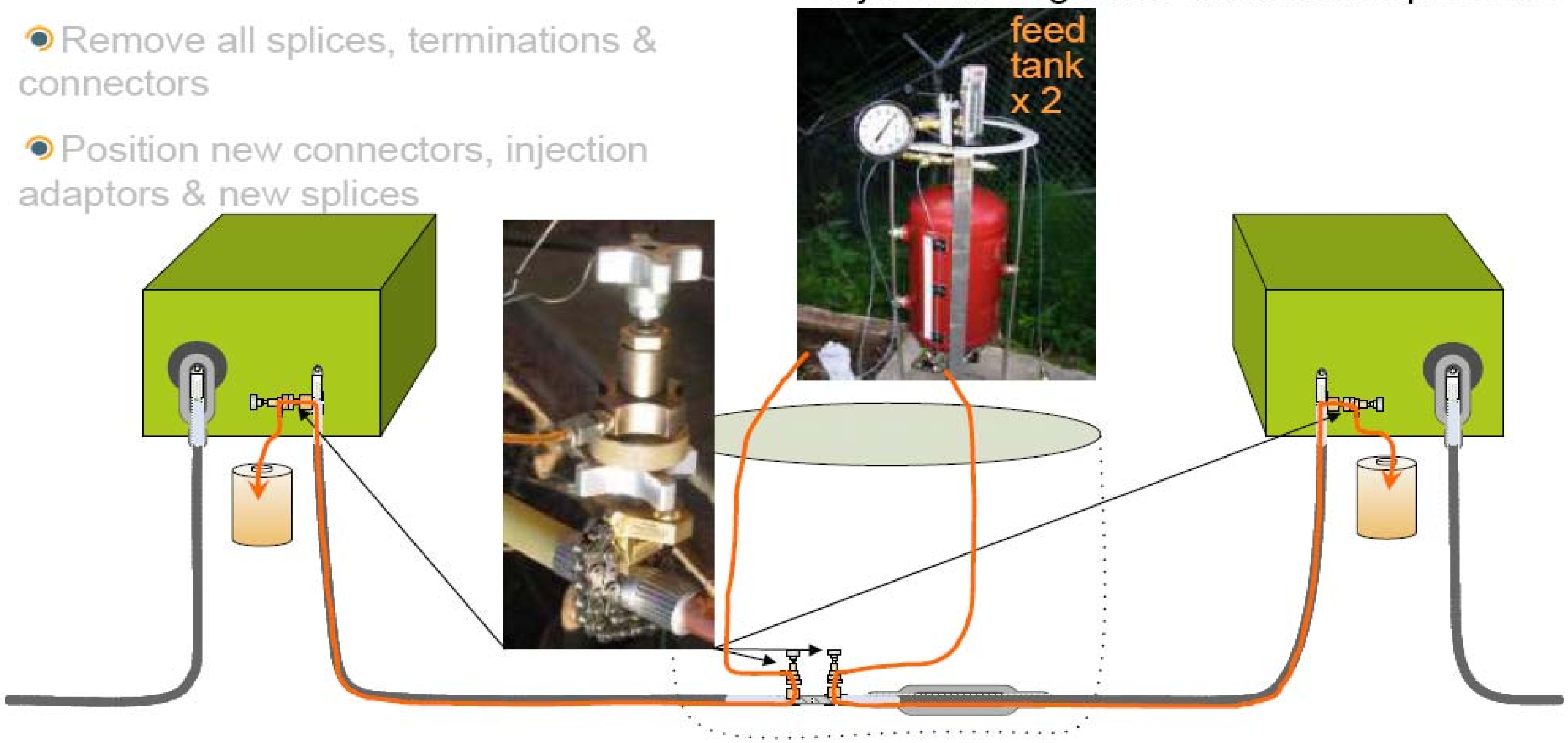
Power Stream Injection Summary — Date 9/27/2009

Novinium #	Equpment Numbers	Phase	Tested	Injected	Length Tested in Meters	Length Tested in Feet	Length Injected in Meters	Disposition	Notes
U0000302	33TP96 - 33TP97	Red	9/9/09		181	593		4 Splices	
1604	33TP97 - 33TP98	Red	9/9/09	9/10/09	160	528	160	Injected	
1605	33TP91 - 33TP090	White	9/9/09	9/14/09	221	726	221	Injected	
1606	33TP98 - 33TP099	Red	9/9/09	9/14/09	515	1692	515	Injected	
1608	33TP091 - 33TP092	White	9/9/09	9/14/09	318	1043	318	Injected	
1620	33TP092 - 33TP093	White	9/14/09	9/23/09	62	204	62	Injected	U00000303 Vacuumed out foundation and gained slack in cables 9-23-09
1609	33TP093 - 33TP094	White	9/14/09	9/15/09	344	1130	344	Injected	
1607	33TP099 - 33TP100	Red	9/14/09	9/15/09	77	255	77	Injected	
1610	33TP305 - 33TP102	Blue	9/15/09		168	552		1-Splice	1-splice @ #7 Normandale Rd.
1612	33TP102 - 33TP103	Blue	9/15/09	9/16/09	177	579	177	Injected	
1611	33TP094 - 33TP095	White	9/15/09	9/15/09	108	353	108	Injected	
1613	33TP103 - 33TP104	Blue	9/16/09	9/24/09	456	1495	456	Injected	1-splice @ 33 Ritter Crescent, splice cleared 9-23-09
1614	33TP104 - 33TP105	Blue	9/16/09	9/16/09	209	686	209	Injected	
1615	33TP100 - 33TP101	Red	9/16/09	9/24/09	182	598	182	Injected	1-Splice @ 46 Ritter Crescent, Splice cleared 9-23-09
1616	33TP101 - 33SW009	Red	9/17/09		246	806		1-Splice	1-Splice @ 7 Ritter Crescent
1617	33TP095 - 33SW009	White	9/17/09	10/1/09	105	346	105	Injected	
1618	33TP105 - 33SW009	Blue	9/17/09	10/1/09	137	450	137	Injected	
1619	33TP305 - 33SW008	Blue	9/21/09	9/21/09	129	423	129	Injected	
1621	33TP096 - 33SW008	Red	9/21/09	9/30/09	353	1157	353	Injected	1-splice 18 ft. west of riser pole
1622	33TP090 - 33SW008	White	9/21/09	9/30/09	178	583	178	Injected	1-splice 18 ft. west of riser pole
					Meters	Feet	Meters		
					4326	14199	3350		0

Appendix D – Sustained Cable Injection Process Selected

Sustained Pressure Injection Process

- De-energize, test & ground cable (A-B)
- Pinpoint all splices; vacuum-excavate
- Remove all splices, terminations & connectors
- Position new connectors, injection adaptors & new splices
- Swage injection adaptors & connectors
- Inject sub-segments at moderate pressure



Appendix E – Comparison of Sustained and Unsustained Cable Injection Process

Process Comparison

	Unsustained Pressure with Soak	Unsustained Pressure without Soak	Sustained Pressure
Visits to site	Four visits	Two visits	One visit
Soak Tanks	Required for 60-120 days, potentially energized	Required for 24-48 hours, potentially energized	None
Accessories	Special Flow Though Elbow	Special Flow Though Elbow	Standard Accessories
Fluid Contact with Accessory	Reduces life, soaks up fluid. Fluid not compatible with all accessories	Reduces life, soaks up fluid. Fluid not compatible with all accessories	Fluid does not touch the accessories
Time for Injection Visit	30-60 minutes	30-60 minutes	45-90 minutes

New Operations Centre - 80 Addiscott Rd., Markham

Assessment of Lease for New Operations Center

Capital Lease Test (per CICA 3065):

Test:	Result	Explanation
1) Is there an automatic transfer of ownership of the assets?	No.	There is no automatic transfer of ownership.
2) there is a bargain purchase option (BPO), or other facts and economic circumstances provide assurance that the lessee will acquire the asset by the end of the lease term	No.	No reasonable certainty regarding purchase option price being below FMV at that time nor of exercising it.
3) The lease term exceeds 75% of the economic life of the asset	No.	The lease term is 25 years. Based on a 50 year life of the building (50%), and infinite life of the land, the lease term does not exceed 75% of the life of the asset
4) the lessor would be assured of recovering the investment in the leased property and of earning a return on the investment as a result of the lease agreement (e.g., the present value of the minimum lease payments at the inception of the lease is 90% or more of the asset's fair value). The retention by the lessor of substantial risks in connection with the leased property (e.g., non-reimbursable costs, performance guarantees, and obsolescence) may mean that no such assurance exists.	Yes	As there is no certainty regarding exercise of the purchase option, the minimum lease payments (MLP) do not include the optional purchase price. See below for the calculation of the NPV of MLP as a % of FMV.

Minimum Lease Payments (MLP) Determination

PowerStream's incremental cost of debt	6.57%	See Note 1.
Fair Market Value ("FMV")	$ 19,041,000	See Note 3
Minimum Lease Payments at Cost of Borrowing - PV of:		
Actual Lease Payment	$18,280,294	
less: executory costs	$0	
less: taxes, maintenance, etc.	$0	
plus: Purchase price option - see Note 2.		
PV of future payments	$18,280,294	
Total PV of Minimum lease payments	**$18,280,294**	lesser of FMV and minimum lease payments
NPV of MLP as a % of current FMV	96.0%	

		37.45%	62.55%
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
Purchase Option end of year 25	40,323,246		

Conclusion:

Building is a capital lease and land is an operating lease for accounting purposes based on CICA 3065.

NOTES

1. PowerStream's incremental cost of debt is based on TD's estimated rate for a 25 year note or debenture issued in May 2008.
2. Purchase option not included in minimum lease payments as there is not a bargain purchase option.
3. FMV at the time that the deal was negotiated (May 2008) per FMV estimate from CresaPartners.

Land	$ 11,400,000	37.45%
Building	$ 19,041,000	62.55%
Total	$ 30,441,000	100.00%

4. Since no BPO, capital lease calculations above only for building portion

New Operations Centre Lease

interest rate -annual	6.57%
interest rate - monthly	0.55%
Net Present value of lease	$ 18,280,294

DETAILED CALCULATION:

Month	Annual payment	monthly payment	NPV
0	1,429,911	119,159	119,159
1	1,429,911	119,159	118,510
2	1,429,911	119,159	117,865
3	1,429,911	119,159	117,223
4	1,429,911	119,159	116,585
5	1,429,911	119,159	115,950
6	1,429,911	119,159	115,319
7	1,429,911	119,159	114,691
8	1,429,911	119,159	114,066
9	1,429,911	119,159	113,445
10	1,429,911	119,159	112,828
11	1,429,911	119,159	112,213
12	1,429,911	119,159	111,602
13	1,429,911	119,159	110,994
14	1,429,911	119,159	110,390
15	1,429,911	119,159	109,789
16	1,429,911	119,159	109,191
17	1,429,911	119,159	108,597
18	1,429,911	119,159	108,005
19	1,429,911	119,159	107,417
20	1,429,911	119,159	106,832
21	1,429,911	119,159	106,251
22	1,429,911	119,159	105,672
23	1,429,911	119,159	105,097
24	1,429,911	119,159	104,524
25	1,429,911	119,159	103,955
26	1,429,911	119,159	103,389
27	1,429,911	119,159	102,826
28	1,429,911	119,159	102,266
29	1,429,911	119,159	101,709
30	1,429,911	119,159	101,156
31	1,429,911	119,159	100,605
32	1,429,911	119,159	100,057
33	1,429,911	119,159	99,512
34	1,429,911	119,159	98,970
35	1,429,911	119,159	98,431
36	1,429,911	119,159	97,895
37	1,429,911	119,159	97,362
38	1,429,911	119,159	96,832
39	1,429,911	119,159	96,305
40	1,429,911	119,159	95,780
41	1,429,911	119,159	95,259
42	1,429,911	119,159	94,740
43	1,429,911	119,159	94,224
44	1,429,911	119,159	93,711
45	1,429,911	119,159	93,201
46	1,429,911	119,159	92,693
47	1,429,911	119,159	92,189
48	1,429,911	119,159	91,687
49	1,429,911	119,159	91,188
50	1,429,911	119,159	90,691
51	1,429,911	119,159	90,197
52	1,429,911	119,159	89,706
53	1,429,911	119,159	89,218
54	1,429,911	119,159	88,732

Month	Annual payment	monthly payment	NPV
55	1,429,911	119,159	88,249
56	1,429,911	119,159	87,768
57	1,429,911	119,159	87,290
58	1,429,911	119,159	86,815
59	1,429,911	119,159	86,342
60	1,429,911	119,159	85,872
61	1,429,911	119,159	85,404
62	1,429,911	119,159	84,939
63	1,429,911	119,159	84,477
64	1,429,911	119,159	84,017
65	1,429,911	119,159	83,559
66	1,429,911	119,159	83,104
67	1,429,911	119,159	82,652
68	1,429,911	119,159	82,202
69	1,429,911	119,159	81,754
70	1,429,911	119,159	81,309
71	1,429,911	119,159	80,866
72	1,429,911	119,159	80,426
73	1,429,911	119,159	79,988
74	1,429,911	119,159	79,552
75	1,429,911	119,159	79,119
76	1,429,911	119,159	78,688
77	1,429,911	119,159	78,260
78	1,429,911	119,159	77,834
79	1,429,911	119,159	77,410
80	1,429,911	119,159	76,988
81	1,429,911	119,159	76,569
82	1,429,911	119,159	76,152
83	1,429,911	119,159	75,738
84	1,429,911	119,159	75,325
85	1,429,911	119,159	74,915
86	1,429,911	119,159	74,507
87	1,429,911	119,159	74,101
88	1,429,911	119,159	73,698
89	1,429,911	119,159	73,297
90	1,429,911	119,159	72,898
91	1,429,911	119,159	72,501
92	1,429,911	119,159	72,106
93	1,429,911	119,159	71,713
94	1,429,911	119,159	71,323
95	1,429,911	119,159	70,934
96	1,429,911	119,159	70,548
97	1,429,911	119,159	70,164
98	1,429,911	119,159	69,782
99	1,429,911	119,159	69,402
100	1,429,911	119,159	69,024
101	1,429,911	119,159	68,648
102	1,429,911	119,159	68,274
103	1,429,911	119,159	67,903
104	1,429,911	119,159	67,533
105	1,429,911	119,159	67,165
106	1,429,911	119,159	66,799
107	1,429,911	119,159	66,436
108	1,429,911	119,159	66,074
109	1,429,911	119,159	65,714
110	1,429,911	119,159	65,356
111	1,429,911	119,159	65,000
112	1,429,911	119,159	64,646
113	1,429,911	119,159	64,294
114	1,429,911	119,159	63,944
115	1,429,911	119,159	63,596
116	1,429,911	119,159	63,250
117	1,429,911	119,159	62,905
118	1,429,911	119,159	62,563
119	1,429,911	119,159	62,222

Month	Annual payment	monthly payment	NPV
120	1,536,873	128,073	66,513
121	1,536,873	128,073	66,150
122	1,536,873	128,073	65,790
123	1,536,873	128,073	65,432
124	1,536,873	128,073	65,076
125	1,536,873	128,073	64,721
126	1,536,873	128,073	64,369
127	1,536,873	128,073	64,018
128	1,536,873	128,073	63,670
129	1,536,873	128,073	63,323
130	1,536,873	128,073	62,978
131	1,536,873	128,073	62,635
132	1,536,873	128,073	62,294
133	1,536,873	128,073	61,955
134	1,536,873	128,073	61,618
135	1,536,873	128,073	61,282
136	1,536,873	128,073	60,949
137	1,536,873	128,073	60,617
138	1,536,873	128,073	60,287
139	1,536,873	128,073	59,958
140	1,536,873	128,073	59,632
141	1,536,873	128,073	59,307
142	1,536,873	128,073	58,984
143	1,536,873	128,073	58,663
144	1,536,873	128,073	58,344
145	1,536,873	128,073	58,026
146	1,536,873	128,073	57,710
147	1,536,873	128,073	57,396
148	1,536,873	128,073	57,083
149	1,536,873	128,073	56,772
150	1,536,873	128,073	56,463
151	1,536,873	128,073	56,156
152	1,536,873	128,073	55,850
153	1,536,873	128,073	55,546
154	1,536,873	128,073	55,243
155	1,536,873	128,073	54,943
156	1,536,873	128,073	54,643
157	1,536,873	128,073	54,346
158	1,536,873	128,073	54,050
159	1,536,873	128,073	53,756
160	1,536,873	128,073	53,463
161	1,536,873	128,073	53,172
162	1,536,873	128,073	52,882
163	1,536,873	128,073	52,594
164	1,536,873	128,073	52,308
165	1,536,873	128,073	52,023
166	1,536,873	128,073	51,740
167	1,536,873	128,073	51,458
168	1,536,873	128,073	51,178
169	1,536,873	128,073	50,899
170	1,536,873	128,073	50,622
171	1,536,873	128,073	50,346
172	1,536,873	128,073	50,072
173	1,536,873	128,073	49,800
174	1,536,873	128,073	49,528
175	1,536,873	128,073	49,259
176	1,536,873	128,073	48,991
177	1,536,873	128,073	48,724
178	1,536,873	128,073	48,458
179	1,536,873	128,073	48,195
180	1,536,873	128,073	47,932
181	1,536,873	128,073	47,671
182	1,536,873	128,073	47,412
183	1,536,873	128,073	47,153
184	1,536,873	128,073	46,897

Month	Annual payment	monthly payment	NPV
185	1,536,873	128,073	46,641
186	1,536,873	128,073	46,387
187	1,536,873	128,073	46,135
188	1,536,873	128,073	45,884
189	1,536,873	128,073	45,634
190	1,536,873	128,073	45,385
191	1,536,873	128,073	45,138
192	1,536,873	128,073	44,892
193	1,536,873	128,073	44,648
194	1,536,873	128,073	44,405
195	1,536,873	128,073	44,163
196	1,536,873	128,073	43,922
197	1,536,873	128,073	43,683
198	1,536,873	128,073	43,445
199	1,536,873	128,073	43,209
200	1,536,873	128,073	42,974
201	1,536,873	128,073	42,740
202	1,536,873	128,073	42,507
203	1,536,873	128,073	42,275
204	1,536,873	128,073	42,045
205	1,536,873	128,073	41,816
206	1,536,873	128,073	41,589
207	1,536,873	128,073	41,362
208	1,536,873	128,073	41,137
209	1,536,873	128,073	40,913
210	1,536,873	128,073	40,690
211	1,536,873	128,073	40,469
212	1,536,873	128,073	40,248
213	1,536,873	128,073	40,029
214	1,536,873	128,073	39,811
215	1,536,873	128,073	39,594
216	1,536,873	128,073	39,379
217	1,536,873	128,073	39,164
218	1,536,873	128,073	38,951
219	1,536,873	128,073	38,739
220	1,536,873	128,073	38,528
221	1,536,873	128,073	38,318
222	1,536,873	128,073	38,109
223	1,536,873	128,073	37,902
224	1,536,873	128,073	37,696
225	1,536,873	128,073	37,490
226	1,536,873	128,073	37,286
227	1,536,873	128,073	37,083
228	1,536,873	128,073	36,881
229	1,536,873	128,073	36,680
230	1,536,873	128,073	36,481
231	1,536,873	128,073	36,282
232	1,536,873	128,073	36,084
233	1,536,873	128,073	35,888
234	1,536,873	128,073	35,693
235	1,536,873	128,073	35,498
236	1,536,873	128,073	35,305
237	1,536,873	128,073	35,113
238	1,536,873	128,073	34,921
239	1,536,873	128,073	34,731
240	1,639,456	136,621	36,848
241	1,639,456	136,621	36,647
242	1,639,456	136,621	36,448
243	1,639,456	136,621	36,249
244	1,639,456	136,621	36,052
245	1,639,456	136,621	35,855
246	1,639,456	136,621	35,660
247	1,639,456	136,621	35,466
248	1,639,456	136,621	35,273
249	1,639,456	136,621	35,081

Month	Annual payment	monthly payment	NPV
250	1,639,456	136,621	34,890
251	1,639,456	136,621	34,700
252	1,639,456	136,621	34,511
253	1,639,456	136,621	34,323
254	1,639,456	136,621	34,136
255	1,639,456	136,621	33,950
256	1,639,456	136,621	33,765
257	1,639,456	136,621	33,582
258	1,639,456	136,621	33,399
259	1,639,456	136,621	33,217
260	1,639,456	136,621	33,036
261	1,639,456	136,621	32,856
262	1,639,456	136,621	32,677
263	1,639,456	136,621	32,499
264	1,639,456	136,621	32,322
265	1,639,456	136,621	32,146
266	1,639,456	136,621	31,971
267	1,639,456	136,621	31,797
268	1,639,456	136,621	31,624
269	1,639,456	136,621	31,452
270	1,639,456	136,621	31,281
271	1,639,456	136,621	31,110
272	1,639,456	136,621	30,941
273	1,639,456	136,621	30,772
274	1,639,456	136,621	30,605
275	1,639,456	136,621	30,438
276	1,639,456	136,621	30,272
277	1,639,456	136,621	30,108
278	1,639,456	136,621	29,944
279	1,639,456	136,621	29,781
280	1,639,456	136,621	29,618
281	1,639,456	136,621	29,457
282	1,639,456	136,621	29,297
283	1,639,456	136,621	29,137
284	1,639,456	136,621	28,978
285	1,639,456	136,621	28,821
286	1,639,456	136,621	28,664
287	1,639,456	136,621	28,508
288	1,639,456	136,621	28,352
289	1,639,456	136,621	28,198
290	1,639,456	136,621	28,045
291	1,639,456	136,621	27,892
292	1,639,456	136,621	27,740
293	1,639,456	136,621	27,589
294	1,639,456	136,621	27,439
295	1,639,456	136,621	27,289
296	1,639,456	136,621	27,141
297	1,639,456	136,621	26,993
298	1,639,456	136,621	26,846
299	1,639,456	136,621	26,700
300	Purchase Option	NA	-
TOTAL		37,865,122	18,280,294

NPV of Lease Payments- One Operations Center vs. Two Separate

	Annual rate	monthly rate
WACC	6.30%	0.5250%
Discou	93.70%	99.4750%

	One Center		Two Centers				
Year	Addiscott	PV	New Markham Center	PV	Vaughan Center	PV	Total
NPV		$ 30,404,343		$ 18,926,381		$ 14,866,100	$ 33,792,481
1	$ 2,406,011		$ 1,502,000		$ 881,882		$ -
2	$ 2,406,011		$ 1,502,000		$ 899,520		$ -
3	$ 2,406,011		$ 1,502,000		$ 917,510		$ -
4	$ 2,406,011		$ 1,502,000		$ 935,860		$ -
5	$ 2,406,011		$ 1,502,000		$ 954,577		$ -
6	$ 2,286,011		$ 1,502,000		$ 973,669		$ -
7	$ 2,286,011		$ 1,502,000		$ 993,142		$ -
8	$ 2,286,011		$ 1,502,000		$ 1,013,005		$ -
9	$ 2,286,011		$ 1,502,000		$ 1,033,265		$ -
10	$ 2,286,011		$ 1,502,000		$ 1,053,931		$ -
11	$ 2,457,011		$ 1,502,000		$ 1,502,000		$ -
12	$ 2,457,011		$ 1,502,000		$ 1,502,000		$ -
13	$ 2,457,011		$ 1,502,000		$ 1,502,000		$ -
14	$ 2,457,011		$ 1,502,000		$ 1,502,000		$ -
15	$ 2,457,011		$ 1,502,000		$ 1,502,000		$ -
16	$ 2,457,011		$ 1,502,000		$ 1,502,000		$ -
17	$ 2,457,011		$ 1,502,000		$ 1,502,000		$ -
18	$ 2,457,011		$ 1,502,000		$ 1,502,000		$ -
19	$ 2,457,011		$ 1,502,000		$ 1,502,000		$ -
20	$ 2,457,011		$ 1,502,000		$ 1,502,000		$ -
21	$ 2,621,011		$ 1,502,000		$ 1,502,000		$ -
22	$ 2,621,011		$ 1,502,000		$ 1,502,000		$ -
23	$ 2,621,011		$ 1,502,000		$ 1,502,000		$ -
24	$ 2,621,011		$ 1,502,000		$ 1,502,000		$ -
25	$ 2,621,011		$ 1,502,000		$ 1,502,000		$ -
	$ 61,135,275	$ -	$ 37,550,000	$ -	$ 32,186,362	$ -	$ -
	(0)		-		(0)		

Notes

New Markham Center cost converted to annual rent as per write-up - cost and lease based on info from CRESA
Vaughan Center Lease payments assumed to continue until current terms then replaced in ten years.
Included $120,000 per year ($10,000 per month) for 5 years in One Center for outside storage at Vaughan.
Included the $300K annual OM&A savings as an additional cost for the separate centre at $150K each per year

Month	Payment	NPV	Payment	NPV	Payment	NPV
1	$ 200,501	$ 200,501	$ 125,167	$ 125,167	$ 73,490	$ 73,490
2	$ 200,501	$ 199,448	$ 125,167	$ 124,510	$ 73,490	$ 73,104
3	$ 200,501	$ 198,401	$ 125,167	$ 123,856	$ 73,490	$ 72,721
4	$ 200,501	$ 197,360	$ 125,167	$ 123,206	$ 73,490	$ 72,339
5	$ 200,501	$ 196,323	$ 125,167	$ 122,559	$ 73,490	$ 71,959
6	$ 200,501	$ 195,293	$ 125,167	$ 121,915	$ 73,490	$ 71,581
7	$ 200,501	$ 194,267	$ 125,167	$ 121,275	$ 73,490	$ 71,205
8	$ 200,501	$ 193,248	$ 125,167	$ 120,639	$ 73,490	$ 70,832
9	$ 200,501	$ 192,233	$ 125,167	$ 120,005	$ 73,490	$ 70,460

Month	Payment	NPV	Payment	NPV	Payment	NPV
10	$ 200,501	$ 191,224	$ 125,167	$ 119,375	$ 73,490	$ 70,090
11	$ 200,501	$ 190,220	$ 125,167	$ 118,749	$ 73,490	$ 69,722
12	$ 200,501	$ 189,221	$ 125,167	$ 118,125	$ 73,490	$ 69,356
13	$ 200,501	$ 188,228	$ 125,167	$ 117,505	$ 74,960	$ 70,371
14	$ 200,501	$ 187,240	$ 125,167	$ 116,888	$ 74,960	$ 70,002
15	$ 200,501	$ 186,257	$ 125,167	$ 116,274	$ 74,960	$ 69,635
16	$ 200,501	$ 185,279	$ 125,167	$ 115,664	$ 74,960	$ 69,269
17	$ 200,501	$ 184,306	$ 125,167	$ 115,057	$ 74,960	$ 68,905
18	$ 200,501	$ 183,338	$ 125,167	$ 114,453	$ 74,960	$ 68,544
19	$ 200,501	$ 182,376	$ 125,167	$ 113,852	$ 74,960	$ 68,184
20	$ 200,501	$ 181,418	$ 125,167	$ 113,254	$ 74,960	$ 67,826
21	$ 200,501	$ 180,466	$ 125,167	$ 112,659	$ 74,960	$ 67,470
22	$ 200,501	$ 179,519	$ 125,167	$ 112,068	$ 74,960	$ 67,115
23	$ 200,501	$ 178,576	$ 125,167	$ 111,480	$ 74,960	$ 66,763
24	$ 200,501	$ 177,639	$ 125,167	$ 110,894	$ 74,960	$ 66,413
25	$ 200,501	$ 176,706	$ 125,167	$ 110,312	$ 76,459	$ 67,385
26	$ 200,501	$ 175,778	$ 125,167	$ 109,733	$ 76,459	$ 67,031
27	$ 200,501	$ 174,855	$ 125,167	$ 109,157	$ 76,459	$ 66,679
28	$ 200,501	$ 173,937	$ 125,167	$ 108,584	$ 76,459	$ 66,329
29	$ 200,501	$ 173,024	$ 125,167	$ 108,014	$ 76,459	$ 65,981
30	$ 200,501	$ 172,116	$ 125,167	$ 107,447	$ 76,459	$ 65,635
31	$ 200,501	$ 171,212	$ 125,167	$ 106,883	$ 76,459	$ 65,290
32	$ 200,501	$ 170,313	$ 125,167	$ 106,321	$ 76,459	$ 64,947
33	$ 200,501	$ 169,419	$ 125,167	$ 105,763	$ 76,459	$ 64,606
34	$ 200,501	$ 168,530	$ 125,167	$ 105,208	$ 76,459	$ 64,267
35	$ 200,501	$ 167,645	$ 125,167	$ 104,656	$ 76,459	$ 63,930
36	$ 200,501	$ 166,765	$ 125,167	$ 104,106	$ 76,459	$ 63,594
37	$ 200,501	$ 165,889	$ 125,167	$ 103,560	$ 77,988	$ 64,526
38	$ 200,501	$ 165,018	$ 125,167	$ 103,016	$ 77,988	$ 64,187
39	$ 200,501	$ 164,152	$ 125,167	$ 102,475	$ 77,988	$ 63,850
40	$ 200,501	$ 163,290	$ 125,167	$ 101,937	$ 77,988	$ 63,515
41	$ 200,501	$ 162,433	$ 125,167	$ 101,402	$ 77,988	$ 63,181
42	$ 200,501	$ 161,580	$ 125,167	$ 100,870	$ 77,988	$ 62,849
43	$ 200,501	$ 160,732	$ 125,167	$ 100,340	$ 77,988	$ 62,520
44	$ 200,501	$ 159,888	$ 125,167	$ 99,813	$ 77,988	$ 62,191
45	$ 200,501	$ 159,049	$ 125,167	$ 99,289	$ 77,988	$ 61,865
46	$ 200,501	$ 158,214	$ 125,167	$ 98,768	$ 77,988	$ 61,540
47	$ 200,501	$ 157,383	$ 125,167	$ 98,249	$ 77,988	$ 61,217
48	$ 200,501	$ 156,557	$ 125,167	$ 97,734	$ 77,988	$ 60,896
49	$ 200,501	$ 155,735	$ 125,167	$ 97,221	$ 79,548	$ 61,787
50	$ 200,501	$ 154,917	$ 125,167	$ 96,710	$ 79,548	$ 61,463
51	$ 200,501	$ 154,104	$ 125,167	$ 96,202	$ 79,548	$ 61,140
52	$ 200,501	$ 153,295	$ 125,167	$ 95,697	$ 79,548	$ 60,819
53	$ 200,501	$ 152,490	$ 125,167	$ 95,195	$ 79,548	$ 60,500
54	$ 200,501	$ 151,690	$ 125,167	$ 94,695	$ 79,548	$ 60,182
55	$ 200,501	$ 150,893	$ 125,167	$ 94,198	$ 79,548	$ 59,866
56	$ 200,501	$ 150,101	$ 125,167	$ 93,704	$ 79,548	$ 59,552
57	$ 200,501	$ 149,313	$ 125,167	$ 93,212	$ 79,548	$ 59,239
58	$ 200,501	$ 148,529	$ 125,167	$ 92,722	$ 79,548	$ 58,928
59	$ 200,501	$ 147,749	$ 125,167	$ 92,235	$ 79,548	$ 58,619
60	$ 200,501	$ 146,974	$ 125,167	$ 91,751	$ 79,548	$ 58,311
61	$ 190,501	$ 138,910	$ 125,167	$ 91,269	$ 81,139	$ 59,165
62	$ 190,501	$ 138,181	$ 125,167	$ 90,790	$ 81,139	$ 58,855
63	$ 190,501	$ 137,455	$ 125,167	$ 90,314	$ 81,139	$ 58,546
64	$ 190,501	$ 136,734	$ 125,167	$ 89,840	$ 81,139	$ 58,238

Month	Payment	NPV	Payment	NPV	Payment	NPV
65	$ 190,501	$ 136,016	$ 125,167	$ 89,368	$ 81,139	$ 57,933
66	$ 190,501	$ 135,302	$ 125,167	$ 88,899	$ 81,139	$ 57,628
67	$ 190,501	$ 134,591	$ 125,167	$ 88,432	$ 81,139	$ 57,326
68	$ 190,501	$ 133,885	$ 125,167	$ 87,968	$ 81,139	$ 57,025
69	$ 190,501	$ 133,182	$ 125,167	$ 87,506	$ 81,139	$ 56,726
70	$ 190,501	$ 132,483	$ 125,167	$ 87,046	$ 81,139	$ 56,428
71	$ 190,501	$ 131,787	$ 125,167	$ 86,589	$ 81,139	$ 56,131
72	$ 190,501	$ 131,095	$ 125,167	$ 86,135	$ 81,139	$ 55,837
73	$ 190,501	$ 130,407	$ 125,167	$ 85,683	$ 82,762	$ 56,655
74	$ 190,501	$ 129,722	$ 125,167	$ 85,233	$ 82,762	$ 56,357
75	$ 190,501	$ 129,041	$ 125,167	$ 84,785	$ 82,762	$ 56,061
76	$ 190,501	$ 128,364	$ 125,167	$ 84,340	$ 82,762	$ 55,767
77	$ 190,501	$ 127,690	$ 125,167	$ 83,897	$ 82,762	$ 55,474
78	$ 190,501	$ 127,020	$ 125,167	$ 83,457	$ 82,762	$ 55,183
79	$ 190,501	$ 126,353	$ 125,167	$ 83,019	$ 82,762	$ 54,893
80	$ 190,501	$ 125,689	$ 125,167	$ 82,583	$ 82,762	$ 54,605
81	$ 190,501	$ 125,030	$ 125,167	$ 82,149	$ 82,762	$ 54,318
82	$ 190,501	$ 124,373	$ 125,167	$ 81,718	$ 82,762	$ 54,033
83	$ 190,501	$ 123,720	$ 125,167	$ 81,289	$ 82,762	$ 53,749
84	$ 190,501	$ 123,071	$ 125,167	$ 80,862	$ 82,762	$ 53,467
85	$ 190,501	$ 122,425	$ 125,167	$ 80,438	$ 84,417	$ 54,250
86	$ 190,501	$ 121,782	$ 125,167	$ 80,016	$ 84,417	$ 53,965
87	$ 190,501	$ 121,143	$ 125,167	$ 79,595	$ 84,417	$ 53,682
88	$ 190,501	$ 120,507	$ 125,167	$ 79,178	$ 84,417	$ 53,400
89	$ 190,501	$ 119,874	$ 125,167	$ 78,762	$ 84,417	$ 53,120
90	$ 190,501	$ 119,245	$ 125,167	$ 78,348	$ 84,417	$ 52,841
91	$ 190,501	$ 118,618	$ 125,167	$ 77,937	$ 84,417	$ 52,564
92	$ 190,501	$ 117,996	$ 125,167	$ 77,528	$ 84,417	$ 52,288
93	$ 190,501	$ 117,376	$ 125,167	$ 77,121	$ 84,417	$ 52,013
94	$ 190,501	$ 116,760	$ 125,167	$ 76,716	$ 84,417	$ 51,740
95	$ 190,501	$ 116,147	$ 125,167	$ 76,313	$ 84,417	$ 51,469
96	$ 190,501	$ 115,537	$ 125,167	$ 75,913	$ 84,417	$ 51,198
97	$ 190,501	$ 114,931	$ 125,167	$ 75,514	$ 86,105	$ 51,948
98	$ 190,501	$ 114,327	$ 125,167	$ 75,118	$ 86,105	$ 51,675
99	$ 190,501	$ 113,727	$ 125,167	$ 74,723	$ 86,105	$ 51,404
100	$ 190,501	$ 113,130	$ 125,167	$ 74,331	$ 86,105	$ 51,134
101	$ 190,501	$ 112,536	$ 125,167	$ 73,941	$ 86,105	$ 50,866
102	$ 190,501	$ 111,945	$ 125,167	$ 73,552	$ 86,105	$ 50,599
103	$ 190,501	$ 111,358	$ 125,167	$ 73,166	$ 86,105	$ 50,333
104	$ 190,501	$ 110,773	$ 125,167	$ 72,782	$ 86,105	$ 50,069
105	$ 190,501	$ 110,191	$ 125,167	$ 72,400	$ 86,105	$ 49,806
106	$ 190,501	$ 109,613	$ 125,167	$ 72,020	$ 86,105	$ 49,544
107	$ 190,501	$ 109,037	$ 125,167	$ 71,642	$ 86,105	$ 49,284
108	$ 190,501	$ 108,465	$ 125,167	$ 71,266	$ 86,105	$ 49,026
109	$ 190,501	$ 107,896	$ 125,167	$ 70,892	$ 87,828	$ 49,744
110	$ 190,501	$ 107,329	$ 125,167	$ 70,519	$ 87,828	$ 49,482
111	$ 190,501	$ 106,766	$ 125,167	$ 70,149	$ 87,828	$ 49,223
112	$ 190,501	$ 106,205	$ 125,167	$ 69,781	$ 87,828	$ 48,964
113	$ 190,501	$ 105,648	$ 125,167	$ 69,415	$ 87,828	$ 48,707
114	$ 190,501	$ 105,093	$ 125,167	$ 69,050	$ 87,828	$ 48,451
115	$ 190,501	$ 104,541	$ 125,167	$ 68,688	$ 87,828	$ 48,197
116	$ 190,501	$ 103,992	$ 125,167	$ 68,327	$ 87,828	$ 47,944
117	$ 190,501	$ 103,446	$ 125,167	$ 67,968	$ 87,828	$ 47,692
118	$ 190,501	$ 102,903	$ 125,167	$ 67,612	$ 87,828	$ 47,442
119	$ 190,501	$ 102,363	$ 125,167	$ 67,257	$ 87,828	$ 47,193

Month	Payment	NPV	Payment	NPV	Payment	NPV
120	$ 190,501	$ 101,826	$ 125,167	$ 66,903	$ 87,828	$ 46,945
121	$ 204,751	$ 108,868	$ 125,167	$ 66,552	$ 125,167	$ 66,552
122	$ 204,751	$ 108,296	$ 125,167	$ 66,203	$ 125,167	$ 66,203
123	$ 204,751	$ 107,728	$ 125,167	$ 65,855	$ 125,167	$ 65,855
124	$ 204,751	$ 107,162	$ 125,167	$ 65,509	$ 125,167	$ 65,509
125	$ 204,751	$ 106,600	$ 125,167	$ 65,166	$ 125,167	$ 65,166
126	$ 204,751	$ 106,040	$ 125,167	$ 64,823	$ 125,167	$ 64,823
127	$ 204,751	$ 105,483	$ 125,167	$ 64,483	$ 125,167	$ 64,483
128	$ 204,751	$ 104,929	$ 125,167	$ 64,145	$ 125,167	$ 64,145
129	$ 204,751	$ 104,379	$ 125,167	$ 63,808	$ 125,167	$ 63,808
130	$ 204,751	$ 103,831	$ 125,167	$ 63,473	$ 125,167	$ 63,473
131	$ 204,751	$ 103,285	$ 125,167	$ 63,140	$ 125,167	$ 63,140
132	$ 204,751	$ 102,743	$ 125,167	$ 62,808	$ 125,167	$ 62,808
133	$ 204,751	$ 102,204	$ 125,167	$ 62,478	$ 125,167	$ 62,478
134	$ 204,751	$ 101,667	$ 125,167	$ 62,150	$ 125,167	$ 62,150
135	$ 204,751	$ 101,133	$ 125,167	$ 61,824	$ 125,167	$ 61,824
136	$ 204,751	$ 100,603	$ 125,167	$ 61,500	$ 125,167	$ 61,500
137	$ 204,751	$ 100,074	$ 125,167	$ 61,177	$ 125,167	$ 61,177
138	$ 204,751	$ 99,549	$ 125,167	$ 60,855	$ 125,167	$ 60,855
139	$ 204,751	$ 99,026	$ 125,167	$ 60,536	$ 125,167	$ 60,536
140	$ 204,751	$ 98,506	$ 125,167	$ 60,218	$ 125,167	$ 60,218
141	$ 204,751	$ 97,989	$ 125,167	$ 59,902	$ 125,167	$ 59,902
142	$ 204,751	$ 97,475	$ 125,167	$ 59,588	$ 125,167	$ 59,588
143	$ 204,751	$ 96,963	$ 125,167	$ 59,275	$ 125,167	$ 59,275
144	$ 204,751	$ 96,454	$ 125,167	$ 58,963	$ 125,167	$ 58,963
145	$ 204,751	$ 95,948	$ 125,167	$ 58,654	$ 125,167	$ 58,654
146	$ 204,751	$ 95,444	$ 125,167	$ 58,346	$ 125,167	$ 58,346
147	$ 204,751	$ 94,943	$ 125,167	$ 58,040	$ 125,167	$ 58,040
148	$ 204,751	$ 94,444	$ 125,167	$ 57,735	$ 125,167	$ 57,735
149	$ 204,751	$ 93,949	$ 125,167	$ 57,432	$ 125,167	$ 57,432
150	$ 204,751	$ 93,455	$ 125,167	$ 57,130	$ 125,167	$ 57,130
151	$ 204,751	$ 92,965	$ 125,167	$ 56,830	$ 125,167	$ 56,830
152	$ 204,751	$ 92,477	$ 125,167	$ 56,532	$ 125,167	$ 56,532
153	$ 204,751	$ 91,991	$ 125,167	$ 56,235	$ 125,167	$ 56,235
154	$ 204,751	$ 91,508	$ 125,167	$ 55,940	$ 125,167	$ 55,940
155	$ 204,751	$ 91,028	$ 125,167	$ 55,646	$ 125,167	$ 55,646
156	$ 204,751	$ 90,550	$ 125,167	$ 55,354	$ 125,167	$ 55,354
157	$ 204,751	$ 90,074	$ 125,167	$ 55,064	$ 125,167	$ 55,064
158	$ 204,751	$ 89,602	$ 125,167	$ 54,775	$ 125,167	$ 54,775
159	$ 204,751	$ 89,131	$ 125,167	$ 54,487	$ 125,167	$ 54,487
160	$ 204,751	$ 88,663	$ 125,167	$ 54,201	$ 125,167	$ 54,201
161	$ 204,751	$ 88,198	$ 125,167	$ 53,916	$ 125,167	$ 53,916
162	$ 204,751	$ 87,735	$ 125,167	$ 53,633	$ 125,167	$ 53,633
163	$ 204,751	$ 87,274	$ 125,167	$ 53,352	$ 125,167	$ 53,352
164	$ 204,751	$ 86,816	$ 125,167	$ 53,072	$ 125,167	$ 53,072
165	$ 204,751	$ 86,360	$ 125,167	$ 52,793	$ 125,167	$ 52,793
166	$ 204,751	$ 85,907	$ 125,167	$ 52,516	$ 125,167	$ 52,516
167	$ 204,751	$ 85,456	$ 125,167	$ 52,240	$ 125,167	$ 52,240
168	$ 204,751	$ 85,007	$ 125,167	$ 51,966	$ 125,167	$ 51,966
169	$ 204,751	$ 84,561	$ 125,167	$ 51,693	$ 125,167	$ 51,693
170	$ 204,751	$ 84,117	$ 125,167	$ 51,422	$ 125,167	$ 51,422
171	$ 204,751	$ 83,675	$ 125,167	$ 51,152	$ 125,167	$ 51,152
172	$ 204,751	$ 83,236	$ 125,167	$ 50,883	$ 125,167	$ 50,883
173	$ 204,751	$ 82,799	$ 125,167	$ 50,616	$ 125,167	$ 50,616
174	$ 204,751	$ 82,364	$ 125,167	$ 50,350	$ 125,167	$ 50,350

Month	Payment	NPV	Payment	NPV	Payment	NPV
175	$ 204,751	$ 81,932	$ 125,167	$ 50,086	$ 125,167	$ 50,086
176	$ 204,751	$ 81,502	$ 125,167	$ 49,823	$ 125,167	$ 49,823
177	$ 204,751	$ 81,074	$ 125,167	$ 49,561	$ 125,167	$ 49,561
178	$ 204,751	$ 80,648	$ 125,167	$ 49,301	$ 125,167	$ 49,301
179	$ 204,751	$ 80,225	$ 125,167	$ 49,042	$ 125,167	$ 49,042
180	$ 204,751	$ 79,804	$ 125,167	$ 48,785	$ 125,167	$ 48,785
181	$ 204,751	$ 79,385	$ 125,167	$ 48,529	$ 125,167	$ 48,529
182	$ 204,751	$ 78,968	$ 125,167	$ 48,274	$ 125,167	$ 48,274
183	$ 204,751	$ 78,553	$ 125,167	$ 48,021	$ 125,167	$ 48,021
184	$ 204,751	$ 78,141	$ 125,167	$ 47,768	$ 125,167	$ 47,768
185	$ 204,751	$ 77,731	$ 125,167	$ 47,518	$ 125,167	$ 47,518
186	$ 204,751	$ 77,323	$ 125,167	$ 47,268	$ 125,167	$ 47,268
187	$ 204,751	$ 76,917	$ 125,167	$ 47,020	$ 125,167	$ 47,020
188	$ 204,751	$ 76,513	$ 125,167	$ 46,773	$ 125,167	$ 46,773
189	$ 204,751	$ 76,111	$ 125,167	$ 46,528	$ 125,167	$ 46,528
190	$ 204,751	$ 75,712	$ 125,167	$ 46,283	$ 125,167	$ 46,283
191	$ 204,751	$ 75,314	$ 125,167	$ 46,040	$ 125,167	$ 46,040
192	$ 204,751	$ 74,919	$ 125,167	$ 45,799	$ 125,167	$ 45,799
193	$ 204,751	$ 74,525	$ 125,167	$ 45,558	$ 125,167	$ 45,558
194	$ 204,751	$ 74,134	$ 125,167	$ 45,319	$ 125,167	$ 45,319
195	$ 204,751	$ 73,745	$ 125,167	$ 45,081	$ 125,167	$ 45,081
196	$ 204,751	$ 73,358	$ 125,167	$ 44,844	$ 125,167	$ 44,844
197	$ 204,751	$ 72,973	$ 125,167	$ 44,609	$ 125,167	$ 44,609
198	$ 204,751	$ 72,589	$ 125,167	$ 44,375	$ 125,167	$ 44,375
199	$ 204,751	$ 72,208	$ 125,167	$ 44,142	$ 125,167	$ 44,142
200	$ 204,751	$ 71,829	$ 125,167	$ 43,910	$ 125,167	$ 43,910
201	$ 204,751	$ 71,452	$ 125,167	$ 43,680	$ 125,167	$ 43,680
202	$ 204,751	$ 71,077	$ 125,167	$ 43,450	$ 125,167	$ 43,450
203	$ 204,751	$ 70,704	$ 125,167	$ 43,222	$ 125,167	$ 43,222
204	$ 204,751	$ 70,333	$ 125,167	$ 42,995	$ 125,167	$ 42,995
205	$ 204,751	$ 69,963	$ 125,167	$ 42,769	$ 125,167	$ 42,769
206	$ 204,751	$ 69,596	$ 125,167	$ 42,545	$ 125,167	$ 42,545
207	$ 204,751	$ 69,231	$ 125,167	$ 42,322	$ 125,167	$ 42,322
208	$ 204,751	$ 68,867	$ 125,167	$ 42,099	$ 125,167	$ 42,099
209	$ 204,751	$ 68,506	$ 125,167	$ 41,878	$ 125,167	$ 41,878
210	$ 204,751	$ 68,146	$ 125,167	$ 41,659	$ 125,167	$ 41,659
211	$ 204,751	$ 67,788	$ 125,167	$ 41,440	$ 125,167	$ 41,440
212	$ 204,751	$ 67,432	$ 125,167	$ 41,222	$ 125,167	$ 41,222
213	$ 204,751	$ 67,078	$ 125,167	$ 41,006	$ 125,167	$ 41,006
214	$ 204,751	$ 66,726	$ 125,167	$ 40,791	$ 125,167	$ 40,791
215	$ 204,751	$ 66,376	$ 125,167	$ 40,576	$ 125,167	$ 40,576
216	$ 204,751	$ 66,027	$ 125,167	$ 40,363	$ 125,167	$ 40,363
217	$ 204,751	$ 65,681	$ 125,167	$ 40,151	$ 125,167	$ 40,151
218	$ 204,751	$ 65,336	$ 125,167	$ 39,941	$ 125,167	$ 39,941
219	$ 204,751	$ 64,993	$ 125,167	$ 39,731	$ 125,167	$ 39,731
220	$ 204,751	$ 64,652	$ 125,167	$ 39,522	$ 125,167	$ 39,522
221	$ 204,751	$ 64,312	$ 125,167	$ 39,315	$ 125,167	$ 39,315
222	$ 204,751	$ 63,975	$ 125,167	$ 39,108	$ 125,167	$ 39,108
223	$ 204,751	$ 63,639	$ 125,167	$ 38,903	$ 125,167	$ 38,903
224	$ 204,751	$ 63,305	$ 125,167	$ 38,699	$ 125,167	$ 38,699
225	$ 204,751	$ 62,972	$ 125,167	$ 38,496	$ 125,167	$ 38,496
226	$ 204,751	$ 62,642	$ 125,167	$ 38,294	$ 125,167	$ 38,294
227	$ 204,751	$ 62,313	$ 125,167	$ 38,093	$ 125,167	$ 38,093
228	$ 204,751	$ 61,986	$ 125,167	$ 37,893	$ 125,167	$ 37,893
229	$ 204,751	$ 61,660	$ 125,167	$ 37,694	$ 125,167	$ 37,694

Month	Payment	NPV	Payment	NPV	Payment	NPV
230	$ 204,751	$ 61,337	$ 125,167	$ 37,496	$ 125,167	$ 37,496
231	$ 204,751	$ 61,015	$ 125,167	$ 37,299	$ 125,167	$ 37,299
232	$ 204,751	$ 60,694	$ 125,167	$ 37,103	$ 125,167	$ 37,103
233	$ 204,751	$ 60,376	$ 125,167	$ 36,908	$ 125,167	$ 36,908
234	$ 204,751	$ 60,059	$ 125,167	$ 36,715	$ 125,167	$ 36,715
235	$ 204,751	$ 59,743	$ 125,167	$ 36,522	$ 125,167	$ 36,522
236	$ 204,751	$ 59,430	$ 125,167	$ 36,330	$ 125,167	$ 36,330
237	$ 204,751	$ 59,118	$ 125,167	$ 36,139	$ 125,167	$ 36,139
238	$ 204,751	$ 58,807	$ 125,167	$ 35,950	$ 125,167	$ 35,950
239	$ 204,751	$ 58,499	$ 125,167	$ 35,761	$ 125,167	$ 35,761
240	$ 204,751	$ 58,191	$ 125,167	$ 35,573	$ 125,167	$ 35,573
241	$ 218,418	$ 61,750	$ 125,167	$ 35,386	$ 125,167	$ 35,386
242	$ 218,418	$ 61,426	$ 125,167	$ 35,201	$ 125,167	$ 35,201
243	$ 218,418	$ 61,103	$ 125,167	$ 35,016	$ 125,167	$ 35,016
244	$ 218,418	$ 60,782	$ 125,167	$ 34,832	$ 125,167	$ 34,832
245	$ 218,418	$ 60,463	$ 125,167	$ 34,649	$ 125,167	$ 34,649
246	$ 218,418	$ 60,146	$ 125,167	$ 34,467	$ 125,167	$ 34,467
247	$ 218,418	$ 59,830	$ 125,167	$ 34,286	$ 125,167	$ 34,286
248	$ 218,418	$ 59,516	$ 125,167	$ 34,106	$ 125,167	$ 34,106
249	$ 218,418	$ 59,203	$ 125,167	$ 33,927	$ 125,167	$ 33,927
250	$ 218,418	$ 58,893	$ 125,167	$ 33,749	$ 125,167	$ 33,749
251	$ 218,418	$ 58,583	$ 125,167	$ 33,572	$ 125,167	$ 33,572
252	$ 218,418	$ 58,276	$ 125,167	$ 33,396	$ 125,167	$ 33,396
253	$ 218,418	$ 57,970	$ 125,167	$ 33,220	$ 125,167	$ 33,220
254	$ 218,418	$ 57,666	$ 125,167	$ 33,046	$ 125,167	$ 33,046
255	$ 218,418	$ 57,363	$ 125,167	$ 32,872	$ 125,167	$ 32,872
256	$ 218,418	$ 57,062	$ 125,167	$ 32,700	$ 125,167	$ 32,700
257	$ 218,418	$ 56,762	$ 125,167	$ 32,528	$ 125,167	$ 32,528
258	$ 218,418	$ 56,464	$ 125,167	$ 32,357	$ 125,167	$ 32,357
259	$ 218,418	$ 56,168	$ 125,167	$ 32,187	$ 125,167	$ 32,187
260	$ 218,418	$ 55,873	$ 125,167	$ 32,019	$ 125,167	$ 32,019
261	$ 218,418	$ 55,579	$ 125,167	$ 31,850	$ 125,167	$ 31,850
262	$ 218,418	$ 55,288	$ 125,167	$ 31,683	$ 125,167	$ 31,683
263	$ 218,418	$ 54,997	$ 125,167	$ 31,517	$ 125,167	$ 31,517
264	$ 218,418	$ 54,709	$ 125,167	$ 31,351	$ 125,167	$ 31,351
265	$ 218,418	$ 54,421	$ 125,167	$ 31,187	$ 125,167	$ 31,187
266	$ 218,418	$ 54,136	$ 125,167	$ 31,023	$ 125,167	$ 31,023
267	$ 218,418	$ 53,851	$ 125,167	$ 30,860	$ 125,167	$ 30,860
268	$ 218,418	$ 53,569	$ 125,167	$ 30,698	$ 125,167	$ 30,698
269	$ 218,418	$ 53,288	$ 125,167	$ 30,537	$ 125,167	$ 30,537
270	$ 218,418	$ 53,008	$ 125,167	$ 30,377	$ 125,167	$ 30,377
271	$ 218,418	$ 52,729	$ 125,167	$ 30,217	$ 125,167	$ 30,217
272	$ 218,418	$ 52,453	$ 125,167	$ 30,059	$ 125,167	$ 30,059
273	$ 218,418	$ 52,177	$ 125,167	$ 29,901	$ 125,167	$ 29,901
274	$ 218,418	$ 51,903	$ 125,167	$ 29,744	$ 125,167	$ 29,744
275	$ 218,418	$ 51,631	$ 125,167	$ 29,588	$ 125,167	$ 29,588
276	$ 218,418	$ 51,360	$ 125,167	$ 29,432	$ 125,167	$ 29,432
277	$ 218,418	$ 51,090	$ 125,167	$ 29,278	$ 125,167	$ 29,278
278	$ 218,418	$ 50,822	$ 125,167	$ 29,124	$ 125,167	$ 29,124
279	$ 218,418	$ 50,555	$ 125,167	$ 28,971	$ 125,167	$ 28,971
280	$ 218,418	$ 50,290	$ 125,167	$ 28,819	$ 125,167	$ 28,819
281	$ 218,418	$ 50,026	$ 125,167	$ 28,668	$ 125,167	$ 28,668
282	$ 218,418	$ 49,763	$ 125,167	$ 28,517	$ 125,167	$ 28,517
283	$ 218,418	$ 49,502	$ 125,167	$ 28,368	$ 125,167	$ 28,368
284	$ 218,418	$ 49,242	$ 125,167	$ 28,219	$ 125,167	$ 28,219

Month	Payment	NPV	Payment	NPV	Payment	NPV
285	$ 218,418	$ 48,983	$ 125,167	$ 28,070	$ 125,167	$ 28,070
286	$ 218,418	$ 48,726	$ 125,167	$ 27,923	$ 125,167	$ 27,923
287	$ 218,418	$ 48,470	$ 125,167	$ 27,777	$ 125,167	$ 27,777
288	$ 218,418	$ 48,216	$ 125,167	$ 27,631	$ 125,167	$ 27,631
289	$ 218,418	$ 47,963	$ 125,167	$ 27,486	$ 125,167	$ 27,486
290	$ 218,418	$ 47,711	$ 125,167	$ 27,341	$ 125,167	$ 27,341
291	$ 218,418	$ 47,461	$ 125,167	$ 27,198	$ 125,167	$ 27,198
292	$ 218,418	$ 47,211	$ 125,167	$ 27,055	$ 125,167	$ 27,055
293	$ 218,418	$ 46,963	$ 125,167	$ 26,913	$ 125,167	$ 26,913
294	$ 218,418	$ 46,717	$ 125,167	$ 26,772	$ 125,167	$ 26,772
295	$ 218,418	$ 46,472	$ 125,167	$ 26,631	$ 125,167	$ 26,631
296	$ 218,418	$ 46,228	$ 125,167	$ 26,491	$ 125,167	$ 26,491
297	$ 218,418	$ 45,985	$ 125,167	$ 26,352	$ 125,167	$ 26,352
298	$ 218,418	$ 45,744	$ 125,167	$ 26,214	$ 125,167	$ 26,214
299	$ 218,418	$ 45,503	$ 125,167	$ 26,076	$ 125,167	$ 26,076
300	$ 218,418	$ 45,265	$ 125,167	$ 25,939	$ 125,167	$ 25,939
TOTAL	$ 61,135,275	$ 30,404,343	$ 37,550,000	$ 18,926,381	$ 32,186,362	$ 14,866,100

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.1 Is the proposed forecast of 2013 Test Year Throughput Revenue appropriate? (C1)

ENERGY PROBE INTERROGATORY #13:

Reference(s): Exhibit C1, Tab 1, Schedule 1

a) Does the increase in total distribution revenue shown in Table 1 between 2012 and 2013 reflect only the increase the number of customers and volumes in 2013 as compared to 2012? If not, what other factors are contributing to the increase in distribution revenues?

b) Please provide the increase in revenues in 2013 that are the result of only the change in the number of customers and volumes forecast for 2013 (i.e. exclude the impacts of customers and volumes added part way through 2012). Please show the calculation of the change into customers, kWh's and kW's. Please reconcile the customers, kWh's and kW's with the 2013 forecast shown in the evidence.

RESPONSE:

a) There are no other factors which are contributing to the increase in 2013 distribution revenue compared to 2012 other than increases in the number of customer and volumes.

b) As explained in the response to 13a) above, increases are the result of changes in the number of customers and volumes forecast for 2013 and therefore no further calculation is required.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.1 Is the proposed forecast of 2013 Test Year Throughput Revenue appropriate? (C1)

VECC INTERROGATORY #14:

Reference(s): Exhibit C1, Tab 1, Schedule 4, Tables 3 – 7

a) Please provide revised versions of Tables 3-7 with the names of the individual customer classes shown.

RESPONSE:

a) Please refer to the response to Energy Probe #19, filed at Exhibit J1, Tab 3, Schedule 3.2.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

BOARD STAFF INTERROGATORY #17:

Reference(s): E C1/ T1/ S1, p. 1

Table 1: "Distribution Revenue at Current Rates" provided the changes in PowerStream's Total Distribution Revenue for the 2009 to 2013 period. It shows a year-over-year increase for the years 2010 to 2012 in the range of 3.7% to 4.1%.

In this context, please explain why PowerStream considers an increase of only 1.1% in the 2013 Test Year to be reasonable.

RESPONSE:

The increases in distribution revenue over the period 2010 to 2012 included incremental distribution revenue generated from the recovery of costs associated with the installation of smart meters. This contributed to increases in excess of 3% annually since 2009. Exhibit C1, Tab 1, Schedule 4, Table 1 identifies the distribution revenue increases excluding the smart meter incremental revenue. Excluding the smart meter increment revenue, distribution revenue increases as a result of growth and IRM adjustments were in the range of 1.3% to 1.8%. Based on PowerStream's current CDM targets combined with the lower trends in customer and consumption growth in recent years the increase of 1.1% in Distribution Revenue at Current Rates is reasonable for the 2013 Test Year.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

BOARD STAFF INTERROGATORY #18:

Reference(s): E C1/ T1/ S1, p. 2

It is stated that:

"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."

Please state what PowerStream would view as being the relative significance of the two factors described above in producing the slower pace of growth for all classes.

RESPONSE:

Both factors combined do not affect each rate class in the same manner. The slowing growth in residential customer additions is significantly impacted by the tapering growth in new residential customer connection requests as compared to higher growth periods in 1999-2003. The service territory has experienced significant development over the years with fewer areas of "green field" growth available as compared to ten to fifteen years ago. In addition, in recent years PowerStream has experienced lower residential customer growth attributable to controlled lot allocations related to water and sewer capacity issues. Table 1 in Exhibit C1, Tab 1, Schedule 3 illustrates the growth rate trend from 1999-2013. Growth rates since 2009 have decreased to approximately 2.0% per year. As filed in Exhibit C1, Tab 1, Schedule 3, residential customer additions have been

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

relatively flat in recent years. External economic factors such the 2008 economic recession, the introduction of harmonized sales tax in July 2010 on new home construction have also contributed to lower growth in the residential customer class.

As shown in Exhibit C1, Tab 1, Schedule 3, Figure 3 and Table 2 General Service customer additions have been significantly impacted since 2008. The economic recession followed by the slow recovery has impacted the commercial class significantly. Although similar growth factors are applicable to both rate classes, the significance of certain factors affect the growth rates in each class differently.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

BOARD STAFF INTERROGATORY #19:

Reference(s): E C1/ T1/ S2, p. 1

It is stated that:

"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."

Please provide details of the studies that were undertaken which supported this conclusion.

RESPONSE:

The tables below show estimated class-specific load forecast models that provided the "best" statistical fit. Compared to the evidence filed in Exhibit C1, Tab 1, Schedule 2, all class-specific models performed worse. The class specific models are not particularly strong with low Adjusted R^2 and high MAPE. There are large unexplained monthly variances and the historical data series are relatively short (starting January 2006). As a result, PowerStream decided not to utilize class-specific models for the purpose of forecasting load for the 2012 Bridge and 2013 Test Year.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Table Board Staff #19-1: Residential Class

Dependent variable – Residential energy sales (MWh)

Model Statistics	RESIDENTIAL
Iterations	1
Adjusted Observations	72
Deg. of Freedom for Error	62
R-Squared	88.8%
Adjusted R-Squared	87.2%
AIC	19.491
BIC	19.807
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-793.82
Model Sum of Squares	126,047,759,686.22
Sum of Squared Errors	15,898,178,178.58
Mean Squared Error	256,422,228.69
Std. Error of Regression	16,013.19
Mean Abs. Dev. (MAD)	11,354.78
Mean Abs. % Err. (MAPE)	5.36%
Durbin-Watson Statistic	1.82
Durbin-H Statistic	#NA
Ljung-Box Statistic	19.91
Prob (Ljung-Box)	0.7018
Skewness	-0.082
Kurtosis	3.045
Jarque-Bera	0.086
Prob (Jarque-Bera)	0.9578

Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.Toronto_RealInc	880	20	44.87	0.00%
mWthr.Lag1CDD18	961	48	19.97	0.00%
mWthr.Lag1HDD10	143	13	10.95	0.00%
mBin.Jul06	(48,285)	16,267	(2.97)	0.43%
mBin.Sep07	(71,539)	16,798	(4.26)	0.01%
mBin.Jan08	92,774	16,329	5.68	0.00%
mBin.Nov10	(48,955)	16,470	(2.97)	0.42%
mBin.Dec07	(35,893)	16,194	(2.22)	3.03%
mBin.Oct	19,521	7,183	2.72	0.85%
mBin.Dec09	48,960	16,244	3.01	0.37%

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Table Board Staff #19-2: GS<50 Class

Dependent variable – GS<50 energy sales (MWh)

Model Statistics	GS<50
Iterations	1
Adjusted Observations	72
Deg. of Freedom for Error	62
R-Squared	77.4%
Adjusted R-Squared	74.1%
AIC	16.905
BIC	17.222
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-700.76
Model Sum of Squares	4,100,073,234.32
Sum of Squared Errors	1,198,493,268.21
Mean Squared Error	19,330,536.58
Std. Error of Regression	4,396.65
Mean Abs. Dev. (MAD)	3,127.26
Mean Abs. % Err. (MAPE)	3.80%
Durbin-Watson Statistic	2.087
Durbin-H Statistic	#NA
Ljung-Box Statistic	24.02
Prob (Ljung-Box)	0.4603
Skewness	0.174
Kurtosis	3.135
Jarque-Bera	0.419
Prob (Jarque-Bera)	0.811

Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.Econ_Index	64,991	1,007	64.56	0.00%
mWthr.HDD10	14	6	2.31	2.42%
mWthr.Lag1HDD10	32	6	5.46	0.00%
mWthr.CDD18	72	15	4.79	0.00%
mWthr.Lag1CDD18	42	17	2.47	1.62%
mBin.Dec06	(14,062)	4,478	(3.14)	0.26%
mBin.Feb	(8,632)	2,265	(3.81)	0.03%
mBin.Apr	(5,877)	2,420	(2.43)	1.81%
mBin.Aug	6,146	2,498	2.46	1.67%
mBin.Jan08	20,342	4,552	4.47	0.00%

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Table Board Staff #19-3: GS>50 Class

Dependent variable – GS>50 energy sales (MWh)

Model Statistics	GS>50
Iterations	1
Adjusted Observations	72
Deg. of Freedom for Error	63
R-Squared	77.7%
Adjusted R-Squared	74.8%
AIC	19.252
BIC	19.537
F-Statistic	27.39
Prob (F-Statistic)	0
Log-Likelihood	-786.24
Model Sum of Squares	44,794,309,366.02
Sum of Squared Errors	12,879,012,315.09
Mean Squared Error	204,428,766.91
Std. Error of Regression	14,297.86
Mean Abs. Dev. (MAD)	9,824.12
Mean Abs. % Err. (MAPE)	2.62%
Durbin-Watson Statistic	2.064
Durbin-H Statistic	#NA
Ljung-Box Statistic	18.66
Prob (Ljung-Box)	0.7698
Skewness	0.548
Kurtosis	3.605
Jarque-Bera	4.703
Prob (Jarque-Bera)	0.0952

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	295,345	15,785	18.71	0.00%
mEcon.ManufGDP	2	0	4.38	0.00%
mWthr.CDD18	153	46	3.30	0.16%
mWthr.Lag1CDD18	146	48	3.02	0.36%
mBin.Mar	21,994	6,256	3.52	0.08%
mBin.Jan08	(87,717)	14,496	(6.05)	0.00%
mBin.Feb08	128,249	14,476	8.86	0.00%
mBin.Sep10	(51,373)	15,388	(3.34)	0.14%
mBin.Jun11	(43,950)	14,539	(3.02)	0.36%

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Table Board Staff #19-4: USL Class

Dependent variable – USL energy sales (MWh)

Model Statistics		USL
Iterations		5
Adjusted Observations		59
Deg. of Freedom for Error		46
R-Squared		41.1%
Adjusted R-Squared		25.7%
AIC		9.695
BIC		10.153
F-Statistic	#NA	
Prob (F-Statistic)	#NA	
Log-Likelihood		-356.73
Model Sum of Squares		430,348.40
Sum of Squared Errors		616,822.64
Mean Squared Error		13,409.19
Std. Error of Regression		115.80
Mean Abs. Dev. (MAD)		75.99
Mean Abs. % Err. (MAPE)		7.97%
Durbin-Watson Statistic		2.016
Durbin-H Statistic	#NA	
Ljung-Box Statistic		14.09
Prob (Ljung-Box)		0.9446
Skewness		0.115
Kurtosis		4.377
Jarque-Bera		4.793
Prob (Jarque-Bera)		0.091

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	1,067	62	17.23	0.00%
mBin.Feb	982	57	17.11	0.00%
mBin.Mar	1,111	57	19.65	0.00%
mBin.Apr	1,042	56	18.48	0.00%
mBin.May	1,103	56	19.57	0.00%
mBin.Jun	908	56	16.12	0.00%
mBin.Jul	898	56	15.93	0.00%
mBin.Aug	969	56	17.21	0.00%
mBin.Sep	958	56	17.01	0.00%
mBin.Oct	1,021	56	18.13	0.00%
mBin.Nov	1,013	56	17.98	0.00%
mBin.Dec	1,106	56	19.63	0.00%
AR(1)	0	0	3.15	0.29%

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Table Board Staff #19-5: Large Use Class

Model Statistics	Large User
Iterations	8
Adjusted Observations	71
Deg. of Freedom for Error	67
R-Squared	73.4%
Adjusted R-Squared	72.2%
AIC	10.8
BIC	10.928
F-Statistic	61.604
Prob (F-Statistic)	0
Log-Likelihood	-480.15
Model Sum of Squares	8,578,113.11
Sum of Squared Errors	3,109,851.53
Mean Squared Error	46,415.69
Std. Error of Regression	215.44
Mean Abs. Dev. (MAD)	159.50
Mean Abs. % Err. (MAPE)	2.56%
Durbin-Watson Statistic	2.234
Durbin-H Statistic	#NA
Ljung-Box Statistic	54.15
Prob (Ljung-Box)	0.0004
Skewness	-0.444
Kurtosis	3.705
Jarque-Bera	3.81
Prob (Jarque-Bera)	0.1488

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	6,220	149	41.64	0.00%
mWthr.CDD18	3	1	5.35	0.00%
mBin.Mar	360	68	5.31	0.00%
AR(1)	1	0	11.86	0.00%

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Table Board Staff #19-6: Sentinel Light Class

Model Statistics	Sentinel Light
Iterations	1
Adjusted Observations	47
Deg. of Freedom for Error	34
R-Squared	80.9%
Adjusted R-Squared	74.1%
AIC	1.042
BIC	1.553
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-78.17
Model Sum of Squares	323.70
Sum of Squared Errors	76.60
Mean Squared Error	2.25
Std. Error of Regression	1.50
Mean Abs. Dev. (MAD)	0.92
Mean Abs. % Err. (MAPE)	2.41%
Durbin-Watson Statistic	1.774
Durbin-H Statistic	#NA
Ljung-Box Statistic	46.88
Prob (Ljung-Box)	0.0035
Skewness	-0.561
Kurtosis	4.041
Jarque-Bera	4.592
Prob (Jarque-Bera)	0.1007

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	43	1	48.60	0.00%
mBin.Feb	36	1	47.66	0.00%
mBin.Mar	43	1	56.85	0.00%
mBin.Apr	39	1	51.62	0.00%
mBin.May	42	1	54.78	0.00%
mBin.Jun	38	1	50.41	0.00%
mBin.Jul	40	1	52.29	0.00%
mBin.Aug	40	1	52.45	0.00%
mBin.Sep	38	1	49.42	0.00%
mBin.Oct	42	1	54.57	0.00%
mBin.Nov	39	1	50.62	0.00%
mBin.Dec	39	1	51.46	0.00%
mBin.Yr2011Plus	(4)	1	(7.88)	0.00%

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Table Board Staff #19-7: Street Light Class

Model Statistics		Street Light
Iterations		1
Adjusted Observations		72
Deg. of Freedom for Error		59
R-Squared		68.0%
Adjusted R-Squared		61.5%
AIC		14.372
BIC		14.783
F-Statistic	#NA	
Prob (F-Statistic)	#NA	
Log-Likelihood		-606.54
Model Sum of Squares		186,234,445.08
Sum of Squared Errors		87,494,069.91
Mean Squared Error		1,482,950.34
Std. Error of Regression		1,217.76
Mean Abs. Dev. (MAD)		834.35
Mean Abs. % Err. (MAPE)		19.29%
Durbin-Watson Statistic		2.262
Durbin-H Statistic	#NA	
Ljung-Box Statistic		40.1
Prob (Ljung-Box)		0.0209
Skewness		0.445
Kurtosis		3.22
Jarque-Bera		2.523
Prob (Jarque-Bera)		0.2832

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	6,024	497	12.12	0.00%
mBin.Feb	4,651	497	9.36	0.00%
mBin.Mar	4,943	545	9.08	0.00%
mBin.Apr	4,982	497	10.02	0.00%
mBin.May	4,839	497	9.73	0.00%
mBin.Jun	3,165	497	6.37	0.00%
mBin.Jul	3,040	497	6.11	0.00%
mBin.Aug	4,848	497	9.75	0.00%
mBin.Sep	3,843	497	7.73	0.00%
mBin.Oct	4,593	497	9.24	0.00%
mBin.Nov	5,419	497	10.90	0.00%
mBin.Dec	7,092	497	14.27	0.00%
mBin.Mar06	(10,359)	1,334	(7.77)	0.00%

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

BOARD STAFF INTERROGATORY #20:

Reference(s): E C1/ T1/ S2, p. 3

It is stated that:

"While these 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."

a) Please elaborate on why PowerStream concluded that method 3 was the most robust and technically sound.
b) Please state whether net or gross CDM targets have been reflected in the proposed load forecast.

RESPONSE:

a) PowerStream spent a considerable amount of time determining how to integrate the impacts of CDM savings on future loads. As per Exhibit C1, Tab 1, Schedule 2, three commonly used methods were explored. The regression statistics were comparable across all three methods.

   Given the fact that the impact from past CDM savings is small in relation to the actual loads (below 2% on an annual level) and the regression statistics are comparable across all three methods, the choice between methods was based simply on judgement in assessing the advantages and disadvantages of each approach.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Method 1 was deemed unacceptable since actual historic loads include CDM impacts from 2005. The effects of CDM will persist in the future which distorts the true load growth trend and leaves this component of the load variation to be unaccounted for, if actual loads are used to forecast forward.

Regarding Method 2, PowerStream noted that the OEB recognized some technical issues with using this method in the past (i.e. collinearity between the variables economic and CDM variables, EB-2010-0131 Decision with Reasons, July 7, 2011), which led to the conclusion that this methodology may not be an appropriate approach to forecast load.

Method 3 was considered the most robust since it accounts for historic and future CDM effects, based on the assumption that the reported validated CDM numbers represent real CDM savings. As such, if these numbers are equivalent to actuals, the actual loads can be adjusted to the levels they would be without any CDM activities, therefore using this as the true trend to forecast forward. This approach allows PowerStream to evaluate the impact of CDM on load to better reflect forecast trends for future load growth.

b) PowerStream reflected the net CDM targets in the proposed load forecast.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

BOARD STAFF INTERROGATORY #21:

Reference(s): <u>E C1/ T1/ S2, p. 6</u>

It is stated that:

"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."

Please state why a three-year time period was used and what impact the selected time period would be expected to have on the resulting allocation and why.

RESPONSE:

With the passage of time consumption patterns in each rate class tend to change, causing changes in these contributions to the total load. Although the load contribution of each rate class to the total load varies from year to year, the variance is minimal. Using the 3-year average is representative of the most current trends.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

BOARD STAFF INTERROGATORY #22:

Reference(s): E C1/ T1/ S2, pp. 11-12

On page 11, it is stated that:

"Several 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."

On page 12, Table 10: "Evaluation of Alternative Forecast Drivers" shows the various models and the independent variables used.

a) Please discuss the impact of the number of independent variables chosen on the expected accuracy of the model.
b) Please describe the process by which it was determined which independent variables would be used for each model. Please include a discussion as to how the number of variables to be included in each model was determined and why some independent variables are shown in the Table but were not used in any of the models.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

RESPONSE:

a) The goal of a multiple regression forecast model is to produce the most accurate forecast possible, given available information on the factors that affect monthly energy purchase variation and growth. The "best" model is one that has strong predictive power but has as few independent variables as possible. The model should also be theoretically strong.

There is a compromise between simplicity (i.e. a small number of predictor variables) and predictive power (i.e. a small forecast error, MAPE). As an example, a forecast model with just HDD and CDD, though simple, can be improved by including additional forecast drivers that capture load growth, such as the GDP trend. An addition of the economic variable would result in a lower forecast error. The resulted model would also have better predictive power. Adding additional variables that do not improve the In-sample statistics or the Out-sample predictive power of the model will only introduce unnecessary forecast error. Typically, no more than five or six independent variables are needed to generate a strong load forecast model.

In preparing its load forecast PowerStream looked for patterns in its historical data. Data patterns are represented by historical patterns plus random variation. Random variation, by definition, cannot be predicted. Historic patterns in load are represented by level (data fluctuates around a constant mean); trend (data exhibits an increasing or decreasing pattern); seasonality (any pattern that regularly repeats itself and is of a constant length); and cycle (for example, patterns created by economic fluctuations). At a minimum, a "best" model should account for these patterns. The objective was to find independent variables that best explain this variation, while minimizing the number of variables required doing so given available data.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

b) The process of selecting a final subset of variables for the forecast models involved first selecting the best initial set of models that captured seasonal variation (e.g., HDD/CDD, seasonal/monthly binary variables), economic trends and cyclical patterns. PowerStream evaluated alternative forecast variables, ultimately selecting the models with relatively strong in-sample statistics and out-of-sample performance.

Some of the variables identified in Table 9 were used to develop and test class-specific modeling, but were not used in the load forecast model to derive total purchases.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

BOARD STAFF INTERROGATORY #23:

Reference(s): <u>E C1/ T1/ S2, p. 20</u>

It is stated that:

"Table 13 presents gross actual and normalized gross energy purchases for 2002 through 2011 and forecasts for 2012-2013. 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."

Please explain the divergence described above between 2012 and 2013.

RESPONSE:

There is an error in the last sentence and the change between 2012 and 2013 is a 1.1% increase. The evidence should read: "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% increase from 2012."

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

BOARD STAFF INTERROGATORY #24

Reference(s): E C1/ T1/ S2, p. 25

It is stated that "Estimated total losses are subtracted from these forecasts to determine the distribution sales forecast."

Please explain how estimated total losses are determined.

RESPONSE:

The average loss factor of 1.0316 was used to convert energy purchased to billed energy. The evidence for the loss factor calculation is found in Exhibit H, Tab 7, Schedule 1. The Table below represents Loss Factors by customer class used for the calculation:

Table Board Staff #24: Loss Factors by Customer Class

Rate Class	Loss Factor
Residential	1.0345
GS <50 kW	1.0345
USL	1.0345
GS> 50 kW	1.0345
Large User	1.0145
Street-Lighting	1.0345
Sentinel	1.0345
AVG Line Loss	**1.0316**

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

BOARD STAFF INTERROGATORY #25

Reference(s): **E C1/ T1/ S3, p. 4**

For Table 3, "Customers by Rate Class," please clarify which of the numbers in the table represent total PowerStream numbers and which are either the North or the South rate zone.

RESPONSE:

Please refer to the table below.

Table Board Staff #25: Customers by Rate Class, North and South Rate Zones

	Barrie 2008 Board Approved	PS South 2009 Board Approved	PS Combined - year-end reported				
			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**

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

BOARD STAFF INTERROGATORY #26

Reference(s): E C1/ T1/ S4, Tables 3 to 6 and E C1/ T1/ S3, Table 3

In the tables in the first reference, there are two groups of columns labelled as "2012 Actual Norm vs 2011 Actual Norm." in each table. Please clarify whether or not the second set of columns is intended to refer to the 2013 Test Year. If not, please explain and provide the equivalent information for the 2013 Test Year.

Table 6 of the first reference appears to contain different "Number of Customers (Connections)" amounts from Table 3 of the second reference. For instance for 2013 in the first reference, this number is 430,475, while in the first reference, the equivalent number is 434,566.

Please explain this differential.

RESPONSE:

Yes, the second set of columns is intended to refer to the 2013 Test Year. The last column heading in the tables should read: "2013 Actual Norm vs 2012 Actual Norm". Please refer to response to Energy Probe IR #19, filed in this Exhibit.

The table in the first reference, Table 6 of Exhibit C1, Tab 1, Schedule 4, reports yearly average values (i.e. 430,475), while values in the second reference Table 3 of Exhibit C1, Tab 1, Schedule 3 represent year-end values (i.e. 434,566).

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

CCC INTERROGATORY #23:

Reference(s): (C1/T1)

What has been the annual customer growth rate for each of the years 2008-2013(forecast)?

RESPONSE:

Please refer to the table below.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Table CCC#23: Annual Customer Growth 2008-2013

Year	PS South	PS North	PSConsolidated
Customer Base			
2006	228,666	67,524	296,190
2007	236,377	68,535	304,912
2008	244,729	69,628	314,357
2009	249,880	70,989	320,869
2010	256,323	72,266	328,589
2011	262,487	73,448	335,935
2012F	268,474	74,734	343,208
2013F	274,462	76,020	350,482
Customer Additions			
2007	7,711	1,011	8,722
2008	8,352	1,093	9,445
2009	5,151	1,361	6,512
2010	6,443	1,277	7,720
2011	6,164	1,182	7,346
2012	5,987	1,286	7,273
2013	5,988	1,286	7,274
Growth Rates, %			
2007	3.4%	1.5%	2.9%
2008	3.5%	1.6%	3.1%
2009	2.1%	2.0%	2.1%
2010	2.6%	1.8%	2.4%
2011	2.4%	1.6%	2.2%
2012	2.3%	1.8%	2.2%
2013	2.2%	1.7%	2.1%

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

ENERGY PROBE INTERROGATORY #14:

Reference(s): Exhibit C1, Tab 1, Schedule 2

a) Are the historic CDM savings shown in Table 3 based on billed kWh savings or billed kWh savings grossed up for losses to represent the reduction in purchases due to CDM?

b) Are the actual MWH figures shown in the first column of Table 4 based on purchases (i.e. billed plus losses)?

c) Please confirm that all three columns of data shown in Table 4 are gross purchase figures in that they all reflect losses in the numbers.

RESPONSE:

a) The historic CDM savings shown in Table 3 represent end-use kWh savings and are not grossed up for losses.

b) Yes. The first column of Table 4 provides a summary of historic actual load that is based on the total quantity of energy purchases from the IESO grid including losses.

c) The first column of Table 4 provides a summary of historic actual load that is based on the total quantity of energy purchased from the IESO grid plus embedded generation and it reflects the losses.

The second column is based on the following data sources:

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

1. 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);*

2. 3rd Tranche LDC programs *(source: PowerStream and former Barrie Hydro Annual CDM Reports for 2005-2008);*

3. 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).*

These values are not based on gross figures as they are consistent with the values in the reports.

As a result of this interrogatory, PowerStream re-estimated the model by utilizing the gross up for losses for net CDM values. As a result of this re-estimate the Total Energy Purchases forecast for the 2013 test year is 8,731,660 MWh, which is slightly lower than the original forecast. Given that the re-estimate does not alter the model results and the reduction in the load forecast is minimal, PowerStream is confident that its original load forecast is valid as filed.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

ENERGY PROBE INTERROGATORY #15:

Reference(s): Exhibit C1, Tab 1, Schedule 2

a) Please confirm that Environment Canada uses a heating degree day calculation based on a base of 18 degrees Celsius.

b) Please provide the regression statistics for each of the models shown in Table 10 using a HDD variable based on 18 degrees Celsius in place of that used by PowerStream.

c) For the model with the best fit, please provide the regression statistics, similar to that provided in Table 11, along with the forecast for 2012 and 2013, as provided in Table 6.

d) Did PowerStream attempt to include the number of customers (excluding USL and street lights) as an explanatory variable in any of the models tested? If not, why not?

e) Please provide a live Excel spreadsheet, similar to that provided in the original evidence, but with the HDD10 variable replaced with the HDD18 variable requested above. Please also include in the live Excel spreadsheet all the explanatory variables used in the various models shown in Table 10, including the forecast for each of these variables for the 2012 through 2013 period. Please also include the number of customers (excluding USL and street lights) for both the historical and forecast periods.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

RESPONSE:

a) Yes. Environment Canada uses a heating degree day calculation based on a base of 18 degrees Celsius.

b) The attached Table EP #15b represents alternative model estimations with HDD10 replaced by standard HDD18 degree Celsius where applicable. The table contains coefficient estimations, Adjusted R2 values, Durbin-Watson statistics and F-test for each model. Compared to the evidence filed in Exhibit C1, Tab 1, Schedule 2, Page 12, all models using the alternative HDD18 scenario performed worse – Adjusted R^2 declined for all models.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

c) Please refer to the table below.

Table EP #15c-1: Summary of Monthly Load Forecast Regression Model Using HDD18

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)	523,035,430	87.79	0.00%
Real GDP	33,957,839	12.72	0.00%
CDD18	1,245,921	22.75	0.00%
HDD18	151,311	12.58	0.00%
Feb	(42,081,651)	0.00	0.00%
Apr	(31,332,125)	0.00	0.00%
Adjusted R-squared	96.2%	MAD	8,620,750
Standard Error of regression	11,323,730	MAPE	1.21%
F-test	337.6	Durbin-Watson statistics	1.7

Table EP #15c-2: Total System Purchases, GWH using HDD18

Year	Actual Gross	Model Predicted	Variance, Actual to Predicted, %	Weather-Normal (WN) 10-Year Actual Gross	Variance, WN Actual to Predicted, %
2002	7,866	7,903	-0.5%	7,711	-2.5%
2003	7,917	7,969	-0.7%	7,939	-0.4%
2004	8,135	8,050	1.0%	8,303	3.0%
2005	8,613	8,640	-0.3%	8,405	-2.8%
2006	8,555	8,554	0.0%	8,598	0.5%
2007	8,781	8,800	-0.2%	8,706	-1.1%
2008	8,673	8,651	0.3%	8,782	1.5%
2009	8,406	8,403	0.0%	8,623	2.5%
2010	8,774	8,726	0.5%	8,725	0.0%
2011	8,827	8,850	-0.3%	8,769	-0.9%
2012 Bridge - Forecast		**8,900**			
2013 Test - Forecast - Normalized 10-year		**9,001**			
2013 Test - Forecast - Normalized 20-year		**8,951**			

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

d) No. PowerStream did not include number of customers in the models tested as an explanatory variable because there are gaps in monthly customer count by class data due to differences in tracking methodologies by the predecessor LDCs. Data gaps exist as far back as the initial merger in 2004. Since the 2013 cost of service load forecast model is estimated on the data set from January 1, 2002, PowerStream determined that the lack of reliable monthly customer data made the inclusion of customer numbers invalid as an explanatory variable.

e) The live Excel file is attached as Appendix A.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

ENERGY PROBE INTERROGATORY #16:

Reference(s): Exhibit C1, Tab 1, Schedule 2

a) Please explain why a three year period was used for the allocation of purchases to each of the rate zones as shown in Table 17 rather than some other length of time.

b) Please explain why a three year period was used in Tables 18 through 21 rather than some other length of time.

RESPONSE:

a) With the passage of time, consumption patterns in each rate zone tends to change, causing changes in the contribution of each rate zone to the total load. Although the contribution of each rate zone to the total load varies from year to year, the variance is minimal. Using the three year average is representative of the most current trends. Please refer to the table below which illustrates the historic contribution of each rate zone to the total load from 2002 to 2011.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Table EP #16a: Contribution of Rate Zones to Total Load – 2002-2011

Year	PSS %	PSN %
2002	82.38%	17.62%
2003	82.19%	17.81%
2004	81.79%	18.21%
2005	82.14%	17.86%
2006	81.71%	18.29%
2007	81.79%	18.21%
2008	81.64%	18.36%
2009	81.20%	18.80%
2010	81.69%	18.31%
2011	81.74%	18.26%
AVG 3-year	**81.54%**	**18.46%**

b) Please see the response to Energy Probe IR#16a).

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

ENERGY PROBE INTERROGATORY #17:

Reference(s): Exhibit C1, Tab 1, Schedule 2, page 25

a) Please provide the loss factor used to convert energy purchases to billed energy and show the derivation of this loss factor or indicate where in the evidence this loss factor is calculated.

b) Please provide the calculations of the loss factor for each year 2002 through 2011, or for the maximum number of years over this period that are available.

RESPONSE:

a) The average loss factor of 1.0316 was used to convert energy purchased to billed energy. The evidence for the loss factor calculation is found in Exhibit H, Tab 7, Schedule 1. The Table below showa loss factors by customer class used for the calculation:

Table EP #17a: Loss Factors by Customer Class

Rate Class	Loss Factor
Residential	1.0345
GS <50 kW	1.0345
USL	1.0345
GS> 50 kW	1.0345
Large User	1.0145
Street-Lighting	1.0345
Sentinel	1.0345
AVG Line Loss	**1.0316**

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

b) Please refer to the attached Table EP #17b.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

ENERGY PROBE INTERROGATORY #18:

Reference(s): Exhibit C1, Tab 1, Schedule 3

a) Please provide the number of residential, GS < 50 and GS > 50 customers for the latest month available in 2012, along with the corresponding number of customers for each of these rate classes for the same month in 2011.

b) Are the customer figures shown in Table 3 year end numbers or averages for the year?

c) Please explain the increase in the Large Use customers from 1 in 2012 to 2 in 2013. Is this a new customer or a customer moving from the GS > 50 class?

d) Please explain how the volumetric forecast (both kWh and kW) for the Large Use class has taken into account this additional customer.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

RESPONSE:

a) Please refer to the table below

Table EP #18a: Number of Residential, GS < 50kW and GS > 50kW Customers, YTD June 2011 and YTD June 2012

2011 June YTD	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
Residential	291,666	292,186	292,644	292,823	293,177	**293,561**
GS < 50	30,119	30,152	30,189	30,227	30,255	**30,280**
GS > 50	4,530	4,535	4,551	4,557	4,559	**4,559**
Total - 3 classes	**326,315**	**326,873**	**327,384**	**327,607**	**327,991**	**328,400**
2012 June YTD						
Residential	298,344	299,075	299,773	300,308	300,618	**301,126**
GS < 50	30,448	30,522	30,582	30,598	30,601	**30,603**
GS > 50	4,629	4,655	4,635	4,650	4,662	**4,676**
Total - 3 classes	**333,421**	**334,252**	**334,990**	**335,556**	**335,881**	**336,405**

b) The customer figures shown in Table 3 are year-end numbers.

c) The increase in the Large Use class is due to the movement of one customer from the GS>50 class to the Large Use class. Please refer to the response to Board Staff interrogatory #48, at Exhibit J1, Tab 5, Schedule 5.1.

d) The 2013 distribution kWh sales forecast is apportioned to various rate classes based on the historical relationships between class-specific and total actual kWh obtained from billing data. PowerStream used historic actual consumption (kWh) for the additional new customer and added it to the existing load in the Large User class, as if this customer was always classified as a Large User. Then, PowerStream calculated a

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

3-year average ratio of Large User kWh to System kWh, which in turn was applied to the forecasted 2013 Test year volumes to derive the forecasted Large Uuse kWh (2009-2011 average ratio is 0.9%, as presented in the table below).

Table EP #18d: Forecasted LU kWh

Year	LU Load (2 customers)	PS Total Actual Load	LU as % of PS Total Load
2002	29,968,611	7,866,379,972	0.4%
2003	54,684,101	7,916,829,431	0.7%
2004	58,350,734	8,134,619,559	0.7%
2005	64,114,018	8,609,993,278	0.7%
2006	68,258,621	8,506,707,336	0.8%
2007	74,950,425	8,709,988,904	0.9%
2008	75,629,756	8,564,464,611	0.9%
2009	73,817,836	8,287,390,807	0.9%
2010	78,815,799	8,648,432,856	0.9%
2011	79,326,578	8,697,307,661	0.9%
AVG 2009-2011			**0.9%**

The historical relationship between kWh and kW was used to translate forecasted kWh to kW for this rate class.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

ENERGY PROBE INTERROGATORY #19:

Reference(s): Exhibit C1, Tab 1, Schedule 4

Please provide versions of Tables 3, 4, 5, 6 and 7 that show the rate class for each line in the tables.

RESPONSE:

Please refer to the attached Tables:

- Table EP #19-1: Distribution Revenue by Rate Class (Table 3)
- Table EP #19-2: Demand and Consumption (Table 4)
- Table EP #19-3: Unit Revenues (Table 5)
- Table EP #19-4 Customer Count by Rate Class (Table 6)
- Table EP #19-5: Residential and General Service Classes – Average Normalized Consumption per Customer (Table 7)

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

VECC INTERROGATORY #15:

Reference(s): Exhibit C1, Tab 1, Schedule 1, page 2 (line 17) / Exhibit C1, Tab 1, Schedule 3, page 2 (lines 1-2)

a) Please provide a schedule that for the years 2010 – 2013 inclusive sets out the number of new Residential suite-metered customers added each year broken down as between new construction and retrofits.

RESPONSE:

a) PowerStream does not track customer statistics for residential suite-metering customers on the basis of new construction vs. retrofits. The table below shows the total residential customer additions for the period 2010-2013 broken down between residential and residential suite metered customers.

Table VECC IR#15a: Residential and Residential Suite-Metered Additions 2010-2013

Year	Total Res	Res Base	Res Suite Metering
2010	**7,286**	5,179	2,107
2011	**7,011**	5,411	1,600
2012F	**6,711**	5,111	1,600
2013F	**6,711**	5,111	1,600

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

VECC INTERROGATORY #16:

Reference(s): Exhibit C1, Tab 1, Schedule 2, page 2 (lines 3-19)

a) Please indicate which of the Canadian users listed use the MetrixND software for revenue forecasting purposes.

RESPONSE:

a) As filed in Exhibit C1, Tab 1, Schedule 2, the list represents Canadian users of MetrixND software for load forecasting purposes. The MetrixND software is typically used for short-term and long-term energy and demand forecasting, price forecasting and individual customer load forecasting. The data generated from the model output are used as an input to forecast revenue. The revenue forecast model typically resides on another software platform; PowerStream uses MS Excel.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

VECC INTERROGATORY #17:

Reference(s): Exhibit C1, Tab 1, Schedule 1, page 1 (lines 14-15)

a) Please provide the model estimated by PowerStream for each customer class that provided the "best" statistical fit. In each case please provide the estimated model (i.e., description of independent and dependent variables, coefficient values and statistical properties).

RESPONSE:

a) Please refer to response to Board IR #19, filed in this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

VECC INTERROGATORY #18:

Reference(s): Exhibit C1, Tab 1, Schedule 1, pages 3-5

a) With respect to Tables 3 and 5 (pages 4 & 5), please provide a schedule that sets out, for each year when there were either third tranche or OPA funded CDM programs the energy savings achieved in that year and the persisting savings in each subsequent year through to 2014. (Note: The last program year in the Table should be 2011 and the total for each year should reconcile with the values reported for OPA and 3rd Tranche programs in Tables 3 and 5).

b) Please confirm that the savings reported by the OPA for programs in the first year they are implemented (e.g. the savings in 2011 from programs implemented in 2011) are the annualized values – assuming the programs were all implemented January 1st and not the actual savings in the first year based on when the programs actually started.

c) Please confirm whether or not the 3rd Tranche reported savings in the first program year are based on the same approach.

d) If either (b) or (c) is confirmed, please indicate what adjustments PowerStream made to the reported values for purposes of its load forecast modeling.

e) If no adjustments were made please restate the historic and projected CDM savings to allow for this factor; re-estimate the load forecast model and provide an updated total purchases projection for 2012 and 2013.

f) Please confirm whether the reported historic results for OPA and 3rd Tranche programs were purchased kWh (i.e. grossed up for losses) or billed kWs. If the latter, have the values been adjusted for purposes of estimating the load forecast model and, if so, how?

g) Given that the load forecast model is based on monthly data, how were the CDM savings shown Tables 3 and 5 converted to monthly values?

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

h) Please provide a copy of OPA's report regarding PowerStream's 2011 CDM program results.

RESPONSE:

a) The table below sets out for each program year, the kWh savings that were achieved in the year the program started, followed by the kWh savings that persisted for the program. The last reported year in the table is 2010 for CDM savings achieved via OPA funded programs pre-2011. The breakdown is consistent with the source data used to develop Table 3 and 5: 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);*

Table VECC #18a: OPA Funded CDM Program energy savings (kWh)

Program Year	2006	2007	2008	2009	2010	2011	2012	2013	2014
2006 Programs	23,745,838	23,745,838	23,745,838	23,745,838	4,124,126	4,124,126	3,772,453	3,772,453	3,544,801
2007 Programs	0	13,574,448	12,601,625	12,491,753	12,491,753	12,489,372	11,946,157	11,946,157	11,946,157
2008 Programs	0	0	38,563,521	37,057,618	37,026,733	37,026,733	35,869,721	35,867,199	34,664,698
2009 Programs	0	0	0	45,671,772	39,646,319	39,646,319	39,632,653	39,158,798	37,574,543
2010 Programs	0	0	0	0	31,869,242	21,388,344	21,352,507	21,344,927	20,906,509
Total	**23,745,838**	**37,320,287**	**74,910,984**	**118,966,981**	**125,158,173**	**114,674,894**	**112,573,489**	**112,089,533**	**108,636,708**

The reports supporting the 3rd Tranche CDM information (*source: PowerStream and former Barrie Hydro Annual CDM Reports for 2005-2008)* in Table 3 and Table 5 of Exhibit C1, Tab 1, Schedule 1 reflect annual savings with no persistence. PowerStream's 3rd Tranche savings were not developed or verified in this manner.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

b) The savings reported by the OPA for programs in the first year they are implemented are the annualized values. The savings achieved count for the whole year regardless of when the program started.

c) The 3rd Tranche reported saving for programs in the first year they are implemented are the annualized values.

d) PowerStream made no adjustments to the reported values for purposes of its load forecast model. PowerStream considered the reported information as the best information available and it is consistent with the Board's Filing Requirements (*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).*

e) It would be difficult to make an adjustment for actualized savings as PowerStream does not have the information available to determine the timing of savings achieved. Assumptions would need to be made in order to determine the pro-rated adjustment to calculate actualized savings. In addition, the OEB has accepted the use of annualized savings in order to determine LRAM adjustments.

f) The reported historic results for OPA and 3rd Tranche programs are billed kWh not grossed up for losses. These values have not been adjusted for purposes of estimating the load forecast model. Please refer to the response to Energy Probe IR #14c) filed in this Exhibit.

g) Annual CDM savings were allocated evenly over the 12 month period for each year

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

h) At the time that this response was prepared, the OPA had not provided final results regarding 2011 CDM results. PowerStream is willing to provide these results when available from the OPA.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

VECC INTERROGATORY #19:

Reference(s): Exhibit C1, Tab 1, Schedule 2, page 7

a) Please provide a table that sets out for 2009, 2010 and 2011 the following:
- The actual purchases for each year
- The actual HDD and CDD values for each year
- The "weather normal" HDD and CDD values for each year (as defined by PowerStream)
- The HDD and CDD coefficients per PowerStream's regression model
- The weather normal adjustment for each year based on the product of a) the HDD and CDD coefficients and b) the differences between the "weather normal" and actual values for HDD and CDD respectively.
- The estimated "weather normal purchases" calculated by adjusting actual purchases by the values calculated in the preceding bullet.

RESPONSE:

a) Please refer to the tables below.

- **Table VECC #19a-1: Actual Purchases for Each Year**

	Actual kWh	CDM Gross up	**Actual Gross kWh**
2009	8,287,390,807	118,966,981	**8,406,357,788**
2010	8,648,432,856	125,158,173	**8,773,591,029**
2011	8,697,307,661	129,311,894	**8,826,619,555**

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

- **Table VECC #19a-2: Actual HDD and CDD Values for Each Year**

	HDD10	CDD18
2009	1,872.950	197.900
2010	1,611.400	439.600
2011	1,761.800	428.100

- **Table VECC #19a-3: "Weather Normal" HDD and CDD Values for Each Year (as defined by PowerStream)**

	HDD10	CDD18
2009	1,785.625	377.000
2010	1,785.625	377.000
2011	1,785.625	377.000

- The HDD and CDD coefficients per PowerStream's regression model:

  PowerStream's regression model coefficients are:

  HDD10 = 191,205 & CDD18 = 1,058,759

- **Table VECC #19a-4: The weather normal adjustment for each year based on the product of a) the HDD and CDD coefficients and b) the differences between the "weather normal" and actual values for HDD and CDD respectively**

	HDD10 coefficient	HDD10 Variance	HDD10 Impact kWh	CDD18 coefficient	CDD18 Variance	CDD18 Impact kWh	Weather Impact Total
2009	191,205	87.325	16,696,977	1,058,759	(179.100)	(189,623,737)	**(172,926,760)**
2010	191,205	(174.225)	(33,312,691)	1,058,759	62.600	66,278,313	**32,965,622**
2011	191,205	(23.825)	(4,555,459)	1,058,759	51.100	54,102,585	**49,547,126**

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

- **Table VECC #19a-5: The estimated "weather normal purchases" calculated by adjusting actual purchases by the values calculated in the preceding bullet**

	Actual Gross kWh	Weather-Normal Actual kWh	Variance
2009	8,406,357,788	8,579,284,548	(172,926,760)
2010	8,773,591,029	8,740,625,407	32,965,622
2011	8,826,619,555	8,777,072,429	49,547,126

The weather normalization (WN) was performed using a weather-trend interactive variable with an emphasis on the isolation of the weather impact on the load; it is not used for forecasting. The weather-trend interaction is defined as the product of a linear trend variable and the HDD/CDD variables. The weather/trend interaction term allows PowerStream to capture changes in the load/temperature relationship over time and results in a slight improvement in the estimates of weather normal sales. The impact of using the weather/trend variable, when compared to the filed evidence, is very small. The table below compares the difference in weather-normal estimates.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Table VECC #19a-6: Comparison of Weather Normal Estimates

Year	*Actual Gross*	*WN Actuals* ***Original Evidence***	*% Change*	*WN Actuals* ***w/o Weather-Trend Variable***	*% Change*
2002	7,866	7,751		7,745	
2003	7,917	7,930	2.3%	7,929	2.4%
2004	8,135	8,274	4.3%	8,279	4.4%
2005	8,613	8,425	1.8%	8,421	1.7%
2006	8,555	8,613	2.2%	8,614	2.3%
2007	8,781	8,689	0.9%	8,690	0.9%
2008	8,673	8,774	1.0%	8,772	0.9%
2009	8,406	8,586	-2.1%	8,579	-2.2%
2010	8,774	8,739	1.8%	8,741	1.9%
2011	8,827	8,774	0.4%	8,777	0.4%
2012 Bridge - Forecast		8,890		8,890	
2013 Test - Forecast		8,989		8,989	

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class-specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

VECC INTERROGATORY #20:

Reference(s): Exhibit C1, Tab 1, Schedule 2, page 14 (line 7)

a) Please explain why 10 degrees was used as the base for the HDD values.

RESPONSE:

When developing its load forecast, PowerStream strives to develop the best model fit that implies the best statistical relationship between independent variables and loads. Energy loads are weather-sensitive and this sensitivity changes depending on changes in technology, end-user behaviour, etc. PowerStream evaluated historic monthly purchases against actual average monthly temperatures in order to determine an accurate reflection of weather-related load patterns. This load-temperature relationship is presented in Exhibit C1 Tab 1 Schedule 2, page 14, Figure 4. The graph illustrates that the HDD base temperature break is positioned around 10 degrees where the load starts to grow and not around the "traditional" 18-degree base where the load is relatively flat.

Based on the preliminary analysis described above, PowerStream chose CDD18, HDD 18, and HDD10 as base weather response points and statistically tested their performance by utilizing base regression models (i.e. weather impact and simple trend). The testing results enabled PowerStream to confirm that CDD18 still properly reflects the cooling load weather-response relationship; whereas the results suggested that the HDD base point should be moved from the traditionally-accepted 18 to 10-degree base for better modeling of the total load.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class-specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

VECC INTERROGATORY #21:

Reference(s): Exhibit C1, Tab 1, Schedule 2, pages 7 and 15 (lines 3-5)

a) Please provide the forecast for 2013 based on 30-year normalized weather – comparable to that for 10 and 20 years as per Table 6.

RESPONSE:

a) Based on a 30-year normalized weather the forecasted value for the 2013 test year is 8,914 GWH. The table below shows 2002 to 2011 historic actual (column "Weather-Normal (WN) 30-Year Actual Gross") and the 2012 forecast weather normalized on 30-year basis. For comparative purposes, the 2013 GWH purchases forecast is shown based on results for 10, 20 and 30-year normalized weather.

Table VECC #21a: 2013 Forecast Based on 30-Year Normalized Weather

Year	Actual Gross	Model Predicted	Variance, Actual to Predicted, %	Weather-Normal (WN) 30-Year Actual Gross	Variance, WN Actual to Predicted, %
2002	7,866	7,870	0.0%	7,681	-1.5%
2003	7,917	7,996	-1.0%	7,858	-0.8%
2004	8,135	8,080	0.7%	8,201	2.4%
2005	8,613	8,619	-0.1%	8,351	-2.3%
2006	8,555	8,533	0.3%	8,538	0.9%
2007	8,781	8,809	-0.3%	8,613	-1.4%
2008	8,673	8,651	0.3%	8,697	1.4%
2009	8,406	8,436	-0.3%	8,508	1.8%
2010	8,774	8,715	0.7%	8,660	0.3%
2011	8,827	8,837	-0.1%	8,694	-0.7%
2012 Bridge - Forecast - Normalized 30-year		**8,815**			
2013 Test - Forecast - Normalized 10-year		8,989			
2013 Test - Forecast - Normalized 20-year		8,951			
2013 Test - Forecast - Normalized 30-year		**8,914**			

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class-specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

VECC INTERROGATORY #22:

Reference(s): Exhibit C1, Tab 1, Schedule 2, page 22

a) Please provide a schedule that sets out the CDM programs Power Stream plans on using to achieve its 2012 forecast kWh CDM savings, and show the planned savings by program.
b) Please describe the current status of PowerStream's 2012 CDM program implementation and the results achieved to date.
c) Please provide any reports that have been prepared by the OPA regarding PowerStream's 2012 CDM program results.

RESPONSE:

a) Please see the table below:

Table VECC #22: CDM 2012 Forecast

Program	Forecast (KWh)
Residential	22,177,272
C&I	33,173,236
Industrial	5,309,547
Low Income	2,713,945
Total	63,374,000

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class-specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

The above forecast varies from the original OEB filing in November 2010 (Board File Number EB-2010-2015) because the strategy was updated in September 2011.

b) PowerStream's implementation of the 2011-2014 CDM plan has been successful over the first 18 months of the contracted term. As expected, the key initiatives that contribute significantly to the targets are PeakSaver Plus, the Equipment Replacement Incentive Initiative, Direct Install Lighting, and Demand Response 3. Other initiatives (appliance retirement, HVAC incentives and coupons) are performing less well compared to our original forecast; however, savings are still being generated. There are a number of initiatives that are still not available from the OPA that were in our original forecast, these initiatives are Midstream Electronic, Midstream Pool Pump, Direct Space Cooling and Demand Response 1.

c) The OPA report regarding PowerStream's 2012 CDM program results are not expected be final and available until September, 2013. PowerStream will file the 2012 program results report with the OEB once it is final on September 30, 2013.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class-specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

VECC INTERROGATORY #23:

Reference(s): Exhibit C1, Tab 1, Schedule 3, pages 1-4

a) With respect to Table 2 please indicate the number of net customer additions for 2012 as of June 30th for each customer class and (for comparative purposes) also provide the net 2011 customer additions as of June 30 2011.
b) Please confirm whether the number of customers by customer class reported in Table 3 are year-end or average annual values.
c) Please indicate for each of 2011, 2012 and 2013 the number of Residential customers that are in-suite metered customers.

RESPONSE:

a) The number of net customer additions as of June 30, 2012 is 3,449. The table below shows the comparative information to June 30, 2011 by customer class.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING REVENUE (Exhibit C)

3.2 Are the proposed customers/connections and class-specific load forecasts (both kWh and kW) for Test Year 2013 appropriate, including the impact of CDM and weather normalization? (C1)

Table VECC #23a: Net Customer Additions by Customer Class

2011	Jan	Feb	Mar	Apr	May	Jun	Jun 30 YTD
Residential	715	520	458	179	354	384	**2,610**
GS < 50	43	33	37	38	28	25	**204**
USL	(13)	(24)	4	(66)	(28)	2	**(125)**
GS > 50	18	5	16	6	2	0	**47**
GS TOU	0	0	0	0	0	0	**0**
Large User	0	0	0	0	0	0	**0**
SL Connections	52	163	120	182	122	174	**813**
Sentinel Lights	(1)	(2)	(2)	0	0	0	**(5)**
SL customers	0	(2)	(6)	0	0	(1)	**(9)**
Total	**762**	**530**	**507**	**157**	**356**	**410**	**2,722**

2012	Jan	Feb	Mar	Apr	May	Jun	Jun 30 YTD
Residential	382	731	698	535	310	508	**3,164**
GS < 50	32	74	60	16	3	2	**187**
USL	6	10	14	2	(2)	8	**38**
GS > 50	15	26	(20)	15	12	14	**62**
GS TOU	0	0	0	0	0	0	**0**
Large User	0	0	0	0	0	0	**0**
SL Connections	281	106	183	110	137	168	**985**
Sentinel Lights	(1)	0	(1)	0	0	0	**(2)**
SL customers	0	0	0	0	0	0	**0**
Total	**434**	**841**	**751**	**568**	**323**	**532**	**3,449**

b) The numbers of customer by customer class reported in Table 3 are year-end values.

c) Please refer to response to VECC IR #15 filed in this Exhibit.

Table EP #15b: Evaluation of Alternative forecast Drivers using HDD18

	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6	Model 7
Constant	341,422,158	129,222,160	248,316,747	(6,162,596)	**523,035,430**	(69,872,685)	575,679,373
Independent Variables							
HDD18	153,506	150,157	150,155	148,875	**151,311**	151,607	138,493
CDD18	1,272,352	1,262,284	1,258,111	1,233,934	**1,245,921**	1,270,039	1,272,263
Ontario GDP Index					**33,957,839**		
GDP for Toronto				2,615			
Population (York Region, Barrie)	314,089						
Toronto population		92,175					
Manufacturing GDP for Toronto							
Non-Manufacturing GDP for Toronto							
Total Empoyment for Toronto						220,902	
Manufacturing Employment for Toronto							
Non-Manufacturing Employment for Toronto							
Real Income for Toronto			2,081,446				
Peak Hours				240,303		239,196	
Simple Trend							9,145,157
Feb	(43,335,045)	(44,874,872)	(45,424,534)	(39,483,996)	**(42,081,651)**	(40,131,113)	
Apr	(31,140,085)	(32,909,931)	(32,878,749)	(30,047,928)	**(31,332,125)**	(29,426,502)	
Aug-03	(60,475,598)	(63,317,688)	(50,612,773)	(47,281,439)	**(55,783,670)**	(58,374,482)	
Oct-03			20,859,871	13,698,487	**14,300,066**		
May-09					**(30,778,143)**		
Jul-10				20,201,098	**27,934,832**		
Model Statistics							
Adjusted R-Squared	92.60%	90.00%	92.50%	94.70%	**96.20%**	92.50%	84.80%
SEE	15,849,450	18,459,190	15,960,740	13,441,900	**11,323,730**	15,979,820	22,673,670
F-Test	249.028	178.642	210.405	236.049	**337.617**	209.865	223.106
DW	0.876	0.656	0.863	0.953	**1.670**	0.696	1.548

Table EP #17b: Loss Factors – 2002-2013

	PS Harmonized	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
	Losses in Distributor's System										
A_1	"Wholesale" kWh delivered to distributor (higher value)	Not available	Not available	Not available	Not available	Not available	Not available	Not available	Not available	Not available	Not available
A_2	"Wholesale" kWh delivered to distributor (lower value)	7,725,712,302	7,858,446,400	8,098,236,716	8,562,998,306	8,502,489,126	8,666,887,254	8,568,153,323	8,238,568,148	8,611,402,381	8,658,416,020
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)	396,326,073	390,381,087	406,795,158	401,950,361	273,918,904	41,045,125	30,336,556	27,205,480	27,609,737	27,116,405
C	Net "Wholesale" kWh delivered to distributor (A_2)-(B)	7,329,386,229	7,468,065,313	7,691,441,559	8,161,047,945	8,228,570,221	8,625,842,129	8,537,816,767	8,211,362,668	8,583,792,644	8,631,299,615
D	"Retail" kWh delivered by distributor	7,476,698,822	7,585,814,984	7,850,063,206	8,317,532,471	8,220,576,557	8,340,776,228	8,357,586,382	8,039,883,040	8,334,777,460	8,394,821,657
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)	392,362,812	386,477,276	402,727,206	397,970,654	271,206,836	41,045,125	30,336,556	27,205,480	27,609,737	27,116,405
F	Net "Retail" kWh delivered by distributor (D)-(E)	7,084,336,010	7,199,337,708	7,447,336,000	7,919,561,817	7,949,369,721	8,299,731,103	8,327,249,826	8,012,677,559	8,307,167,723	8,367,705,252
G	Loss Factor in distributor's system [(C)/(F)]	1.0346	1.0373	1.0328	1.0305	1.0351	1.0393	1.0253	1.0248	1.0333	1.0315
	Losses Upstream of Distributor's System										
H	Supply Facility Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses										
I	Total Loss Factor [(G)x(H)]	1.0392	1.0420	1.0374	1.0351	1.0398	1.0440	1.0299	1.0294	1.0379	1.0361

Table EP #19-1: Distribution Revenue by Rate Class (Table 3)

	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.		2013 Actual Norm vs 2012 Actual Norm.	
	$	$	$	$	$	$	%	$	%	$	%	$	%
Residential	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%
GS Less Than 50 kW	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%
GS 50 to 4,999 kW	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%
GS 50 to 4,999 kW Legacy	26,506	0	0	0	0	(26,506)	-100.0%	0		0		0	
Large Use	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%
Unmetered Scattered Load	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%
Sentinel Lighting	13,107	14,477	14,371	14,457	14,528	1,370	10.4%	(106)	-0.7%	86	0.6%	72	0.5%
Street Lighting	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%
TOTAL	**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 EP #19-2: Demand and Consumption (Table 4)

Demand

	Load (kW)					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.		2013 Actual Norm vs 2012 Actual Norm.	
	kW	kW	kW	kW	kW	kW	%	kW	%	kW	%	kW	%
Residential	0	0	0	0	0	0		0		0		0	
GS Less Than 50 kW	0	0	0	0	0	0		0		0		0	
GS 50 to 4,999 kW	11,841,293	11,993,106	12,059,393	12,194,106	12,130,724	151,813	1.3%	66,286	0.6%	134,713	1.1%	(63,381)	-0.5%
GS 50 to 4,999 kW Legacy	0	0	0	0	0	0		0		0		0	
Large Use	81,160	82,797	83,361	83,894	187,932	1,637	2.0%	564	0.7%	533	0.6%	104,038	124.0%
Unmetered Scattered Load	0	0	0	0	0	0		0		0		0	
Sentinel Lighting	1,197	1,221	1,229	1,237	1,240	24	2.0%	8	0.7%	8	0.6%	3	0.2%
Street Lighting	171,479	173,224	174,100	176,348	176,787	1,745	1.0%	877	0.5%	2,248	1.3%	439	0.2%
TOTAL	12,095,130	12,250,349	12,318,083	12,455,585	12,496,684	**155,219**	**1.3%**	**67,735**	**0.6%**	**137,502**	**1.1%**	**41,099**	**0.3%**

Consumption

	Consumption (kwh)					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.		2013 Actual Norm vs 2012 Actual Norm.	
	kWh	kWh	kWh	kWh	kWh	kwh	%	kWh	%	kWh	%	kWh	%
Residential	2,645,607,890	2,673,270,148	2,686,931,286	2,721,123,173	2,727,901,711	27,662,258	1.0%	13,661,138	0.5%	34,191,887	1.3%	6,778,537	0.2%
GS Less Than 50 kW	1,017,968,580	1,029,072,171	1,034,413,080	1,047,268,438	1,049,877,268	11,103,591	1.1%	5,340,909	0.5%	12,855,357	1.2%	2,608,830	0.2%
GS 50 to 4,999 kW	4,445,407,912	4,500,600,497	4,525,154,776	4,576,906,372	4,553,483,283	55,192,585	1.2%	24,554,279	0.5%	51,751,596	1.1%	(23,423,089)	-0.5%
GS 50 to 4,999 kW Legacy	0	0	0	0	0	0		0		0		0	
Large Use	27,221,419	27,770,469	27,959,582	28,138,353	63,032,980	549,050	2.0%	189,112	0.7%	178,772	0.6%	34,894,627	124.0%
Unmetered Scattered Load	12,540,625	12,648,823	12,709,369	12,886,447	12,918,549	108,198	0.9%	60,547	0.5%	177,078	1.4%	32,101	0.2%
Sentinel Lighting	457,217	466,439	469,615	472,618	473,795	9,222	2.0%	3,176	0.7%	3,003	0.6%	1,177	0.2%
Street Lighting	58,436,961	59,052,787	59,355,422	60,107,512	60,257,245	615,826	1.1%	302,635	0.5%	752,090	1.3%	149,733	0.2%
TOTAL	8,207,640,604	8,302,881,333	8,346,993,130	8,446,902,913	8,467,944,830	**95,240,730**	**1.2%**	**44,111,797**	**0.5%**	**99,909,783**	**1.2%**	**21,041,917**	**0.2%**

Table EP #19-3: Unit Revenues (Table 5)

	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.		2013 Actual Norm vs 2012 Actual Norm.	
	$/Customer	$/Customer	$/Customer	$/Customer	$/Customer	$	%	$	%	$	%	$	%
Residential	$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%
GS Less Than 50 kW	$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%
GS 50 to 4,999 kW	$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%
GS 50 to 4,999 kW Legacy	$17,670.67												
Large Use	$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%
Unmetered Scattered Load	$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%
Sentinel Lighting	$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%
Street Lighting	$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%
TOTAL	**$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%**

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 3
Schedule 3.2
Table EP #19-4
Page 1 of 1
Filed: August 31, 2012

Table EP #19-4: Customer Count by Rate Class (Table 6)

	Number of Customers (Connections)				
	Actual Normalized 2009 #	Actual Normalized 2010 #	Actual Normalized 2011 #	Bridge Year Normalized 2012 #	Test Year 2013 #
Residential	280,560	287,731	294,314	301,597	**308,309**
GS Less Than 50 kW	29,254	29,978	30,288	30,691	**31,199**
GS 50 to 4,999 kW	4,681	4,515	4,567	4,631	**4,662**
GS 50 to 4,999 kW Legacy	2	0	0	0	**0**
Large Use	1	1	1	1	**2**
Unmetered Scattered Load	2,744	2,811	2,784	2,791	**2,814**
Sentinel Lighting	137	132	123	120	**120**
Street Lighting	77,135	78,776	80,185	81,813	**83,370**
TOTAL	**394,514**	**403,943**	**412,262**	**421,644**	**430,475**

	Variance Analysis							
	2010 Actual Norm vs 2009 Actual Norm.		2011 Actual Norm vs 2010 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.		2013 Actual Norm vs 2012 Actual Norm.	
	$	%	$	%	$	%	$	%
Residential	7,170	2.6%	6,583	2.3%	7,284	2.5%	6,711	2.2%
GS Less Than 50 kW	724	2.5%	310	1.0%	404	1.3%	508	1.7%
GS 50 to 4,999 kW	(166)	-3.5%	52	1.2%	63	1.4%	31	0.7%
GS 50 to 4,999 kW Legacy	(2)	-100.0%	0		0		0	
Large Use	0	0.0%	0	0.0%	0	0.0%	1	100.0%
Unmetered Scattered Load	67	2.5%	(28)	-1.0%	8	0.3%	23	0.8%
Sentinel Lighting	(5)	-3.7%	(9)	-6.5%	(3)	-2.8%	0	0.0%
Street Lighting	1,641	2.1%	1,409	1.8%	1,628	2.0%	1,557	1.9%
TOTAL	**9,429**	**2.4%**	**8,319**	**2.1%**	**9,383**	**2.3%**	**8,831**	**2.1%**

Table EP #19-5: Residential and General Service Classes –

Average Normalized Consumption per Customer (Table 7)

	Average consumption (kwh/customer)				
	Actual Normalized 2009 kWh/customer	Actual Normalized 2010 kWh/customer	Actual Normalized 2011 kWh/customer	Bridge Year Normalized 2012 kWh/customer	Test Year 2013 kWh/customer
Residential	9,430	9,291	9,129	9,022	8,848
GS Less Than 50 kW	34,797	34,328	34,153	34,123	33,651
Average	**11,825**	**11,653**	**11,464**	**11,341**	**11,127**

	Variance Analysis							
	2010 Actual Norm vs 2009 Actual Norm.		2011 Actual Norm vs 2010 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.		2013 Actual Norm vs 2012 Actual Norm.	
	kwh/customer	%	kwh/customer	%	kwh/customer	%	kwh/customer	%
Residential	(139)	-1.5%	(161)	-1.7%	(107)	-1.2%	(174)	-1.9%
GS Less Than 50 kW	(470)	-1.3%	(175)	-0.5%	(30)	-0.1%	(472)	-1.4%
Average	**(172)**	**-1.5%**	**(189)**	**-1.6%**	**(124)**	**-1.1%**	**(214)**	**-1.9%**

2002-2013 Load Forecast Model Drivers

								Outliers											
Year	**Month**	**Gross Purchases**	**CDD18**	**HDD18**	**GDP Index**	**Feb**	**Apr**	**Jul-10**	**May-09**	**Aug-03**	**Oct-03**	**GDP for Toronto**	**Population (York/Barrie)**	**Population Toronto**	**Employment Toronto**	**Real Income Toronto**	**Peak Hours**	**Simple Trend**	**Customer Count excl USL_SL**
2002	1	**648,141**	**0.0**	**572.2**	**0.51**	**0**	**0**	0	0	0	0	190,953.915	738.306	4,938.590	2,569.845	163.940	352	0.08	*no data*
2002	2	**593,198**	**0.0**	**540.2**	**0.72**	**1**	**0**	0	0	0	0	192,180.802	741.739	4,970.379	2,584.327	164.546	320	0.17	*no data*
2002	3	**628,227**	**0.0**	**545.6**	**0.88**	**0**	**0**	0	0	0	0	192,180.802	745.273	4,970.379	2,584.327	164.546	320	0.25	*no data*
2002	4	**595,135**	**8.3**	**329.5**	**1.02**	**0**	**1**	0	0	0	0	192,578.994	748.707	4,979.451	2,576.372	164.231	336	0.33	*no data*
2002	5	**604,018**	**7.8**	**227.5**	**1.14**	**0**	**0**	0	0	0	0	192,578.994	752.141	4,979.451	2,576.372	164.231	352	0.42	*no data*
2002	6	**661,273**	**70.0**	**36.2**	**1.24**	**0**	**0**	0	0	0	0	192,578.994	755.575	4,979.451	2,576.372	164.231	320	0.50	*no data*
2002	7	**793,206**	**192.4**	**0.0**	**1.34**	**0**	**0**	0	0	0	0	192,915.218	759.109	4,987.704	2,584.425	164.082	352	0.58	*no data*
2002	8	**749,567**	**142.7**	**0.0**	**1.44**	**0**	**0**	0	0	0	0	192,915.218	762.543	4,987.704	2,584.425	164.082	336	0.67	*no data*
2002	9	**669,740**	**87.6**	**21.8**	**1.52**	**0**	**0**	0	0	0	0	193,313.410	766.076	4,996.776	2,576.470	163.764	320	0.75	*no data*
2002	10	**633,405**	**10.0**	**292.2**	**1.61**	**0**	**0**	0	0	0	0	193,610.867	769.510	5,004.211	2,590.107	163.685	352	0.83	*no data*
2002	11	**634,781**	**0.0**	**445.0**	**1.69**	**0**	**0**	0	0	0	0	194,009.059	772.944	5,013.283	2,582.151	163.363	336	0.92	*no data*
2002	12	**655,689**	**0.0**	**619.4**	**1.76**	**0**	**0**	0	0	0	0	194,942.932	776.278	5,033.413	2,612.950	162.567	320	1.00	*no data*
2003	1	**707,086**	**0.0**	**814.5**	**1.79**	**0**	**0**	0	0	0	0	195,243.123	779.169	5,037.856	2,622.059	162.008	352	1.08	*no data*
2003	2	**641,302**	**0.0**	**699.0**	**1.83**	**1**	**0**	0	0	0	0	196,176.996	782.059	5,057.986	2,652.858	161.196	320	1.17	*no data*
2003	3	**661,928**	**0.0**	**581.1**	**1.86**	**0**	**0**	0	0	0	0	196,176.996	784.950	5,057.986	2,652.858	161.196	336	1.25	*no data*
2003	4	**612,757**	**2.4**	**372.5**	**1.89**	**0**	**1**	0	0	0	0	196,268.452	787.841	5,064.653	2,646.606	161.575	336	1.33	*no data*
2003	5	**607,840**	**0.0**	**177.9**	**1.92**	**0**	**0**	0	0	0	0	196,268.452	790.731	5,064.653	2,646.606	161.575	336	1.42	*no data*
2003	6	**655,654**	**52.9**	**43.4**	**1.95**	**0**	**0**	0	0	0	0	196,268.452	793.722	5,064.653	2,646.606	161.575	336	1.50	*no data*
2003	7	**729,638**	**118.3**	**0.0**	**1.98**	**0**	**0**	0	0	0	0	196,376.731	796.613	5,071.370	2,644.009	161.516	352	1.58	*no data*
2003	8	**695,230**	**128.0**	**2.0**	**2.01**	**0**	**0**	0	0	**1**	0	196,376.731	799.504	5,071.370	2,644.009	161.516	320	1.67	*no data*
2003	9	**633,603**	**24.0**	**54.9**	**2.04**	**0**	**0**	0	0	0	0	196,468.187	802.394	5,078.036	2,637.756	161.895	336	1.75	*no data*
2003	10	**649,240**	**0.0**	**276.0**	**2.07**	**0**	**0**	0	0	0	**1**	197,329.738	805.285	5,084.804	2,644.115	162.685	352	1.83	*no data*
2003	11	**644,011**	**0.0**	**398.5**	**2.09**	**0**	**0**	0	0	0	0	197,421.194	808.176	5,091.470	2,637.862	163.065	320	1.92	*no data*
2003	12	**678,539**	**0.0**	**561.5**	**2.12**	**0**	**0**	0	0	0	0	198,488.506	810.966	5,111.990	2,650.510	164.285	336	2.00	*no data*
2004	1	**734,924**	**0.0**	**849.1**	**2.17**	**0**	**0**	0	0	0	0	198,585.988	813.760	5,119.026	2,659.397	164.770	336	2.08	*no data*
2004	2	**663,761**	**0.0**	**618.8**	**2.22**	**1**	**0**	0	0	0	0	199,653.300	816.453	5,139.546	2,672.045	165.995	320	2.17	*no data*
2004	3	**685,307**	**0.0**	**487.4**	**2.27**	**0**	**0**	0	0	0	0	199,653.300	819.246	5,139.546	2,672.045	165.995	368	2.25	*no data*
2004	4	**623,909**	**0.0**	**343.4**	**2.32**	**0**	**1**	0	0	0	0	200,556.652	822.039	5,146.328	2,681.710	166.751	336	2.33	*no data*
2004	5	**637,436**	**8.6**	**155.2**	**2.36**	**0**	**0**	0	0	0	0	200,556.652	824.832	5,146.328	2,681.710	166.751	320	2.42	*no data*
2004	6	**664,921**	**31.3**	**48.8**	**2.41**	**0**	**0**	0	0	0	0	200,556.652	827.625	5,146.328	2,681.710	166.751	352	2.50	*no data*
2004	7	**715,224**	**81.5**	**3.6**	**2.45**	**0**	**0**	0	0	0	0	201,048.427	830.418	5,153.074	2,679.698	167.459	336	2.58	*no data*
2004	8	**702,483**	**63.6**	**12.8**	**2.50**	**0**	**0**	0	0	0	0	201,048.427	833.211	5,153.074	2,679.698	167.459	336	2.67	*no data*
2004	9	**678,092**	**42.4**	**28.2**	**2.54**	**0**	**0**	0	0	0	0	201,951.778	836.004	5,159.856	2,689.363	168.217	336	2.75	*no data*
2004	10	**647,420**	**1.5**	**220.0**	**2.58**	**0**	**0**	0	0	0	0	202,352.346	838.798	5,166.566	2,685.620	168.736	320	2.83	*no data*
2004	11	**665,217**	**0.0**	**372.5**	**2.62**	**0**	**0**	0	0	0	0	203,255.697	841.491	5,173.348	2,695.285	169.497	352	2.92	*no data*
2004	12	**715,926**	**0.0**	**646.9**	**2.66**	**0**	**0**	0	0	0	0	204,644.598	844.184	5,193.045	2,687.793	170.861	336	3.00	*no data*
2005	1	**736,155**	**0.0**	**770.0**	**2.71**	**0**	**0**	0	0	0	0	205,141.157	846.538	5,199.286	2,686.057	170.991	320	3.08	*no data*
2005	2	**659,920**	**0.0**	**616.4**	**2.75**	**1**	**0**	0	0	0	0	206,530.058	848.793	5,218.982	2,678.565	172.361	320	3.17	*no data*
2005	3	**705,973**	**0.0**	**608.6**	**2.79**	**0**	**0**	0	0	0	0	206,530.058	851.147	5,218.982	2,678.565	172.361	352	3.25	*no data*
2005	4	**639,295**	**0.0**	**306.8**	**2.83**	**0**	**1**	0	0	0	0	206,937.193	853.502	5,225.793	2,692.427	172.645	336	3.33	*no data*
2005	5	**650,847**	**0.8**	**189.4**	**2.88**	**0**	**0**	0	0	0	0	206,937.193	855.756	5,225.793	2,692.427	172.645	336	3.42	*no data*
2005	6	**806,394**	**146.3**	**8.9**	**2.92**	**0**	**0**	0	0	0	0	206,937.193	858.211	5,225.793	2,692.427	172.645	352	3.50	*no data*
2005	7	**829,556**	**188.7**	**0.0**	**2.96**	**0**	**0**	0	0	0	0	207,552.569	860.566	5,232.739	2,704.849	173.193	320	3.58	*no data*
2005	8	**803,438**	**140.7**	**0.0**	**2.99**	**0**	**0**	0	0	0	0	207,552.569	863.020	5,232.739	2,704.849	173.193	352	3.67	*no data*
2005	9	**701,298**	**52.1**	**22.6**	**3.03**	**0**	**0**	0	0	0	0	207,959.704	865.575	5,239.549	2,718.711	173.478	336	3.75	*no data*
2005	10	**671,652**	**7.6**	**220.2**	**3.07**	**0**	**0**	0	0	0	0	208,643.932	868.029	5,246.633	2,720.678	174.463	320	3.83	*no data*
2005	11	**684,869**	**0.0**	**388.4**	**3.11**	**0**	**0**	0	0	0	0	209,051.067	870.484	5,253.443	2,734.540	174.749	352	3.92	*no data*
2005	12	**723,726**	**0.0**	**665.3**	**3.15**	**0**	**0**	0	0	0	0	211,173.872	872.938	5,274.400	2,738.763	177.420	320	4.00	*no data*
2006	1	**732,616**	**0.0**	**551.8**	**3.18**	**0**	**0**	0	0	0	0	211,997.072	874.603	5,281.327	2,728.596	178.554	336	4.08	*no data*
2006	2	**678,047**	**0.0**	**604.3**	**3.21**	**1**	**0**	0	0	0	0	214,119.877	877.493	5,302.285	2,732.819	181.248	320	4.17	*no data*
2006	3	**718,688**	**0.0**	**516.6**	**3.24**	**0**	**0**	0	0	0	0	214,119.877	880.483	5,302.285	2,732.819	181.248	368	4.25	*no data*
2006	4	**631,458**	**0.0**	**293.3**	**3.27**	**0**	**1**	0	0	0	0	214,166.235	883.373	5,309.759	2,742.616	181.372	304	4.33	*no data*
2006	5	**687,437**	**26.0**	**136.9**	**3.30**	**0**	**0**	0	0	0	0	214,166.235	886.263	5,309.759	2,742.616	181.372	352	4.42	*no data*

2002-2013 Load Forecast Model Drivers

Year	Month	Gross Purchases	CDD18	HDD18	GDP Index	Feb	Apr	Jul-10	May-09	Aug-03	Oct-03	GDP for Toronto	Population (York/Barrie)	Population Toronto	Employment Toronto	Real Income Toronto	Peak Hours	Simple Trend	Customer Count excl USL_SL
2006	6	743,208	73.6	19.5	3.33	0	0	0	0	0	0	214,166.235	889.253	5,309.759	2,742.616	181.372	352	4.50	no data
2006	7	840,310	167.3	0.0	3.36	0	0	0	0	0	0	214,141.448	892.143	5,317.487	2,746.335	182.179	320	4.58	no data
2006	8	785,933	101.6	4.2	3.39	0	0	0	0	0	0	214,141.448	895.033	5,317.487	2,746.335	182.179	352	4.67	no data
2006	9	656,761	12.9	80.9	3.42	0	0	0	0	0	0	214,187.807	897.823	5,324.961	2,756.131	182.304	320	4.75	no data
2006	10	684,000	1.1	288.3	3.45	0	0	0	0	0	0	214,615.735	900.514	5,332.943	2,759.119	183.260	336	4.83	no data
2006	11	691,035	0.0	382.2	3.48	0	0	0	0	0	0	214,662.094	903.204	5,340.417	2,768.916	183.385	352	4.92	no data
2006	12	705,042	0.0	500.5	3.51	0	0	0	0	0	0	215,595.918	905.894	5,364.926	2,788.836	185.527	304	5.00	no data
2007	1	753,835	0.0	649.6	3.53	0	0	0	0	0	0	216,126.601	908.536	5,373.724	2,802.050	185.897	352	5.08	no data
2007	2	715,260	0.0	740.1	3.55	1	0	0	0	0	0	217,060.426	911.078	5,398.233	2,821.970	188.052	320	5.17	no data
2007	3	725,410	0.0	546.7	3.58	0	0	0	0	0	0	217,060.426	913.619	5,398.233	2,821.970	188.052	352	5.25	no data
2007	4	665,398	0.0	355.1	3.60	0	1	0	0	0	0	217,709.455	916.161	5,406.498	2,822.769	188.195	304	5.33	no data
2007	5	690,776	22.4	136.4	3.62	0	0	0	0	0	0	217,709.455	918.703	5,406.498	2,822.769	188.195	352	5.42	no data
2007	6	777,489	99.2	16.5	3.65	0	0	0	0	0	0	217,709.455	921.345	5,406.498	2,822.769	188.195	336	5.50	no data
2007	7	780,763	106.1	3.2	3.67	0	0	0	0	0	0	218,271.208	923.887	5,414.791	2,828.335	189.301	336	5.58	no data
2007	8	822,246	141.0	5.2	3.69	0	0	0	0	0	0	218,271.208	926.428	5,414.791	2,828.335	189.301	352	5.67	no data
2007	9	704,462	47.5	36.9	3.71	0	0	0	0	0	0	218,920.238	929.070	5,423.056	2,829.134	189.445	304	5.75	no data
2007	10	699,578	19.8	137.7	3.74	0	0	0	0	0	0	219,304.217	931.612	5,431.379	2,834.874	190.148	352	5.83	no data
2007	11	709,184	0.0	462.5	3.76	0	0	0	0	0	0	219,953.246	934.154	5,439.643	2,835.673	190.292	352	5.92	no data
2007	12	736,790	0.0	630.7	3.78	0	0	0	0	0	0	220,197.927	936.696	5,464.760	2,856.706	192.164	304	6.00	no data
2008	1	771,035	0.0	626.0	3.77	0	0	0	0	0	0	219,496.875	938.886	5,473.260	2,866.433	192.217	352	6.08	no data
2008	2	723,329	0.0	674.7	3.77	1	0	0	0	0	0	219,741.556	941.077	5,498.376	2,887.466	194.099	320	6.17	no data
2008	3	735,147	0.0	610.2	3.76	0	0	0	0	0	0	219,741.556	943.268	5,498.376	2,887.466	194.099	304	6.25	no data
2008	4	670,354	0.0	253.9	3.75	0	1	0	0	0	0	219,981.238	945.559	5,506.697	2,894.113	193.574	352	6.33	no data
2008	5	669,096	2.5	193.5	3.75	0	0	0	0	0	0	219,981.238	947.750	5,506.697	2,894.113	193.574	336	6.42	no data
2008	6	743,772	71.5	22.7	3.74	0	0	0	0	0	0	219,981.238	949.941	5,506.697	2,894.113	193.574	336	6.50	no data
2008	7	806,541	111.0	1.0	3.73	0	0	0	0	0	0	219,856.896	952.232	5,514.987	2,888.071	192.749	352	6.58	no data
2008	8	746,570	64.0	12.7	3.73	0	0	0	0	0	0	219,856.896	954.423	5,514.987	2,888.071	192.749	320	6.67	no data
2008	9	693,013	26.7	59.5	3.72	0	0	0	0	0	0	220,096.578	956.714	5,523.308	2,894.717	192.218	336	6.75	no data
2008	10	683,229	0.0	278.6	3.71	0	0	0	0	0	0	218,810.706	958.905	5,531.568	2,894.219	192.023	352	6.83	no data
2008	11	692,181	0.0	451.6	3.71	0	0	0	0	0	0	219,050.388	961.096	5,539.888	2,900.866	191.488	320	6.92	no data
2008	12	738,678	0.0	654.6	3.70	0	0	0	0	0	0	215,542.787	963.287	5,564.165	2,886.238	190.536	336	7.00	311,483
2009	1	768,218	0.0	830.2	3.67	0	0	0	0	0	0	213,445.399	965.148	5,571.891	2,878.151	190.620	336	7.08	311,975
2009	2	673,005	0.0	576.9	3.63	1	0	0	0	0	0	209,937.798	967.009	5,596.168	2,863.524	189.650	320	7.17	312,480
2009	3	708,633	0.0	533.8	3.59	0	0	0	0	0	0	209,937.798	968.871	5,596.168	2,863.524	189.650	352	7.25	312,903
2009	4	657,533	1.2	305.8	3.55	0	1	0	0	0	0	210,252.301	970.732	5,604.568	2,854.751	189.056	320	7.33	313,092
2009	5	644,299	6.9	158.8	3.52	0	0	0	1	0	0	210,252.301	972.594	5,604.568	2,854.751	189.056	320	7.42	313,546
2009	6	678,296	34.2	49.3	3.48	0	0	0	0	0	0	210,252.301	974.455	5,604.568	2,854.751	189.056	352	7.50	313,766
2009	7	705,773	43.7	6.2	3.44	0	0	0	0	0	0	211,481.978	975.757	5,613.138	2,856.720	189.770	352	7.58	314,247
2009	8	774,749	91.0	9.8	3.40	0	0	0	0	0	0	211,481.978	976.960	5,613.138	2,856.720	189.770	320	7.67	314,723
2009	9	684,843	20.9	55.2	3.36	0	0	0	0	0	0	211,796.481	978.262	5,621.538	2,847.948	189.173	336	7.75	315,488
2009	10	683,702	0.0	287.8	3.32	0	0	0	0	0	0	212,861.265	979.464	5,630.279	2,855.514	189.895	336	7.83	316,547
2009	11	680,910	0.0	361.2	3.28	0	0	0	0	0	0	213,175.768	980.667	5,638.679	2,846.741	189.294	336	7.92	317,291
2009	12	746,395	0.0	631.3	3.24	0	0	0	0	0	0	216,222.896	981.869	5,664.902	2,859.737	191.164	336	8.00	317,916
2010	1	771,339	0.0	720.0	3.28	0	0	0	0	0	0	216,975.562	984.033	5,673.814	2,863.199	191.596	320	8.08	318,851
2010	2	693,009	0.0	598.3	3.32	1	0	0	0	0	0	220,022.690	986.197	5,700.037	2,876.195	193.478	304	8.17	319,399
2010	3	710,538	0.0	422.8	3.35	0	0	0	0	0	0	220,022.690	988.361	5,700.037	2,876.195	193.478	368	8.25	320,248
2010	4	641,438	0.0	225.1	3.39	0	1	0	0	0	0	220,552.254	990.625	5,709.119	2,879.440	194.126	320	8.33	320,926
2010	5	709,952	45.7	107.9	3.43	0	0	0	0	0	0	220,552.254	992.789	5,709.119	2,879.440	194.126	320	8.42	321,254
2010	6	730,106	58.7	21.7	3.46	0	0	0	0	0	0	220,552.254	994.953	5,709.119	2,879.440	194.126	352	8.50	321,961
2010	7	875,547	164.9	1.8	3.50	0	0	1	0	0	0	220,654.336	997.217	5,718.372	2,902.481	194.086	336	8.58	322,513
2010	8	828,473	138.8	2.1	3.54	0	0	0	0	0	0	220,654.336	999.381	5,718.372	2,902.481	194.086	352	8.67	322,908
2010	9	687,839	31.5	78.2	3.57	0	0	0	0	0	0	221,183.900	1,001.645	5,727.454	2,905.725	194.736	336	8.75	323,847
2010	10	673,820	0.0	241.6	3.61	0	0	0	0	0	0	221,526.685	1,003.809	5,736.878	2,906.371	195.756	320	8.83	324,203
2010	11	694,449	0.0	405.3	3.64	0	0	0	0	0	0	222,056.249	1,005.973	5,745.960	2,909.616	196.408	352	8.92	325,041

2002-2013 Load Forecast Model Drivers

Year	Month	Gross Purchases	CDD18	HDD18	GDP Index	Feb	Apr	Jul-10	May-09	Aug-03	Oct-03	GDP for Toronto	Population (York/Barrie)	Population Toronto	Employment Toronto	Real Income Toronto	Peak Hours	Simple Trend	Customer Count excl USL_SL
2010	*12*	**757,080**	**0.0**	**676.2**	**3.67**	**0**	**0**	0	0	0	0	223,514.822	1,008.137	5,771.675	2,933.635	197.037	336	9.00	325,540
2011	*1*	**783,035**	**0.0**	**775.3**	**3.70**	**0**	**0**	0	0	0	0	224,528.527	1,009.474	5,778.714	2,933.966	196.680	320	9.08	326,316
2011	*2*	**700,611**	**0.0**	**654.2**	**3.72**	**1**	**0**	0	0	0	0	225,987.100	1,010.812	5,804.429	2,957.985	197.304	304	9.17	326,874
2011	*3*	**746,275**	**0.0**	**572.8**	**3.75**	**0**	**0**	0	0	0	0	225,987.100	1,012.149	5,804.429	2,957.985	197.304	368	9.25	327,385
2011	*4*	**664,726**	**0.0**	**332.3**	**3.77**	**0**	**1**	0	0	0	0	226,028.167	1,013.487	5,811.386	2,960.473	197.080	304	9.33	327,608
2011	*5*	**682,984**	**13.0**	**134.1**	**3.80**	**0**	**0**	0	0	0	0	226,028.167	1,015.436	5,811.386	2,960.473	197.080	336	9.42	327,992
2011	*6*	**734,191**	**52.2**	**19.0**	**3.82**	**0**	**0**	0	0	0	0	226,028.167	1,016.162	5,811.386	2,960.473	197.080	352	9.50	328,401
2011	*7*	**886,672**	**198.6**	**0.0**	**3.84**	**0**	**0**	0	0	0	0	226,201.367	1,017.499	5,818.424	2,963.198	196.993	320	9.58	328,848
2011	*8*	**816,129**	**122.2**	**0.0**	**3.87**	**0**	**0**	0	0	0	0	226,201.367	1,018.836	5,818.424	2,963.198	196.993	352	9.67	329,604
2011	*9*	**702,202**	**39.7**	**48.2**	**3.89**	**0**	**0**	0	0	0	0	226,242.433	1,020.174	5,825.382	2,965.687	196.767	336	9.75	330,348
2011	*10*	**686,071**	**2.4**	**235.5**	**3.92**	**0**	**0**	0	0	0	0	226,609.000	1,018.866	5,832.664	2,967.682	197.323	320	9.83	331,394
2011	*11*	**690,309**	**0.0**	**342.1**	**3.94**	**0**	**0**	0	0	0	0	226,650.067	1,021.062	5,839.622	2,970.170	197.096	352	9.92	332,274
2011	12	**733,416**	**0.0**	**534.0**	**3.96**	**0**	**0**	0	0	0	0	227,748.700	1,023.259	5,862.247	2,982.112	197.903	320	10.00	332,993
2012	1		**0.0**	**715.9**	**3.98**	**0**	**0**	0	0	0	0	228,307.570	1,024.620	5,870.550	2,989.330	198.240	336	10.08	333,597
2012	2		**0.0**	**632.3**	**4.00**	**1**	**0**	0	0	0	0	229,406.200	1,025.970	5,893.180	3,001.270	199.050	320	10.17	334,201
2012	3		**0.0**	**542.6**	**4.02**	**0**	**0**	0	0	0	0	229,406.200	1,027.330	5,893.180	3,001.270	199.050	352	10.25	334,806
2012	4		**1.2**	**311.8**	**4.04**	**0**	**1**	0	0	0	0	230,082.630	1,028.690	5,901.810	3,009.320	199.380	320	10.33	335,410
2012	5		**13.4**	**161.8**	**4.06**	**0**	**0**	0	0	0	0	230,082.630	1,030.670	5,901.810	3,009.320	199.380	352	10.42	336,014
2012	6		**69.0**	**28.6**	**4.08**	**0**	**0**	0	0	0	0	230,082.630	1,031.400	5,901.810	3,009.320	199.380	336	10.50	336,618
2012	7		**137.3**	**1.6**	**4.10**	**0**	**0**	0	0	0	0	230,789.570	1,032.760	5,910.680	3,018.220	199.780	336	10.58	337,222
2012	8		**113.4**	**4.9**	**4.12**	**0**	**0**	0	0	0	0	230,789.570	1,034.120	5,910.680	3,018.220	199.780	352	10.67	337,827
2012	9		**38.5**	**48.6**	**4.14**	**0**	**0**	0	0	0	0	231,466.000	1,035.480	5,919.310	3,026.260	200.110	304	10.75	338,431
2012	10		**4.2**	**247.8**	**4.15**	**0**	**0**	0	0	0	0	232,205.800	1,034.150	5,928.350	3,034.960	200.570	368	10.83	339,035
2012	11		**0.0**	**400.9**	**4.17**	**0**	**0**	0	0	0	0	232,882.230	1,036.380	5,936.980	3,043.000	200.900	352	10.92	339,639
2012	12		**0.0**	**612.0**	**4.19**	**0**	**0**	0	0	0	0	235,255.570	1,038.610	5,963.800	3,068.990	202.520	304	11.00	340,243
2013	1		**0.0**	**715.9**	**4.21**	**0**	**0**	0	0	0	0	236,182.170	1,039.990	5,972.700	3,077.370	203.270	352	11.08	340,849
2013	2		**0.0**	**632.3**	**4.24**	**1**	**0**	0	0	0	0	238,555.500	1,041.360	5,999.520	3,103.350	204.890	304	11.17	341,453
2013	3		**0.0**	**542.6**	**4.26**	**0**	**0**	0	0	0	0	238,555.500	1,042.740	5,999.520	3,103.350	204.890	320	11.25	342,057
2013	4		**1.2**	**311.8**	**4.28**	**0**	**1**	0	0	0	0	239,318.030	1,044.120	6,008.500	3,110.730	205.430	336	11.33	342,661
2013	5		**13.4**	**161.8**	**4.30**	**0**	**0**	0	0	0	0	239,318.030	1,046.130	6,008.500	3,110.730	205.430	352	11.42	343,265
2013	6		**69.0**	**28.6**	**4.32**	**0**	**0**	0	0	0	0	239,318.030	1,046.880	6,008.500	3,110.730	205.430	320	11.50	343,870
2013	7		**137.3**	**1.6**	**4.35**	**0**	**0**	0	0	0	0	240,056.230	1,048.250	6,017.570	3,117.090	205.940	352	11.58	344,474
2013	8		**113.4**	**4.9**	**4.37**	**0**	**0**	0	0	0	0	240,056.230	1,049.630	6,017.570	3,117.090	205.940	352	11.67	345,078
2013	9		**38.5**	**48.6**	**4.39**	**0**	**0**	0	0	0	0	240,818.770	1,051.010	6,026.550	3,124.470	206.480	320	11.75	345,682
2013	10		**4.2**	**247.8**	**4.41**	**0**	**0**	0	0	0	0	241,539.670	1,049.660	6,035.700	3,130.440	206.980	352	11.83	346,286
2013	11		**0.0**	**400.9**	**4.43**	**0**	**0**	0	0	0	0	242,302.200	1,051.920	6,044.690	3,137.820	207.520	336	11.92	346,890
2013	12		**0.0**	**612.0**	**4.45**	**0**	**0**	0	0	0	0	244,452.270	1,054.190	6,072.160	3,155.590	209.010	320	12.00	347,495

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

BOARD STAFF INTERROGATORY #27:

Reference(s): C2/ T1/ S1/p. 3

PowerStream states that it proposes to harmonize the Specific Service Charges in the South and North rate zones using the Board default amounts from the 2006 EDR Handbook, as currently used in PowerStream South.

Please state whether or not PowerStream anticipates any impacts on revenue from this change and, if so, what such impact would be.

RESPONSE:

The proposed harmonization of Specific Service Charges is expected to result in about a $270,000 increase in revenues on this line. This increase is anticipated to be partially offset by a forecast decrease in collection charges, due to availability of the LEAP program.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

BOARD STAFF INTERROGATORY #28:

Reference(s): <u>C2/ T1/ S1/pp. 3-4 and May 28, 2012 Letter to Board</u>

In the first reference, PowerStream states that it proposes to introduce two new specific service charges. In the second reference, PowerStream provided further justification for these two charges. These two charges are described as follows:

- "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. PowerStream states that the only reason to introduce a new charge is that a current definition of the existing charge assumes that the current charge is to be applied in cases of non-payment only and does not address the situation with vacant properties
- "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. PowerStream states that its proposed treatment is "consistent with the provisions of the *Distribution System Code* (Section 2.9, added on July 1, 2011), which considers installation of load control devices to be an activity equivalent to disconnecting supply. Consequently, PowerStream does not consider this charge as unique and proposes to use the established standard charge."

In both cases the difference between the standard Board charge and the charge that PowerStream is proposing is that existing charges that were designed for customer non-payment situations are being used in situations where it appears customers will continue to pay their accounts but usage levels will drop (i.e. in the case of the first charge because the property is vacant and in the second when a load control device is installed in the winter time).

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

a) Please clarify whether or not the two proposed charges would be applicable in customer non-payment situations.
b) If these charges are not intended for customer non-payment situations, please state why PowerStream believes that the costs underlying such charges would be the same as the Board's standard charges which were designed for non payment situations.

RESPONSE:

a) The "Disconnect/Reconnect at meter during/after regular hours" charge to be used in the cases of vacant rental properties with no active account is not applicable to customer non-payment. It applies to the case where the property is vacant and an owner, landlord or tenant has not assumed responsibility for any charges at that location. To avoid the situation where no one has assumed responsibility for the charges but consumption may be occurring, it is PowerStream's practice to disconnect the service.

The "Install/Remove load control devices during/after regular hours" charge is to be used in lieu of service disconnection in cases when a load control device is installed during the winter months, among other circumstances. As noted, the install/remove of load control devices occurs because of non-payment. The installation of a load control device follows the same collection activities and timelines due to non-payment as the full disconnection process. The practice of installing load control devices occurs so as to allow heat for customers and avoid damage due to freezing water pipes. The customer will be fully disconnected at some point, if required and as weather permits.

b) The "Disconnect/Reconnect at meter during/after regular hours" charge is to be used in cases of vacant rental properties with no active account". Upon review, this Disconnect/Reconnect

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

process very closely mirrors a Disconnect/Reconnect for non-payment process. The property needs to be tracked as to a status, notices are sent to the service address detailing the process, a service person must visit the property to disconnect the service, call center activity occurs when someone contacts PowerStream to assume responsibility for the service and a service person visits the property to reconnect. Based on the review of the process, PowerStream estimates that the same charges as for Disconnect/Reconnect for non-payment are appropriate.

The "Install/Remove load control devices during/after regular hours" charge is to be used in cases when a load control device is installed instead of disconnecting the service. As noted, this situation does concern a non-payment situation; the only difference is that when the service person visits the property to disconnect, they replace the meter with a load limiter. All other activities administratively and operationally are the same. Therefore the same charge should apply as a standard Disconnect/Reconnect charge.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

CCC INTERROGATORY #24:

Reference(s): C2/T1/S1/pp. 3-4)

Please explain how the proposed changes to the Specific Service Charges impact the 2013 forecast. What is the forecast for the revenue associated with the install/remove load control devices?

RESPONSE:

The proposed changes to Specific Service Charges increases 2013 revenue by approximately $460,000.

The revenue from the introduction of 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 amounts is forecasted to be approximately $190,000.

This activity commenced mid 2011, so at this time PowerStream has limited history on the activity levels for this situation. Based on data gathered PowerStream has forecasted 2,500 of these charges for 2013, with an estimated 90% of these to be during regular hours.

The introduction of 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 will not have any effect on PowerStream's 2013 forecast and associated revenue as PowerStream currently treats these as a disconnect/reconnect process.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

The harmonization of Specific Service Charges is forecast to result in increased revenue of about $270,000, as discussed in response to Board Staff IR# 27, filed in this Exhibit.

Those increases are forecasted to be partially offset by the decrease in other charges.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

CCC INTERROGATORY #25:

Reference(s): (C2/T1/S1/p. 4)

What is PowerStream's policy regarding pole attachments? What is the 2013 revenue forecast associated with pole attachments?

RESPONSE:

It is PowerStream's policy to allow third-party attachments between our system neutral (in general, PowerStream's lowest wire on the pole) and final grade (ground level). A maximum of two (2) joint-use communication attachments are allowed per pole. A maximum of four (4) joint-use communication attachments are allowed at intersection crossings. Only one (1) attachment per communication company is allowed on a pole and two (2) attachments per company are allowed on an intersection pole. All attachments on the pole shall be on the same side as the neutral. Only one (1) streetlight attachment is allowed per pole with one additional streetlight attachment allowed at intersection crossings. All joint-use owners must adhere to ESA's "Guidelines for Third-party Attachments."

The 2013 revenue forecast associated with pole attachments is $700,000.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

ENERGY PROBE INTERROGATORY #20:

Reference(s): Exhibit C2, Tab 1, Schedule 1

Please provide the most recent year-to-date figures available for 2012 in the same level of detail as shown in Table 1, along with the corresponding figures for the same period in 2011.

RESPONSE:

Please refer to the table below summarizing the year-to-date June 2012 actual in comparison with the same period in 2011.

Table EP #20: Revenue Offsets June 2011 YTD and June 2012 YTD (000's)

($K)	June YTD Actual 2011	June YTD Actual 2012
Specific Services Charges	-1,897	-1,563
Late Payment Charges	-1,126	-996
Other Distribution Revenue	-974	-702
Other Income and Deductions	-532	-742
Total Revenue Offsets	**-4,530**	**-4,003**

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

ENERGY PROBE INTERROGATORY #21:

Reference(s): Exhibit C2, Tab 1, Schedule 1

a) Has PowerStream included revenues from the MicroFIT rate class in Table 1? If yes, please indicate where. If not, please indicate where these revenues have been included in the evidence.

b) Please provide the number of MicroFIT customers at the end of 2009, 2010, 2011 and the forecasts for the end of 2012 and 2013.

c) Based on the most recent information available, how many MicroFIT customers does PowerStream currently have?

RESPONSE:

a) Yes, the revenues from the MicroFit rate class are included in Table 1, in “Specific Service Charges”, account 4235, as prescribed by the Accounting Procedures Handbook (FAQ issued Dec.23,2010).

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

b) Please see the table below.

Table EP #21b: 2009-2013 MicroFit Customers

	2009	2010	2011	2012 Forecast	2013 Forecast
MicroFit Customers	1	74	173	273	383

c) As at the end of July 2012, PowerStream has 224 MicroFit customers.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

ENERGY PROBE INTERROGATORY #22:

Reference(s): Exhibit C2, Tab 1, Schedule 2

a) Please provide the most recent year-to-date figures available for 2012 in the same level of detail as shown in Table 5, along with the corresponding figures for the same period in 2011.

b) Please explain the drop in account 4210 rent from electric property of more than $70,000 shown between 2011 and 2012 after the significant increases shown in 2010 and 2011.

c) Please provide a table that shows the 2009 through 2013 actual/forecast revenue in account 4210 (mainly pole rentals), the corresponding expenses related to pole rentals in account 5095, and the associated net revenue.

d) Please provide the most recent year-to-date figures available for 2012 in the same level of detail as shown in Table 6, along with the corresponding figures for the same period in 2011.

e) Please provide more details on the loss on disposition of $532,500 shown for 2010 in Table 6. In particular, please provide details of the assets disposed of and their associated losses, along with any assets disposed of with a gain on disposition.

f) Does PowerStream plan on replacing any vehicles in 2013? If yes, are these vehicles being replaced as part of the capital expenditures for the bridge and test years? Also, what will be the net present value of any vehicles replaced in 2013 when they are replaced?

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

g) Please provide the average cash balance and interest rates used to forecast the 2012 and 2013 amounts in account 4405. Please also provide the average balance and interest rate for 2011.

h) Please provide the actual amount of damage claims received in each of 2009 through 2011. Please confirm that in 2009 and 2010 any such amounts received were included in contributed capital.

RESPONSE:

a) Please refer to the table below summarizing the year-to-date June 2012 actual in comparison with the same period in 2011:

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

Table EP #22a: Other Distribution Revenue: June 2011 YTD and June 2012 YTD

($)	MIFRS	June YTD Actual 2011	June YTD Actual 2012
4078	SSS Admin Charges	(434,840)	(458,025)
4082	Retail Services Revenues	(186,130)	(153,998)
4084	Service Transaction Requests Revenue	(15)	(15)
4090	Electric Services Incidental to Energy Sales	-	-
4210	Rent from Electric Property	(353,122)	(89,965)
4215	Other Utility Operating Income	-	-
4220	Other Electric Revenues	-	-
	Total	**(974,106)**	**(702,002)**

b) The increases in 2011 were attributable to the one- time recognition of 2010 revenue for pole rentals in the amount of $42,000. In addition, there was one-time revenue of $7,000 related to the rental of the Lazenby Transformer Station property.

The 2012 budget excludes one-time adjustments and represents rental revenue based on historical trends.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

c) Please see table below for a summary on account 4210 and 5095 for the period covering 2009 through 2013:

Table EP #22c: 2009-2013 Revenue from Pole Rentals

Object	Sub	Account Description	Actual 2009	Actual 2010	Actual 2011	Bridge 2012	Budget 2013
4210	8101	Cash	(5,400)	(8,775)	(10,125)		
4210	0276	Rent-Lazenby TS Lease		(2,260)	(6,780)		
4210	0449	Pole - Rental	(672,636)	(697,868)	(753,461)	(700,000)	(700,000)
		Total Revenue	**(678,036)**	**(708,903)**	**(770,366)**	**(700,000)**	**(700,000)**
5095	0449	Pole - Rental	65,515	94,141	68,099	80,000	80,000
		Total Expense	**65,515**	**94,141**	**68,099**	**80,000**	**80,000**
		Net Revenue	(612,521)	(614,762)	(702,267)	(620,000)	(620,000)

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

d) Please see table below showing year-to-date June 2012 actual in comparison to the actual for the same period in 2011:

Table EP #22d: Other Income and Deductions June 2011 YTD and June 2012 YTD

Other Income and Deductions			
		June YTD Actual 2011	June YTD Actual 2012
4355	Gain on disposition of utility and other property	(196,820)	(2,000)
4390	Miscellaneous Non-Operating Income	(258,501)	(695,185)
4405	Interest and Dividend Income	(77,064)	(44,978)
	Total	**(532,385)**	**(742,164)**

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

e) Please see table below for the details on the loss on disposition of $532,500 for 2010:

Table EP #22e: 2010 (Gain)/Loss on Disposition of Assets

(GAIN)/LOSS Description	December 2010 GL 4355
Freightliner	(24,900.14)
CIS - Cash Batch #0117 - Sale of file cabinet	(46.30)
Facilities' Asset disposal - Leasehold Improvements at Markham Office	404,813.43
Facilities' Asset disposal - Leasehold Improvements at Vaughan/Cochrance	51,932.32
Adjust Deprecation on Leasehold Improvements that were disposed	(38,913.34)
Facilities' Asset disposal - Office Furniture Disposed Markham Office	179,314.45
Facilities' Asset disposal - Store Equipement Disposed Markham/Vaughan	57,746.95
Vehicles and Tools disposal	(81,186.82)
Simple disposal-Vehicles	(15,923.82)
Simple Disposal - Meters	(331.76)
Total	532,505.01

f) Yes, PowerStream is planning on replacing vehicles in 2013 and the replacement costs have been included as part of the capital budget for 2013.

PowerStream has interpreted Energy Probe's request for the net present value as the net book value. The net book value of the vehicles to be replaced in 2013 is $113,500.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

g) Please see table below:

Table EP #22g: Average Cash Balance and Interest Rates 2011-2013

($M)	2011	2012	2013
	Actual	Budget	Budget
Average Cash Balance	11.2	20.0	28.0
Interest Rate	1.3%	1.3%	1.3%

h) In 2009 costs or amounts received from damages were not reflected in the determination of revenue requirement. Therefore in 2009 amounts received for damage claims were not recorded as contributed capital. This was changed in 2010 – costs and amounts received from damages do form part of the revenue requirement. All amounts received since 2010 for damage claims have been recorded as contributed capital.

Please see table below for damage claims from 2009 through 2011.

Table EP #22h: 2009-2011 Damage Claims

Damage Claims			
	2009	2010	2011
Total	(677,859)	(930,968)	(728,301)

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

ENERGY PROBE INTERROGATORY #23:

Reference(s): Exhibit C2, Tab 1, Schedule 3

a) The sale of scrap averaged approximately $245,000 in 2009 through 2011 and about $280,000 in 2010-2011. Please explain the drop to $200,000 in 2012 and 2013.

b) What is included in the miscellaneous line of account 4390?

c) The miscellaneous component of account 4390 averaged more than $280,000 in 2009 through 2011. Please explain the drop to $120,000 in 2012 and 2013.

RESPONSE:

a) The sale of scrap fluctuates each year. In 2010 and 2011, transformer scrap was higher because of the retirement of an old transformer station and the completion of building a new one. In 2012 and 2013, the sale of scrap level is back to the historical average.

b) Please see table below showing the main items in the miscellaneous line of account 4390:

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

Table EP #23b: Account 4390 Miscellaneous Line Items

1	4390	0421	Power Diversion
2	4390	2204	Unpresented Cheques W/ O
3	4390	5010	Apprentice Incentive Program
4	4390	5020	suite water meter recovery
5	4390	8101	Cash - Sale of scrap
6	4390	8125	Cash Discount
7	4390	8195	Admin. Processing Fee
8	4390	8196	Markup on damage claims
9	4390	8197	Damage Claims Cap Contribution

c) The budget for account 4390 (Miscellaneous Non-Operating Income) was developed at the total miscellaneous revenue level. The values within each line item of account 4390 are an attempt to split the total Non-Operating Income reasonably amongst the line items.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

VECC INTERROGATORY #24:

Reference(s): Exhibit C2, Tab 1, Schedule 2, page1 and 3 (lines 13-17)

a) Please provide a schedule that shows the 2010, 2011, 2012 and 2013 revenues from Specific Service Charges broken down by charge and specifically isolate the annual revenues associated with gains on work orders.

b) Please indicate where and how in Exhibit B the treatment of gains and losses after 2012 have been incorporated as a "capital contribution".

RESPONSE:

a) The table below shows the revenues from Specific Service Charges, broken down by charge.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

Table VECC #24a: Specific Service Charges, by Charge

	2010 Actual	2011 Actual	2011 Actual/MIFRS	2012 Forecast*	2013 Proposed*
Arrears certificate	$ 36,105	$ 39,495	$ 39,495	*$ 40,000*	*$ 40,000*
Statement of account	$ 90	$ 125	$ 125	*$ -*	*$ -*
Duplicate invoices for previous billing	$ 1,410	$ 1,100	$ 1,100	*$ 1,000*	*$ 1,000*
Easement letter	$ 5,040	$ 3,975	$ 3,975	*$ 3,750*	*$ 3,750*
Income tax letter	$ 330	$ 360	$ 360	*$ 360*	*$ 360*
Account history	$ 2,640	$ 30	$ 30	*$ 30*	*$ 30*
Returned cheque charge (plus bank charges)	$ 50,865	$ 44,400	$ 44,400	*$ 45,000*	*$ 40,000*
Legal letter charge	$ 11,310	$ 10,500	$ 10,500	*$ 10,000*	*$ 10,000*
Account set up charge/change of occupancy charge	$ 1,283,460	$ 1,221,130	$ 1,221,130	*$ 1,250,000*	*$ 1,275,000*
Special meter reads	$ 390	$ -	$ -	*$ -*	*$ -*
Collection of account charge	$ 1,499,910	$ 1,398,555	$ 1,398,555	*$ 1,400,000*	*$ 1,452,360*
Disconnect/Reconnect at meter - during regular hours	$ 201,390	$ 254,815	$ 254,815	*$ 250,000*	*$ 250,000*
Install/Remove load control device - during regular hours	$ -	$ -	$ -	*$ -*	*$ 146,250*
Disconnect/Reconnect at meter - after regular hours	$ 71,595	$ 85,650	$ 85,650	*$ 90,000*	*$ 80,000*
Install/Remove load control device - after regular hours	$ -	$ -	$ -	*$ -*	*$ 46,250*
Disconnect/Reconnect at pole - during regular hours	$ -	$ -	$ -	*$ -*	*$ -*
Disconnect/Reconnect at pole - after regular hours	$ -	$ -	$ -	*$ -*	*$ -*
Meter dispute charge	$ 30	$ -	$ -	*$ -*	*$ -*
Gain/Loss on Work Orders	$ 979,586	$ 817,513	$ 819,244	*$ -*	*$ -*
Microfit generators	$ 1,600	$ 7,018	$ 7,018	*$ 10,000*	*$ 20,000*
Miscellaneous charges	$ 17,182	$ 22,293	$ 22,293	*$ 20,000*	*$ 20,000*
Total In account 4235	**$ 4,162,933**	**$ 3,906,959**	**$ 3,908,690**	**$ 3,120,140**	**$ 3,385,000**
Balance in Account 4235 in the application	$ 4,162,933	$ 3,906,959	$ 3,908,690	$ 3,270,000	$ 3,385,000
Difference	$ (0)	$ 0	$ 0	$ (149,860)	$ -

PowerStream does not budget revenues in this account at the detailed level requested. The Specific Service Charges are forecast on a higher level, based on the customer growth trend, updated for known changes such as removal of gain/loss on work orders from this revenue line. The numbers in the table above represent PowerStream's best attempt to split the forecast data to the level of data available for the actual.

The 2012 forecast for Specific Service Charges in the rate application is $3,270,000. This amount should be revised to $3,120,140, as per the table above. Therefore, the decrease in

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

Specific Service Charges in 2012 due to the removal of gains on work orders is $819,000, not $667,000, as stated in Exhibit C2, Tab 1, Schedule 2.

b) There is no adjustment to contributed capital as a result of this change. The amount of contributed capital in the capital budget correctly reflects the amount that is expected to be recovered though contributions. Due to the accounting treatment as described at Exhibit C2, Tab 1, Schedule 2, page 3, lines 13-17, in the past PowerStream was not recording all of the amounts received as contributed capital. In certain cases, some of the amount collected towards the cost of construction was recorded as a gain on work orders and shown as other income rather than contributed capital reducing the cost of the asset. This has been corrected and is properly reflected in the Application.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

VECC INTERROGATORY #25:

Reference(s): Exhibit C2, Tab 1, Schedule 3, page 1

a) Please provide a schedule that sets out the June 30th 2012 year to date Other Operating Revenue for each account and provide the equivalent values for June 2011.

RESPONSE:

a) Please see the table below. June YTD 2011 figures are under CGAAP while the 2012 are under MIFRS. For 2011 the company did not convert monthly data from CGAAP to MIFRS.

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

Table VECC #25a: Other Operating Revenue June 2011 YTD and June 2012 YTD

		June YTD Actual 2011 CGAAP	June YTD Actual 2012 MIFRS
4235	Miscellaneous Services Charges	(1,897,173)	(1,562,606)
4225	Late Payment Charges	(1,126,154)	(996,444)
4078	SSS Admin charge	(434,840)	(458,025)
4082	Retail Services Revenues	(186,130)	(153,998)
4084	Service Transaction Requests (STR) Revenues	(15)	(15)
4090	Electric Services Incidental to energy Sales	-	-
4205	Interdepartmental Rents	-	-
4210	Rent from Electric Property	(353,122)	(89,965)
4215	Other Utility Operating Income	-	-
4220	Other Electric Revenues	-	-
4324	Special Purpose Charge Recovery	(2,516)	133
4355	Gain on Disposition of Utility and Other Property	(196,820)	(2,000)
4360	Loss on Disposition of Utility and Other Property	-	-
4375	Revenues from Non-Utility Operations	(5,009,392)	(6,922,846)
4380	Expenses of Non-Utility Operations	4,591,378	4,594,028
4385	Non-Utility Rental Income	(3,089)	(2,768)
4390	Miscellaneous Non-Operating Income	(258,501)	(695,185)
4405	Interest and Dividend Income	(77,064)	(44,978)
4105	Transmission Charges Revenue	-	-
4110	Transmission Services Revenue	-	-
4230	Sales of Water and Water Power	-	-
	Total	**(4,953,437)**	**(6,334,670)**
Specific service Charges		(1,897,173)	(1,562,606)
Late Payment Charges		(1,126,154)	(996,444)
Other Distribution Revenue		(974,106)	(702,002)
Other Income & Expenses		(532,385)	(742,164)
	Total revenue offsets	(4,529,818)	(4,003,216)
Other revenue (not included in revenue offsets)		(423,619)	(2,331,453)
	Total	**(4,953,437)**	**(6,334,670)**

RESPONSES TO INTERROGATORIES BY ISSUE

3. OPERATING REVENUE (Exhibit C)

3.3 Is the proposed Test Year forecast of other revenues appropriate? (C2)

VECC INTERROGATORY #26:

Reference(s): Exhibit C2, Tab 1, Schedule 2, pages 8 and 11

a) Please explain the $70,000 drop in Rent from Electric Property as between 2011 and after (per page 8).

b) What is the basis for the reduced forecast for miscellaneous non-operating income and sales of scrap in 2012 and 2013 as compare to 2011?

RESPONSE:

a) The increases in 2011 were attributable to the one-time recognition of revenue for pole rentals in the amount of $42,000. In addition, there was one-time revenue of $7,000 related to the rental of Lazenby Transformer Station property.

The 2012 budget excludes one-time adjustments and represents rental revenue based on historical trends.

b) The sale of scrap fluctuates each year. In 2010 and 2011, transformer scrap was higher because of the retirement of an old transformer station and the completion of building a new one. In 2012 and 2013, the sale of scrap level is back to historical average.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

BOARD STAFF INTERROGATORY #29:

Reference(s): <u>E D1</u>

Please identify the increases (decreases) in OM&A expense for the test year, arising from other than from a decrease (increase) in capitalized overhead

RESPONSE:

Please see table below for the increase in OM&A costs within the 2013 test year.

Table Board Staff #29: OM&A Change from 2012 Bridge to 2013 Budget ($000)

OM&A Change from 2012 Bridge to 2013 Budget ($000)		
2012 Bridge	$ 81,596	
		$ 81,596
Compensation	$ 1,667	
Additional Staff	$ 1,038	
Asset Maintenance	$ 335	
Customer Services / Regulatory	-$ 252	
IS Strategy	$ 180	
Locates	$ 140	
Corporate Development	$ 200	
Insurance	$ 358	
Other	$ 524	
Net Change		**$ 4,190**
Ending Balance		**$ 85,786**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

BOARD STAFF INTERROGATORY #30:

Reference(s): **E D1/T1/S1/p.5**

It is stated that:

"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."

a) Of the referenced eighteen additional staff, please state when they were hired and which of these staff were hired to work in the PMO and which were hired to assist in developing the referenced business-driven technology strategy.
b) Please provide a year-by-year breakdown of costs for each of these initiatives from the time of their establishment.
c) Please expand on the explanation provided as to why PowerStream created the PMO and provide any quantification of savings that have been achieved through its establishment.

RESPONSE:

a) Two Project managers were hired to assist in the Project Management Office. The referenced Business-Driven Technology Strategy plan has been developed and the twelve additional staff will be assisting, either directly or indirectly in the implementation of this strategy.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table Board Staff #30a: Technology Strategy Staff

	Position	Date Filled
Information Services	Senior Technical Specialist	September 6, 2011
	Application Support Analyst	October 3, 2011
	Senior Business Analyst	September 26, 2011
	Director, Information Services	April 4, 2011
	Executive Assistant II	September 26, 2011
	Security Administration Analyst	Vacant (2012 hire)
	Senior Business Analyst	Vacant (2012 hire)
	Application Support Analyst	Vacant (2013 hire)
	Application Support Analyst	Vacant (2013 hire)
	Service Desk Analyst	Vacant (2013 hire)
	Senior Technical Specialist	Vacant (2013 hire)
	Supervisor, IS Support Services	Vacant (2013 hire)
Legal	Administrative Assistant	March 7, 2011
	VP General Counsel	February 1, 2010
Project Management Office	PMO Project Manager	May 19, 2010
	PMO Project Manager	July 7, 2011
Enterprise Risk and Internal Audit	Manager, Enterprise Risk and Internal Audit	June 15, 2009
	Senior Internal Audit	Vacant (2012 hire)

b) Please find below a table noting costs breakdown of legal, Enterprise Risk and Internal Audit, PMO and IS Staff for the business driven technology strategy:

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table Board Staff #30b: Technology Strategy Staff Costs

	2009	2010	2011	2012	2013
Project Management Office	N/A	80,000	186,400	288,063	277,528
Enterprise Risk & Internal Audit	78,193	317,449	310,289	395,417	485,718
Legal	N/A	200,892	285,513	398,765	405,083
Information Services	N/A	NA	835,061	985,045	1,436,106

Note that Information Services costs are allocated to either OM&A or capital.

c) Please see the response to CCC IR#55, filed at Exhibit J1, Tab 1, Schedule 4.5.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

BOARD STAFF INTERROGATORY #31:
Reference(s): E D1

Please identify the inflation rate used for the 2013 OM&A forecast and the source document for the inflation assumptions.

RESPONSE:

The inflation rate used for the 2013 OM&A forecast is based on the average of Consumer Price Index from 2009 to 2013 summarized in the table below:

Table Board Staff #31: 2009-2013 Consumer Price Index

Year	Consumer Price Index	Source
2010	1.8	Statistics Canada
2011	2.9	Statistics Canada
2012	1.8	Scotiabank\Global Forecast Update
2013	2.3	Scotiabank\Global Forecast Update
Average	**2.2**	

Based on this analysis PowerStream used 2% as the inflation rate for the non-labour portion of the 2013 OM&A forecast which is the rate that is contained in the budget guidelines. Note that labour costs are assumed to increase 3% annually.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

BOARD STAFF INTERROGATORY #32:

Reference(s): <u>E D1/T5/S3/p.1</u>

On this page donations are discussed. For all charitable donations included in the revenue requirement, please identify the amounts and the account in which the donations are recorded, and whether the amounts are compliant with Section 2.7.2.5 of the Filing Requirements.

RESPONSE:

Table 1 from Exhibit D1, Tab 5, Schedule 3 has been updated below, to show the account codes.

Donations	USoA Account	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
<u>Not included for Rate Recovery</u>						
United Way	*6205*	$ 89,304	$ 31,818	$ 40,926	$ 57,000	$ 57,000
Other	*6205*	$ 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
<u>Rate Recoverable</u>						
LEAP	*6205*		$ 186,289	$ 187,009	$ 200,000	$ 200,000
Winter Warmth	*6205*	$ 30,000				
Georgian College	*6205*		$ 150,000	$ 150,000	$ 150,000	$ 150,000
York University	*5665 /6205 for Actual*			$ 75,000	$ 213,750	$ 213,750
Total Included in 2013 Rate Application		$ 30,000	$ 336,289	$ 412,009	$ 563,750	$ 563,750
Total Donations		**$ 130,683**	**$ 380,062**	**$ 459,834**	**$ 633,750**	**$ 633,750**

PowerStream is compliant with Section 2.7.2.5 of the Filing Requirements. Non-recoverable contributions were identified and excluded from the revenue requirement calculation. No political contributions have been included for recovery.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

For those items included for rate recovery, the LEAP and Winter Warmth contributions provide assistance to customers in paying their electricity bills and assistance to low income consumers.

The contribution to Georgian College has enabled the purchase state-of-the-art protection & control equipment for use in labs. Students are learning on up-to-date equipment and have experience in protection & control when they graduate. This new equipment is also being used to provide training to PowerStream staff. PowerStream and Georgian College have co-developed specialized courses for PowerStream staff. Georgian College provides the instructors, space and equipment at a reduced price for PowerStream.

As a result of the partnership, PowerStream participates on the Electrical Advisory Committee and in strategic sessions with the College where PowerStream provides both input to course curriculum and insight into the electrical industry so Georgian College can meet the needs of the industry.

PowerStream is also invited regularly to participate in student sessions. This, combined with a special PowerStream notice board on campus and coverage in college publications, allows students to become aware of PowerStream as a company. As a result PowerStream has been able to attract the highest quality of co-op students and graduates from the two- and three-year electrical programs.

In PowerStream’s view, the contribution to Georgian College benefits customers and should be rate recoverable.

The contribution to York University is more recent and is expected to provide similar benefits in the Test Year and beyond.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #26:

Reference(s): (A2/T1/S1/p. 6)

In the document entitled Summary of the Application it states that PowerStream's OM&A expenses are forecast to increase by $32.5 million relative to 2009. Please explain how this number was derived. What is the impact on OM&A of moving to MIFRS for 2012 and 2013?

RESPONSE:

Please see Table 2: OM&A Cost Driver Summary illustrated on page 3 in Exhibit D1, Tab 1, Schedule 1 for a listing of the main costs behind the increase of $32.6M relative to 2009. (The difference between $32.6M and $32.5M is a result of using 2009 Barrie actuals as the starting point as opposed to 2008 Barrie Board-approved.)

The impact of MIFRS on 2012 and 2013 OM&A is shown in Exhibit Appendix 1, Schedule 21 OEB Appendix 2-G OM&A Cost Driver Table.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #27:

Reference(s): (A2/T1/S1/p. 6)

Please provide a table setting out PowerStream's OM&A per customer, for the years 2009 to 2012 inclusive, compared to utilities which PowerStream regards as of comparable size and circumstances.

RESPONSE:

PowerStream has done high level cost per customer comparisons against other distributors as evidenced in the response to CCC IR# 2b, as filed in Exhbit J1, Tab 1, Schedule 1.1. Due to accounting differences and differences in many other factors, meaningful comparability is difficult, especially for ratemaking purposes. PowerStream reviews comparative information but does not have any detailed analysis of its own on comparability with other utilities of comparable size and circumstances at this time.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #28:

Reference(s): (D1/T1/S1/p. 10)

Please provide a schedule setting out detailed OM&A costs in the same format as Table 1. Please include the most recent forecast for 2012 having regard to actual spending to date.

RESPONSE:

The attached Appendix D represents detailed OM&A costs in the format of Table 1. PowerStream has not prepared forecasts for 2012 therefore the 2012 budget as submitted with this Cost of Service Application is PowerStream's current 2012 Forecast.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #29:

Reference(s): (D1/T1/S2/ p. 2)

Please indicate why the OM&A per customer has increased significantly since 2009. Please indicate to what extent the increase is specifically related to the transition to MIFRS.

RESPONSE:

Please see table below for the main cost drivers' impact per customer including the MIFRS change for the 2009-2013 period. In accordance with the table, the increase from 2009 to 2013 is 48.1%. Close to half (22.4%) of the increase is associated with the implementation of MIFRS.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table CCC#29: OM&A Cost Per customer Change from 2009 Approved to 2013 Budget

OM&A Cost per Customer Change from 2009 PowerStream Approved to 2013 Budget				
Weighted Average Cost per Customer			**$ 167.0**	*Note 1
IFRS	$	37.4		
Compensation	$	12.7		
Additional Staff	$	7.8		
Asset Maintenance	$	10.7		
Smart Meter	$	8.5		
Customer Services / Regulatory	$	6.2		
IS Strategy	$	4.5		
Locates	$	3.6		
Corporate Development	$	3.7		
Insurance	$	2.2		
Other	$	0.7		
Net Change			**$ 98.0**	
Adjustment for Changes in Customer Level *			**(17.6)**	*Note 2
Ending Balance (2013)			**$ 247.4**	

- Note 1 – The Weighted Average Cost per Customer of **$167.0 is** based on the Board approved 2009 OM&A costs for PowerStream and 2009 Barrie actual divided by the number of customers for each entity.
- Note 2 – As the customer number changes, the cost is spread over a larger number of customers therefore each year there is a reduction in the cost per customer. This adjustment is reflected for 2009 to 2013 in the "Adjustment for Changes in Customer Level" of ($17.6) at the bottom of the table above.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #30:

Reference(s): (D1/T1/S1/p. 1)

Please provide the year to date OM&A spending for 2012.

RESPONSE:

Please see table below for the June year to date 2012 OM&A expenses:

Table CCC #30: June Year-to-Date 2012 OM&A Expenses ($000)

	June YTD 2012 Actual
Operation & Maintenance (O&M)	13,780
Administration Expenses	24,186
OM&A Expenses	37,966

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #31:

Reference(s): (D1/T1/S1/p. 3)

Of the total OM&A increase since 2009 of $32.640 million how much is related to Regulatory Requirements and/or Legislative Requirements? Please include all assumptions.

RESPONSE:

The company does not track separately expenditures associated with regulatory and legislative requirements. To be of assistance, please refer to Exhibit D1, Tab 1, Schedule 1 where examples of some regulatory increases are noted.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #32:

Reference(s): (D1/S1/p. 9)

The evidence indicates that training costs have increased by $544,000 corporate wide. What is the proposed training budget for 2013? Please provide a detailed breakdown of that budget.

RESPONSE:

The proposed training budget for 2013 is $1.1M. Please see breakdown per division. For assistance, further breakdown is provided where appropriate to highlight Human Resources and Health & Safety that is provided to staff corporate wide.

Table CCC #32: 2013 Proposed Training Budget

(in '000)

Division		Total
Human Resources	$	245
Health & Safety	$	104
Other Corporate Services	$	219
Finance	$	208
Engineering Services	$	151
Operations and Construction	$	120
Executive Mgmt Group	$	62
Total	**$**	**1,109**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #33:

Reference(s): (D1/t1/S3/p. 1)

The evidence indicates that PowerStream's corporate strategy includes an initiative to grow through mergers and acquisitions. Please provide any internal documentation/ reports/ presentations related to this strategy. Are there costs included in the 2013 revenue requirement related to mergers and acquisitions activities? If so, please identify those costs. How many employees spend time on this initiative? How are the costs allocated between the distribution company and the shareholders?

RESPONSE:

PowerStream does not have any formal documentation/reports/presentations other than identifying this as an initiative on its strategy map. Mergers and acquisitions (M&A) require willing parties to participate, which means at any given time there may be no activity.

Since the merger with Barrie Hydro in 2009 there has been limited activity. The strategic partnership with the Town of Collingwood as described in Exhibit D1, Tab1, Schedule 3 did not require significant staff time as the day-to-day operations were not integrated into PowerStream's operations as was necessary in the merger with Barrie Hydro.

From time to time discussions may ensue regarding possible M&A activity. The costs for these initiatives are not tracked separately from the core business.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #34:

Reference(s): (D1/T3/s1/p. 2)

Please provide the expected savings related to the introduction of e-billing? Have these savings been reflected in the 2013 revenue requirement? If not, why not? If so, where are they reflected?

RESPONSE:

PowerStream's proposed 2013 revenue requirement does not reflect specific savings relating to its e-billing program. Based on the current billing platform, PowerStream will not be providing full e-billing service. The program is currently in its infancy and it is expected to remain so throughout the 2013 Test Year. The program will be under assessment in the foreseeable future while PowerStream gains more experience in this activity and implements a new CIS platform to support full e-billing services. Given the above, any potential savings would be minimal.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #35:

Reference(s): (D1/T3/S1/p. 3)

Please provide a detailed budget for the rates and Regulatory Affairs Department for the years 2009-2013. Please break out the costs both, internal and external, specifically related to this rate application and explain how they are to be recovered.

RESPONSE:

Please see table below for the detailed budget for the Rates and Regulatory Affairs Department from 2009- 2013.

For details of the costs related to the current rate application and their recovery please refer to responses to Interrogatory Energy Probe #29, filed in this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table CCC #35: 2009-2013 Budget - Rates and Regulatory Affairs Department

Account Description	Budget 2009	Budget 2010	Budget 2011	Budget 2012	Budget 2013	Cost Type Internal/External
Payroll: Regular	474,585	522,785	746,075	774,403	797,635	Internal
Pay: Summer Student				17,417	18,624	Internal
Payroll Burden	179,081	197,093	233,329	212,279	218,412	Internal
Meals: Food & Beverage	800	1,000	2,000	2,000	2,000	Internal
Memberships	-	-	200	200	200	Internal
Membership Fees: Profession	3,400	3,400	3,700	5,100	5,100	Internal
Staff Training & Develop.	2,500	2,500	5,500	43,000	43,000	Internal
Conferences	10,000	4,000	7,000	7,000	7,000	Internal
Mileage/Parking/Tolls	500	600	1,300	1,300	1,300	Internal
Telephone: Mobile				1,200	1,200	Internal
Consulting	100,000	50,000	50,000	150,000	50,000	External
Legal Services	100,000	60,000	60,000	560,000	60,000	External
Total Rates	**870,866**	**841,377**	**1,109,104**	**1,773,899**	**1,204,471**	
Payroll: Regular	114,729	104,668	104,669	111,043	160,506	Internal
Payroll Burden	42,690	38,946	38,947	31,565	45,635	Internal
Consulting	100,000	73,000	100,000	170,000	110,000	External
Legal Services	100,000	73,000	50,000	50,000	50,000	External
OEB Intervener Costs	80,000	79,200	80,000	80,000	50,000	External
Meals: Food & Beverage	4,000	1,000	500	500	750	Internal
Memberships	-	4,100	4,100	4,100	4,100	Internal
Postage	1,000	-				Internal
Staff Training & Development	3,000	3,000	3,000	3,000	3,500	Internal
Conferences	2,000	2,000	2,000	2,000	3,000	Internal
Mileage/Parking/Tolls	2,800	2,300	2,000	2,000	2,250	Internal
Telephone: Mobile				2,400	2,400	Internal
OEB Cost Assessment	1,260,000	1,123,000	1,123,000	1,102,500	1,157,625	External
Total Regulatory	**1,710,219**	**1,504,215**	**1,508,216**	**1,559,108**	**1,589,766**	
Grand Total	**2,581,085**	**2,345,592**	**2,617,320**	**3,333,007**	**2,794,237**	
Total Internal costs	**841,085**	**887,392**	**1,154,320**	**1,220,507**	**1,316,612**	
Total External costs	**1,740,000**	**1,458,200**	**1,463,000**	**2,112,500**	**1,477,625**	

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #36:

Reference(s): (D1/T3/S1/p. 7)

Please provide a detailed budget for the Information Services Department for the years 2009-2013. Please include capital and OM&A costs.

RESPONSE:

Please see table below for the detailed OM&A budget from 2009 to 2013 for the Information Services Department. For the information requested regarding capital, please refer to Exhibit J1, Tab 2, Schedule 2.3, Table CCC IR #16: Detailed Capital Expenditures 2009-2013, filed in response to CCC IR #16 .

Table CCC #36: 2009-2013 OM&A Information Services Department

OM&A Budget - IS	2009	2010	2011	2012	2013
Labour	726,953	1,286,842	1,804,892	2,308,804	2,697,639
Contract/Consulting	350,000	52,000	184,000	230,000	287,600
Computer	1,366,000	1,827,929	2,227,650	2,684,850	2,866,515
Supplies & Equipment	100,000	105,000	120,000	113,600	127,308
Telephone	885,000	1,162,000	925,000	826,560	855,532
Training	58,000	53,000	80,004	132,610	117,251
Other	31,750	86,250	112,196	339,956	353,434
TOTAL EXPENSES	3,517,703	4,573,021	5,453,742	6,636,380	7,305,279

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #37:

Reference(s): (D1/T3/S1/p. 8)

Please provide a detailed budget for the Legal Department for the years 2009-2013. Please include all expenses related to the use of outside legal counsel.

RESPONSE:

Please see table below for detailed budget for the Legal Department from 2009 through to 2013.

Table CCC #37: 2009-2013 Budget - Legal Department

OM&A - Legal	2009	2010	2011	2012	2013
Labour	-	186,392	372,076	326,174	335,381
Contract/Consulting	-	-	-	100,000	100,000
Memberships	-	2,800	2,800	3,400	3,400
Mileage	-	2,500	2,500	2,500	2,500
Miscellaneous	-	-	-	30,000	30,000
Other	-	9,200	16,500	17,700	17,700
TOTAL EXPENSES	-	200,892	393,876	479,774	488,981

There are no external legal dollars in the legal department's budget.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #38:

Reference(s): (D1/T3/S1/p. 9)

Please provide a detailed budget for Fleet Services for the years 2009-2013. Please include both capital and OM&A costs. What is PowerStream's policy regarding vehicles for senior management? Please file any written policies regarding company vehicles.

RESPONSE:

Please see tables below for detailed Fleet budget for both OM&A and Capital over the period from 2009 to 2013:

Table CCC #38-1: Fleet Services Budget 2009-2013 – OM&A

OM&A - Fleet	2009 CGAAP	2010 CGAAP	2011 CGAAP	2012 MIFRS	2013 MIFRS
Labour	478,489	599,616	475,828	476,731	489,819
Materials	21,000	28,500	44,250	44,250	44,250
Mtce, Repair & Fuel	1,596,700	2,019,400	1,829,900	1,794,080	1,794,080
Insurance	115,000	149,367	160,000	134,068	150,000
Mileage	120,500	128,500	135,000	206,000	206,000
Other	19,500	17,700	17,200	201,100	201,100
Applied Burden	-2,354,189	-2,943,083	-2,662,179	-2,443,677	-2,473,099
TOTAL EXPENSES	-3,000	0	-1	412,552	412,150

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table CCC #38-2: Fleet Services Budget 2009-2013 – Capital Expenditures

Fleet Capital Expenditures

in $000's	**2009 Budget**	**2010 Budget**	**2011 Budget**	**2012 Budget**	**2013 Budget**
Vehicle replacements - Heavy	2,127	1,876	770	1,100	1,155
Vehicle replacements - Light	259	942	326	748	685
Miscellaneous	182	100	299	182	1,093
	2,568	2,918	1,395	2,030	2,933

Examples:

Heavy Vehicles: Lines aerial devices
Light/Medium Vehicles: Vans, Pickups and Automobiles
Miscellaneous: Trailers, Tension machines, Fork lifts, Tools, Replacements, Repairs

The company does not have a written policy on vehicles for senior management. Any vehicles for senior management would be part of their employment contract.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #39:

Reference(s): (D1/T3/S1/p. 10)

Please provide a detailed budget for the Corporate Communications department for the years 2009-2013. Are any of these costs allocated to the shareholders? If not, why not?

RESPONSE:

The detailed budget for the Corporate Communications department is shown in the table below. All of these costs form part of the revenue requirement as they represent the net budget after allocation of the appropriate cost to the non-rate regulated activities (the non-rate regulated activities currently consist of Solar, CDM, and allocations to the shareholders such as expenditures on sponsorships.)

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table CCC #39: Detailed Budget - Corporate Communications Department Budget

	CGAAP 2009	CGAAP 2010	CGAAP 2011	MIFRS 2012	MIFRS 2013
Labour	305,375	462,390	682,145	648,960	730,539
Sponsorships	37,265	29,000	42,405	16,500	16,500
Donations	30,000	150,000	420,000	350,000	350,000
Contract / Consulting	30,000	30,000	-	45,000	45,000
Meals	6,000	6,000	6,500	6,250	6,500
Memberships	10,000	8,000	8,000	9,000	9,000
Mileage	7,500	10,500	11,500	8,250	8,500
Advertising	51,200	55,000	55,000	130,000	130,000
Printing	64,000	66,000	66,740	60,500	60,500
Newsletter/Publications	57,500	37,500	37,500	50,000	55,000
Promotional Items	1,000	1,000	11,000	36,500	36,500
Sundry	1,000	1,000	1,000	1,500	1,500
Telephone	-	-	-	7,800	7,800
Training	6,000	15,000	17,500	21,250	22,500
	606,840	**871,390**	**1,359,290**	**1,391,510**	**1,479,839**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #40:

Reference(s): (D1/T3/S2/p. 1)

What it the current forecast for 2012 Bad Debt Expense given year to date actuals?

RESPONSE:

The table below shows the 2012 forecast and YTD actual as of June:

Table CCC #40: 2012 Bad Debt Expense

	YTD (June)Actual	2012 Forecast
Bad Debt - Energy	$1,046, 499	$1,835,000
Bad Debt - Misc.	$282,936	$250,000
Total	**$1,329,435**	**$2,085,000**

PowerStream has not performed an updated bad debt forecast from that contained in the original 2012 budget.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #41:

Reference(s): (D1/T3/S2)

Please provide the Property Tax amounts for 2009-2013. Where are property taxes accounted for in the calculation of the revenue requirement?

RESPONSE:

Please see the table below that illustrates the Property tax amounts for 2009-2013.

Table CCC #41: Property Tax Amounts 2009-2013

Property Taxes	Actual CGAAP 2009	Actual CGAAP 2010	Actual CGAAP 2011	Actual MIFRS 2011	Budget 2012	Budget 2013
Totals	947,459.31	1,061,755.99	1,212,881.96	1,603,354.88	1,700,435.00	1,795,039.00

Property taxes are included in the "Other Distribution expense" line of Exhibit D1, Tab 3,Schedule 2 page 2.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #42:

Reference(s): (D1/T3/S2/p. 2)

Please provide all of the cost categories included in "Other Distribution Expenses". Please provide a detailed budget for the years 2009-2013 for Other Distribution Expenses.

RESPONSE:

Please see table below for a break-down of "Other Distribution Expense" and the annual budget for the years 2009 – 2013:

Table CCC #42: Other Distribution Expenses 2009-2013

Object Account	Account Description	2009	2010	2011	2012	2013
6105	Property Taxes	1,746,245	1,526,606	1,563,539	1,700,435	1,795,039
6105	Allocate Building Costs	-111,036	-387,163	-390,473	-	-
6215	Late Charges	30,000	30,000	30,000	30,600	31,212
Total Other Distribution Expense		**1,665,209**	**1,169,443**	**1,203,066**	**1,731,035**	**1,826,251**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

CCC INTERROGATORY #43:

Reference(s): (D1/T5/S3/p. 1)

Please explain why Charitable Contributions are included in the revenue requirement for 2013.

RESPONSE:

Please see the response to Board Staff IR# 32 filed in this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

ENERGY PROBE INTERROGATORY #24:

Reference(s): Appendix 1, Schedule 8

a) Does PowerStream pay any costs to MEC, VHI or BHHI as shown on the Corporate Entities Relationship Chart? If yes, please identify these costs.

b) Does PowerStream pay any of the costs associated with the Board of Directors of MEC, VHI or BHHI? If yes, please quantify.

c) What is the cost associated with the Board of Directors of PowerStream?

RESPONSE:

a) PowerStream does not pay any costs to MEC, VHI or BHHI.

b) PowerStream does not pay any of the costs associated with the Board of Directors of MEC, VHI or BHHI.

c) The 2012 budget made allowances for an anticipated increase in meetings of the Board of Directors, however, this did not materialize. Based on the June 30th 2012 actual and the forecast for the remainder of the year, the Board of Directors' costs for 2012 and 2013 will not increase materially over 2011. A revised Table 6 is listed below.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table EP #24c: Board of Directors' Cost

	2009	2010	2011	2012	2013
Original	$294,147	$297,146	$326,081	$460,176	$472,872
Revised				$372,005	$382,055

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

ENERGY PROBE INTERROGATORY #25:

Reference(s): Exhibit D1, Tab 1, Schedule 1

a) Please confirm that the figures shown in Table 1 include the savings due to the merger and the transition costs associated with the merger. If the latter is confirmed, please provide a version of Table 1 that excludes all transition costs associated with the merger.

b) Please confirm that in the absence of IFRS in the 2013 test year, the OM&A based on CGAAP would be $12,441 lower based on the figures shown in Table 2.

c) Table 2 shows an increase between 2009 and 2013 of $2,731,000 for smart meters. Where there any smart meter costs included in the 2009 Barrie Actual or 2009 PowerStream South Approved costs? If yes, please quantify. If no, please quantify the 2009 OM&A costs related to smart meters that were included in a deferral account for recovery.

d) Please quantify the increase related to the requirement to remove shared services revenue from OM&A and report it as other revenue. Please confirm that this amount is part of the $12,441,000 IFRS impact.

RESPONSE:

a) Yes, the figures in Table 1 include the merger savings and transition costs. The table below reflects a version that excludes all transition costs associated with the merger.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table EP #25a: OM&A Costs 2009-2013 – Excluding Merger Costs ($000)

	PowerStream South	PowerStream Combined					
In $000	2009 Approved	2009 Actual	2010 Actual	2011 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Operation & Maintenance	GAAP				MIFS		
	15,889	22,680	19,320	21,528	26,932	30,644	32,601
Administration Expenses	27,327	34,645	37,518	40,558	46,955	50,952	53,100
Total OM&A	43,216	57,325	56,838	62,086	73,887	81,596	85,701
$ change		14,109	(487)	5,248	11,801	7,709	4,105
% change		33%	-1%	9%	N/A	10%	5%

b) Powerstream confirms that the 2013 OM&A would be $12,441,000 lower under CGAAP.

c) There are no smart meter costs in the Barrie 2009 Actual OM&A amounts or in the Barrie 2008 COS Approved amounts. In PowerStream's 2009 Approved amounts there were OM&A costs of $897,600 related to the operation of the meters installed up to the end of 2007 in the PowerStream South service area.

PowerStream recorded $1,905,000 of 2009 OM&A costs in account 1556 for smart meters installed in the Barrie service area in 2009 and smart meters installed in PowerStream South in 2008 and 2009.

d) The shared services revenue removed from OM&A and reported as Other Revenue to meet IFRS requirement is $3.90 million. The company confirms that this amount is part of the $12.441 million IFRS impact.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

ENERGY PROBE INTERROGATORY #26:

Reference(s): Exhibit D1, Tab 1, Schedule 1

What is the current status of negotiations for a new collective agreement to replace the one that ends March 31, 2013?

RESPONSE:

The management and union negotiating teams have been selected. Negotiations are scheduled to begin in January 2013and the process of determining the bargaining agenda is under way.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

ENERGY PROBE INTERROGATORY #27:

Reference(s): Exhibit D1, Tab 2, Schedule 2

Please provide the most recent year-to-date figures available for 2012 and the figures for the corresponding period in 2011 in the same level of detail as shown in the table on page 1.

RESPONSE:

For 2011 PowerStream did not convert monthly data from CGAAP to MIFRS. June YTD 2011 figures are under CGAAP while the 2012 are under MIFRS. PowerStream does provide a response to the question in the table below, however caution should be exercised as to the direct comparability of the numbers cited.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table EP #27: OM&A Expenses
Variance Analysis for 2011 YTD and 2012 YTD

Function within O&M	June 2011 Actual CGAAP	June 2012 Actual MIFRS
System Control	**$1,553**	**$1,586**
$ Increase		$33
% Increase		2%
Lines	**$4,291**	**$5,352**
$ Increase		$1,061
% Increase		25%
Protection & Control	**$428**	**$622**
$ Increase		$195
% Increase		46%
Stations	**$669**	**$1,012**
$ Increase		$343
% Increase		51%
Metering	**$507**	**$1,200**
$ Increase		$694
% Increase		137%
Cable Locates	**$992**	**$1,133**
$ Increase		$141
% Increase		14%
Engineering	**$72**	**$2,170**
$ Increase		$2,098
% Increase		2901%
Other	**$1,425**	**$704**
$ Increase		($721)
% Increase		-51%
Total	**$9,937**	**$13,780**
$ Increase		$3,843
% Increase		39%

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

ENERGY PROBE INTERROGATORY #28:

Reference(s): Exhibit D1, Tab 3, Schedule 2

Please provide the most recent year-to-date figures available for 2012 and the figures for the corresponding period in 2011 in the same level of detail as shown in Table 1.

RESPONSE:

For 2011 the company did not convert monthly data from CGAAP to MIFRS. June YTD 2011 figures are under CGAAP while the 2012 are under MIFRS. The company does provide a response to the question below. However caution should be exercised as to the direct comparability of the numbers cited.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

	2011 June YTD	Bridge Year 2012 JUNE YTD
Billing and Collection	**$ 4,698**	**$ 5,897**
$ Increase		$ 1,199
% Increase		26%
Community Relations	**$ 494**	**$ 473**
$ Increase		$ (21)
% Increase		-4%
Community Relations - CDM	**$ (0)**	**$ 0**
$ Increase		$ -
% Increase		0%
Administrative and General Expenses	**$ 9,838**	**$ 14,871**
$ Increase		$ 5,033
% Increase		51%
Insurance Expense	**$ 820**	**$ 744**
$ Increase		$ (76)
% Increase		-9%
Bad Debt Expense	**$ 985**	**$ 1,152**
$ Increase		$ 166
% Increase		$ (819)
Charitable Contributions	**$ 0**	**$ 175**
$ Increase		$ 175
% Increase		0%
Other Distribution Expenses	**$ 545**	**$ 874**
$ Increase		$ 329
% Increase		60%
TOTAL	**$ 17,380**	**$ 24,186**
$ Increase		$ 6,806
% Increase		39%

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

ENERGY PROBE INTERROGATORY #29:

Reference(s): Exhibit D1, Tab 5, Schedule 2, Appendix 2-K

a) There do not appear to be any intervenor costs associated with the current application shown in the table. Have these costs been included in line 2 "OEB Hearing Assessments (applicant originated)?

b) Please confirm that the total costs associated with the current application are $270,000, as shown in line 13.

c) Has PowerStream amortized the current application costs over 4 years? If not, please explain why not and what period they are allocated to.

d) Please reconcile the total regulatory cost for 2013 shown on line 14 of $2,388,002 with the figure of $1,396,665 shown in Appendix 2-F of Exhibit D1, Tab 2-3.

RESPONSE:

a) Intervenor costs are included in line 3 “OEB Section 30 Costs (OEB-initiated)”. PowerStream has now updated Appendix 2-K “Regulatory Expenses” to match the revised format as per the Board’s *Filing Requirements for Electricity Transmission and Distribution Rate Applications* dated June 28, 2012. Please refer to response to Board Staff Interrogatory #5, filed at Exhibit J1, Tab 1, Schedule 1.0, for revised schedules. Intervenor costs are shown separately on line 11 in Appendix 2-M.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

b) As shown in the attached "Regulatory Expenses" Appendix 2-M, total costs associated with this Rate Application are $1,018,345. Most of those expenses ($790,000) are forecast to happen in the 2012 Bridge Year.

c) PowerStream has not amortized the costs of the current application, since 85% of those costs are incurred before the Test Year. Only $160,000 is forecasted for the 2013 Test Year. This amount is less than amortizing the cost of the rate application over four years.

d) The regulatory costs shown on line 14 are recorded in different USoA accounts, while the appendix 2-F of Exhibit D1 shows the totals by USoA account. The amounts are reconciled in the table below:

Table EP #29d: Reconciliation of Regulatory Costs

	USoA Account		**2013 Test year**
Total in account 5655 (Appendix 2-F)		$	1,396,665
Add amounts recorded in accounts other than 5655:			
ESA assessments	*9083*	$	141,000
Operating expenses associated with Staff resources	*5610, 5620,5665*	$	753,377
Legal and Consulting costs for regulatory matter	*5630*	$	270,000
less			
Professional membership costs (EDA, OEA) - not included in Appendix 2-H	*5655*	$	(173,040)
Regulatory Costs shown on line 14	***5655***	**$**	**2,388,002**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

ENERGY PROBE INTERROGATORY #30:

Reference(s): Exhibit D1, Tab 2-3, Appendix 2-F

a) Please provide the most recent year-to-date figures for account 6105 for 2012, along with the corresponding figures for 2011.

b) Please explain what type of penalties are included in account 6215 and why the forecasts for 2012 and 2013 are significantly higher than the actuals posted in previous years.

RESPONSE:

a) For 2011 PowerStream did not convert monthly data from CGAAP to MIFRS. June YTD 2011 figures are under CGAAP while the 2012 are under MIFRS. PowerStream does provide a response to the question below, however, caution should be exercised as to the direct comparability of the numbers cited.

Table EP #30a: Account 6105 – 2011 YTD and 2012 YTD

Account Description	YTD June CGAAP Actual 2011	YTD June MIFRS Actual 2012
GL 6105	544,449.39	859,595.45

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

b) Penalties relate to interest/penalties charged by the tax authorities for reassessments. The 2012 and 2013 forecasts reflect PowerStream's historic practice of using $30,000 in its budget.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

ENERGY PROBE INTERROGATORY #31:

Reference(s): Exhibit D1, Tab 5, Schedule 3 &
Exhibit D1, Tab 2-3, Appendix 2-F

Please reconcile the 2013 donations of $563,750 shown in the first reference with the $350,000 shown in account 6205 in the second reference.

RESPONSE:

The difference between the amounts is $213,750. This is the amount that PowerStream pays for its strategic partnership with York University, as mentioned in Ex.D1, Tab 5, Schedule 5. This donation for 2012-2013 is budgeted, in account 5665 “Miscellaneous general expenses” and not in account 6205.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #23:

Reference(s): [A3/1/1, p. 5 and D1/2/1, p. 3]

Please provide any internal document that provides a summary or table of the "cyclic maintenance requirements" referred to.

RESPONSE:

PowerStream's Transformer Station and Municipal Substation cyclic maintenance requirements are guided by Procedures SM1 and SM2 attached as Appendix E and Appendix F respectively.

PowerStream's distribution system cyclic maintenance requirements are guided by the following table:

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table SEC #23: Distribution Inspection and Maintenance Programs

PowerStream Distribution Inspection and Maintenance Programs

Equipment/ Program	Insp/ Mtce/ Both	Area	Cycle	Work By	Record Keeping / Tracking Mechanism
LIS Maintenance	Mtce	North	5 year cycle/100 switches/20 per year	In-House	ATF Form
		South	5 year cycle/860 switches/170 per year	Contracted	ATF Form/Spreadsheet in J Drive
Tree Trimming	Mtce	North	3 Year cycle by feeder	In House 30% Contracted 70%	SQL Database
		South	5 yr cycle by grid areas	Contracted	Hi-lited hard copy maps
Infrared	Insp	North	2 Yr cycle By municipality Yr 1 - outlying areas + half Barrie Yr2 half Barrie	Contracted	Electronic reports provided by contractor, then stored in SQL Database, Hard copy reports of deficiencies stored in binders
		South	Entire 3 phase overhead system annually	Contracted	Electronic reports provided by contractor stored in J:
Switchgear Maintenance/ Dry Ice Cleaning	Mtce	North	Started in 2011	Contracted	SQL Database
		South	5 Yr Cycle, all switchgear is inspected/cleaned on 5 yr cycle	Contracted	Spreadsheet, electronic reports in J:\Drive
Insulator Washing	Both	North	Bi-yearly, geographically, 3-ph porcelain, high traffic	Contracted	Marked up hard copy maps
		South	Same as above plus polymer hot spots (e.g 407)	Contracted	Marked up hard copy maps
Pole Inspections	Insp	North	Part of ACA Program, 3 years to complete, 5 year cycle	Contracted	Lists generated by Planning, by municipality
		South	Part of ACA Program, 3 years to complete, 5 year cycle	Contracted	Lists generated by Planning, on gid maps by municipality
Transformer Inspections	Insp	North	3 Yr Cycle	In-House	SQL database tracks station feeders completed
		South	3 Yr Cycle	Contracted	Excel spreadsheet, marked up maps

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #24:

Reference(s): [A3/1/1, p. 5]

Please explain the sentence that begins "The Operating and Maintenance budget is done at a work order level…"

RESPONSE:

The Operating and Maintenance budget is budgeted by work programs. The "Work Order" is a tracking system that is used to budget and track work programs' costs. Each work program is assigned with specific work order (s) based on the nature of work.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #25:

Reference(s): [D1/1/1, p. 3]

Please confirm that Table 2 shows OM&A increases for the four years 2009 to 2013 which, if you exclude IFRS impacts, total 38.1%, or a compound rate of about 8.5% per year. Please indicate where on Table 2 the Applicant has reflected:

a) Productivity savings, and
b) Savings arising out of the merger,

and for each provide the dollar figures included in each category.

RESPONSE:

Yes, Table 2 shows the increases from 2009 to 2013. Without the IFRS impact, the increase is $20,199k or 38.1%.

a) Productivity savings are reflected within the individual categories, therefore they are not separable from general overall increases in costs.

b) As responded in Interrogatory Energy Probe 45c, in Exhibit J1, Tab 4, Schedule 6, the actuals for 2009 reflect the merger savings – the 2009 actuals would have been higher if the two companies remained separate. These were reflected in the budgets for each company in 2009 and were not part of the original Board Approved amounts that are shown in Table 2.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #26:

Reference(s): [D1/1/1, p. 6]

Please provide data for the period 2008 – 2011 showing the annual increases in incidents of vandalism and motor vehicle accidents in the Applicant's service territory.

RESPONSE:

The dollar increases associated with accidents and vandalism for the period 2009 to 2011 are shown below. The dollar increase for the 2008 year is not being provided because such number is available only for PowerStream but not for Barrie Hydro(pre-merger) and therefore comparability would not have any probative value. The context of the question appears to relate to the $454,000 value of cost increase within asset maintenance discussed in the reference given by the question.

Table SEC #26: 2009-2011 Increases in OM&A ('000s)

Increases in O&M Costs from previous year	2009 Actual	2010 Actual	2011 Actual
Accidents & Vandalism (non-recoverable)	119	11	6

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #27:

Reference(s): [D1/1/1, p. 6]

Please explain why the increased efficiency from the OMS does not result in a reduction in the cost of emergency and reactive maintenance.

RESPONSE:

Three driving factors are leading to an increase in PowerStream's emergency and reactive maintenance costs: 1. Aging Assets, 2. Customer Growth and resulting growth to asset infrastructure, and 3. Increased thunderstorm activity. As a result PowerStream is experiencing an increase in outages and trouble calls year over year.

The Outage Management System enables PowerStream to better manage this increase in number of outages and dispatch crews to site to improve response times. Quicker response times in turn reduce overall restoration times, which will help mitigate the increase, but not reduce, the emergency and reactive maintenance costs resulting from increased system outage activity.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #28:

Reference(s): [D1/1/1, p. 7]

Please provide the five year technology strategy referred to, together with any supporting business case, and any presentations to executive management or the Board of Directors showing the costs and benefits of the strategy.

RESPONSE:

PowerStream has attached the Five Year Technology strategy as Exhibit J1, Tab 2, Schedule 2.3, Appendix D, in response to CCC interrogatory #12.

A business case to support the development of this strategy was not prepared. However, PowerStream undertook a comprehensive vendor selection process, resulting in the attached recommendation to Executive Management that KPMG be awarded the engagement for the preparation of this strategy. PowerStream staff prepared a Vendor Recommendation report for its Executive Management, which includes comments on, and scoring of, the three prospective vendors' proposals, as well as discussions of their pricing and methodologies. The proposals were provided in confidence, and the Vendor Recommendation Report was provided in confidence to PowerStream's Board of Directors. PowerStream is prepared to file a copy of this report in confidence in accordance with the Board's *Practice Direction on Confidential Filings* (the "Practice Direction"). The basis for the confidentiality request is as follows:

KPMG and the other proponents are consulting firms engaged in competitive businesses. The public disclosure of their proposed methodologies and pricing with respect to this project could reasonably be expected to prejudice the economic interest of, significantly prejudice the

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

competitive position of, cause undue financial loss to, and be injurious to the financial interest of each of these consultants since it would enable their competitors, including their fellow proponents, to ascertain the scope and pricing of services in similar projects. Similarly, the public disclosure of this information may reasonably be expected to prejudice the economic interest of, significantly prejudice the competitive position of, cause undue financial loss to, and be injurious to the financial interest of PowerStream in that (for example) potential proponents in future consulting engagements may not be willing to submit proposals knowing that they may be made public, and/or PowerStream's ability to obtain truly competitive proposals, reflecting a variety of methodologies and prices may be impaired.

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

In keeping with the requirements of the Practice Direction, PowerStream is filing a confidential, unredacted version of the Vendor Recommendation Report. The unredacted version of the

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

document has been placed in a sealed envelope marked "Confidential". PowerStream has designated the Vendor Recommendation Report as Appendix A to this Schedule.

Going forward, PowerStream generally expects to develop a business case for each project on the IT strategy roadmap valued at over $500,000.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #29:

Reference(s): [D1/1/2, p. 2]

Please confirm that the 2013 OM&A per customer on a CGAAP basis is proposed to be $211.30. Please confirm that this represents a 26.5% increase of $44.30 per customer from the weighted average of the Board-approved OM&A per customer for the two merging companies. Please explain the appropriateness of a 6.1% per year increase in OM&A per customer when inflation was less than 2% per year. Please confirm that, after accounting for merger savings of $6.2 million, the overall increase in OM&A on a CGAAP basis is from $147.55 per customer to $211.30 per customer, a $63.75 increase that is 43.2% or about 9.4% per year.

RESPONSE:

Yes, the 2013 OM&A per customer on a CGAAP basis would have been $211.30.

Yes, this represents a 26.5% increase of $44.30 per customer from the weighted average of the Board-approved OM&A per customer for the two merging companies.

PowerStream's application contains a substantial amount of pre-filed evidence in justifying the 6.1% increase in OM&A per customer. The inflation rate is only one of many variables that would affect OM&A expenses. For a summary of the proposed OM&A cost changes in the 2013 test year and the substantiation of same, please see the company's exhibit D1,Tab 1,Schedule 1.

PowerStream understands the source of the numbers cited in the interrogatory on the basis of the analysis posited, and can confirm the analysis on that basis only. However the company does not agree with the logic of the analysis. As indicated in the response to VECC #35 as filed in this

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Exhibit, the $6.2 million in merger savings was the result of rationalization of FTE positions that were either eliminated or avoided that were never included in the Board approved rebasing years for both Barrie and PowerStream.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #30:

Reference(s): [D1/2/2/p.1]

Please provide updated year-to-date expenses for 2012 as shown in the O&M Expense table.

RESPONSE:

June year to date O&M Expenses are reflected in the table below:

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table SEC #30: June 2012 O&M YTD Expenses

Function within O&M	June 2012 Actual MIFRS
System Control	**$1,586**
$ Increase	N/A
% Increase	N/A
Lines	**$5,352**
$ Increase	N/A
% Increase	N/A
Protection & Control	**$622**
$ Increase	N/A
% Increase	N/A
Stations	**$1,012**
$ Increase	N/A
% Increase	N/A
Metering	**$1,200**
$ Increase	N/A
% Increase	N/A
Cable Locates	**$1,133**
$ Increase	N/A
% Increase	N/A
Engineering	**$2,170**
$ Increase	N/A
% Increase	N/A
Other	**$704**
$ Increase	N/A
% Increase	N/A
Total	**$13,780**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #31:

Reference(s): [D1/2/2, p. 4]

Please provide an explanation of the harmonization of the burden methodology, and its impacts.

RESPONSE:

Following the merger, it was identified that while the principles behind allocating a portion of costs to capital jobs was similar between the former Barrie Hydro and PowerStream, the pool of costs being allocated was slightly different. Specifically,

- The depreciation of vehicles and other major tools and equipment was included in the PS pool method but was excluded from the Barrie Hydro distribution of costs.
- At Barrie Hydro, only a portion of the labour costs for Engineering and Operations attributable to capital jobs were allocated to capital, whereas at PowerStream the burden pool consists of the entire Engineering departmental costs including the non union labour costs, and the Operations non union labour costs. This pool was then allocated to all productive work orders – both capital and O&M.

The impact of this harmonization in 2010 on OM&A was a decrease of $1,562,000 as indicated in the above noted reference of the evidence.

To further assist, please note that this harmonization methodology has changed significantly under MIFRS - please see section under the Burden Process in Exhibit A3, Tab1, Schedule 3.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #32:

Reference(s): [D1/3/2/p.1]

Please provide updated year-to-date expenses for 2012 as shown in the Administration Expenses table.

RESPONSE:

Please see the table below.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table SEC #32: Summary of 2012 Administration Expenses (Year To Date)

	Bridge Year 2012 JUNE YTD MIFRS Actual
Billing and Collection	**$ 5,897**
$ Increase	N/A
% Increase	N/A
Community Relations	**$ 473**
$ Increase	N/A
% Increase	N/A
Administrative and General Expenses	**$ 14,871**
$ Increase	N/A
% Increase	N/A
Insurance Expense	**$ 744**
$ Increase	N/A
% Increase	N/A
Bad Debt Expense	**$ 1,152**
$ Increase	N/A
% Increase	N/A
Charitable Contributions	**$ 175**
$ Increase	N/A
% Increase	N/A
Other Distribution Expenses	**$ 874**
$ Increase	N/A
% Increase	N/A
TOTAL	**$ 24,186**
$ Increase	N/A
% Increase	N/A

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #33:

Reference(s): [D1/3/1, p. 8]

Please provide details of the savings that have resulted from the creation of the Legal Department.

RESPONSE:

In the above-noted reference PowerStream has set out the activities performed by the company's Legal Department. It is the PowerStream's belief that there are savings by having these activities performed internally rather than externally. Please note that the Legal Department consists of one lawyer, one administrative assistant and one law clerk. Please note also that a portion of the costs of the legal department are allocated to non-rate regulated activities (Solar and CDM).

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #34:

Reference(s): [D1/3/2, pp. 3 and 5]

Please reconcile the figure of $1,600,000 on page 3 with the figure of $1,000,000 on page 5.

RESPONSE:

The transition costs were not included in the 2009 Board Approved amount for PowerStream South. However, in 2009, actual transition payout of $1.6M occurred which is referred to on page 3 of Exhibit D1, Tab 3, Schedule 2. The transition payout package continued in 2010 in the amount of $608,000, which produces the difference of $1,000,000 referred to on page 5.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #35:

Reference(s): [D1/3/2, p. 8]

Please provide the business case or other supporting document for the establishment of the Organizational Effectiveness business unit. Please provide the report of the external consultants relating to strategic management.

RESPONSE:

The Organizational Effectiveness business unit was not a new business unit in 2011 as is indicated in the reference; rather, it was in existence prior to 2009. The “new” aspect of the Organizational Effectiveness business unit was the establishment of a new area *within* Organizational Effectiveness called The Project Management Office (PMO). Please refer to PowerStream’s evidence at Exhibit D1, Tab 3, Schedule 1, page 6, lines 25-28 and page 7, lines 1-12, for a description of the purpose and key activities of the Organizational Effectiveness department with specific reference to the newly established PMO.

PowerStream’s “strategic management system” is a term used to describe all of the components used to manage PowerStream’s performance e.g. Mission, Vision, Values, Strategic Objectives, Strategy Map etc. The $200,000 increase in external consultant costs referred to above is explained at lines 26-28 of Exhibit D1, Tab 1, Schedule 1 and for convenience is repeated here: “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.”

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #36:

Reference(s): [D1/3/2, p. 8]

Please provide the consultant's report on the technology strategy and Governance/Enterprise Model.

RESPONSE:

The Feb 24, 2012 Proposed IT Governance Model is hereto attached as Appendix B.

PowerStream's Apr 16, 2012 Enterprise Data Model is hereto attached as Appendix C.

The Five-Year Technology strategy is filed as Exhibit J1, Tab 2, Schedule 2.3, Appendix C, in response to CCC interrogatory #12.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

SEC INTERROGATORY #37:

Reference(s): [D1/5/2/App.2-H]

Please provide a copy of this table with the footnotes.

RESPONSE:

PowerStream has revised the format of Appendix 2-H, to match the revised format as per the Board's *Filing Requirements for Electricity Transmission and Distribution Rate Applications* dated June 28, 2012. Please refer to the Appendix 2-M "Regulatory Costs", filed as part of the response to Board Staff IR # 5.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #27:

Reference(s): Exhibit D

a) Please file the detailed OM&A accounts for 2009 through 2013 (Board Guidelines Appendix 2-F).

b) Please file the detailed Compensation and FTE (Board Guidelines Appendix 2-K).

RESPONSE:

a) OEB appendix 2-F was filed in PowerStream's evidence under Appendix 1, Schedule 21 "OEB Schedules-supplementary to evidence".

b) OEB appendix 2-K was filed in PowerStream's evidence under Appendix 1, Schedule 21 "OEB Schedules-supplementary to evidence".

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #28:

Reference(s): Exhibit D

a) Please provide an OM&A table in the same form as VECC IR# showing the IS OM&A costs.

RESPONSE:

a) PowerStream assumes that the missing IR reference is VECC IR#4a and the company has responded based on this assumption. Please see table below.

Table VECC #28a: Information Services OM&A

Item	2010	2011	2012**	2013**	2014**	2015**	2016**
CIS Hardware							
CIS Software & Maintenance (See Note 2)	$427,000	$445,000	$812,000	$868,000	$874,960	$892,459	$910,308
ERP Hardware							
ERP Software & Maintenance (See Note 2)	$438,000	$395,000	$393,000	$382,874	$390,532	$398,343	$406,309
SCADA Hardware							
SCADA Software & Maintenance	$32,000	$20,000	$20,000	$20,000	$22,000	$22,000	$23,000
Outage Management System Hardware							
Outage Management System Software&Maint	See note 1	See note 1	See note 1	See note 1	See note 1	See note 1	See note 1
AMI/ODS Hardware							
AMI/ODS Software & Maintenance (See Note 3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other IS Hardware							
Other IS Software & Maintenance (See Note 2)	$513,000	$285,000	$728,000	$874,384	$961,872	$981,109	$1,000,732
Other IS Maintenance Costs - Hardware Maintenance	$206,000	$254,000	$312,000	$687,000	$720,000	$734,400	$749,088
IS Consulting Fees	$42,000	$342,000	$130,000	$60,000	$51,000	$52,020	$53,060
Other IS Costs - ESRI GIS/OMS Software Maintenance	$322,000	$204,000	$252,000	$260,000	$265,200	$270,504	$275,914
	$1,980,000	$1,945,000	$2,647,000	$3,152,259	$3,285,564	$3,350,835	$3,418,412

Notes:
1) ESRI Maintenance costs cover both GIS and OMS OM&A Maintenance.
2) Cost only reflect OM&A Maintenance
3) AMI / ODS costs are contracted out as hosting service fees rather than maintenance
** Figure for this year are based on budgets and forcasts

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #29:

Reference(s): Exhibit D1, Tab 1, Schedule 1, page 6

a) PowerStream identifies $454,000 in additional costs related to environmental changes, vandalism and vehicle accidents. Please provide a breakdown of these costs for 2009 through 2014. Please include insurance costs and claims.
b) Are all of these costs recouped through insurance claims? If not please explain why.

RESPONSE:

a) and b) Please see the table below which itemizes the $454,000 figure. These activities are not insured by the company and therefore there are no claims. The company has historically not been insured for those occurrences and the company understands that this is a widely held practice throughout the electricity distribution sector in Ontario.

The accidents & vandalism incidents that can be recovered from a third party are not included in the amounts below.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table VECC #29a: Environmental/Weather Impacts to Customer ($000)

	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS	2012 Bridge	2013 Test	Total Change
Environmental / Weather Impacts to Customer	520	(316)	250	-	-	-	454
Storm Damage	320	(445)	189				64
Accidents & Vandalism (non-recoverable)	119	11	6				137
OH LIS Switch Mtce		83	45				128
OH Voltage problems		25	14				39
OH Customer Premises	76						76
OH Switching for control room		10	(0)				10

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #30:

Reference(s): Exhibit D1, Tab 1, Schedule 1, page 6

a) Please provide explain how the $797,000 in 2013 OM&A attributable to soil remediation is calculated
b) Is this work outsourced? If so have contracts been awarded?
c) Please provide a list of the sites which PowerStream believes will need similar remediation after 2013.

RESPONSE:

a) To clarify, the amount of $797,000 discussed on page 6 of Exhibit D1,Tab 1, Schedule 1 referred to in the interrogatory, relates to the period from 2009 actual to 2013 Test Year. Of this amount, $562,000 is for the period 2009 to 2012. The balance of $235,000 pertains to the 2013 Test Year.

b) The work is outsourced and the contracts have been awarded.

c) PowerStream has not completed at this point its assessment of what remediation is required after 2013.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #31:

Reference(s): Exhibit D1, Tab 1, Schedule 1, page 6

a) Please provide the incremental OM&A costs related to the maintenance and ongoing operation of smart meters.

RESPONSE:

a) The incremental 2013 OM&A costs relates to the maintenance and ongoing operation of smart meters total $2.7 million and consists of $1.6 million in costs related to the operation of the advanced meter infrastructure (AMI) and associated costs to get the data to the MDM/R - provincial smart meter entity (SME) but does not include any cost related to the use of the MDM/R - SME services, $0.5 million in increased meter maintenance costs, and $0.6 million related to additional customer inquiries.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #32:

Reference(s): Exhibit D1, Tab 1, Schedule 1

a) Please provide the fees (separately) paid to the EDA, CEA for the years 2009 through 2014. Please confirm PowerStream is seeking recovery of these costs in rates.

RESPONSE:

a) Please see table below that shows the fees paid to EDA and CEA for the years 2009 through 2013. The company has not completed its budget for 2014. PowerStream is seeking recovery of the 2013 budget costs in 2013 rates.

Table VECC #32a: Fees Paid to EDA and CEA 2009-2013

Description	Actual 2009	Actual 2010	Actual 2011	Budget 2012	Budget 2013
EDA	102,600	105,850	106,500	120,000	123,600
CEA	2,400	5,600	2,800	2,800	2,800
Total	105,000	111,450	109,300	122,800	126,400

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #33:

Reference(s): Exhibit D1, Tab 1, Schedule 1, page 8,9

a) Please provide a table of all training costs for the period 2009 through 2014. Please breakdown these costs by engineering training related and non-engineering related.

RESPONSE:

The table below identifies the engineering and non-engineering training budgets within the Operations and Maintenance and Administration. Please note that engineering training costs may be included in non-engineering training costs, for example for such departments as Health and Safety. The 2014 budget has not been completed and hence the number is not available.

Table VECC #33: Training Costs 2009-2013

Category	2009 Actual	2010 Actual	2011 Actual	2012 Budget	2013 Budget
Engineering Related	41,921	131,257	120,847	144,050	151,300
Non-Engineering related	376,703	468,173	601,931	966,355	957,816
Total Training Costs	**418,624**	**599,430**	**722,779**	**1,110,405**	**1,109,116**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #34:

Reference(s): Exhibit D1, Tab 1, Schedule 1, page 9

a) Please provide a list of the various types of insurance purchased by PowerStream (e.g. Credit Risk Insurance etc.), the associated premiums, and the carrier for the period 2009 through 2014).

RESPONSE:

Please see table below. The request with respect to 2014 can not be provided as the budget has not been completed.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table VECC #34: Insurance Data 2009-2013

$(000) Type of Insurance	Provider	2009 Actual	2010 Actual	2011 Actual	2012 Budget	2013 Budget
Total Liability	MEARIE	467	556	611	523	673
Directors & Officers Liability	MEARIE	261	140	138	143	153
Property & Boiler & Machinery	MEARIE	446	764	866	808	1,006
Automobile	MEARIE	118	154	141	134	150
Credit Risk Insurance	Euler	250	370	385	395	403
Sub Total		1,541	1,985	2,141	2,004	2,385
REBATE from MEARIE			-227			
GRAND TOTAL		1,541	1,757	2,141	2,004	2,385

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #35:

Reference(s): Exhibit D1, Tab 1,Schedule 2, page 2, Table 1/ Schedule 3, page 3

a) PowerStream states that savings as the result of the merger with Barrie Hydro were $6.2 million. Table 1 shows that the OM&A cost per customer for 2009 through 2011 was either at or exceeded the cost per customer of either standalone utility. Please explain how the 6.2 million was calculated and why on a cost per customer basis no savings appear to have been achieved.

RESPONSE:

a) The $6.2 million in merger savings was the result of rationalization of FTE positions that were either eliminated or avoided. Additional pressures to the business caused an offsetting increase to other costs included in the OM&A causing the cost per customer to increase. Please see cost driver per customer table below for the impacts.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

Table VECC #35a: OM&A Cost per Customer

OM&A Cost per Customer Change from 2009 PowerStream Approved to 2011 Actual				
Weighted Avg Cost Per Customer			**$ 167.0**	Note 1
IFRS	$	-		
Compensation	$	0.6		
Additional Staff	$	2.9		
Asset Maintenance	$	5.9		
Smart Meter	$	11.1		
Customer Services / Regulatory	$	3.3		
IS Strategy	$	1.5		
Locates	$	3.2		
Corporate Development	$	1.8		
Insurance	$	1.1		
Other	-$	3.5		
Net Change			**$ 27.9**	
Adjustment for Changes in Customer Level			**(8.0)**	Note 2
Ending Balance			**$ 186.9**	

* Note 1 – The Weighted Average Cost per Customer of **$167.0** is based on the Board approved OM&A costs for both Barrie and PowerStream divided by the customers for each entity.
* Note 2 – As the customer number changes, the cost is spread over a larger number of people therefore each year there is a reduction in the cost per customer. This adjustment is reflected for 2009 to 2011 in the “Adjustment for Changes in Customer Level” of **($8.0)** at the bottom of the table above.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #36:

Reference(s): Exhibit D1, Tab 1, Schedule 3, page 4

a) What are the 2013 and 2014 estimated cost of the Collingwood partnership?

RESPONSE:

a) There are no costs reflected in the 2013 rate filing with respect to this partnership. The company does not anticipate any costs with respect to this partnership in 2014.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #37:

Reference(s): Exhibit D1, Tab 1, Schedule 3

a) Please provide a table which shows for each year 2009 through 2014 total consulting costs. Please breakdown the table into categories: Engineering related; Corporate/Strategic/HR; Other.

RESPONSE:

Please find below is a table reflecting the consulting costs by year for 2009 to 2011 actual, and budget for 2012 and 2013. Note that consulting costs for Operations is included in Engineering. The OM&A 2014 budget has not been completed at this time.

Table VECC #37: 2009-2013 Consulting Costs

	ACTUAL			BUDGET	
	2009	2010	2011	2012	2013
Engineering Related	186,268	212,237	1,133,703	488,000	454,600
Corporate / Strategic / HR	733,269	744,991	1,416,716	1,244,224	1,304,648
Other	1,109,627	-331,190	465,666	1,396,880	270,000
Total	2,029,164	626,038	3,016,085	3,129,104	2,029,248

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #38:

Reference(s): Exhibit D1, Tab 2, Schedule 2, page 7

a) Please clarify the total fibre optic link costs between Vaughn and Barrie and in which year these costs were incurred.

RESPONSE:

To clarify, the company's reference "between Vaughan and Barrie" pertains to the connection of Barrie to the rest of the PowerStream system. The total fibre optic link costs for the company by year are noted in the table below:

Table #VECC38a: Fibre Optic Link Costs Between Vaughan and Barrie

	Actual 2009	Actual 2010	Actual 2011	Budget 2012	Budget 2013
Fibre Optic	98,907	117,715	238,065	244,000	246,000

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #39:

Reference(s): Exhibit D1, Tab 5, Schedule 3, page 1, Table 1

a) Please provide further detail on the Georgian College and York University donations and why PowerStream believes these costs are appropriately borne by ratepayers.

RESPONSE:

Please see response to Board Staff IR #32, filed in this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.1 Is the overall Test Year 2013 OM&A forecast appropriate? (D1)

VECC INTERROGATORY #40:

Reference(s): Exhibit D1, Tab 3, Schedule 1, page 10

a) Please provide the Corporate Communications costs for 2009 through 2014.

RESPONSE:

Please see table below. Please note that the company has not completed its budget for 2014.

Table VECC #40: Corporate Communications Costs 2009-2014

	Actual				Budget	Budget
Corporate Communications	2009 CGAAP	2010 CGAAP	2011 CGAAP	2011 MIFRS	2012 MIFRS	2013 MIFRS
TOTAL	$ 709	$ 1,047	$ 1,396	$ 1,384	$ 1,392	$ 1,480

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 4
Schedule 4.1
Appendix B
17 Pages
Filed: August 31, 2012

KPMG
cutting through complexity™

IT Governance

February 24, 2012

Contents

The contacts at KPMG in connection with this report are:

Ian Shelley
Partner
+ 416.777.8894
ishelley@kpmg.ca

Raphael Ly
Manager
+ 416.777.8369
rly@kpmg.ca

What is IT Governance?

IT Governance prescribes decision rights and accountabilities

IT Management is the process of making the decision

IT is everywhere and can no longer be the responsibility of a single department.

The governance of IT must be a shared responsibility across all organizational units.

The lack of IT governance results in tactical decision making

Business needs are constantly changing in light of market trends and regulatory obligations. Most often, these business changes require or impact information technology (IT) assets. As such, having an agile decision making model for IT is paramount in order to support business agility and competitive advantage. This decision making model is termed IT Governance and is the subject of this document.

Every organization will have a governance model that is unique and aligned to their corporate culture, strategies and objectives. Generally speaking, there is no right or wrong governance model, however there are leading principles that should be considered. These principles include the following:

- IT Governance defines the decisions, decision rights and accountabilities;
- IT Management is the process of making the decisions; and
- IT cannot be governed and managed by a single department; it has to be shared and reflect enterprise needs.

Underpinning every governance model are guiding principles and organizational behaviours that embody corporate culture, strategies and objectives. The absence of one or both of these elements will promote tactical IT decisions, which often yields sub-optimal value and return on investment.

Furthermore, the IT Governance model should be consistent throughout the enterprise. Exceptions to the IT governance model can lead to adoption risks and may impede the following:

- Ability to articulate enterprise needs;
- Alignment and consistency with the Corporate Strategy, IT Strategy, and IT Standards; and
- Short lived investment value.

When designing an IT Governance model, the existing role and responsibilities for a certain individual or business unit may likely change. As a leading practice, one should always design a model based on what is required vs. what is available.

In a previous governance workshop led by KPMG, the Senior Leadership Team discussed and agreed to an enhanced role for IS that would require more leadership and ownership with:

- introducing innovation;
- managing technology vendor relationships;
- designing solutions; and
- implementing solutions.

Note: exceptions to the above were made for engineering (GIS, Designer) and operations (SCADA). Rational: 1) these assets have historically resided within their respective group, and 2) these assets require specialized skills specific to engineering and operations.

Each organization will have a different IT Governance model, however they should all answer the following five interrelated decision areas:

1. IT Principles & Strategy;
2. Business Needs;
3. IT Investments;
4. IT Architecture; and
5. IT Delivery.

This document outlines the IT Governance model for PowerStream, and is written in a prescriptive (bullet) manner for the purposes of clarity. This document should be referenced and must updated as required.

The Five Major IT Decisions

The below diagram identifies the key decisions, advisor(s) and decision maker(s) for each of the five IT Governance areas. Each governance actor (e.g. CPSC) is described later in this document. For clarity, an Advisor is an individual(s) that is responsible for conducting the work (e.g. analysis), whereas the Decision Maker, as the name implies, is the individual(s) accountable for making the decision.

IT Principles and Strategy are fundamentally the guiding principles and roadmap for IT. They should be established by the business for the business, hence the engagement of the SLT Subset (Advisor) and EOC (Decision Maker), a cross-functional group of individuals. Note: The term SLT Subset is used throughout this document and refers to the authors and owners of the IT Strategy.

Business Needs are harvested from the ground up, however should align with the corporate strategy, objectives, and principles (e.g. reducing customer cost). Given their intimate knowledge of the business processes and systems, Managers are well suited to identify business needs. These needs are then forwarded to their Director for consideration, which may result in the creation of a business case.

IT Investments over $100k are presented under the form of a business case and are reviewed by the SLT Subset. Qualified investments (business cases) are then forwarded to the Optimizer Team for prioritization. Note: The EOC defines the annual IT Budget.

IT Architecture reflects the IT blueprint and standards, and is typically done by an Architect. The Architecture Committee approves and enforces the blueprint and standards, however will examine exceptions as needed.

IT Delivery embodies the implementation of IT Investments. As such, the PMO is responsible for providing project management oversight, enforcing leading practices, and monitoring performance. The Project Managers are responsible for scheduling tasks, mitigating risks, and delivering the investment. The Corporate Project Steering Committee provides direction and resolves material issues.

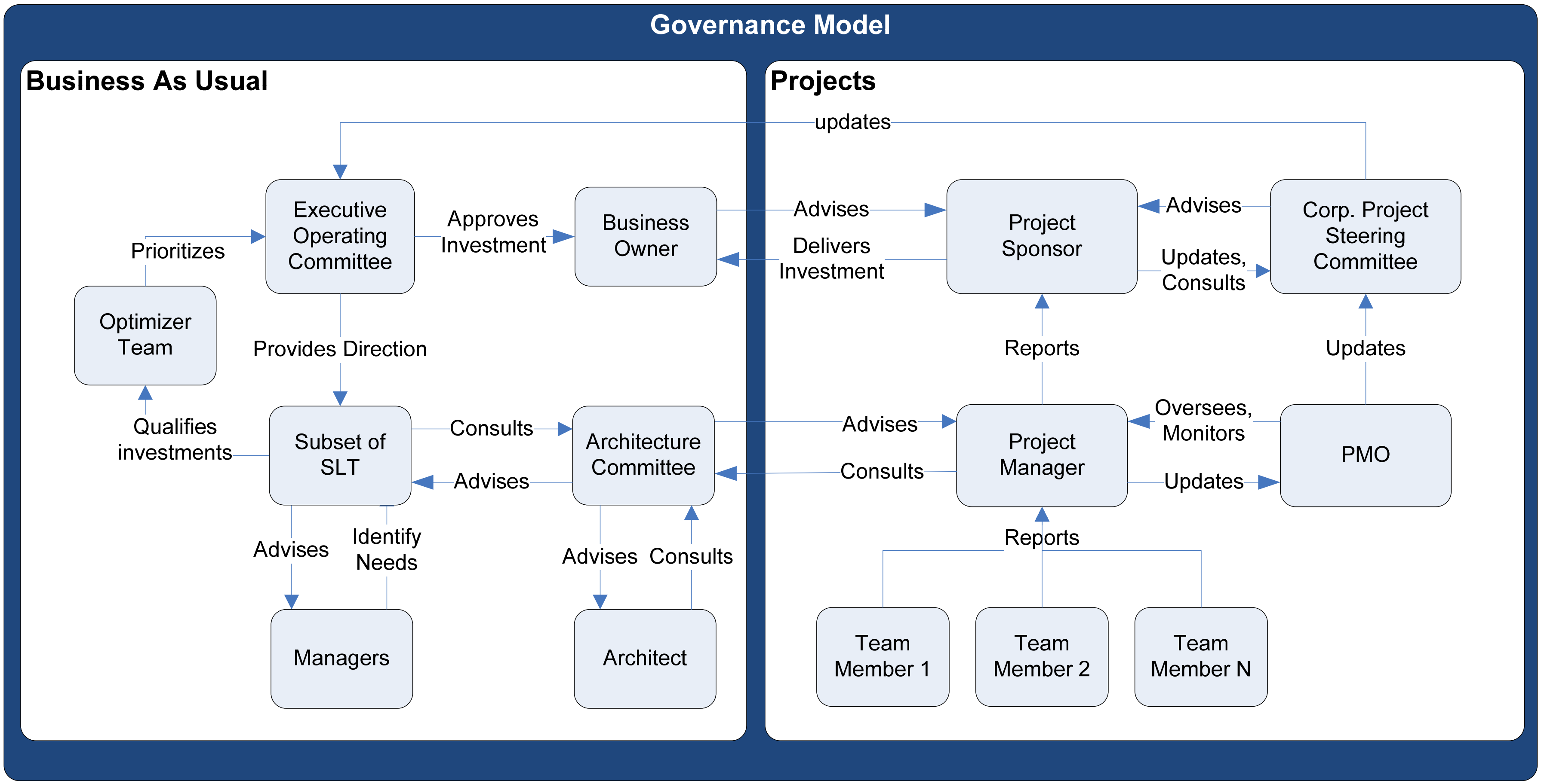
The process for each of these governance items are described under Appendix A – IT Governance Procedures.

	IT Principles & Strategy	Business Needs	IT Investments	IT Architecture	IT Delivery
Key Decision(s)	What is the role of IT (principles and strategy)?	What does the organization need in IT in the coming year?	What is the budget and priorities for IT investments in the coming year?	What is the enterprise architecture? What are the technology standards?	What are the key roles and responsibilities in delivering IT projects?
Advisor(s)	SLT Subset (Authors and owners of the IT Strategy)	Managers	SLT Subset, Capital Optimizer Team	Architect	PMO, Project Manager, Managers
Decision Maker	Executive Operating Committee	Director	Executive Operating Committee	Architecture Committee	Corporate Project Steering Committee (CPSC)

Suggested IT Governance Model

The following diagram reflects a suggested governance model under two operating conditions: 1) Business As Usual (BAU), and 2) Projects. Both conditions are interrelated and are therefore outlined herein. Please note, the intended meaning for the word “reports” is in the context of reporting relationship.

Each arrow qualifies a general relationship between two entities and is therefore not exhaustive. The proceeding pages describe each of these entities. Note: the Board of directors is not depicted in this diagram, however is engaged as required.



Today vs. Tomorrow

Today

	Infrastructure Investments	Business Unit Investments	X-Functional Investments
Investments	All investments are forwarded to the Optimizer Team		
	Prioritized by IS Department	Prioritized by Business Unit	Prioritized by PMO
Project Management	IS Project Manager	Business Unit Project Manager	PMO Project Manager[1]
Project Monitoring	Monitored by the TRC	Informal monitoring or PM guidance[1]	Monitored by the PMO[2]
Project Direction	Not reported to CPSC	Not reported to CPSC	Reported to the CPSC

Tomorrow

	Infrastructure Investments	Business Unit Investments	X-Functional Investments
Investments	IT investments are reviewed for strategic alignment, and value by the SLT Subset[3]		
	Qualified IT investments are forwarded to the Optimizer Team for prioritization		
Project Management	IS Project Manager	Business Unit Project Manager	PMO Project Manager
Project Monitoring	Monitored and supported by the PMO[4]		
Project Direction	Reported to CPSC by the PMO		

1. Current resource constraints prevent the PMO from providing this role on most cross-functional projects. In such instances, the PMO provides guidance whereby the PM is often nominated / provided by the Business Owner.
2. The Technology Review Committee (TRC) provides PM and implementation guidance to projects that have an infrastructure component
3. SLT Subset refers to the group of individuals that created and are responsible for executing the IT Strategy
4. The broader scope of PMO responsibilities will require resource planning, i.e. additional support

IT Governance Schedule Summary

IT Principles & Strategy Progress Meeting

- Reviewed and updated annually by the SLT Subset (4th quarter)
- Material changes are reviewed and approved by the EOC, as amended (annually)

Innovation Forum

- IS researches emerging technology trends on a routine basis
- IS delivers annual Innovation Forum in March, in order to inform the capital planning activities scheduled for June

Business Needs

- Managers convene on a quarterly basis to present and identify improvement opportunities (Feb, May, Aug, Nov). The frequency of a quarterly cycle is intended to generate and maintain momentum in identifying creative methods for improving the business.
- Director reviews and may request a formal business case that will be forwarded to the SLT Subset for review

IT Investments

- Business cases are reviewed by SLT Subset (annually) for value and alignment with the IT Strategy. The Architecture committee is engaged to review architectural compliance

IT Investments (continued)

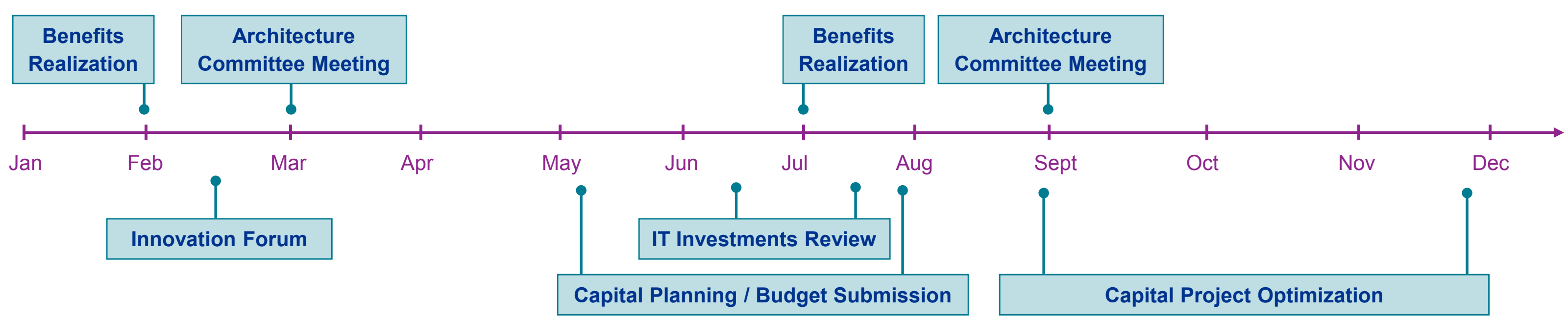
- Qualified business cases are forwarded to the Optimizer Team (annually)
- Optimizer Team prioritizes and calculates IT Investment scores. **NOTE: the current optimizer criteria needs to consider the use of IT relevant prioritization criteria.**

IT Architecture

- Architecture Committee convenes semi-annually to review the current and proposed IT Portfolio (March and September)

IT Delivery

- PMO will provide oversight and monitor the performance of investments above a certain threshold calculated by the Capital Optimizer (to be determined). **NOTE: PMO capacity requirements need to be reviewed in order to support a broader mandate of oversight and monitoring.**
- PMO, including the Sponsor and Project Manager, will report progress to the CPSC (monthly)
- CPSC will provide guidance and advice for project issues that cannot be resolved within the project team. E.g. Competing resource demands, vendor issues, change orders, etc.
- Business owner will calculate benefits realization semi-annually; post-implementation



Entity Descriptions (1/2)

The following information provides a bullet form description for each of the entities outlined under the Suggested Governance Model

Where possible, membership full names have been provided. Consequently, role names have been provided to denote vacant roles.

Please note, a vacant role should not be interpreted as a vacant position. Lastly, the word “crafts” includes updating and measuring progress, if not specified.

Executive Operating Committee (EOC)

- Defines the capital budget
- Provides strategic direction
- Articulates the business drivers
- Reviews and Approves the IT Principles and IT Strategy
- Reviews and Approves proposed IT Portfolio Investments
- Membership: Brian Bentz, John Glicksman, Dennis Nolan, and Mark Henderson

Senior Leadership Team (SLT) Subset

- Crafts and socializes the IT Principles
- Examines exceptions to the IT Principles
- Crafts and measures progress with the IT Strategy
- Canvas business needs from directors and managers
- Verifies business case alignment with IT strategy
- Forwards IT investments to the Optimizer Team
- Membership: Barb Gray, Colin Macdonald, Ed Benvenuto, Mike Matthews, Shelly Cunningham, Ted Wojcinski, William Schmidt, Carolyn Young

Optimizer Team

- Prioritizes the IT Investments using evaluation criteria relevant to information technology and the IT Strategy
- Membership: Shelly Cunningham, William Schmidt, Mark Henderson, Ted Wojcinski, Rob Antenucci, Louise Gauthier, John McClean, John Mulrooney, Dianne Petrucci, Tony D'Onofrio

Managers

- Identify business needs
- Develop business cases (as requested)
- Support IT implementations either as Project Manager, Business Analyst, or Technical Analyst
- Membership: individuals with the appropriate skills and acumen to produce the required deliverables

Architecture Committee

- Reviews and approves the Enterprise Architecture (Blueprint)
- Examines exceptions to the Architecture as required
- Provides architectural guidance
- Ensures architectural compliance
- Membership: Architect, ERP specialist, SCADA specialist, GIS specialist, Database specialist, Infrastructure specialist, Operational specialist, Designer specialist
- Note: the Architect is deemed responsible for strategic use of technology, whereas other members may be more operational as a result of their immediate mandate (e.g. JDE, ESRI, etc)

Architect

- Crafts the Enterprise Architecture (Business, Applications, Security, Information (data), and Infrastructure)
- Aware of market trends and leading technical practices
- Membership: a general architect

Entity Descriptions (2/2)

The following information provides a bullet form description for each of the entities outlined under the Suggested Governance Model

Where possible, membership full names have been provided. Consequently, role names have been provided to denote vacant roles.

Please note, a vacant role should not be interpreted as a vacant position. Lastly, the word “crafts” includes updating and measuring progress, if not specified.

Project Sponsor

- Accountable for overall success of the IT Investment
- Owns the vendor relationship during implementation
- Consults and updates the CPSC during the project period
- Works closely with the Business Owner (investment recipient)
- Membership: typically an Executive Vice President

Business Owner

- Measures IT Investment success / benefits realization during the Operational period
- Owns the vendor relationship, post-implementation
- Provides advice to the Project Sponsor as required
- Membership: typically a Vice President

Project Manager

- Creates the overall project plan
- Delegates tasks, mitigates risk, and monitors progress
- Membership: typically a manager with business and technical acumen

Team Member

- Delivers specific tasks and work products identified in the project plan such as: functional requirements, technical requirements, use cases, design documentation, deployment models, data models, security models, test cases, etc
- Membership: generally manager(s) or business analyst(s) with the skills required to deliver a specific task for deliverable

Project Management Office

- Provides leading project management practices, oversees and monitor project performance
- Supports the PM in developing a comprehensive project plan that addresses and / or links to leading practices (e.g. SDLC)
- Monitors and reports project performance to the CPSC
- Membership: group of PM specialists, led by Louise Gauthier

Corporate Project Steering Committee

- Monitors the portfolio of Corporate Projects
- Provides guidance and direction to all Corporate Projects. This may include resolution or approval for : change requests, contractual issues, competing resource demands, and critical defects with no workarounds
- Membership: Barb Gray, Bill Schmidt, Louise Gauthier, Carolyn Young, Eddie Augusto, Linas Medelis, Mark Henderson, Mike Matthews, Rob Antenucci, Shelly Cunningham

IT Governance Procedures

Appendix A

IT Principles & Strategy

The IT Strategy should reflect a roadmap of IT Investments that support the corporate strategy, and objectives. Developed in 2011, PowerStream has a five year IT Strategy that was reviewed and approved by the EOC in June. The following steps outline the process of creating and maintaining the IT Strategy.

1. EOC shares the business drivers with the SLT Subset
2. SLT Subset reviews the business drivers, corporate strategy and objectives and identifies supporting IT investments. IT Investments are in the form of:
   - People: organizational behaviour, structure, and skills
   - Process: automation, redesign, and outsourcing
   - Technology: architectures, upgrades, redesigns, implementations, etc
3. SLT Subset estimates the costs, benefits, and resources associated to each IT Investment
4. SLT Subset creates evaluation criteria and scores each of the IT Investments within their respective category, if any. Note: PowerStream leveraged elements of the Capital Optimizer Team in order to rank the IT Investments for the 2011 IT Strategy
   - Alignment with the corporate strategy and objectives must always be considered, as well as costs, quantitative and qualitative benefits
5. SLT Subset plots the IT Investments over time, while taking into consideration dependencies with other IT Investments
6. SLT Subset crafts and presents the IT Strategy to the EOC. This should be done annually in the fourth fiscal quarter in order to coincide with the capital planning activity
7. EOC reviews and amends the IT Strategy. The EOC uses the IT Strategy to inform the IT Budget
8. SLT Subset measures progress against the IT Strategy on a semi-annual basis in order to measure progress and identify corrective courses of action, if any
9. SLT Subset amends the strategy as required / when the business needs have changed

IT Principles are meant to shape and guide decisions. They are not absolute, however do reflect general consensus from the SLT Subset and the EOC. These principles should always be referenced when making any IT investment decision

In a previous KPMG engagement, IT Principles were drafted and are included under Appendix B – IT Principles. These principles should be reviewed on an annual basis by the SLT Subset

1. SLT Subset translates the corporate strategy and objectives into supporting IT statements
   - A corporate objective such as “internal cost optimization” could translate into “identify and promote the use of cost effective technologies”
2. SLT Subset identifies additional IT Principles based on desired or required corporate culture and behaviours
   - A conservative corporate culture could translate into “use a phased approach for delivering technologies in order to mitigate operational risks”
   - A desired behaviour for more innovation could translate into “collaboratively identify operational efficiencies through innovation”
3. EOC reviews, SLT Subset amends the IT Principles, as required
4. SLT Subset socialize and promote the IT Principles throughout the year
5. Any exception to the IT Principles must first be reviewed by SLT Subset, and may require EOC consultation, materiality pending

Business Needs

The identification of business needs is a multi-faceted approach. At one spectrum, the managers, individuals that are intimately familiar with the operational procedures and systems, should continuously raise improvement opportunities to their Director(s). At the other spectrum, the IS should hold an annual Innovation Forum where it presents the latest trends and emerging technologies. The following describes the process at each spectrum:

1. Managers will convene quarterly, as part of an existing or new meeting, in order to present and identify improvement opportunities for their business unit. Business Analysts should be considered as participants. The improvement opportunities will be submitted to the corresponding Director[1] for review
2. The Director(s) will review the improvement opportunities and determine the need or desire for further analysis: costs, benefits, and general value
3. The Director will inform the corresponding Manager to pursue with a Business Case (business case criteria / cost threshold is > $100k)
4. The Manager will develop a business case that outlines the high level timeline, resource requirements both internally and externally, costs, and benefits (qualitative and quantitative). The Business Case should demonstrate how it aligns with the corporate strategy and objectives
5. The Manager will present their Business Case to the Director
6. The Director shall forward the Business Case to the SLT Subset
7. The SLT Subset will review the business case. Note: this process continues under "IT Investments"

1. In the absence of a Director(s) , this role may be assigned to a VP

With regards to the Innovation Forum, the intent is to engage the IS department in a manner that promotes and augments IT thought leadership within the organization. IS will continue to support unique needs at the business unit level, however IS will also overlay a horizontal focus in order to identify cross-functional needs and synergies.

1. IS will engage Business Analysts that will develop a cross-functional understanding of the organization. The Business Analysts should be a technical individual capable of translating business requirements to a technical audience, and vice-versa
2. These Business Analysts will provide ad-hoc support to the business units for general technical matters (ideas, suggestions, complaints, etc)
3. Throughout the year, the Business Analysts will research and identify emerging technologies that may benefit the business
4. The Business Analysts will schedule and present their findings (or demonstrations) to the SLT Subset as part of an Annual Innovation Forum
5. The outcome of the Annual Innovation Forum is awareness, however may lead to an IT Investment request

IT Investments

The process begins when the SLT Subset has received a business case for review.

1. The SLT Subset reviews and verifies the business case for
   - alignment with the corporate strategy and objectives
   - alignment with the IT Strategy
   - quantitative and qualitative value
2. The SLT Subset qualifies which business cases are recommended for capital planning / capital optimizer
3. The Optimizer Team prioritizes determines the IT Investment Portfolio
4. The EOC reviews the IT Investment Portfolio, as part of the broader Corporate portfolio, for approval
5. Approved IT Investments will be communicated to the corresponding Business Owner
6. The Business Owner nominates a Project Sponsor, typically a VP, to be accountable for the overall success
7. The Project Sponsor and the Business Owner consult the Corporate Project Steering Committee in order to mobilize and engage the appropriate resources
8. Post implementation , the Business Owner will be responsible for reporting and measuring the desired benefits / outcomes of the IT Investment. This should occur on a semi-annual basis and reported to the SLT Subset. Corrective measures / course of actions will be determined by the SLT Subset

KPMG

IT Architecture

IT Architecture reflects the IT blueprint and standards for the enterprise and is and is typically done by an Architect. The scope of the architecture is broad and includes items such as applications, information, security and communications. The Architecture Committee approves and enforces the blueprint and standards, however will examine exceptions as needed.

1. Working closely with the Director of IS, the Architect will create the IT standards for hardware, software, integration and data management with guidance from the IT principles. Sample standards include:
   - Dell vs. HP; MS Windows vs. MAC OS
   - Java vs. .NET; Oracle vs. MS SQL; and
   - Message based vs. Service Oriented Architecture;
2. The Architect will take labour/skill cost into consideration when establishing the standards
   - Skill availability and cost should always be considered. For instance, an ERP based on common technologies is arguably more affordable than another ERP based on specialized and scarce skills
3. The Architect will develop an enterprise architecture that reflects the following items:
   - Business;
   - Application;
   - Information;
   - Communications;
   - Security and privacy; and
   - Disaster recovery
4. The Architect will present (or review) the IT standards and architecture to the Architecture Committee for approval. This should be done annually in the first or third fiscal quarter in order to inform the capital planning activity
5. The Architecture Committee is responsible for ensuring ongoing operations and projects comply with the Architecture and its underlying standards. This should be done on a semi-annual basis, however may be required on a ad-hoc basis for a given project(s)

IT Delivery

IT Delivery embodies the implementation of IT Investments. As such, the PMO is responsible for providing leading project management practices, oversight, tools, and monitoring, whereas Project Managers are responsible for scheduling tasks and mitigating risks. The Corporate Project Steering Committee provides direction and resolves material issues.

1. The Project Sponsor, typically an Executive Vice President (EVP) will be accountable for the overall success of the implementation, however shall be supported by a Project Manager, the underlying analysts, and the Corporate Project Steering Committee
2. The Project Sponsor (during implementation) and the Business Owner (post implementation) will have primary responsibility for vendor relationships, if any
3. The Corporate Project Steering Committee (CPSC) will support the planning and mobilization of resources
4. The PMO will be responsible for providing leading project management practices and methodologies, including monitoring, and oversight. They will also enforce the use of other leading methodologies as prescribed by the IS Department such as:
   - Analysis & Design - requirements traceability, requirements template (technical, functional, security), SLA, design templates, etc
   - Build - server deployment, release schedule, change and configuration control, etc
   - Test - testing plan, scenarios, test cases, test scripts, forms of testing (performance, security , UAT), automation, defect tracking, etc
   - Train - training approach (train the trainer, classroom, computer based training (CBT)), training schedule, etc
   - Deploy - readiness assessment, release strategy, onsite support, etc
   - Maintain - maintenance schedule, triage, help desk scripts, points of contact, etc
5. The Project Sponsor, PM and PMO will jointly update the CPSC on a monthly basis
6. The Project Manager, typically a manager, will develop and manage the project plan and budget
7. The Project Team will be responsible for meeting deadlines and producing deliverables
8. The Project Sponsor escalates issues that cannot be resolved within the core team to the CPSC, such issues include:
   - change requests, competing resource demands, severity one defects, and contractual issues
9. The CPSC provides recommendations and guidance to the Project Sponsor

IT Principles

Appendix B

KPMG

IT Principles

Key Principles:

- Business drives IT investment
- Technology must enable information integration
- Leverage technology across the enterprise
- Use industry standards, where feasible
- Research emerging, however favor proven technologies
- Re-use before Buy, Buy before Build

IT principles provide a set of guidelines that will assist us to make decisions about IT investments

- The list below represents the principles developed at the outset of our strategic planning process. As we developed our strategy, these principles were continuously applied.

Technology must enable integration and interoperability	Technology is an enterprise-wide asset	Enterprise-wide technology standards enable optimization	Business Plans and Strategies drive Technology investments
■ Eliminate information and processing duplication and redundancy ■ Enable information sharing and seamless interoperability with partners and customers ■ Technology must be agile and enable the business to adapt to change	■ The full life cycle of technology assets must be managed ■ Technology must be leveraged across the enterprise ■ Decisions must be based on full life cycle cost ■ Technology must be scalable to increasing demand	■ Share and re-use technology assets ■ Adopt industry standards where possible ■ Research emerging technologies for consideration, however favour proven technologies to support core business processes ■ Re-use before buy, buy before build	■ Technology investments support and enable the realization of business strategies ■ Technology investments are aligned with business improvement initiatives ■ Technology investments are based on business cases (benefits and costs) , and benefits realization is measured ■ The business implications of technology decisions must be clearly articulated

KPMG
cutting through complexity™

PowerStream Enterprise Data Model

KPMG Advisory

Final – April 16, 2012

Contents

The contacts at KPMG in connection with this report are:

Sandy McBride, Partner
+ 416.777.8213
samcbride@kpmg.ca

Ian Shelley, Partner
+ 416.777.8894
ishelley@kpmg.ca

Alonso Perez, Sr. Manager
+ 416.777.8215
alonsoperez@kpmg.ca

Patrick Sue, Manager
+ 416.777.8323
psue@kpmg.ca

Raphael Ly, Manager
+ 416.777.8369
rly@kpmg.ca

Sri Santhanagopalan, Sr. Consultant
+ 416.777.8500
ssanthanagopalan@kpmg.ca

This report is also accompanied by the EDM model created in the Sparx EA tool for future use by PowerStream.

PowerStream EDM

Executive Summary

Executive Summary

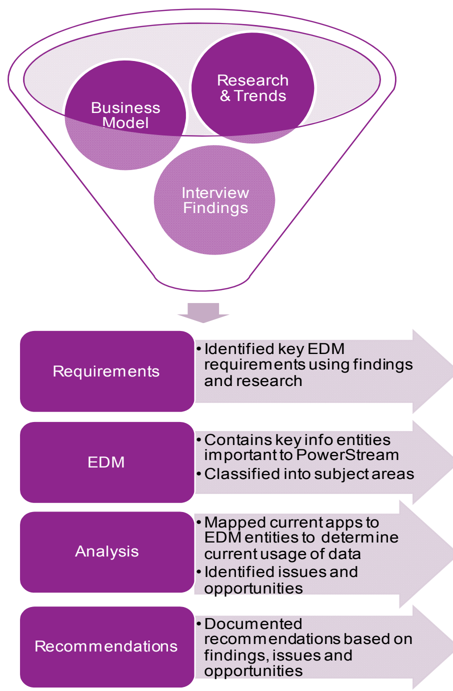
KPMG interviewed over fifteen individuals across the entire organization to gather information requirements. During this process data gaps, overlaps and integration issues., were identified.

The Enterprise Data Model was developed by reusing existing models in related industries, identifying the key data entities identified in the interviews, business model and the requirements. The data entities were classified into groupings known as "subject areas".

One of the key recommendations of the IT strategy developed for Power Stream early in 2011 was to define an information blueprint, or conceptual data model, of the business to support a number of strategic initiatives in the information technology area. Chief among those is the development of an in application integration and data rationalization strategy. This report documents the study done between October 2011 and February 2012 to define a Enterprise Data Model (EDM) for PowerStream.

APPROACH

The study was performed as described in the figure below:

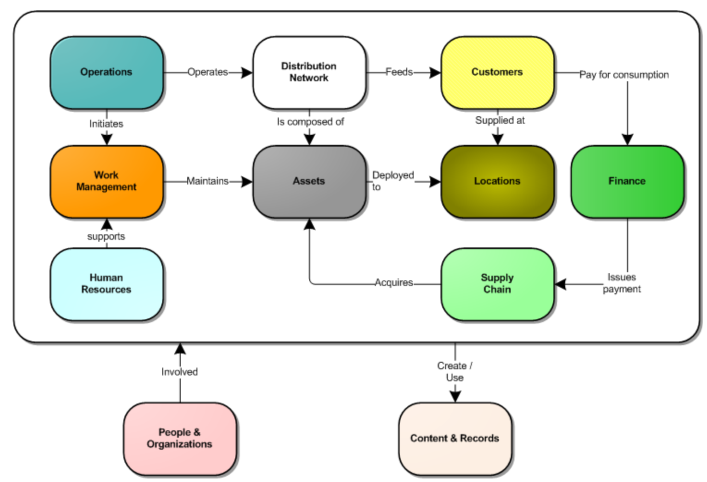


RECOMMENDATIONS

PowerStream must continue to develop and further its maturity with information management. The following provides three priority areas for the near-term.

- Data quality management
- Data Governance
- Data Integration Strategy
- Application Rationalization

Based on the analysis, a number of potential "quick wins" to resolve some of the findings mentioned in this report. In the next phase of this assignment, PowerStream will identify and prioritize a number of integration solutions as part of the Integration Strategy.



PowerStream Information Subject Areas (High0level Enterprise Data Model)

PowerStream EDM

Introduction

What is the objective of this project?

PowerStream needs to harness the breadth and depth of data available today and tomorrow

In advance of Business Intelligence, PowerStream must first define a blueprint for its data; Enterprise Data Model

In order to enable Business Intelligence, PowerStream must define an integration strategy that prescribes when data should be synchronized, replicated, or consolidated

The EDM is a blueprint of your data needs, and outlines their relationships

Objective

PowerStream is executing a multi-year IT Strategy that prescribes a number of foundational and strategic initiatives required to modernize the PowerStream business and its underlying technologies. Within five years, PowerStream aims to implement a new Customer Information System, Asset Management, and Business Intelligence tool, among many other investments. Coupled with the Smart Grid technology, PowerStream needs to harness the breadth and depth of data available today and tomorrow.

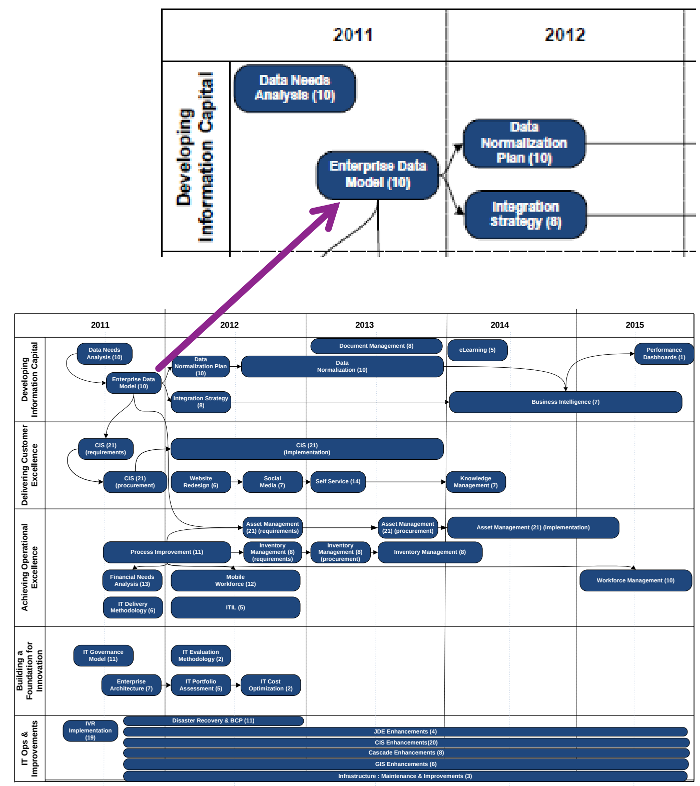
PowerStream engaged KPMG to review their current data architecture and develop an integration strategy based on leading practices. As a precursor to the integration strategy, two fundamental elements are required: an understanding of the business information needs and an enterprise data model (EDM) that articulates the current as well as future relationships between data entities. These two elements are the subject of this report.

Through this assignment, KPMG has identified a number of data gaps, data overlaps, and data quality issues. These observations have informed the development of an EDM, depicted and explained later in this report.

With this information, PowerStream will develop a data and application integration strategy that addresses the data gaps, overlaps, integration issues and quality issues outlined under this report. The output of this report answers the following questions:

1. What data do we need?
2. Where do we have gaps and overlaps?
3. Where do we have integration and quality issues?
4. What are the relationships amongst data entities?

The IT Strategy prescribes a series of initiatives and investments under five themes. This report addresses two initiatives under "Developing Information Capital" : Data Needs Analysis, and Enterprise Data Model (EDM). As depicted below, the EDM will inform the Integration Strategy, slated for 2012.

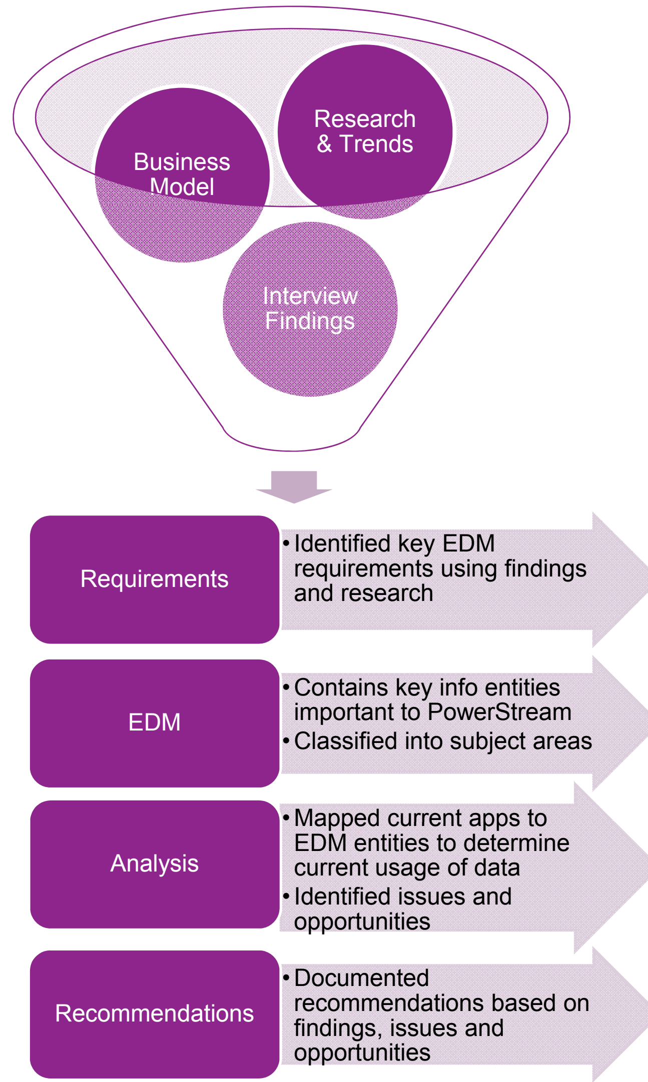


How was the EDM developed?

The data model development process requires the "discovery" of information objects important to the business by understanding the business processes, resources and environment of the enterprise. Due to the fact that many enterprises have similar business processes, it is possible to develop an initial version of some of the information objects by using already developed models, especially for corporate support or "back office" processes , and utility industry models and trends.

Designing an EDM requires an iterative process for requirements gathering, refinement and analysis. As illustrated to the right, the process as follows:

- **Research & Trends.** KPMG reviewed a number of PowerStream artifacts such as process descriptions, management reports, and previous requirements documents to name a few. In addition, we also performed a market scan of data trends specific to the utilities industry, which informed the design of the EDM.
- **Business Model.** At the onset of the project, KPMG developed a high level construct of the PowerStream business model. Leveraged in parts from the organizational effectiveness group, and the business model framed the structure for upcoming interviews and analysis.
- **Interview Findings.** KPMG interviewed over fifteen individuals to gather information requirements. During this process, we began to capture gap, overlaps and integration issues.
- **Requirements.** Based on the findings, KPMG outlined a number of requirements to be reflected in the EDM.
- **EDM.** The EDM was developed by reusing existing models in related industries, identifying the key data needs from the previous steps and classifying the data entities into groupings known as "subject areas".
- **Analysis.** Based on EDM, KPMG and PowerStream mapped the data entities to 1) business functions (as per the business model), and 2) current systems. Using this technique, KPMG refined and identified further gaps and overlaps.
- **Recommendations.** Throughout this process, KPMG developed and refined its recommendations for addressing some of the gaps and overlaps. In a separate project, PowerStream will need to develop an integration strategy in a order to address a number of related opportunities.



Acknowledgements

The advisory team wishes to express its sincere gratitude to the PowerStream staff members who spent their precious time in openly sharing their perspectives on the challenges and opportunities with data in the company.

In particular we would like to thank:

- Bill Schmidt and
- Basil Henriques

For their continuing support throughout the process and for trusting that the effort placed on this engagement would pay dividends in the future.

STAFF INTERVIEWED:

- Doug Fairchild
- Alex Cestra
- Richard Wang
- Glenn Allen
- Stephen Perry
- Linas Medelis
- Tammi Myshrall
- Robert Antenucci
- Louise Gauthier
- Kamran Khazraie (for Lorne McHoull)
- Rick Lapp
- Vince Polsoni
- Bev Rice (alternate for Debbie Smyth)
- Norah Dallimore
- Jack Jacoby
- Kevin Decaire
- Fiona Gardner
- John Mulrooney
- Patrick Leung
- Rusty Hastings
- Dianne Petrucci

CORE TEAM MEMBERS:

Special thanks to:

- Eddie Augusto
- Gina Arruda
- James Ilari

who, along with Basil Henriques supported us in the interview process and spent many hours analyzing and documenting the current applications data usage matrix.

Special thanks to Ann Tino for her patience and persistence in organizing and coordinating the interview sessions.

PowerStream EDM

Findings

- Common Data Challenges & Trends for Utility Companies
- Business driven approach for gathering and analyzing data needs
- Data Requirements

Common Data Challenges & Trends for Utility Companies

This page summarizes the research conducted by KPMG, and points to current challenges and trends within the utility industry

This information, along with our understanding of the PowerStream business, has been weaved into our analysis and has informed the development of the Enterprise Data Model

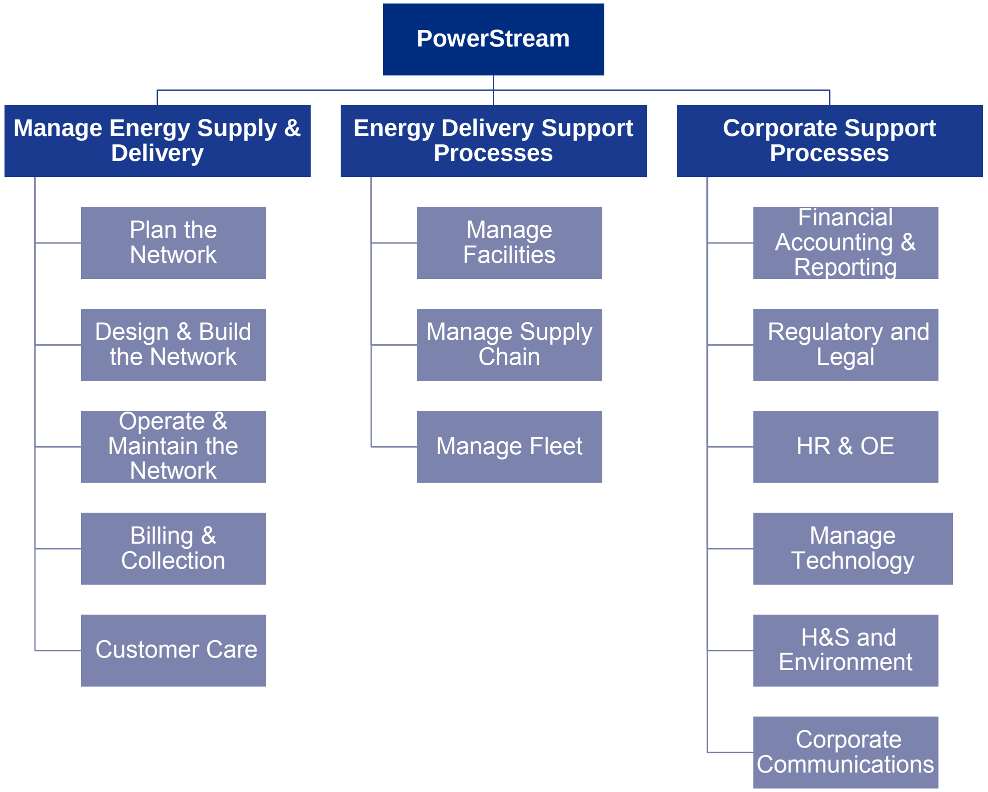
Coupled with a sound enterprise data model and data integration strategy, Business Intelligence software will enable utility companies to maintain and lead competitive advantage

Common Utility Challenges	Common Utility Trends
Increasing Data Storage Requirements. The sheer volume of data points in today's distribution network (meters, switches, transformers, stations, etc), coupled with Smart Grid technology is quickly driving utility companies to revisit their data storage strategy. Previously periodic-based, Smart Grid offers greater data granularity in real time. The surge in "Big Data" will impact the performance of relational databases and reporting engines.	**Cloud Based Computing and Storage.** Developing an infrastructure that can store the ever-increasing amount of data, and still provide satisfactory performance is a costly investment that many utility companies will need to examine as part of their overall architecture and investment plan. All industries are witnessing the emergence of cloud based solutions that provide infrastructure and data management as a service.
Renewable Energy. The NDP Group, predicts that wind power will triple from 2011 to 2017. Referring to the previous comments, this means ever more data coming into the information network. But the real challenge is the added complexity coming into the energy delivery system; dramatic fluctuations.	**Renewable Energy Management.** In order to harness the new / mixed flow of energy, utility companies will need to invest in new software to manage the flow of renewable energy into the grid. From an information perspective, this means multiple forms of data analytics and modeling, e.g. simulating transient wind conditions with gust, noise, disturbance, etc.
Duplicate Asset Data. Asset data is primarily maintained in a central system, however, it is also stored in separate systems, such as GIS and SCADA. This creates subsets of data at different locations, resulting in data redundancy and quality issues (the source of truth). The key is to develop an integration strategy that prescribes when and how data should be shared. This is the underlying topic addressed under this report.	**Data Architecture & Integration.** In order to satisfy and prepare for new regulatory reporting requirements, the enterprise must have an underlying architecture and integration strategy that is open and flexible to support new data capturing technologies / devices. The fragmentation of data is attributed to legacy systems that are too old or too complex to integrate. The decision becomes whether or not to replace the legacy system (a cost/benefit decision) or develop an integration architecture that can handle those situations.
Asset Optimization. In order to optimize the life of an asset, asset management systems need to 1) auto-identify the asset health based upon the various operational parameters and 2) trigger condition based preventive or breakdown maintenance	**Asset Health Management.** Asset transducers, sensors and a built-in intelligence will enable asset management systems to trigger condition-based preventative maintenance based on operational parameters and conditions.
Market Consolidation. The utility industry will continue to transform as a result of legislative pressures, globalization, mergers and acquisitions, and deregulation. As a result, utility companies are or will eventually be faced with disparate and geographically dispersed technology architectures. Integration will be an obvious problem, however un-federated and untapped data stores will be the biggest strategic issue.	**Business Intelligence.** Coupled with a sound enterprise data model and data integration strategy, Business Intelligence software will enable utility companies to maintain and lead competitive advantage by developing "Information Capital"; a key pillar of the PowerStream IT Strategy. With full and easy access to information, PowerStream will have the strategic agility to analyze, decide and respond to changing customer and regulatory requirements

Business driven approach for gathering and analyzing data needs

The business model was developed in order to frame the context and structure of our interviews and analysis

The following diagram reflects a PowerStream business model and was leveraged supported by three core domains and underlying functions. Informed by work artifacts from the organizational effectiveness group, KPMG structured its interviews and analysis around these 14 functions. Specifically, we meet with representatives from each functional group to understand their current and future needs. Through this exercise, we identified a preliminary list of gaps, overlaps, and integration issues. Please refer to **Appendix A** for a description of the PowerStream Business Model.



Summarizing the findings into data requirements (1/2)

Based on our findings, KPMG identified seven key data requirements to be incorporated under the EDM

This table describes each of these requirements, and demonstrates how it shaped the design of the EDM

Please see Appendix B for details on the interviews and corresponding findings

Data Requirements	EDM Considerations
Asset Utilization. Although PowerStream has some technologies that can measure asset utilization, data from the Engine Control Module (ECM), for instance, is not currently stored.	To address this issue, the EDM includes: 1) Asset Utilization Entity to store asset usage, With this entity, PowerStream will be able to measure and optimize the utilization of its assets.
Asset Lifecycle Management. There is currently no effective means to track the lifecycle of an asset from cradle-to-grave. For instance, PowerStream is not able to track the utilization, maintenance, and repairs for a specific asset. This lack of information impairs condition based maintenance and preventative maintenance. The net effect is sub-optimal asset optimization.	To address this issue, the EDM includes 1) Asset Utilization Entity to store asset usage, 2) Asset Inspection Work Order Entity to schedule asset inspections and record asset condition, 3) Repair Work Order Entity to record repair work done on assets All three entities are linked to an Asset. With these entities and relationships, PowerStream will be able to measure the total cost of ownership based on usage and work done on them.
Asset Failure History. There is no means to store the failure history for a given asset.	To address this issue, the EDM includes: 1) Asset Specification Entity to store asset specifications 2) Failure Event entity to store the time and nature of an asset failure With these new entities, PowerStream will be able to measure the number of failure rates for a given asset.
Event Based Work Orders. In some instances, PowerStream uses standing work orders to track different types of services provided. For instance, there is a single work order in which individuals charge their time for Repairs, Construction, etc. With this model, PowerStream is unable to perform activity based costing. Note: construction and major repairs use individual work orders.	To address this issue, the EDM includes: 1) Event Entity to store the instance of an event 2) Work Order Entity to store specific work instructions 3) Work Effort Entity to store the planned and actual times spent on a given work order The Work Order is linked to an Event, which can now be measured by the Work Effort Entity. With these entities and relationships, PowerStream will be able to measure the specific cost or effort for a given event, in addition to measuring the cost for a given work order type (standing order model).

Summarizing the findings into data requirements (2/2)

Data Requirements	EDM Considerations
Integrated / Coordinated Work Orders. Work Orders are largely initiated by the operations group, whereas Service Orders are typically initiated by the customer. Under certain circumstances, an event would necessitate multiple work orders and service orders which are not currently coordinated or linked to a specific event. E.g. A work order may require excavation in order to repair a cable. A service order will be manually created to fill / repair the hole. From a data perspective, the work order and service order are not linked and therefore independent.	To address this issue, the EDM includes: • Interdependencies (relationships) between work orders and service orders. With those relationship, PowerStream will be able to coordinate and monitor the associated work orders and service orders for a given event. Coupled with the Event entity, previous mentioned, this also enables PowerStream to measure the total cost for a given event.
Inventory Forecasting. There is no effective means to forecast inventory based on variables such as current or planned consumption (project forecast).	To address this issue, the EDM includes: • Material Requisition entity associated with the different types of Work Order entities (which include scheduled work orders and work orders associated with Projects) With these entities and relationship, PowerStream will be able to forecast and budget future material requirements and to schedule appropriate purchase orders to satisfy them when the work orders require them.
Geographic Area. The current data structure prevents PowerStream from analyzing data based on geographic area. E.g. Number of Faults for Subdivision X, Revenue for Subdivision Y, Fleet Usage for Area X, etc.	To address this issue, the EDM includes: • Geographic Area entity that is linked to the Address entity With this entity and relationship, PowerStream will be able to analyze data based on geographic area.

PowerStream EDM

Enterprise Data Model Overview

- The Enterprise Data Model Development
- PowerStream's Conceptual Enterprise Data Model

The Enterprise Data Model Development

Creating a model of something requires us to make some abstractions about the real "something".

- **The real world is composed of objects that are related to one another in some fashion.**
- **We describe the "real world" conceptually though lists (business objects and their attributes) and diagrams that show the relationship between business objects (entities) in a given context, or business area. This is the appropriate level of detail for the EDM.**

Definition:

A conceptual data model is a diagrammatic representation of structure of information about in-scope, high-level business components (e.g. "objects") and their relationships to portray the external and internal data needed to manage and operate an enterprise

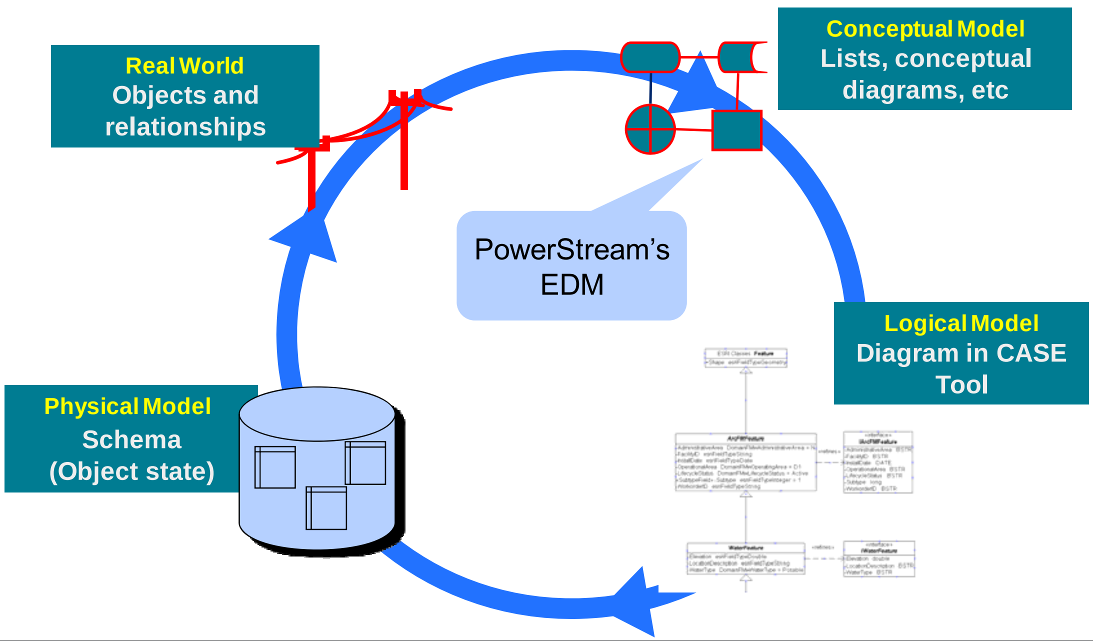
Purpose:

- Enhances communication with business staff
- Clarifies rules involving business information

- Suppresses technical details by including:
  - Business entities that have business meaning
  - Important relationships between entities
  - Major attributes of entities (i.e. not all entities and their attributes are represented)

Role in planning:

- Used to identify and manage architectural scope
- Used to determine high-level requirements for planning purposes

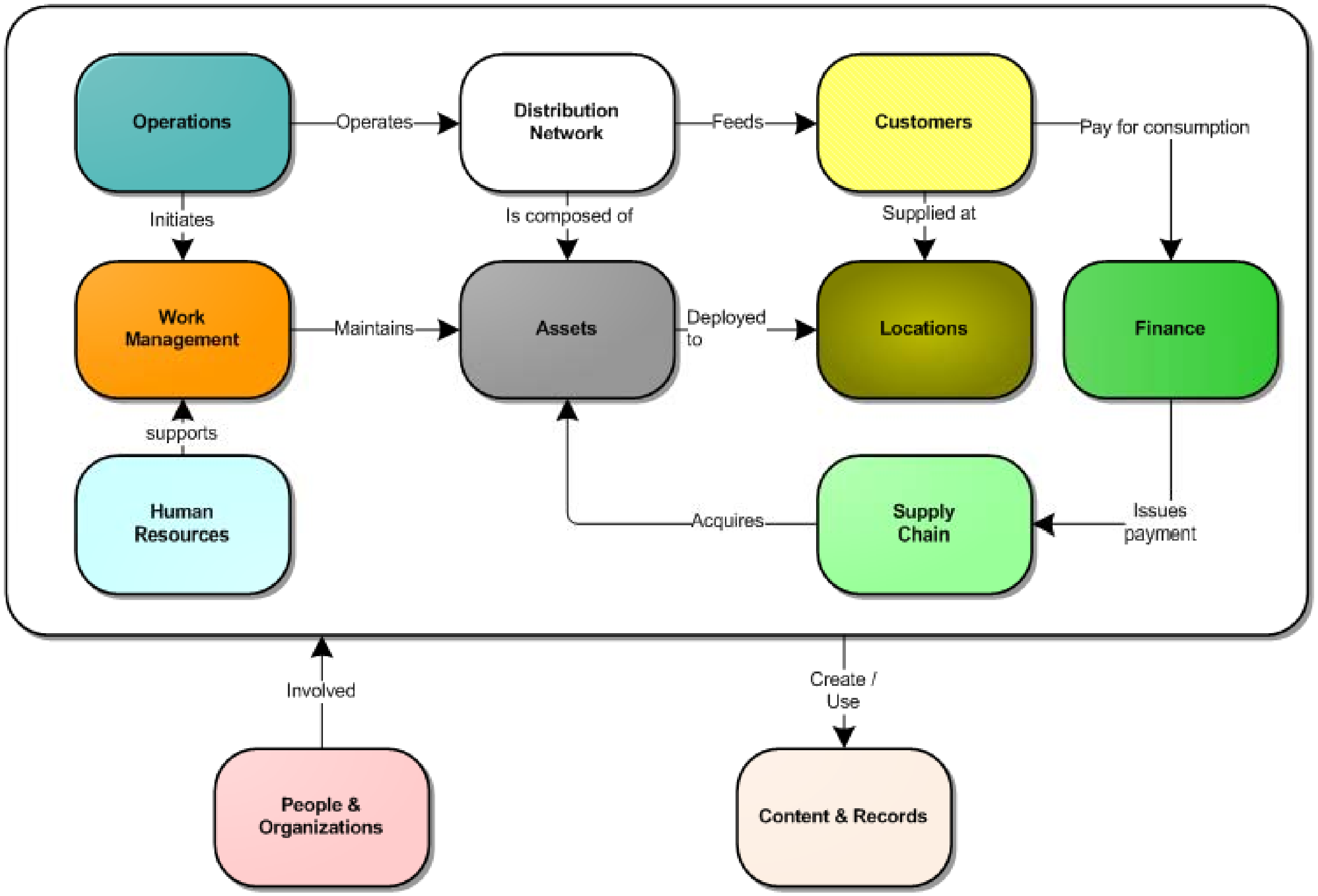


PowerStream's Conceptual Enterprise Data Model

At a very high level, PowerStream's data can be organized under 11 subject areas (data groupings). Appendix C provides a detailed view of the underlying data entities and their relationship of each of those areas.

The following pages provide a description of the subject areas.

As part of the deliverables of this engagement KPMG has included a copy of the Sparx EA file that has an electronic version of the model.



[*] Entities in the conceptual model diagrams are color-coded as per corresponding subject area

PowerStream's Conceptual Enterprise Data Model – Subject Area Descriptions (1 of 2)

ASSETS

The Assets subject area identifies data about the business and distribution network assets required for PowerStream's operations.

The subject area diagram illustrates the classification of asset types, as well as related business aspects such as:
- Location
- Acquisition
- Work performed
- Employees
- Asset condition
- Utilization

Key components of this area are:
- Facilities: Business and Network
- Network Assets, that may be included in a network facility
- Business Assets, that include vehicles and equipment (as well as all other business assets of interest to PowerStream)

CUSTOMER

The Customer subject area identifies the data about the parties with role "Customer".

This structure facilitates the association of all the information about a customer and the different roles the related party may have with PowerStream (vendor, employee, joint tenant, etc.)

FINANCE

The Finance subject area identifies data used to account for operational business transactions that impact PowerStream's financial position, from the budget and actual perspectives.

The subject area diagram illustrates expense transactions from projects and work orders as well as revenues from customers.

DISTRIBUTION NETWORK

The Distribution Network subject area defines the information required to describe PowerStream's electricity distribution network. This subject area associates the network design (blueprint) with the actual built and operating network.

It introduces the concept of network nodes and links, that can be used to describe arbitrary networks (electrical or otherwise), irrespective of the particular assets located in the nodes or the links.

The "Network Component" can be either a node or a link and it is the element that links the electricity distribution assets; e.g. a particular transformer is deployed on a specific component (of type "Node"), at a specific location. The lines that link the transformer to other nodes is a "Link", to which a specific type of cable is deployed.

PowerStream's Conceptual Enterprise Data Model – Subject Area Descriptions (2 of 2)

HUMAN RESOURCES

The Human Resources subject area identifies data used in human resources management.

The subject area diagram illustrates the relationship between employees and related business aspects such as:

- Employment terms
- Training
- Health and safety
- Job assignments
- Employee performance
- Assignment of business assets to employees (vehicles, computers, tools, etc.)

An important feature of this model is the representation of an "Employee" as a party role. This provides flexibility in being able to look at an employee as a customer and an applicant (for an internal position), since they are all roles of a Person (Party).

LOCATIONS

The Locations subject area provides the means of describing geospatial features in a flexible way, while associating parties, assets and network components with geographic locations.

The Geographic Location structure supports the definition of segments (lines or pathways) as well as areas (as collections of *Pathways*).

OPERATIONS

The Operations subject area leverages information for other areas to identify the key information entities required to support the operations of the electricity distribution network and the services PowerStream performs.

SUPPLY CHAIN

The Supply Chain subject area describes the information entities and their key relationships required to manage the acquisition of assets, supplies and services as well as the suppliers.

PEOPLE & ORGANIZATIONS

The People and Organizations (Parties) subject area defines the parties of interest to PowerStream, the roles they play (customer, employee, vendor, etc.) as well as their relationships.

There are many types of relevant Party relationships, some important ones are:

- *Residential Customer Relationship*
- *Commercial Customer Relationship*
- *Electricity Supplier Relationship*
- *Vendor Relationship*
- *Employment Relationship* (represented as Employee Assignment).

WORK MANAGEMENT

The Work Management subject area describes the information objects and their relationships in the processes related to managing and executing projects , work orders and assigning work to parties.

CONTENT & RECORDS

The Content and Records subject area describes the types of documents that are created or maintained by PowerStream in the course of its operations. They include documents, legal records (e.g. contracts,), correspondence, web content, reports (regulatory or otherwise) and others.

PowerStream EDM

Analysis

Analysis (1/2)

An enterprise data model has a number of uses:

- **Information Management: From the business point of view the EDM can be used to determine the data management responsibilities within the functional areas of the organization.**
- **Strategic Planning: From a business planning point of view the EDM can be used to identify data/information areas where PowerStream should put more emphasis in collecting data for strategic planning purposes**
- **Information Technology: From an information technology point of view the EDM can be used to identify data duplication and potential data gaps in current information systems, justify application rationalization initiatives and support the development of an application integration strategy.**

INFORMATION MANAGEMENT

The Business Function to Data Entity matrix (Appendix E) was used to determine how the business functions identified by the Operational Effectiveness Group (see the definitions in Appendix A) use data (as represented by the EDM). The matrix in Appendix E shows the advisor's perspective on how the business functional areas would use the data entities identified in the EDM. This matrix was populated based on the knowledge and experience of the advisory team. The analysis is mainly based on the potential duplication of the creation of data in different functional areas. The counts along the main functional areas of the matrix (rows 7, 49, 72, 79, 85 and 94) represent the number of "creates" for a given data entity within the functional area. The key observations to be made from this matrix are:

- By and large there is minimal duplication of conceptual data entity creation activities across functional areas. The potential duplications are explained by the fact that the data being created is for different domains of data (e.g. electricity distribution assets vs. information technology assets);
- Vendor contracts creation are potentially done in multiple areas; this may be acceptable given the different types of contracts being created.

On the other hand, when we map the current applications to the EDM entities (Appendix F) we find that there are many instances where multiple applications are creating or updating entities (see counts along top row). This situation has some of the documented consequences in the reliability of the information, conflicting reporting and process results, unclear accountability for the quality of the information (see the **Findings** section) . Some of the areas of special concern are: Assets; Distribution Network; Human Resources (specifically Employee information) ; Parties and Geographic Locations.

.

STRATEGIC PLANNING

Using the matrix in Appendix E again, as well as the Current Applications to Conceptual Data Entity mapping matrix in Appendix F, the focus of the analysis shifts now to a specific functional area: **Planning and Admin.** Although conceptually the Planning and Admin function reads a number of entities (See Appendix E row 96) there are no applications supporting strategic planning, performance reporting and market development. By rationalizing some of the data stores it will be possible to use business intelligence and reporting tools to perform analytics that will help in developing sound business strategies.

INFORMATION TECHNOLOGY

Looking at the '"C" Count' column in appendix F it is clear that there is a core number of application that deal with most of the information in PowerStream. The key issue is that there is considerable overlap in the creation of information across those applications. This is the rationale for the IT Strategy recommendation for the development of an application integration strategy for PowerStream (not to mention the clear overlap in functionality among many applications, which would require an application rationalization initiative that could resolve some of the information management issues as well as lowering the operational costs of maintaining multiple applications performing the same functions.)

The following observations by subject area can be gleaned from the matrix:

- **Customers** – although the CIS initiative will consolidate most information about customer, there are still a number of applications that manage such information. Need to decide on the "master" for customer information and use proper a application integration /data mastering approach to resolve.

Analysis (2/2)

INFORMATION TECHNOLOGY (Continued)

- **Operations –** There is a relatively low number of data overlaps among the applications used to manage the operations of the distribution network; nevertheless, it is worth considering rationalizing the applications in this area. This is a relatively low priority requirement.
- **Work Management** - this subject area has similar characteristics as the Operations area. It is known that there are still a number of business areas where work orders are managed manually and is worth considering reusing some of the existing applications to support them. JD Edwards is an obvious choice.
- **Assets** – This subject area has one of the largest number of overlaps in data management in PowerStream. Partially this is due to the different data domains that assets belong to (either geographic or by asset use—network vs. business operations). In any case, it is worth considering rationalizing the management of asset data by the following means:
  - Application rationalization
  - Creation of a common data repository for asset information (to become the master repository that would feed all other applications). This repository could be created new or could be the asset database managed by an existing application (e.g. JDE or Cascade).
- **Distribution Network** - this area is relatively in good shape but could be rationalized better by consolidating applications.
- **Supply Chain** – This area is in good shape.
- **Finance –** This area may require some review to ensure that proper financial controls are in place to ensure integrity between the different applications generating financial transactions.
- **Human Resources** - there is some overlap in the creation of employees in various applications. If not already done, consideration should be given to a proper data mastering strategy.
- **People & Organizations** – This is an abstract subject area not currently being addressed explicitly by any current application but the considerable overlap in the creation of the conceptual entities in this subject area require careful analysis.
- **Locations** – There is considerable overlap in the management of geographic information among many application in PowerStream. Some consideration should be given to adopting a master mapping function that would be the source of all geographic information across the organization.
- **Content & Records** – There are no issues with this subject area. Better use of existing document management capabilities (e.g. SharePoint) can mitigate the number of data stores managing documents and records across the organization.

FUTURE USES OF THE CURRENT APPLICATIONS TO CONCEPTUAL DATA ENTITY MAPPING MATRIX

The matrix in Appendix F will have an important role in the future steps of the transformation of IT in PowerStream. Aside from the already mentioned uses, this matrix will support:

- Application Rationalization – identifying overlapping data management and, potentially, functionality in current applications
- Application Integration –
  - identifying data usage overlaps and supporting the decisions for Data Mastering
  - Supporting the application integration messaging definition

PowerStream EDM

Recommendations

Recommendations

Broadly speaking, PowerStream must continue to develop and further its maturity with information management. The following provides three priority recommendations for the near-term.

Data quality management. Moving forward, PowerStream must resolved the root cause and correct data quality issues fo the data findings outlined earlier in this report. For example, to address inaccurate asset geo-coordinates, analyse problems with the Asset Tracking Form (ATF), implement changes to minimize errors, and develop and implement a strategy for correcting errors.

Data Governance. During the analysis phase, KPMG identified some instances where data ownership and accountabilities were not formalized or well understood. The general recommendation is to establish clear responsibilities and accountabilities, along with well defined data standards. The following are some instances were governance was not well defined:

- Which department should create or update assets and other key entities?
- Who is responsible for associating GL accounts to SKUs (so that use of inventory items are properly reflected in the financial statements)?
- What are the data standards for asset naming and labeling, numbering, customer names, stock codes, and addresses?

Data Integration Strategy. The subsequent phase of this engagement should address where and how data will be stored and shared throughout the enterprise (integration initiatives). E.g. Determination of what data to store in GIS versus elsewhere (asset history, asset maintenance, etc.). The findings, analysis and EDM developed under this report will inform how data will be integrated today and for tomorrow. “Ball park” cost-benefit estimates will need to be produced in order to help plan and prioritize the integration initiatives.

Application Rationalization. PowerStream should consider initiating an application rationalization project that would look at functional and data overlaps among the existing application with a view towards improving business processes and minimizing the number of applications. This would have operational and cost reductions benefits.

Based on our analysis, we have identified potential “quick wins” to resolve some of the findings mentioned earlier in this report. In the next phase of this assignment, KPMG will analyse, identify and prioritize a number of integration solutions as part of the Integration Strategy.

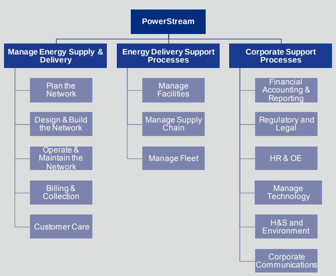
- Allow access to operational data (SCADA, ODS)
- Standardization of asset naming and labeling going forward
- Unified asset numbering scheme across all of PowerStream
- Revise process for updating HR data to take into account changes required in IS, e.g. for system logon.
- Update labour units in JDE
- Revise or add new JDE kits to reflect current conditions and labour requirements
- Address mislabeling of GL String on SKUs

Appendix A
Business Model

PowerStream EDM

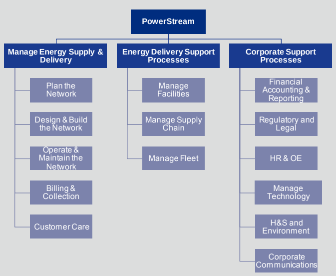
Functional Descriptions (1/2)

The following two pages are brief descriptions of PowerStream's major functions as depicted on the previous page. Functions are grouped generically according to type of activity, independentl of organizational structure.



Function Name	Function Description
Manage Energy Supply & Delivery	
Plan the Network	Plans changes to PowerStream's distribution network and metering infrastructure, including the addition of new and replacement of existing network components. Functions performed in support of these objectives include: 1) Engineering studies to optimize system performance and ensure security of supply, 2) Distribution network automation and reliability improvement, 3) Approval of all disribution system materials, 4) Creation and maintenance of distribution construction standards, and 5) Maintaining a Geographic Information System (GIS) of the location of assets in the field
Design & Build the Network	Designs and builds the stations and distribution lines that comprise the PowerStream distribution network, from transmission grid feeders down to the sub-division level. Functions include: 1) Stations design and construction, 2) Distribution network design and construction, and 3) Inspection of network facilities and assets, and cable location
Operate & Maintain the Network	Operates and maintains the stations and distributions lines that comprise the PowerStream distribution network. Functions include: 1) Distribution system control, 2) Network protection and control, 3) Station sustainment, and 4) Lines maintenance
Billing & Collection	Bills, receives payments, and collects payments in arrears from customers. Other functions include: 1) Disconnection of service, and 2) Meter reading, both manual and automated
Customer Care	Provides broad support to PowerStream customers to meet their service needs. Functions include: 1) Receiving and processing service requests such as move-ins, move-outs, cable locates, and 2) Response to customer queries and complaints, e.g., regarding bills, electricity usage, safety, outages

Functional Descriptions (2/2)



Function Name	Function Description
Energy Delivery Support	
Manage Facilities	Manages PowerStream's facilities to ensure that they are properly maintained.
Manage Supply Chain	Procures and warehouses materials so that they are available for construction and maintenance of the distribution network on a timely basis.
Manage Fleet	Maintains the fleet of vehicles required in the construction and maintaintenance of the distribution network, and the delivery of services to customers.
Corporate Support	
Finance, Accounting & Reporting	Provides financial analysis and reporting, accounting, payroll, strategic planning and budgeting for the coirporation.
Regulatory and Legal	Manages relationships and communications with regulatory and governmantal bodies, establishes electricity rate requirements, and manages the submission and approval of rate applications.
Human Resources & Organizational Effectiveness	• Manages human resources including recruitment, training, promotion and termination, • Develops and implements human resource policies, and • Conducts organizational development programs to improve organizational effectiveness.
Manage Technology	Plans, designs, Implements, and operates the information and communications technologies supporting all aspects of PowerStream operations.
Health & Safety and Environment	Develops and implements policies and programs to maintain health and safety of PowerStream employees, and to manage environmental impacts as well.
Corporate Communications	Manages communications in all media with PowerStream stakeholders, including customers, employees, regulators, governments, and suppliers.

Appendix B
Interview Findings

Interview Findings (1/4)

The following table provides a summary of findings, grouped by Business Function and Data Observation (gap, overlap, or quality)

The listing of Business Functions was leveraged from the Value Stream project* and by insight gained by KPMG from previous engagements within the utility sector

For further information on the PowerStream Business Model, please refer to Appendix A

Business Function	Information Need	Findings
Customer Care	• Capture more and link associated customer data	• Data Gap. Service order history, geo-coordinates (major intersection, and time of use is not linked to customer data in the CIS; Customer marketing consent is not captured
	• Ability to view project activity near a customer's location	• Data Gap. Information is not integrated with CIS
	• Ability for the customer or the customer care centre to schedule a service order	• Data Gap. Users are unable to view service team availability, and can therefore only request a convenient time-window. Self-service functionality is not currently provided by CIS.
	• More customer self serve features	• Data Gap. Customer is unable to setup pre-authorized payments; unable to schedule service
	• Stronger data validation to prevent inaccuracies such as mailing address	• Data Quality. Customer information can be incomplete and quality is inconsistent (missing alternate number, quality of phone numbers, contact information, owner-tenant status)
	• Ability to link or re-use data from a return customer	• Data Quality. Current system allows for multiple instances of the same customer; Manual process for identifying return customers
	• Greater consistency with customer data	• Data Overlap. A subset of customer data is extracted to JDE, and not synchronized with the system of record (CIS)
	• Capture Information from the Field	• Data Quality. Paper based process for updating service orders can lead to data entry errors.
Revenue	• Greater forecasting accuracy	• Data Gap. Unable to access ODS (meter data) in order to calculate un-billed revenue
	• Geo-based revenue reporting	• Data Gap. Lack of GIS integration with JDE prevents the ability to calculate revenue by subdivision
	• Premise class based revenue reporting	• Data Gap. Unable to calculate revenue by subdivision

KPMG

Interview Findings (2/4)

The following table provides a summary of findings, grouped by Business Function and Data Observation (gap, overlap, or quality)

The listing of Business Functions was leveraged from the Value Stream project* and by insight gained by KPMG from previous engagements within the utility sector

For further information on the PowerStream Business Model, please refer to Appendix A

Business Function	Information Need	Findings
Procurement	• Ability to manage an asset from cradle to grave	• Data Gap. Vehicle ECM data is not currently stored; Unable to measure and view fleet utilization; Sub-optimal information for condition based maintenance; Unable to track and manage an asset from cradle to grave; Unable to schedule preventative maintenance proactively
	• JIT based inventory management	• Data Gap. Unable to forecast inventory demand
	• Improve Vendor Data Quality	• Data Quality. Difficult to generate vendor reports e.g. PO per vendor; Vendor list is not always accurate
	• Consistent stock codes	• Data Quality. Inconsistency is reflected by amalgamations
	• Ability to explode stock codes	• Data Quality. Stock codes cannot be exploded into sub-items
	• Incorrect Item GL codes	• Some items have the wrong GL code, which causes inconsistent accounting
Common	• Accurate GIS data	• Data Quality. Geo coordinates, particularly for older assets, are not accurate; Paper based process for repairing coordinates is prone to errors and potentially confusing due to multiple Asset Tracking Form (ATF)
	• Consistent asset attributes	• Data Overlap. Multiple systems store asset data (CIS, Cascade, GIS, BAT) which promotes inconsistent data capture. Not all assets have a vintage attribute, cost,
	• Consistent GIS symbology	• Data Quality. Inconsistent symbology is primarily a reflection of historic consolidation and acquisition activities; Standardization continues to be an issue
	• Data ownership & accountabilities	• Data Quality. Data ownership is unclear. E.g. CU values change over time, unclear as to which department should update the information.
	• Consistent asset numbering	• Data Quality. There is no single system for creating asset numbers. The "South" uses XLS for switches and CIS for transformers, however the "North" uses BAT for both. • Data Overlap. Switches and Transformers are entered in GIS, CIS, BAT and SCADA
	• Streamlined data entry • Project Tracking	• Data Overlap. Many tools (spreadsheets) are used for project tracking, with no automation or integration with JDE

Interview Findings (3/4)

The following table provides a summary of findings, grouped by Business Function and Data Observation (gap, overlap, or quality)

The listing of Business Functions was leveraged from the Value Stream project* and by insight gained by KPMG from previous engagements within the utility sector

For further information on the PowerStream Business Model, please refer to Appendix A

Business Function	Information Need	Findings
New Services	• Capture More GIS Data • Capture Pole Data • Capture Forecasting Data • Accurate Land Based Data • Streamline Labour Estimating • Consistent GL string for SKUs	• Data Gap. Manhole, cable chambers, and general underground information is not captured in GIS • Data Gap. Historical data, inspection data, and “joint-use tenants” is not captured in GIS; Quantity, and vintage is often missing; Diameter (pole class) is often inaccurate and requires verification against the As-Built • Data Gap. Unable to store and reuse / re-load forecasting data from previous quarter. • Data Quality & Data Overlap. Outdated labour units in JDE promotes the use of Excel for developing labour estimates. Excel based estimates are later entered into JDE manually. • Data Quality. Land base data in the GIS is often lacking and not reliable, and often requires a survey • Data Quality. GL string associated to SKUs is often inaccurate; GL string data ownership is not well defined
Human Resources	• Automated employee record management • Employee Data Accuracy	• Data Quality. Process for adding and removing employees into JDE is largely paper based, time consuming and prone to errors. • Data Quality/Data Overlap. Calculating actual head count is challenging due to employee info information is replicated in multiple systems/databases
Information Technology	• Leverage employee data from JDE for user access management	• Data Quality. Employee data in JDE is not linked or synchronized with IT, e.g. Employee profile information such as name changes and departures are not cascaded to IT
Station Design & Construction	• More GIS data for Fiber Network • Access to Fault Information	• Data Gap. Unable to see unused fiber network; unable to trace the nodes; • Data Gap. Fault Information does not reside on the corporate network; manual process for requesting (extracting) fault information.

Interview Findings (4/4)

The following table provides a summary of findings, grouped by Business Function and Data Observation (gap, overlap, or quality)

The listing of Business Functions was leveraged from the Value Stream project* and by insight gained by KPMG from previous engagements within the utility sector

For further information on the PowerStream Business Model, please refer to Appendix A

Business Function	Information Need	Findings
New Developments	• Updated JDE Kits	• Data Quality. JDE Kits are outdated and do not reflect current labour requirements, this promotes the use of MS Excel and MS Access. Estimates are later inputted into JDE manually.
Standards	• Trace Materials to Finished Goods • Store Failure Rates	• Data Gap. Unable to barcode materials; unable to trace materials to finished goods • Data Gap. Unable to capture material failure rates
System Control	• Access to SCADA data	• Data Gap. Historical SCADA data is not stored
Planning	• Access to ODS • Access to SCADA data	• Data Gap. Transformer and meter data is not accessible to corporate users
Sustainment	• Streamlined Process for Time-Entry • Activity Based Work-Orders	• Data Quality & Overlap. Time sheets are entered in Excel and manually re-entered into JDE • Data Gap. Work Orders are currently setup as standing/open orders and not sufficiently granular to reflect activity based costing.
System Control	• Streamlined Process for Work Order • Accurate Outage Information	• Data Gap. Unable to link Work Orders (Operations Heat) to Service Orders (CIS). E.g. Although a given work-order may be complete, a service order is required and created separately in CIS. • Data Gap. Unable to qualify an outage event from Responder (planned vs. un-planned outage) which may lead to unnecessary site visits. E.g. a planned meter replacement would raise an outage alert to the System Control team (false negative)

cutting through complexity™

Appendix C

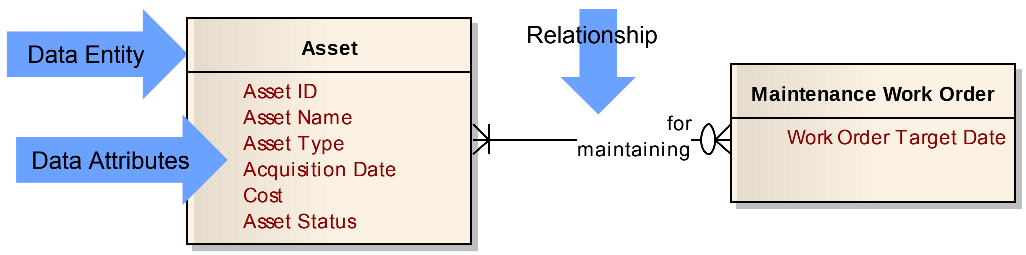
PowerStream Enterprise Data Model (Detail)

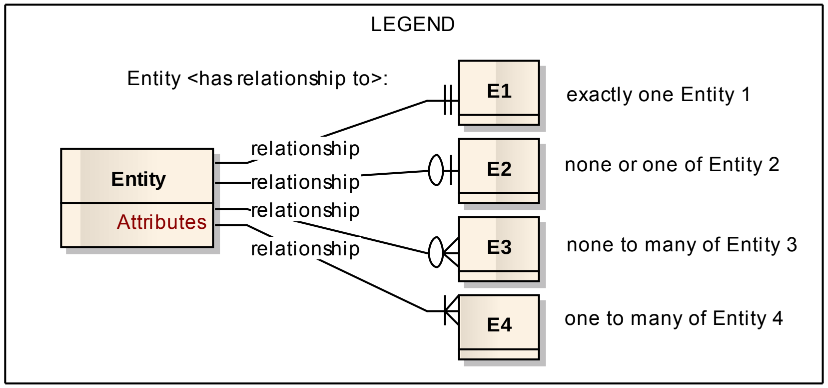
Understanding the EDM

The Enterprise Data Model is a blueprint of PowerStream's information needs

It is graphically represented as an entity relationship diagram, which outlines the following four components:

- **Subject Areas** are high level groupings of data entities, such as Assets, Customers, Distribution Network, etc.
- **Data Entities** are information objects required to support the enterprise. E.g. Asset Specification, Asset Utilization, Facility
- **Attributes** describe the characteristics of an entity. E.g. Customer Name, Customer Phone, Customer Email, etc.
- **Relationships** define the business rules between entities. E.g. a Customer has an Invoice, an Asset is part of the Distribution Network.





PowerStream EDM

EDM Subject Area - Assets

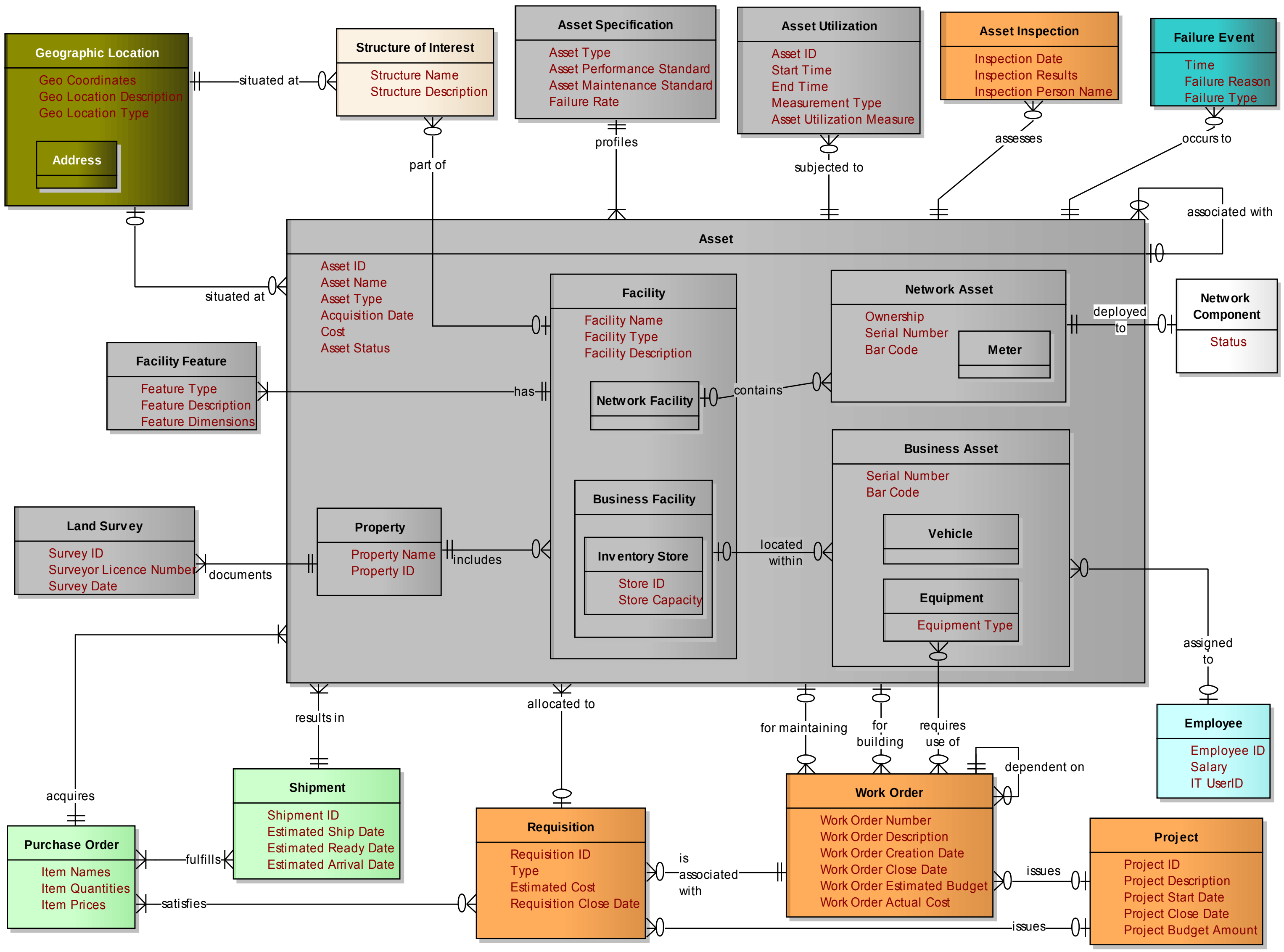
The Assets subject area identifies data about the business and distribution network assets required for PowerStream's operations.

The subject area diagram illustrates the classification of asset types, as well as related business aspects such as:

- **Location**
- **Acquisition**
- **Work performed**
- **Employees**
- **Asset condition**
- **Utilization**

Key components of this model are:

- **Facilities: Business and Network**
- **Network Assets, that may be included in a network facility**
- **Business Assets, that include vehicles and equipment (as well as all other business assets of interest to PowerStream)**

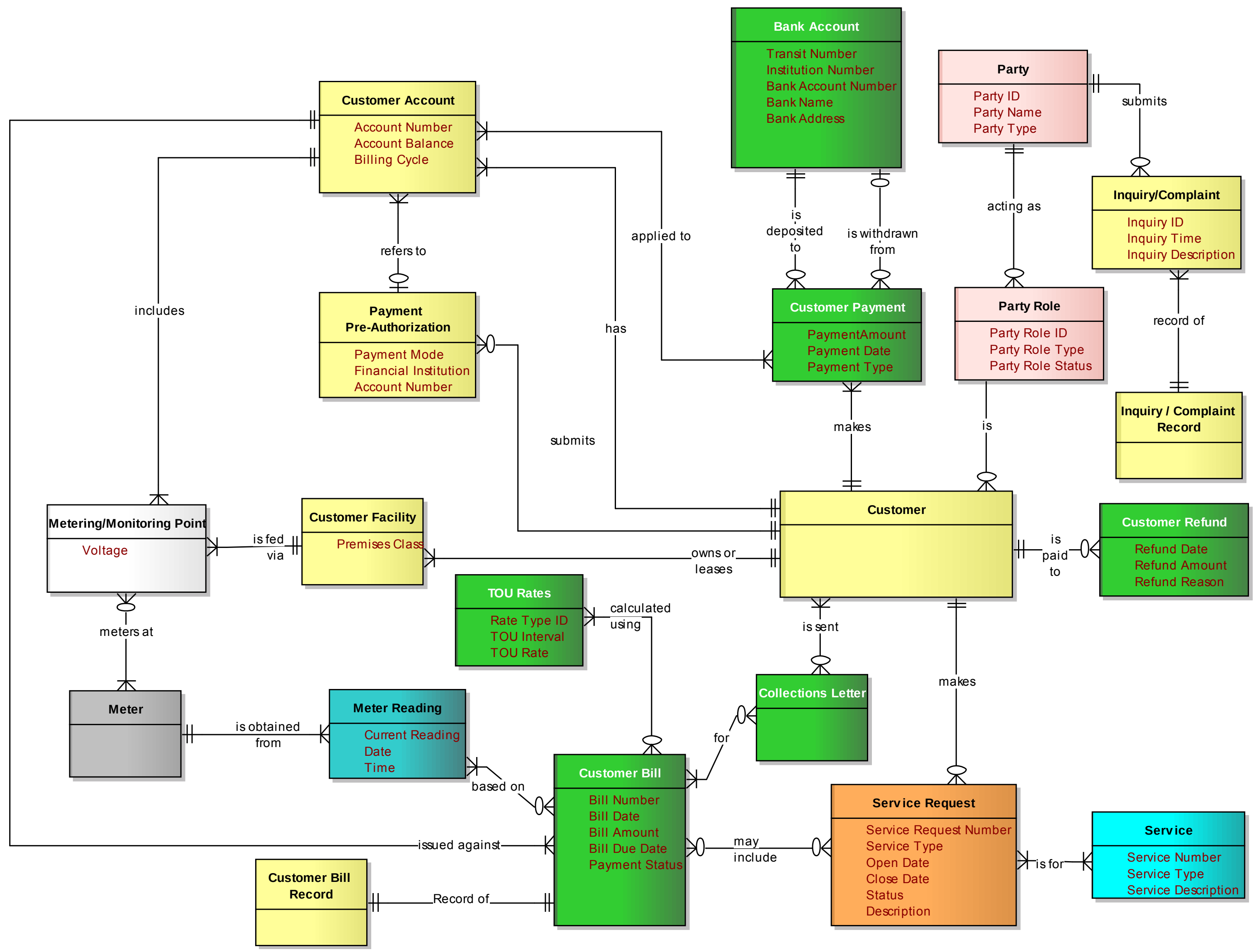


PowerStream EDM

EDM Subject Area - Customer

The Customer subject area identifies the data about the parties with role “Customer”.

This structure facilitates the association of all the information about a customer and the different roles the related party may have with PowerStream (vendor, employee, joint tenant, etc.)



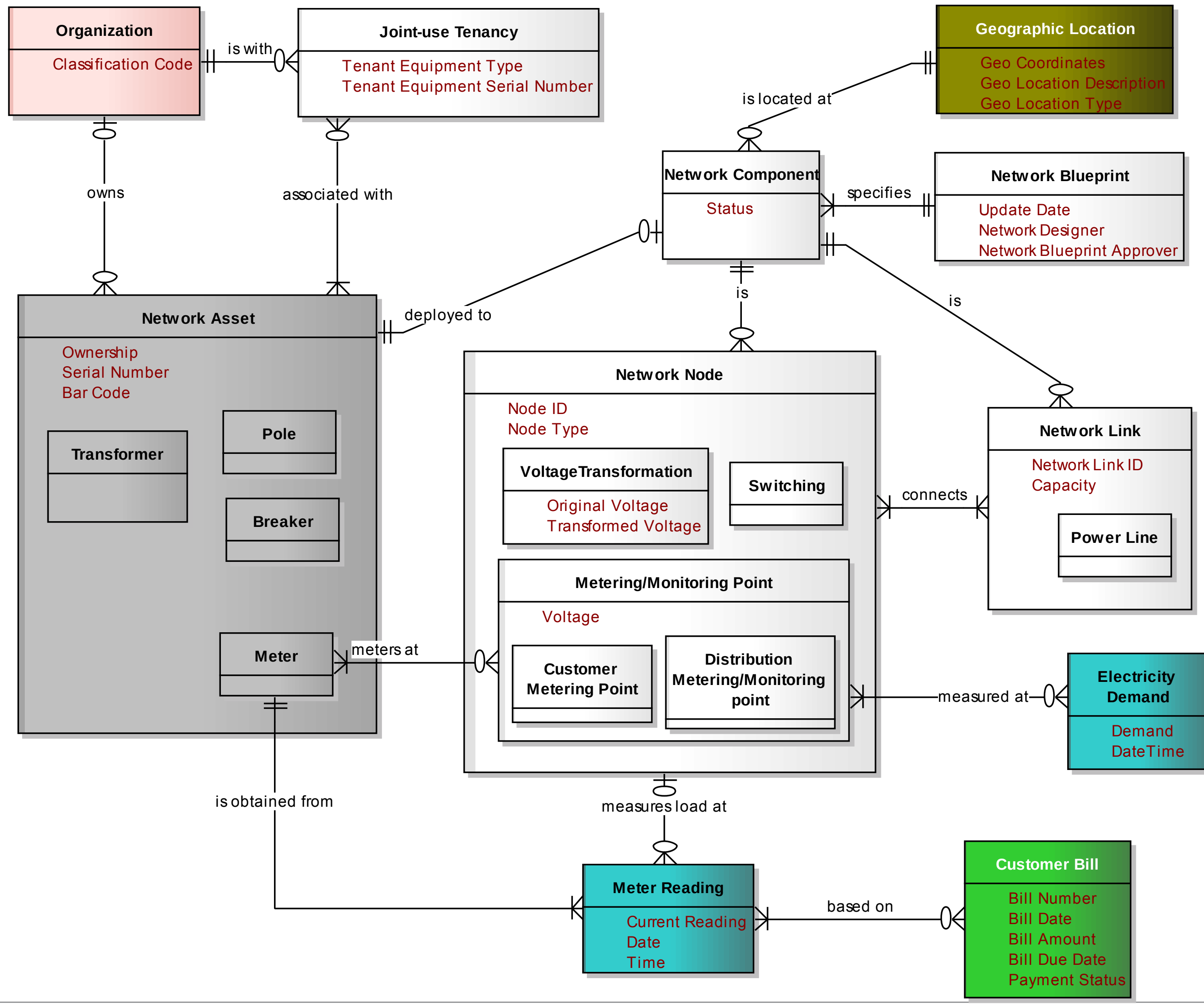
PowerStream EDM

EDM Subject Area – Distribution Network

The Distribution Network subject area defines the information required to describe PowerStream's electricity distribution network. This subject area associates the network design (blueprint) with the actual built and operating network.

It introduces the concept of network *nodes* and *links*, that can be used to describe arbitrary networks (electrical or otherwise), irrespective of the particular assets located in the nodes or the links.

The "Network Component" can be either a node or a link and it is the element that links the electricity distribution assets; e.g. a particular transformer is deployed on a specific component (of type "*Node*"), at a specific location. The lines that link the transformer to other nodes is a "Link", to which a specific type of cable is deployed.

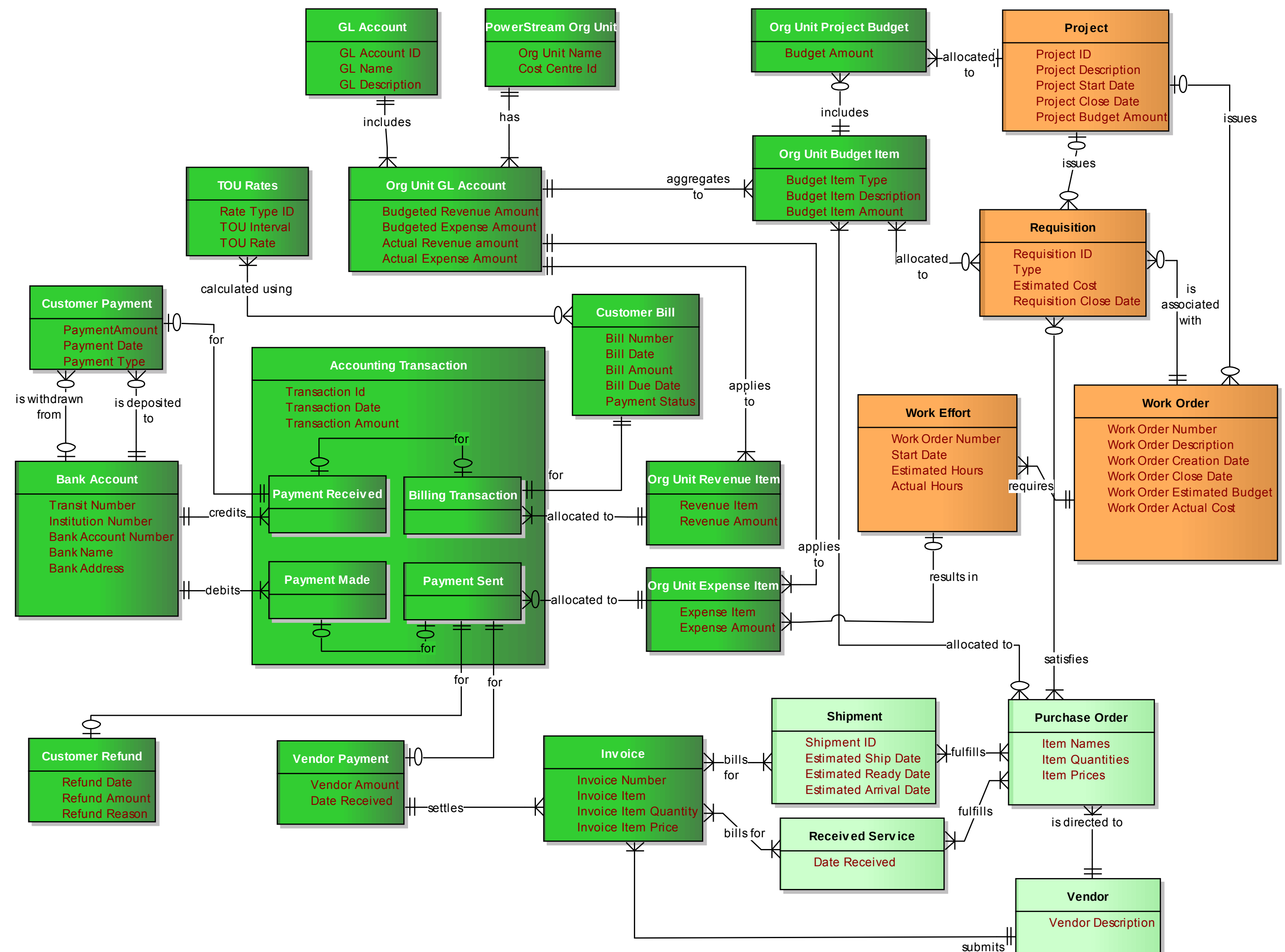


PowerStream EDM

EDM Subject Area - Finance

The Finance subject area identifies data used to account for operational business transactions that impact PowerStream's financial position, from the budget and actual perspectives.

The subject area diagram illustrates expense transactions from projects and work orders as well as revenues from customers.



PowerStream EDM

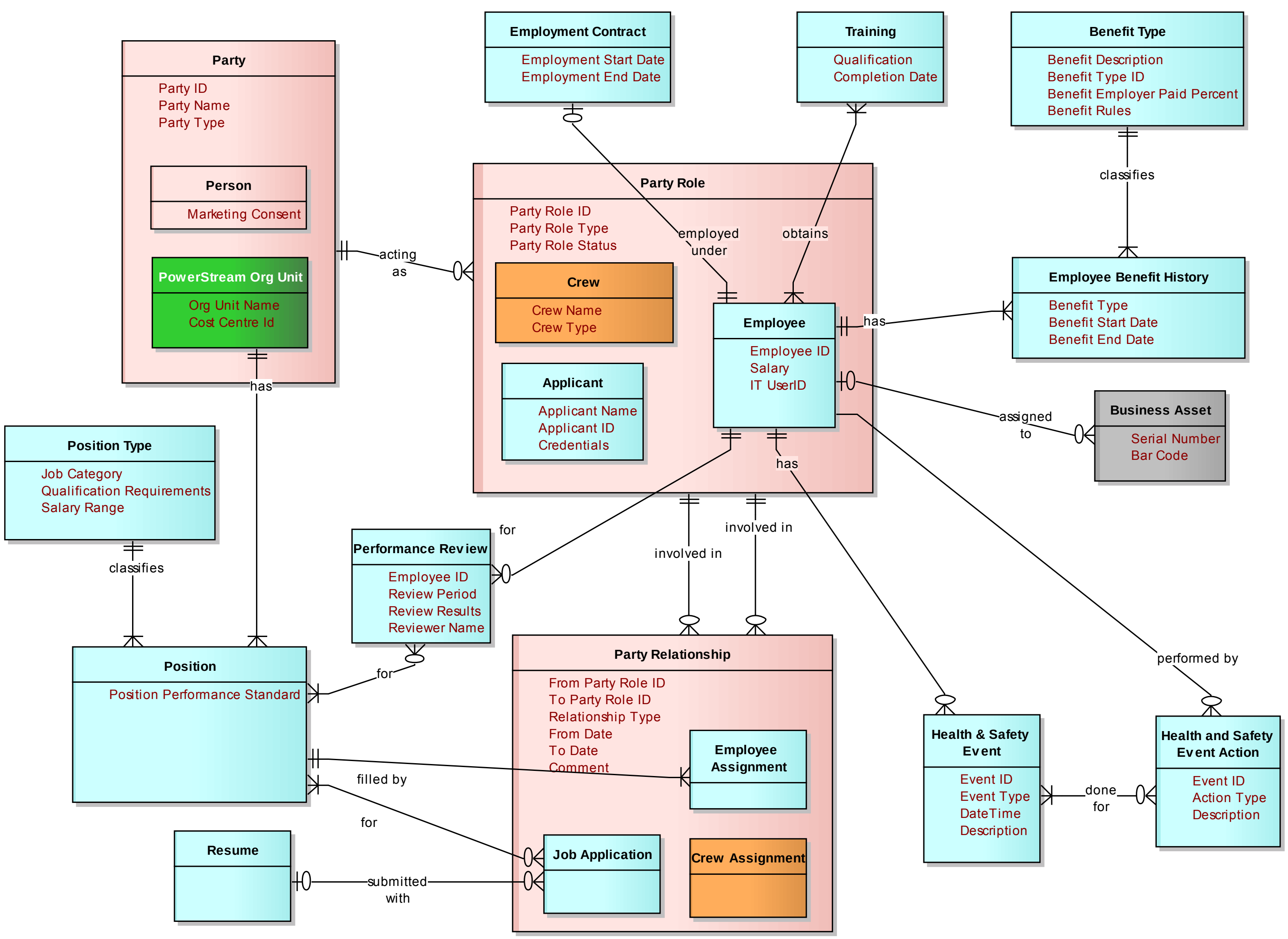
EDM Subject Area – Human Resources

The Human Resources subject area identifies data used in human resources management.

The subject area diagram illustrates the relationship between employees and related business aspects such as:

- **Employment terms**
- **Training**
- **Health and safety**
- **Job assignments**
- **Employee performance**
- **Assignment of business assets to employees (vehicles, computers, tools, etc.)**

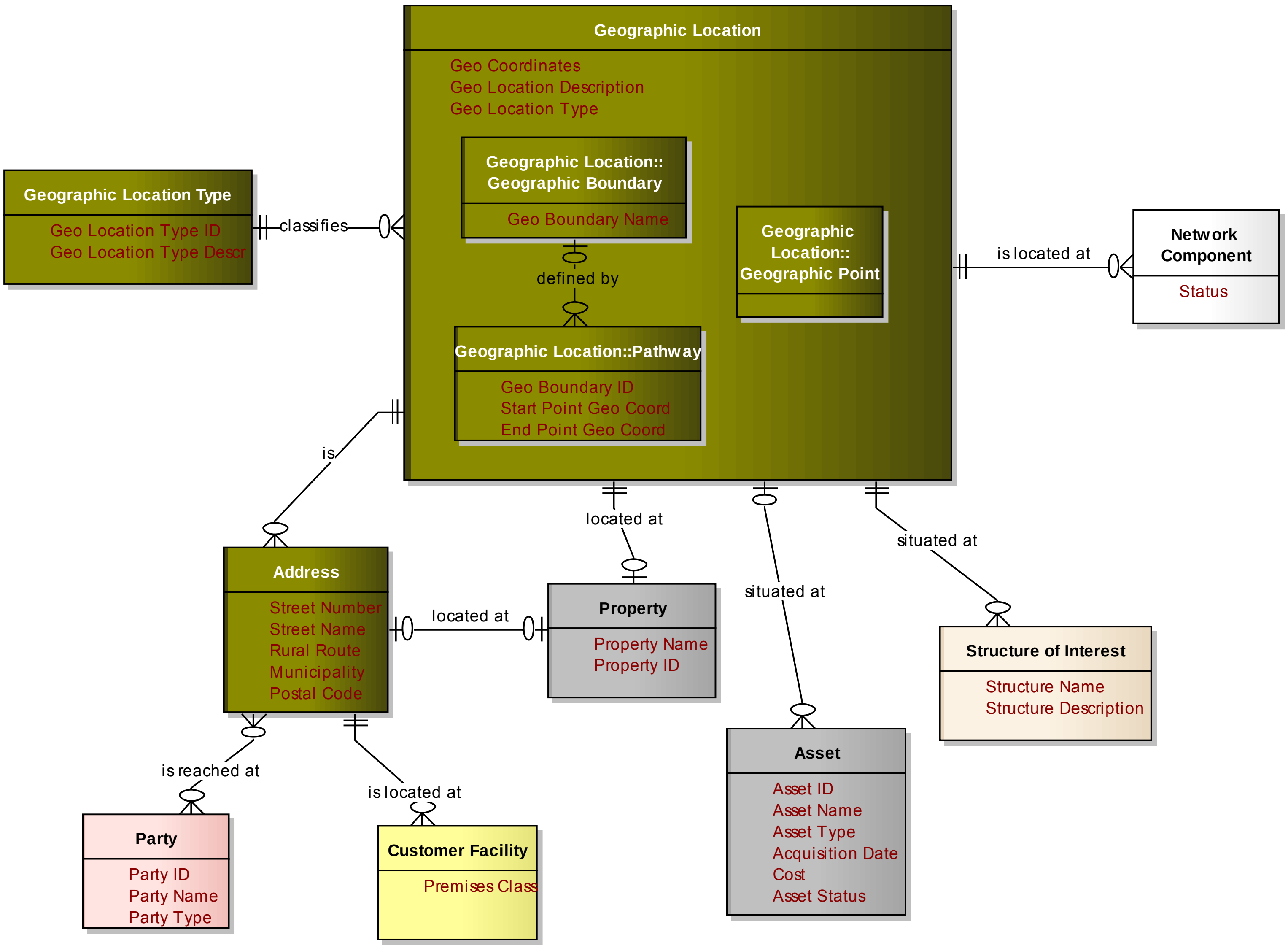
An important feature of this model is the representation of an "Employee" as a party role. This provides flexibility in being able to look at an employee as a customer and an applicant (for an internal position), since they are all roles of a *Person* (*Party*).



EDM Subject Area - Locations

This subject area provides the means of describing geospatial features in a flexible way, while associating parties, assets and network components with geographic locations.

The *Geographic Location* structure supports the definition of segments (lines or pathways) as well as areas (as collections of *Pathways*).

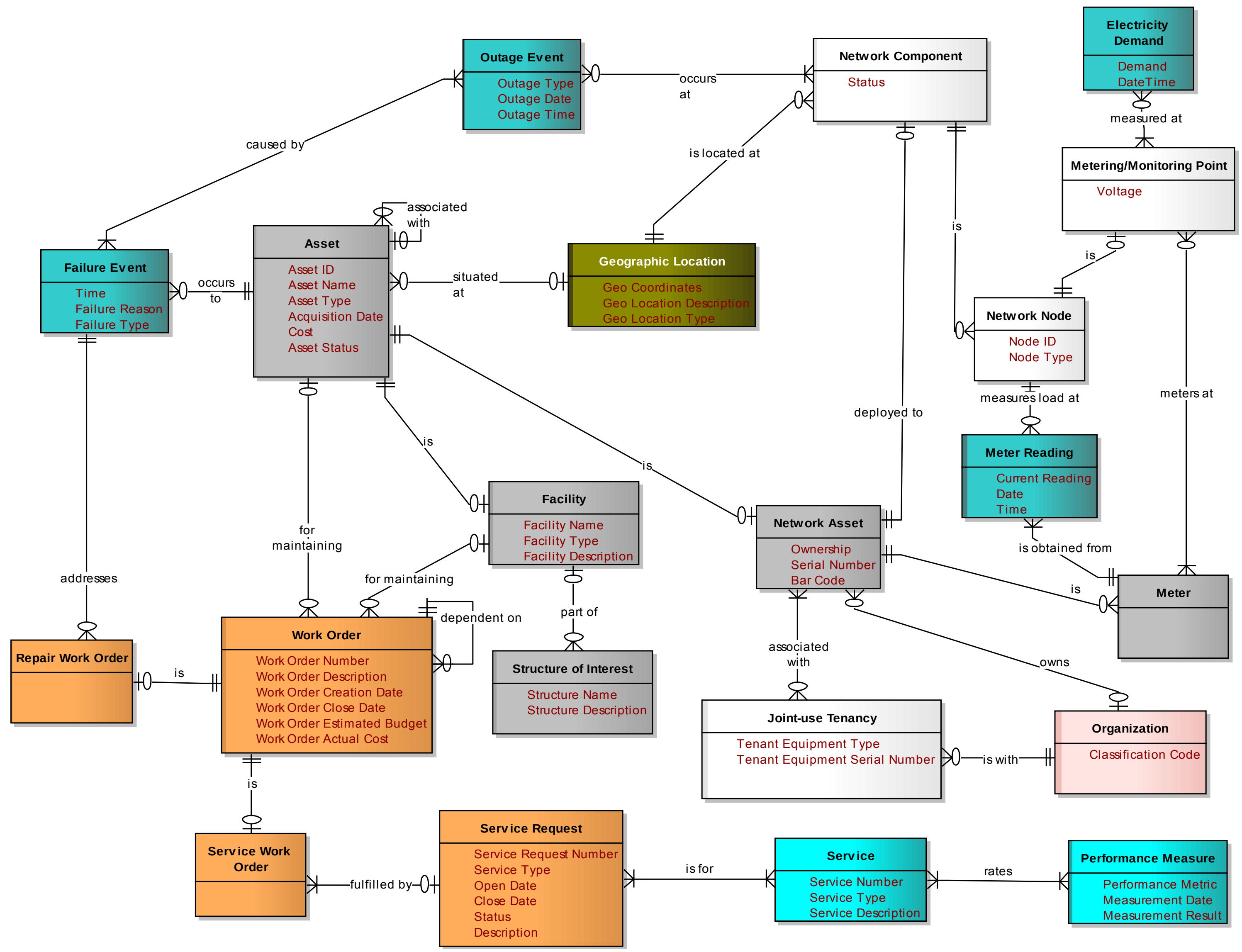


KPMG

PowerStream EDM

EDM Subject Area - Operations

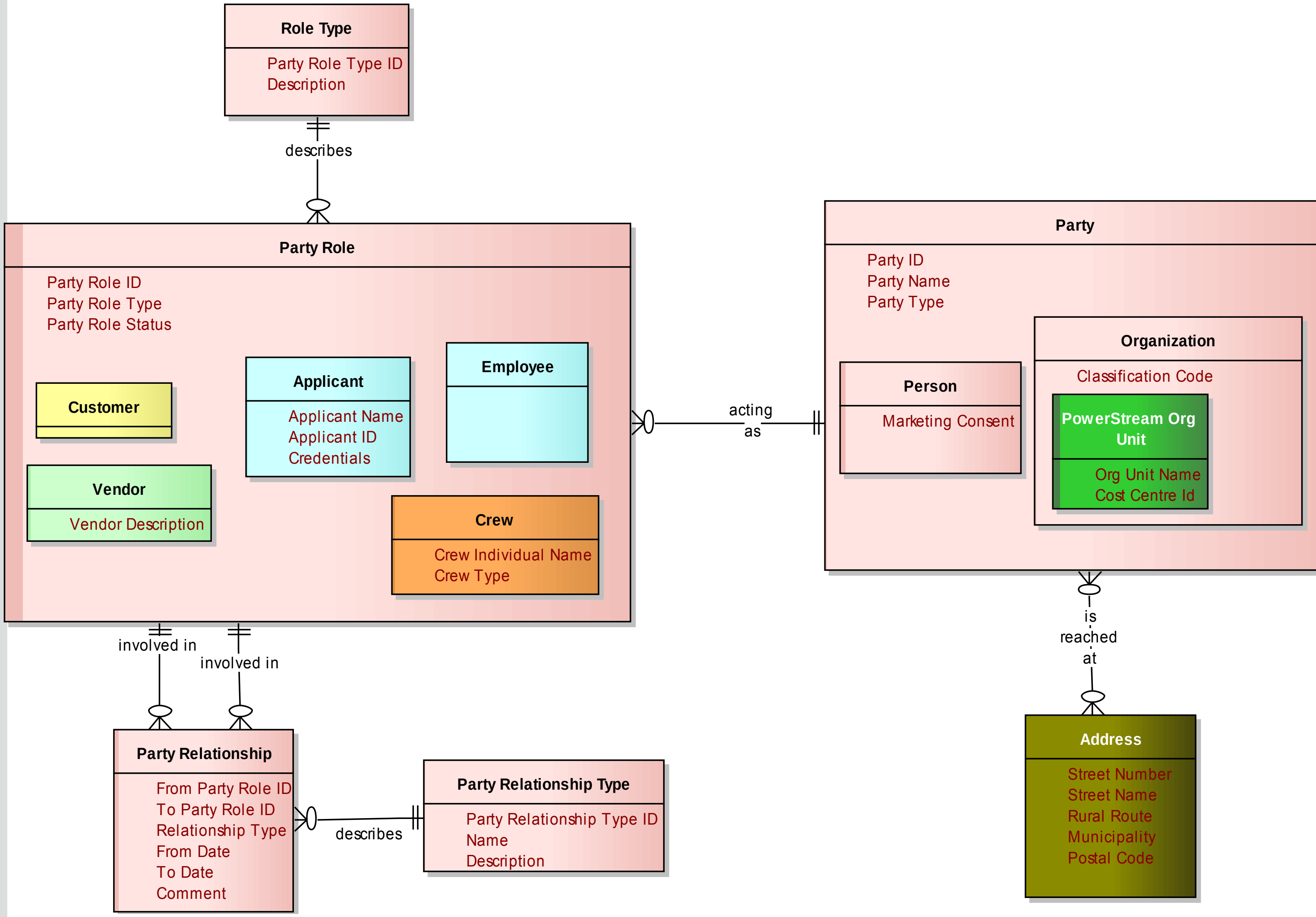
The Operations subject area leverages information for other areas to effectively manage electricity demand and network events.



EDM Subject Area – Persons & Organizations

The Persons and Organizations (*Parties*) subject area defines the parties of interest to PowerStream, the roles they play (customer, employee, vendor, etc.) as well as their relationships.

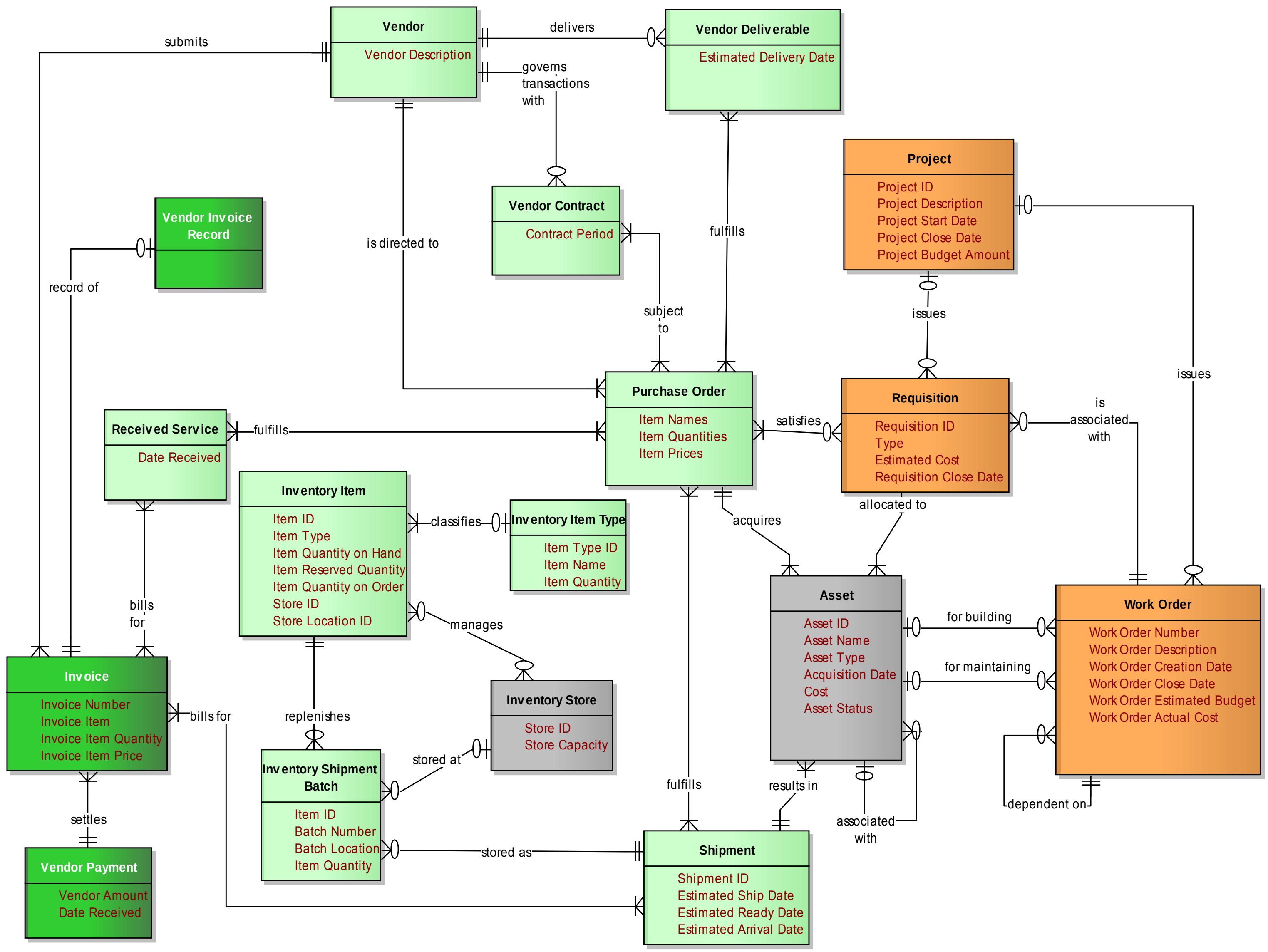
There are many types of relationships, among them: *Residential Customer Relationship, Commercial Customer Relationship, Electricity Supplier Relationship, Vendor Relationship, Employment (represented as Employee Assignment*), and so on.



PowerStream EDM

EDM Subject Area – Supply Chain

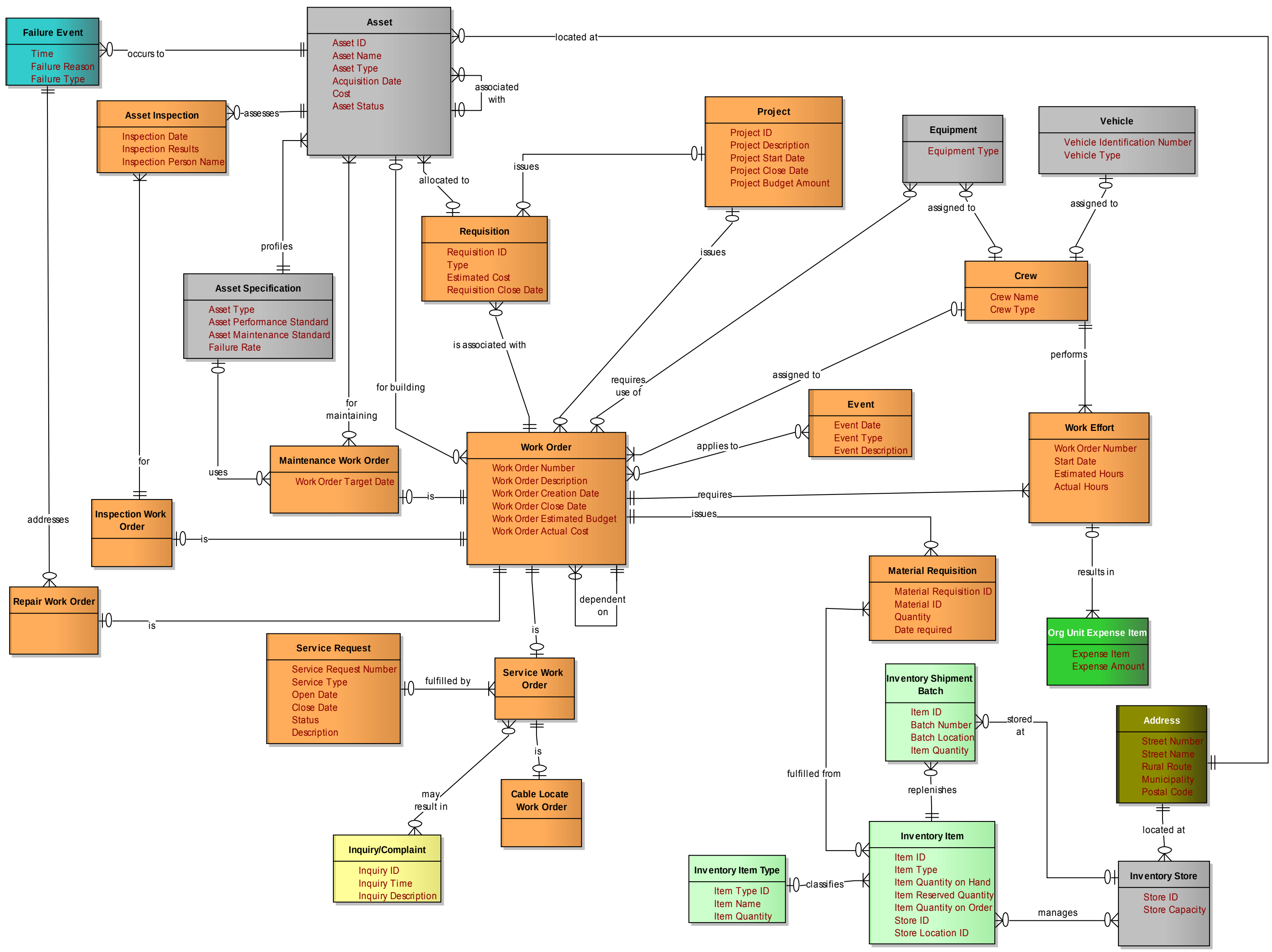
The Supply Chain subject area describes the information and thee relationships in managing the acquisition of assets, supplies and services.



PowerStream EDM

EDM Subject Area – Work Management

The Work Management subject area describe the information objects and their relationships in the processes related to managing and executing projects and work orders.



Appendix D

Entity Definitions

Please refer to external file:

Appendix D - PowerStream EDM Entities & Attributes Report.v02.htm

Appendix E

Business Functions by Entity

Please refer to external file:

Appendix E – Business Functions by Entity Mapping.v01.XLSX

Appendix F

Current System by Conceptual Data Entity

Please refer to external file:

Appendix F –

PowerStream App Analysis.v01

KPMG

cutting through complexity™

PowerStream - Detailed OM&A Costs 2009 -2013

	PowerStream South	PowerStream Combined					
	2009	Actual				Bridge Year	Test Year
	Board Approved	2009 CGAAP	2010 CGAAP	2011 CGAAP	2011 MIFRS	2012 MIFRS	2013 MIFRS
Distribution Expenses - Operations							
5005 Operation Supervision and Engineering	-	1,486,553	447,286	42,483	7,769,885	8,100,774	8,609,802
5010 Load Dispatching	2,495,564	2,579,484	2,852,958	3,384,605	3,279,023	3,138,721	3,243,717
5012 Station Buildings and Fixtures Expense	292,238	565,513	297,789	147,889	110,184	-	-
5014 Transformer Station Equipment - Operation Labour	527,297	128,227	46,325	425,125	308,720	368,917	423,291
5015 Transformer Station Equipment - Operation Supplies and Expenses	94,735	4,441	517	532	404	97,855	97,487
5016 Distribution Station Equipment - Operation Labour	237,540	170,417	332,254	409,927	1,196,539	1,476,418	1,590,179
5017 Distribution Station Equipment - Operation Supplies and Expenses	111,428	15,524	33,214	62,538	55,394	309,064	296,096
5020 Overhead Distribution Lines and Feeders - Operation Labour	496,263	1,863,369	836,130	1,210,001	815,593	783,108	795,256
5025 Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	688,772	377,498	488,574	413,356	418,879	-	-
5030 Overhead Subtransmission Feeders - Operation	-	155,454	-	(391)	(371)	-	-
5035 Overhead Distribution Transformers- Operation	46,919	46,538	34,821	49,384	36,132	1,189,539	1,492,466
5040 Underground Distribution Lines and Feeders - Operation Labour	153,787	800,835	597,925	615,280	420,749	487,840	498,302
5045 Underground Distribution Lines & Feeders - Operation Supplies & Expenses	437,979	183,956	305,776	426,212	426,031	704,917	705,151
5050 Underground Subtransmission Feeders - Operation	-	-	-	-	-	-	-
5055 Underground Distribution Transformers - Operation	182,749	90,382	86,774	73,128	49,767	232,683	237,914
5060 Street Lighting and Signal System Expense	-	-	-	-	-	-	-
5065 Meter Expense	1,305,362	2,016,932	1,334,321	1,403,475	1,654,650	3,358,106	3,385,695
5070 Customer Premises - Operation Labour	1,449,087	1,874,703	1,882,702	1,911,309	1,321,511	1,389,870	1,431,431
5075 Customer Premises - Materials and Expenses	855,798	912,392	981,920	1,373,411	1,372,173	1,467,940	1,527,217
5085 Miscellaneous Distribution Expense	-	983	26,415	108,629	108,629	250,000	400,000
5090 Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-
5095 Overhead Distribution Lines and Feeders - Rental Paid	-	65,515	94,141	68,099	68,099	80,000	80,000
5096 Other Rent	42,500	22,822	151,628	167,417	167,417	181,000	150,000
Total Operation	**9,418,016**	**13,361,537**	**10,831,471**	**12,292,411**	**19,579,408**	**23,616,751**	**24,964,005**

	PowerStream South	PowerStream Combined					
	2009	Actual				Bridge Year	Test Year
	Board Approved	2009 CGAAP	2010 CGAAP	2011 CGAAP	2011 MIFRS	2012 MIFRS	2013 MIFRS
Distribution expenses - Maintenance							
5105 Maintenance Supervision and Engineering	-	382,045	12,801	15,739	13,521	-	-
5110 Maintenance of Buildings and Fixtures - Distribution Stations	-	-	-	86,545	70,034	-	-
5112 Maintenance of Transformer Station Equipment	602,195	646,223	611,983	352,050	244,628	228,173	253,627
5114 Maintenance of Distribution Station Equipment	501,294	438,509	355,572	492,815	371,602	255,871	521,275
5120 Maintenance of Poles, Towers and Fixtures	211,559	617,048	375,491	302,076	221,489	182,166	184,777
5125 Maintenance of Overhead Conductors and Devices	1,667,824	2,215,523	1,568,593	2,339,695	1,868,502	1,928,140	1,968,169
5130 Maintenance of Overhead Services	109,956	345,033	345,566	372,922	262,426	250,957	256,649
5135 Overhead Distribution Lines and Feeders - Right of Way	350,000	355,777	991,570	1,215,673	1,101,652	103,103	105,390
5145 Maintenance of Underground Conduit	24,284	16,688	6,579	9,951	6,217	1,665	1,665
5150 Maintenance of Underground Conductors and Devices	1,483,260	3,520,437	3,392,349	2,989,356	2,432,846	3,335,421	3,600,600
5155 Maintenance of Underground Services	1,222,913	353,266	450,365	725,054	503,923	501,422	499,390
5160 Maintenance of Line Transformers	297,277	428,387	337,507	333,925	253,465	240,463	245,090
5170 Sentinel Lights - Labour	-	-	-	-	-	-	-
5172 Sentinel Lights - Materials and Expenses	-	-	-	-	-	-	-
5175 Maintenance of Meters	-	-	40,237	204	204	-	-
5178 Customer Installations Expenses- Leased Property	-	-	-	-	-	-	-
5195 Maintenance of Other Installations on Customer Premises	-	-	-	-	-	-	-
Total Maintenance	**6,470,562**	**9,318,936**	**8,488,612**	**9,236,005**	**7,350,509**	**7,027,380**	**7,636,633**

PowerStream - Detailed OM&A Costs 2009 -2013

		PowerStream South	PowerStream Combined					
		2009	Actual				Bridge Year	Test Year
		Board Approved	2009 CGAAP	2010 CGAAP	2011 CGAAP	2011 MIFRS	2012 MIFRS	2013 MIFRS
	Billing and Collecting							
5305	Supervision	1,006,652	654,094	567,030	1,344,097	1,441,809	1,500,346	1,693,462
5310	Meter Reading Expense	2,821,326	2,280,044	4,163,571	2,741,828	3,156,370	1,124,885	1,157,296
5315	Customer Billing	870,031	2,728,518	2,940,784	3,796,816	5,815,198	6,356,534	7,015,483
5320	Collecting	1,857,982	1,389,848	2,290,521	2,793,283	3,398,603	3,548,627	3,764,039
5325	Collecting- Cash Over and Short	-	908	(1,742)	480	480	-	-
5330	Collection Charges	-	38,444	53,414	59,000	59,000	-	-
5335	Bad Debt Expense	1,236,000	2,873,302	1,910,962	1,781,069	1,781,069	2,085,000	2,126,700
5340	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-
	Total Billing and Collection	**7,791,992**	**9,965,156**	**11,924,541**	**12,516,572**	**15,652,528**	**14,615,393**	**15,756,981**
	Community Relations							
5405	Supervision	305,375	376,569	468,587	682,730	660,761	754,260	838,998
5410	Community Relations - Sundry	329,000	568,444	594,488	1,418,296	1,413,144	418,257	425,604
5415	Energy Conservation	64,100	9,667	268,327	66,924	0	-	-
5420	Community Safety Program	-	139,152	458	-	-	-	-
	Total Community Relations (incl. Sales Expense)	**698,475**	**1,093,831**	**1,331,860**	**2,167,950**	**2,073,905**	**1,172,518**	**1,264,602**
	Administrative and General Expenses							
5605	Executive Salaries and Expenses	3,705,126	3,229,300	4,067,329	3,530,641	4,049,642	4,000,690	4,176,861
5610	Management Salaries and Expenses	3,935,182	3,658,965	4,274,054	4,558,388	8,224,723	9,108,697	9,874,777
5615	General Administrative Salaries and Expenses	967,129	1,730,289	1,698,893	1,448,206	1,995,430	1,987,392	2,052,903
5620	Office Supplies and Expenses	1,126,848	1,424,212	280,684	752,981	752,981	1,028,050	1,288,086
5625	Administrative Expense Transferred Credit	-	-	-	-	-	-	-
5630	Outside Services Employed	1,943,205	2,630,476	897,896	1,362,003	1,362,044	2,045,800	1,376,840
5635	Property Insurance	58,416	61,616	2,041	-	-	21,931	30,000
5640	Injuries and Damages	924,000	1,112,170	1,237,301	1,618,214	1,618,214	1,458,451	1,808,025
5645	Employee Pensions and Benefits	-	(147,905)	1,057,252	(174,071)	(305,561)	288,000	296,640
5650	Franchise Requirements	-	-	-	-	-	-	-
5655	Regulatory Expenses	1,512,800	1,384,907	1,199,956	1,236,537	1,236,537	1,364,500	1,396,665
5660	General Advertising Expenses	-	-	-	-	-	-	-
5665	Miscellaneous General Expenses	3,524,803	7,775,923	5,535,358	6,348,193	6,938,100	9,442,413	10,434,519
5670	Rent	274,728	256,722	7,795	499,875	1,003,875	1,232,423	1,266,677
5675	Maintenance of General Plant	710,159	928,665	1,557,403	1,518,481	2,356,865	2,614,127	2,829,037
5695	OM&A contra account	(1,004,750)	901,322	1,047,116	1,543,831	1,543,831	1,333,236	-
6205	Donations	41,000	30,000	336,289	412,009	412,009	350,000	350,000
JS	Less Cost of Joint Services	-	-	-	-	(3,568,659)	(2,843,108)	(2,928,402)
	Other Distribution Expenses							
6105	Taxes Other Than Income Taxes	1,088,609	947,459	1,061,756	1,212,882	1,603,355	1,700,435	1,795,039
6215	Penalties	30,000	13,544	121	5,624	5,624	30,600	31,212
6225	Other Deductions	-	-	-	-	-	-	-
	Total A&G expenses	**18,837,255**	**25,937,666**	**24,261,244**	**25,873,793**	**29,229,011**	**35,163,637**	**36,078,880**
	Total Administration Expenses	**27,327,722**	**36,996,654**	**37,517,646**	**40,558,315**	**46,955,444**	**50,951,548**	**53,100,464**
	Total OM&A Expenses	**43,216,300**	**59,677,127**	**56,837,729**	**62,086,731**	**73,885,361**	**81,595,680**	**85,701,101**

Procedure No. SM 1

Issue Date: *Sept. 26, 2005*

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 4
Schedule 4.1
Appendix E
5 Pages
Filed: August 31, 2012

CORPORATE PROCEDURE

SUBJECT: Maintenance Program for Distribution Stations (MS's)

This Procedure is new.

Originator:	**J. Garnish – Station Maintenance Manager**	**Date:**	*Sept. 26,2005*
Reviewed By:	**R. Antenucci – Protection & Control Manager**	**Date:**	*Nov. 15/05*
Approved By:	**M. Matthews – Director Lines, Construction, and Maintenance**	**Date:**	*Nov. 15/05*
To Be Reviewed By:	**J. Garnish**	**Date:**	*Sept. 26, 2008*

OBJECTIVE:

PowerStream distribution stations shall be maintained in proper operating condition.

PowerStream distribution stations shall be maintained in good condition.

REGULATORY REFERENCES/CODES/STANDARDS:

Occupational Health and Safety Act – Section 25(1)(b)
Electrical Safety Authority – OR 22/04 – Section 4(3) and 4(6)

PROCEDURE:

Distribution station equipment shall be withdrawn from operation for maintenance and repair in accordance with maintenance schedules established by the Station Maintenance department. The schedule shall be revised annually.

Maintenance shall consist of the following:

- Site inspections shall be carried out monthly.
- Vegetation shall be sprayed annually or more frequently if required.
- All equipment shall be scanned for infra red radiation annually.
- The oil of all transformers shall be tested annually.
- Batteries and power conversion equipment shall be tested, inspected, and maintained annually where applicable.
- Transformers shall be tested annually when they can be withdrawn from operation without customer outages.
- Primary disconnects, fuse gear, and lightning arresters shall be tested, inspected, and maintained annually where applicable.

- Medium voltage bus work – metal enclosed/metalclad and outdoor – shall be inspected and maintained as required. All bus work shall be inspected, cleaned, and maintained every five years when it can be withdrawn without customer outages.

- Where applicable circuit breakers and reclosers shall be tested and inspected on a five year rotation.

- Equipment shall be tested and maintained per the manufacturer's recommendations. If the manufacturer does not recommend test and maintenance procedures then the best industry practices shall apply. Not withstanding the manufacturer's recommendations best industry practices may apply.

- Problematic equipment will require more frequent monitoring, inspection, and testing. The severity of the problem and best industry practices will dictate the maintenance procedures.

- Replacement of parts will be with "like for like" when possible. When "like for like" replacement parts are not available then the substituted parts must be approved by one of the bodies accepted by the Electrical Safety Authority of Ontario.

- A file on each station is maintained in the Station Maintenance department office. All test data, repair records, purchased equipment records, maintenance records, monthly station inspection records, records of repair inspections, and certificates of station equipment repair are kept in this file.

Maintainable Items	Maintenance cycle
Site Inspections	Monthly
Vegetation control	Yearly
Infra Red Scan	Yearly
Batteries	Yearly
Power Conversion Equipment	Yearly
Transformer	Yearly
Disconnects	Yearly
Fuse Gear	Yearly
Lightning Arresters	Yearly
Buswork	Five Years
Circuit Breakers & Reclosers	Five Years

RECORD OF INSPECTION OF STATION EQUIPMENT REPAIR

STATION ____________________________ DATE_________________________

EQUIPMENT I.D. ____

REPAIR PROJECT ____

ITEM	COMPLY		COMMENTS
	YES	NO	
Approved Parts			CSA#_________ Other_________
Equipment Operating Properly			
Clearances for Operation and Mtce.			
Grounding			
Barriers, Guards, Signs			
Conductor Supports and Bracing			

CERTIFICATE OF STATION EQUIPMENT REPAIR

This certifies that the repair as recorded in the "Record of Inspection of Station Equipment Repair" above is consistent with the safety requirements of OR22/04.

☐ FINAL REPAIR

☐ EMERGENCY REPAIR

☐ LIKE FOR LIKE

☐ NO UNDUE HAZARD

☐ FURTHER REPAIR ____

NAME (PRINT) ________________________ DATE _________________________

SIGNATURES _________________________ POSITION _____________________

DISTRIBUTION STATION (MS) – MONTHLY INSPECTION

STATION ___________________________ DATE ___________________________

ITEM	OK	COMMENTS
Fence, Gates, Signs		
Grounding		
Weeds, Debris, etc…		
Oil Leaks		
Conductor Supports and Barriers		
Battery – if applicable		
Outside Lights		
Inside Lights		
Heater / HVAC		
Security – Locks		
Yard Stone		

OTHER : ____

____

____

____

INSPECTOR ____

Procedure No. SM 2

Issue Date: Nov. 21/05

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 4
Schedule 4.1
Appendix F
3 Pages
Filed: August 31, 2012

CORPORATE PROCEDURE

SUBJECT: Maintenance Program for Transformer Stations (TS's)

This Procedure replaces and supersedes HVDI Procedures SM 7 dated 05/04/02 and SC- 13 dated 09/06/00 and RHHI Procedure EO- 8 dated 01/09/03.
Revised January 25, 2006 to add MV insulator washing.

Originator:	**J. Garnish** **Manager Station Maintenance**	**Date:**	*Jan. 25/06*
Reviewed By:	**R. Antenucci** **Protection & Control Manager**	**Date:**	*Jan. 25/06*
Approved By:	**M. Matthews** **Director Lines, Construction & Maintenance**	**Date:**	*Jan. 26/06*
To Be Reviewed By:	**J. Garnish**	**Date:**	*Jan. 25/09*

OBJECTIVE:

PowerStream transformer stations shall be maintained in proper operating condition.
PowerStream transformer stations shall be maintained in good condition.

REGULATORY REFERENCES/CODES/STANDARDS:

Occupational Health and Safety Act - Section 25(1) (b)
IESO Market Rules - Grid Connection Requirements
IESO Market Rules - Power System Reliability

SUBJECT: Maintenance Program for Transformer Stations (TS's)

PROCEDURE:

Transformer station equipment shall be withdrawn from operation for maintenance and repair in accordance with maintenance schedules established by the Station Maintenance department. The schedule shall be revised annually.

Maintenance shall consist of the following:

Maintainable Items	Maintenance cycle
Site Inspections	Monthly
Vegetation control	Yearly
Infra red scan of equipment	Yearly
Primary disconnect switches	4 years
Grounding switches	4 years
Backup auxiliary power systems	Yearly
UPS systems	Yearly
Primary lightning arresters	Yearly
Primary bus work	4 years
Load Tap Changers/Diverters	2 years
Batteries	Yearly
Power Conversion Equipment	Yearly
Transformers	Yearly
Transformer oil analysis	Yearly
Transformer cooling equipment	2 years
MV Disconnects/Isolator Switches	Yearly
MV Circuit breakers	4 years
MV Circuit breaker cells	4 years
MV bus work/Metalclad bus	4 years
Lightning Arresters	Yearly
MV Cables	Five Years
MV Insulator washing	Yearly
Grounding equipment	Five Years

.

SUBJECT: Maintenance Program for Transformer Stations (TS's)

- Equipment shall be tested and maintained per the manufacturer's recommendations. If the manufacturer does not recommend test and maintenance procedures then the best industry practices shall apply. Not withstanding the manufacturer's recommendations best industry practices may apply.

- Problematic equipment will require more frequent monitoring, inspection, and testing. The severity of the problem and best industry practices will dictate the maintenance procedures.

- Replacement of parts will be with "like for like" when possible. When "like for like" replacement parts are not available then the substituted parts must be approved by one of the bodies accepted by the Electrical Safety Authority of Ontario.

- A file on each station is maintained in the Station Maintenance department office. All test data, repair records, purchased equipment records, maintenance records, monthly station inspection records, and records of repairs are kept in this file.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.2 Is the proposed level of the Depreciation/Amortization expense for 2013 appropriate? (D1)

BOARD STAFF INTERROGATORY #33:

Reference(s): <u>Ref: E D1/T4/S1/p.1</u>

PowerStream states that for the purposes of this application, it has included a full year of depreciation and amortization expense for 2013 additions which has increased depreciation expense by $1,569,000 compared with the amount determined using the half-year rule.

Please state whether PowerStream believes that there are any circumstances specific to it that would justify a departure from the Board's normal practices in this regard. If yes, please explain what they are. If no, please explain why this proposal wouldn't be more appropriately considered in a more generic proceeding such as the Renewed Regulatory Framework for Electricity process.

RESPONSE:

The inclusion of only a half year of depreciation in the 2013 test year additions in revenue requirement means in subsequent years, until the next rebasing, there will be only a half year of depreciation in rates but a full year of depreciation expense with respect to the capital additions. This shortfall is further compounded by increased depreciation expense on both additions during the IRM period due to assets being replaced at higher costs than was the case historically and for the costs of new assets placed into service.

This shortfall in depreciation is only partially offset by the amount of depreciation no longer required on assets being fully depreciated during the IRM period. PowerStream performed a comparison between the depreciation on additions and the depreciation on assets that become

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.2 Is the proposed level of the Depreciation/Amortization expense for 2013 appropriate? (D1)

fully depreciated in 2009 and found a short fall of $1.0 million between the depreciation required on additions and the depreciation in rates provided by fully depreciated assets. This is discussed in Exhibit I, Tab 1, Schedule 12, pages 4 to 7. The Table from that section is reproduced below.

Table Board Staff #33-1: Comparison of Depreciation Expense on 2009 Additions

	Cost	Annual Depreciation Expense
2009 Fixed Assets Additions	63,972,605.67	2,051,981.58
2009 Fully Depreciated Assets	18,179,992.00	1,051,460.32
Difference	**45,792,613.67**	**1,000,521.26**

Based on the evidence provided above, this is a serious issue for PowerStream and one that it believes should be addressed in this application. Through its work on the Renewed Regulatory Framework for Electricity Task Force, PowerStream has learned that is an issue for other distributors but cannot comment whether treatment as a generic issue is the best course of action.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.2 Is the proposed level of the Depreciation/Amortization expense for 2013 appropriate? (D1)

ENERGY PROBE INTERROGATORY #32:

Reference(s): Exhibit D1, Tab 4, Schedule 1

a) The evidence states that the half year rule was applied for 2009 and 2012 (lines 6-7 on page 1). Please confirm that the half year rule was not applied to 2010 and 2011 because the amortization expense was calculated on a monthly basis once the assets were placed into service.

b) Which amortization methodology did the rates approved for 2009 include (half year, full year, monthly, etc.)?

c) Please provide a row to Table 2 that shows the methodology applied to each year.

d) Please provide a version of Table 2 that calculates the depreciation expense for all years (and both CGAAP and MIFRS for 2011) if the depreciation expense had been calculated using the half year rule in all years.

e) Please reconcile, if required, the $1,569,000 difference in the 2013 test year noted on page 1 between the depreciation expense calculated using the full year rule and the half year rule requested in part (d) above for 2013.

RESPONSE:

a) PowerStream confirms it used the in-service date for additions when calculating depreciation for the historical years 2010 and 2011.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.2 Is the proposed level of the Depreciation/Amortization expense for 2013 appropriate? (D1)

b) The 2009 rates were based on depreciation expense estimated using an in-service assumption of six months (i.e. a half year) on average for the forecasted 2009 Test Year additions.

c) Please see the attached Table EP #32-1.

d) Please see the attached Table EP #32-2. This is provided in response to this IR. In doing so PowerStream is not proposing a change to its Application.

e) Please see Table EP #32-3 below.

Table EP #32-3: 2013 Depreciation Expense Comparison ($000)

	As filed	Additional Half Year Depreciation	Per part (d)
2013 Depreciation Expense	$37,321	$1,569	$35,752

Note:
For 2013 PowerStream applied the half year depreciation rule on new additions but also added an additional half year of depreciation as described in Exhibit D1, Tab 4 Schedule 1, page 1

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.2 Is the proposed level of the Depreciation/Amortization expense for 2013 appropriate? (D1)

SEC INTERROGATORY #38:

Reference(s): [D1/4/1, p. 2 and 3]

Please provide a table, in the format of Table 1, showing each difference in depreciation rate for an asset category or sub-category between

a) the existing Powerstream useful lives,
b) the proposed Powerstream useful lives,
c) the useful lives recommended in the study done by Kinectrics for Powerstream, and
d) the lives in the 2010 OEB study,

and an explanation of each material difference.

RESPONSE:

a) through d)

PowerStream engaged Kinectrics Inc. to carryout a component and useful life study on various infrastructure distribution assets. The terms of reference required Kinectrics to provide a brief technical report on the above mentioned subject areas and that the back-up information would be based on industry standards, operational experience, surveys and other research documents.

The report was generic in nature with technical information provided from sources in other jurisdictions both within and outside of Canada. Therefore, in most cases the Kinectrics report provided ranges of useful life.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.2 Is the proposed level of the Depreciation/Amortization expense for 2013 appropriate? (D1)

Subsequently PowerStream used the Kinectrics report as a guideline but also carried out an internal assessment to evaluate and determine an estimated average useful life of PowerStream's assets. Factors such as specific knowledge and operational experience with the distribution assets were utilized in making these determinations. As a result, in a some instances PowerStream's asset useful lives were outside the ranges provided in the Kinectrics report.

Similarly, there are a few instances where PowerStream's average useful life deviated from the ranges provided by the 2010 OEB study.

Table SEC #38-1, attached, provides the comparisons between PowerStream's existing useful lives, proposed useful lives, the Kinectrics Report for PowerStream , and the Kinectrics Report for the OEB.

Table SEC #38-2, attached, provides explanations of any material differences.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.2 Is the proposed level of the Depreciation/Amortization expense for 2013 appropriate? (D1)

SEC INTERROGATORY #39:
Reference(s): [D1/4/1, p. 4]

With respect to Table 2:

a) Please restate the column labelled "2011 Actual MIFRS" without including the cost of assets taken out of service.
b) Please explain the drop in annual depreciation for each of accounts 1815, 1820, and 1855.

RESPONSE:

a) Please see the attached Table SEC #39-1.

b) The reason for the decrease in depreciation expense between 2011 and 2012 for accounts 1815, 1820 and 1855 is due to:

- Assets that were fully amortized upon transition to IFRS (January 1, 2011) were included in depreciation expense for 2011. This is a one-time depreciation amount for certain assets that did not have any useful life remaining due to a shorter useful life under IFRS compared to CGAAP.
- Assets that became fully amortized during fiscal 2011 contributed to depreciation expense in fiscal 2011, but would not have any depreciation in future years.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.2 Is the proposed level of the Depreciation/Amortization expense for 2013 appropriate? (D1)

- These amounts were partially offset by the incremental depreciation expense in fiscal 2012 relating to additions during this period.

Please refer to Attachment Board Staff 5-2 in Exhibit J1, Tab 1, Schedule 1.0 for additional detail regarding the one-time depreciation amounts on transition to IFRS. This Exhibit is filed in response to Board Staff IR #5.

Table: EP 32-1

RATE BASE DEPRECIATION SUMMARY (000's)

PERIOD: 2009 TO 2013

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	5.88%		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	6.25%		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
		DEPRECIATION METHODOLOGY			Half Year	Monthly in-service	Monthly in-service	Monthly in-service	Half Year	Full Year

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

TABLE EP#32-2

RATE BASE DEPRECIATION SUMMARY (000's)

PERIOD: 2009 TO 2013 (Applying Half-Year Rule to 2010 CGAAP, 2011 CGAAP, and 2011 MIFRS)

CCA Class	GL account	Detail Asset Class	Depreciation Rate (1)	Notes	2009 Actual CGAAP	Restated 2010 CGAAP (Half year) (5)	Restated 2011 CGAAP (Half year) (5)	Restated 2011 MIFRS (Half year) (5)	2012 Forecast MIFRS	Restated 2013 Forecast MIFRS (4)
Distribution Assets										
47	1610	Hydro One TS - Contributed Capital	5.88%		0		16	16	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	137	143	192	196	196
47	1810	Major spare parts	0		0	0	440	0	0	0
47	1815	Transformer Stations	2.50%	2	2,393	2,713	3,099	5,003	4,299	4,128
47	1820	Distribution Stations	2.50%	2	342	1,070	1,101	2,087	1,165	1,210
47	1830	Poles, Towers & Fixtures	2.22%		4,290	5,016	5,440	2,369	2,637	2,889
47	1835	O/H Cond & Devices	2.50%		5,754	5,931	6,134	2,821	3,062	3,433
47	1840	U/G Conduit	1.67%		5,660	4,114	4,283	1,126	1,257	1,294
47	1845	U/G Cond & Devices	2.22%		11,459	12,310	12,195	5,098	5,547	6,127
47	1850	Line Transformers	2.85%	3	9,065	9,466	9,381	5,873	6,266	6,607
47	1855	Services (OH and UG)	2.86%	3	1,733	3,803	3,858	4,482	3,233	3,272
47	1860	Meters	5.00%	3	1,538	1,583	808	1,074	1,159	1,349
47	1860	Smart Meters	6.67%		1,629	3,116	3,768	3,758	3,417	3,457
		Subtotal Distribution Assets	n/a		44,719	49,259	50,664	33,899	32,270	33,994
General Plant Assets										
13	1870	Leased Property	6.25%		0	0	0	0	0	0
47	1908	Building & Fixtures - Head office	2.00%	2	560	906	482	920	939	955
13	1910	Leasehold Improvements	10.00%		310	89	0	0	0	0
8	1915	Office Equipment	10.00%		230	476	479	476	494	508
10	1920	Computer hardware	20.00%	2	1,834	1,814	1,577	1,629	1,679	1,916
12	1925	Computer Software	25.00%		2,704	2,511	4,299	2,335	2,626	2,737
10	1930	Transportation	8.33%	2	2,207	2,429	2,475	1,232	1,403	1,634
8	1935	Stores Equipment	10.00%		11	4	0	0	(0)	1
8	1940	Tools, Shop & Garage	10.00%		347	371	361	377	422	446
8	1955	Communication Equipment	22.22%	3	84	193	67	405	394	415
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0
47	1980	System Supervisory Equip	6.67%		913	1,042	1,022	1,452	963	955
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	10,260	9,770	8,826	8,919	9,566
Other Capital										
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		0	366	731	731	733	731
		Subtotal Other Capital Assets	n/a		0	366	731	731	733	731
		Total Assets Depreciation Before Contributed Capital	n/a		54,238	59,884	61,165	43,456	41,922	44,291
47	1995	Contributed Capital Amortization	varies		(9,819)	(10,372)	(11,678)	(7,444)	(8,004)	(8,539)
		NET DISTRIBUTION ASSETS DEPRECIATION	n/a		44,419	49,512	49,487	36,012	33,918	35,752
		DEPRECIATION METHODOLOGY			Half Year	Half Year	Half Year	Half Year	Half Year	Half Year

NOTES:

(1) Depreciation rates are based on PowerStream's depreciation study and implemented under MIFRS effective 2011

(2) Depreciation rate exhibited is the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(3) Based on the average depreciation rate of 2 subclass of assets within the asset group

(4) Depreciation is based on the half year rule applied to new 2013 additions. The additional half year depreciation of $ 1,569,129 which was included in the filed 2013 depreciation has been removed

(5) Depreciation has been recalulated on new additons by applying the half year depreciation rule . Powerstream had used the monthly depreciation methodology for 2010 and 2011

Table SEC#38-1 Proposed Useful Life vs. Kinetrics Report for PowerStream Comparison[1]

						PowerStream Proposed[4]		Kinectrics Study for PowerStream [2]		2010 OEB Study [3]	
Current GL	Account name	Component	New G/L	CGAAP (yrs)	Existing UL (2011) MIFRS (yrs) (a)	Proposed UL MIFRS (yrs) (b)	Variance (a)-(b)	Range / Average (yrs) (c)	Within Range (Yes/No) / Variance (a)-(c)	Range /TUL (yrs) (d)	Within Range (Yes/No) / Variance (a)-(d)
1805	Land		1805	0	0	0	0	-	n/a	-	n/a
1806	Land Rights		1806	0	0	0	0	-	n/a	-	n/a
1808	Building and Fixtures- TS and MS	Building Structure	1808	50	40	40	0	30-50	yes	40-60	yes
1810	Major Spare Parts		1810	0	0	0	0	-	n/a	-	n/a
1815	Transformer Stations	Other	1815	40	40	40	0	-	n/a	-	n/a
		Power Transformer	1816	40	40	40	0	30-55	yes	30-60	yes
		Tap Changer	1817	40	25	25	0	20-30	yes	20-60	yes
		Winding	1818	40	40	40	0	32-55	yes	30-60	yes
		230 KV Bus including Supporting Steel Structure	1819	40	40	40	0	35-100	yes	35-90	yes
		Grounding System	1821	40	40	40	0	40	0	-	n/a
		Protection and Control System TS	1822	40	20	20	0	-	n/a	10-30	yes
		SwitchGear and Relays	1823	40	30	30	0	40-60	NO	30-60	yes
		Capacitor Banks	1824	40	30	30	0	25-40	yes	-	n/a
1820	Distribution Stations	Other	1820	30	30	30	0	-	n/a	-	n/a
		Power Transformer	1826	30	40	40	0	30-55	yes	30-60	yes
		Protection and Control System	1827	30	20	20	0	-	n/a	10-30	yes
		SwitchGear and Relays	1828	30	30	30	0	40-60	NO	30-60	yes
1830	Poles, Towers & Fixtures		1830	25	45	45	0	40-50	yes	35-70	yes
1835	Overhead Cond.& Devices		1835	25	40	40	0	50-77	NO	40-65	yes
1840	Underground Conduit		1840	25	60	60	0	50	10	30-85	yes
1845	Underground Conductor & Devices		1845	25	45	45	0	20-50	yes	20-55	yes
1849	Overhead\Transformers		1849	25	40	40	0	30-40	yes	30-60	yes
1850	Underground Transformers		1850	25	30	30	0	30-40	yes	25-45	yes
1855	Overhead Services		1855	25	40	40	0	-	n/a	50-75	NO
1856	Underground Services		1856	25	25	25	0	-	n/a	30-50	NO
1860	Meters		1860	25	25	25	0	-	n/a	30-35	NO
1861	Interval Meters		1861	25	15	15	0	-	n/a	15-30	yes
1862	Smart meters		1862	15	15	15	0	-	n/a	10-15	yes
1875	Street Lighting		1875	25	25	25	0	-	n/a	-	n/a
1908	Building & Fixtures	Other	1908	50	50	50	0	-	n/a	-	n/a
		Building - Structure	1912	50	50	50	0	-	n/a	50-75	yes
		Building - Windows	1913	50	30	30	0	-	n/a	-	n/a
		Barrie Hydro building- Structural	1914	60	60	60	0	-	n/a	50-75	yes
		Barrie Hydro building- Other	1916	50	50	50	0	-	n/a	-	n/a
1910	Leasehold Improvements		1910	10	10	10	0	-	n/a	-	n/a
1915	Office Furniture & Equipment		1915	10	10	10	0	-	n/a	5-15	yes
1920	Computer hardware	Other	1920	5	5	5	0	-	n/a	-	n/a
		Desktops/Laptops	1921	5	4	4	0	-	n/a	3-5	yes
		Servers (including servers and SAN)	1922	5	5	5	0	-	n/a	-	n/a
		MFP's (including all printers)	1923	5	5	5	0	-	n/a	-	n/a

Table SEC#38-1 Proposed Useful Life vs. Kinetrics Report for PowerStream Comparison[1]

Current GL	Account name	Component	New G/L	CGAAP (yrs)	Existing UL (2011) MIFRS (yrs) (a)	PowerStream Proposed[4] Proposed UL MIFRS (yrs) (b)	PowerStream Proposed[4] Variance (a)-(b)	Kinectrics Study for PowerStream [2] Range / Average (yrs) (c)	Kinectrics Study for PowerStream [2] Within Range (Yes/No) / Variance (a)-(c)	2010 OEB Study [3] Range /TUL (yrs) (d)	2010 OEB Study [3] Within Range (Yes/No) / Variance (a)-(d)
		Switches/Routers	1924	5	6	6	0	-	n/a	-	n/a
1925	Computer Software Application		1925	3	4	4	0	-	n/a	2-5	yes
	Computer Software Operations		1926	3	3	3	0	-	n/a	2-5	yes
1930/1931	Transportation		NA	0	0	0	0	-	n/a	-	n/a
		Heavy Vehicles	1931	8	12	12	0	-	n/a	5-15	yes
		Light Vehicles	1930	5	7	7	0	-	n/a	5-10	yes
		Trailers	1932	5	22	22	0	-	n/a	5-20	NO
1935	Stores Equipment		1935	10	10	10	0	-	n/a	5-10	yes
1940	Tools, Shop & Garage		1940	10	10	10	0	-	n/a	5-10	yes
1955	Communication Equipment		1955	10	6	6	0	-	n/a	-	n/a
1956	Wireless Communication Devices		1956	3	3	3	0	-	n/a	2-10	yes
1961	Process Re-Engineering		1961	3	3	3	0	-	n/a	-	n/a
1980	System Supervisory Equip	Communication Equipment	1980	15	15	15	0	-	n/a	-	n/a
		Remote Terminal Units	1981	15	15	15	0	-	n/a	15-30	yes
		Display Wall	1982	15	10	10	0	-	n/a	-	n/a
1985	Sentinel Light		1985	10	10	10	0	-	n/a	-	n/a
2005	Property Under Capital Lease		2005	25	25	25	0	-	n/a	-	n/a
2075	Non-Utility Property Owned Equipment		2075	0	0	0	0	-	n/a	-	n/a

UL Useful Lives
TUL Typical Useful Lives
n/a Not Applicable, line items were not included in the study

Notes:

1. This table provides a summary comparison between PowerStream's existing asset useful life and i)PowerStream's proposed asset useful life; ii) Useful life ranges provided in the Kinectrics Study for PowerStream; and iii) Useful life ranges in the 2010 OEB Study. In instances where the useful life range were not provided the average / typical useful life was used.
2. The scope of the Kinectrics Study for PowerStream only provided studies on useful lives of core transmission/distribution system assets and their components.
3. The 2010 OEB Study provided useful lives by component within each asset class..
4. 4) PowerStream' s useful life components were determined by estimating the typical weighted average of the various component unit cost values to the whole unit and then further adjusting for known facts specific to PowerStream's system.

Table SEC#38-2 Asset Useful Life Variance Explanations

PowerStream Existing Useful Life vs. PowerStream Kinectrics Study

G/L	Account Description	PowerStream Existing UL (2011) MIFRS (yrs) (a)	Kinectrics Study for PowerStream MIN UL (yrs)	Kinectrics Study for PowerStream Kinectrics Average (yrs) (c)	Kinectrics Study for PowerStream MAX UL (yrs)	Within Range (Yes/No) / Variance (a)-(c)	Explanation
1823	Transformer Stations : SwitchGear and Relays	30	40	40	60	NO	A switchgear is composed mainly of breakers which have an average useful life of 40 years. PowerStream has had premature breaker failures, despite proper maintenance, and therefore it was determined that the average useful life should be reduced from 40 years to 30 years. The Kinectrics report stated 40 years as an average.
1828	Distribution Stations : SwitchGear and Relays	40	40	40	60	NO	Same as account 1823 Transformer Stations SwitchGear
1835	Overhead Cond.& Devices	40	50	60	77	NO	PowerStream's current useful life of 40 years is below the range provided by Kinectrics. However, PowerStream's engineers assessed the overheand conductors and based on past experience, weather conditions, and knowledge of the cable type determined that 40 years was appropriate. The prior CGAAP useful life was only 25 years
1840	Underground Conduit	60		50		10	Most of Powerstream's underground conduit is made of plastic or concrete pipe that houses cabling. Based on past experience and the stronger quality of material used it was determined that PowerStream's conduits are expected to last longer then the Kinectrics report of 50 years.

PowerStream Existing Useful Life vs. 2010 OEB Study

G/L	Account Description	PowerStream Existing UL (2011) MIFRS (yrs) (a)	2010 OEB Study MIN UL (yrs)	2010 OEB Study TUL (yrs) (d)	2010 OEB Study MAX UL (yrs)	Within Range (Yes/No) / Variance (a)-(d)	Explanation
1855	Overhead Services	40	50	60	75	NO	Board report has included all overhead conductor in the UL results. Therefore overhead feeder lines and secondary cable are grouped together. By experience PowerStream has determined that both OH primary conductor and and OH secondary have equivalent UL. By definition services costs are secondary cable and PowerStream defines UL as the anticipated average life of installed services. The OEB report has based its UL on an actual replacement basis where overhead cable are only replaced upon failure. Therefore the Board average UL is longer then the average expected UL which PowerStream uses.
1856	Underground Services	25	30		50	NO	Secondary PILC cables are rarely used by PS, therefore, the useful life of PILC cable is not included in the estimated weighting. Therefore the Board report range is higher as it would include all cable types used in Ontario such as PILC. In additon, PS defines service UL as being the anticipated average life of new installed services. The OEB report has based its UL on an Ontario average where overhead services are replaced only upon failure. Therefore the Board average UL is longer then the PowerStream UL
1860	Meters	25	30		35	NO	The Board report factors in CT and PT components which have a longer UL then the primary meter base. PowerStream basis its meter class UL only on the main meter component resulting in lower UL than the Board report
1932	Transportation: Trailers	22	5		20	NO	PowerStream's trailer existing UL is longer then the top range of the OEB Study. As a result of actual experience and knowledge of trailer replacements Powerstream has estimated that its trailer fleet on average will last 22 years. This UL difference is nominal and trailers comprise a small dolalr amount of the total vehicle class .

Table SEC#39-1
RATE BASE DEPRECIATION SUMMARY (000's)
PERIOD: 2009 TO 2013

CCA Class	GL account	Detail Asset Class	Depreciation Rate (1)	Notes	2009 Actual CGAAP	2010 Actual CGAAP	2011 Actual CGAAP	Filed: 2011 Actual MIFRS	2011 NBV of Fully Depreciated Assets	Restated 2011 MIFRS Without Fully Depreciated (5)	2012 Forecast MIFRS	2013 Forecast MIFRS (4)
Distribution Assets												
47	1610	Hydro One TS - Contributed Capital	5.88%		0	0	29	29		29	32	32
n/a	1805	Land	0		0	0	0	0		0	0	0
CEC	1806	Land Rights	0		1	0	0	0		0	0	0
47	1808	Building & Fixtures	2.50%		853	136	143	191		191	196	196
47	1810	Major spare parts	0		0	0	440	0		0	0	0
47	1815	Transformer Stations	2.50%	2	2,393	2,622	3,071	4,970	333	4,637	4,299	4,179
47	1820	Distribution Stations	2.50%	2	342	1,106	1,094	2,079	962	1,117	1,165	1,279
47	1830	Poles, Towers & Fixtures	2.22%		4,290	4,906	5,370	2,331		2,331	2,637	3,038
47	1835	O/H Cond & Devices	2.50%		5,754	5,813	6,057	2,776		2,776	3,062	3,669
47	1840	U/G Conduit	1.67%		5,660	4,069	4,128	1,081		1,081	1,257	1,343
47	1845	U/G Cond & Devices	2.22%		11,459	12,163	12,080	5,021		5,021	5,547	6,570
47	1850	Line Transformers	2.85%	3	9,065	9,370	9,267	5,782		5,782	6,266	6,809
47	1855	Services (OH and UG)	2.86%	3	1,733	3,798	3,852	4,469	1,346	3,123	3,233	3,339
47	1860	Meters	5.00%	3	1,538	1,461	803	1,103		1,103	1,159	1,424
47	1860	Smart Meters	6.67%		1,629	3,116	3,754	3,735		3,735	3,417	3,481
		Subtotal Distribution Assets	n/a		44,719	48,561	50,088	33,566	2,641	30,925	32,270	35,359
General Plant Assets												
13	1870	Leased Property	6.25%		0	0	0	0		0	0	0
47	1908	Building & Fixtures - Head office	2.00%	2	560	919	481	919		919	939	958
13	1910	Leasehold Improvements	10.00%		310	89	0	0		0	0	0
8	1915	Office Equipment	10.00%		230	476	477	473		473	494	510
10	1920	Computer hardware	20.00%	2	1,834	1,791	1,520	1,568	81	1,487	1,679	2,114
12	1925	Computer Software	25.00%		2,704	2,383	4,055	2,137	1	2,136	2,626	2,737
10	1930	Transportation	8.33%	2	2,207	2,424	2,531	1,267		1,267	1,403	1,806
8	1935	Stores Equipment	10.00%		11	4	(0)	(0)		(0)	(0)	1
8	1940	Tools, Shop & Garage	10.00%		347	363	356	371		371	422	472
8	1955	Communication Equipment	22.22%	3	84	193	212	398	50	348	394	420
8	1960	Miscellaneous equipment	10.00%		0	0	0	0		0	0	0
47	1980	System Supervisory Equip	6.67%		913	1,034	1,022	1,452	446	1,006	963	975
47	1990	Other Tangible property	20.00%		0	0	0	0		0	0	0
12	1961	Process Re-engineering	33.33%		319	424	(991)	0		0	0	0
		Subtotal General Plant Assets	n/a		9,519	10,100	9,663	8,584	578	8,006	8,919	9,994
Other Capital												
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		0	731	731	731		731	733	731
		Subtotal Other Capital Assets	n/a		0	731	731	731	0	731	733	731
		Total Assets Depreciation Before Contributed Capital	n/a		54,238	59,392	60,482	42,882	3,219	39,663	41,922	46,084
47	1995	Contributed Capital Amortization	varies		(9,819)	(10,630)	(11,839)	(7,383)	0	(7,383)	(8,004)	(8,763)
		NET DISTRIBUTION ASSETS DEPRECIATION	n/a		44,419	48,762	48,643	35,499	3,219	32,280	33,918	37,321
		DEPRECIATION METHODOLOGY			Half Year	Monthly in-service	Monthly in-service	Monthly in-service	n/a	Monthly in-service	Half Year	Full Year

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
(5) The 2011 NBV of Fully Depreciated Assets represents the NBV at December 31, 2010 of assets that became fully depreciated on transition to IFRS on January 1, 2011
and has been included in 2011 MIFRS depreciation expense..

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.3 Is the Test Year 2013 forecast of PILs appropriate? (D2)

Energy Probe INTERROGATORY #33:

Reference(s): Exhibit D2, Tab 1, Schedule 1

Please update Table 2 to reflect the most current rates approved to be in place for 2012 and 2013.

RESPONSE:

Table EP #33-1 reflects the current legislated tax rates for 2012 and 2013 applicable to PowerStream.

Table EP#33-1: 2012 and 2013 Tax Rates

Income Tax Rates	2011 Historical Year	2012 Bridge Year	2013 Test Year
Federal income tax			
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%	11.50%	11.50%
Combined Federal and Ontario Income Tax Rate	28.25%	26.50%	26.50%

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.3 Is the Test Year 2013 forecast of PILs appropriate? (D2)

Energy Probe INTERROGATORY #34:

Reference(s): Exhibit D2, Tab 1, Schedule 2

a) Do the tax credits shown in Tables 1 & 2 for 2011 correspond to the actual tax credits claimed in the 2011 tax filing? If not, please update Tables 1 & 2 to reflect actual tax credits claimed in the 2011 tax filing.

b) Please show the number of positions eligible for the Ontario apprenticeship training tax credit in each of 2010, 2011, 2012 and 2013 and show the calculation of the credits shown in Table 2 for 2012 and 2013.

c) Please show the number of positions eligible for the co-op credits in each of 2010, 2011, 2012 and 2013 and show the calculation of the credits shown in Table 2 for 2012 and 2013.

d) Please expand Tables 1 and 2 to include data for 2010.

e) Please file the 2011 tax return.

f) Please explain why there are no federal job creation tax credits included in the forecast. Please provide the number of positions eligible for this tax credit in 2013.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.3 Is the Test Year 2013 forecast of PILs appropriate? (D2)

RESPONSE:

a) Due to the timing of the rate application the amounts in Table 1 and 2 were taken from the tax working papers prepared during the year end but before finalization of the 2011 tax filing. The tables below have been updated to include the actual 2011 tax return amounts.

Table EP #34-1: Summary of Tax Credits Updated

	2010 Historical Year	2011 Historical Year	2012 Bridge Year	2013 Test Year
Investment Tax Credits	$ 605,688	$ 601,332	$ 473,100	$ 473,100
Miscellaneous Tax Credits	$ 238,572	$ 227,277	$ 227,000	$ 227,000
Total Tax Credits	**$ 844,260**	**$ 828,609**	**$ 700,100**	**$ 700,100**

Table EP#34-2: Miscellaneous Tax Credits

	2010 Historical Year	2011 Historical Year	2012 Bridge Year	2013 Test Year
Apprenticeship credits	$ 137,315	$ 111,672	$ 120,000	$ 120,000
Co-op credits	$ 83,862	$ 100,039	$ 90,000	$ 90,000
Other miscellaneous credits	$ 17,395	$ 15,566	$ 17,000	$ 17,000
Total Tax Credits	**$ 238,572**	**$ 227,277**	**$ 227,000**	**$ 227,000**

On the basis of the updated 2011 actual tax return, PowerStream has also updated the forecasted tax credits for 2012 and 2013.

b) The table below shows the actual number of Co-op and Apprenticeship positions for 2010 and 2011 and the projected number for 2012 and 2013. The credits for 2012 and 2013 were

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.3 Is the Test Year 2013 forecast of PILs appropriate? (D2)

estimated based on the trend in dollars rather than the number of positions as the amounts can differ for each person.

Table EP#34-3: Co-op & Apprenticeship Positions

	2010 Historical Year	2011 Historical Year	2012 Bridge Year	2013 Test Year
Number of apprenticeship positions *	19	24	20	20
Number of co-op positions *	30	40	34	34

c) Please see the response to part (b) above.

d) Please see the response to part (a) above.

e) Please see the response to Board Staff IR#5 filed at Exhibit J1, Tab 1, Schedule 1.0.

f) PowerStream has not claimed any federal job creation tax credits so this was not included in the forecast. In discussion with our tax advisors, they estimate that this would reduce 2013 taxes payable by about $17,000.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.3 Is the Test Year 2013 forecast of PILs appropriate? (D2)

Energy Probe INTERROGATORY #35:

Reference(s): Exhibit D2, Tab 1, Schedule 3

Please explain why the PILs/Income Taxes Work Form is labelled as PowerStream Inc. - South. Please confirm that the tax calculations are for the merged entity.

RESPONSE:

The PILs/Income Tax form only allowed the name to be selected from a drop down list. This was the closest match. PowerStream confirms that the tax calculations are for the merged entity.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.3 Is the Test Year 2013 forecast of PILs appropriate? (D2)

Energy Probe INTERROGATORY #36:

Reference(s): Exhibit D2, Tab 1, Schedule 3

a) Please update the CCA schedules for the historical bridge and test years to reflect the actual 2011 CCA schedule for the historical year if this is not already reflected in the historical year data shown in Schedule 8. Please calculate the resulting impact on the test year tax calculation.

b) Please update the 2011, 2012 and 2013 cumulative eligible capital schedules to reflect actual data for 2011 if this is not already reflected in the historical year data shown in Schedule 8. Please calculate the resulting impact on the test year tax calculation.

RESPONSE:

a) PowerStream has updated the PILs,/Income Taxes Work form (PILs model) with the actual amounts from the 2011 tax return. Both of these documents have been filed in response to Board Staff IR#5 filed at Exhibit J1, Tab 1, Schedule 1.0 . PowerStream has not attempted to quantify the impact of only this change on the test year tax calculation. The revised PILs model contains all changes from updating with 2011 actual tax amounts as well as the changes noted in the response to Staff IR#4 filed at Exhibit J1, Tab 1, Schedule 1.0 and EP#34(a) filed at Exhibit J1, Tab 1, Schedule 4.3.

b) There was no change in the cumulative eligible capital schedules for 2011 from the application as filed.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.3 Is the Test Year 2013 forecast of PILs appropriate? (D2)

Energy Probe INTERROGATORY #37:

Reference(s): Exhibit D2, Tab 1, Schedule 3 &
Exhibit B1, Tab 2, Schedule 5

a) Please reconcile the CCA additions for the bridge year shown in Schedule 8 CCA - Bridge Year of Exhibit D2, Tab 1, Schedule 3 of $69,066,620 with the additions of $70,293,000 shown in the 2012 fixed asset continuity schedule in Exhibit B1, Tab 2, Schedule 5.

b) Please reconcile the CCA additions for the test year shown in Schedule 8 CCA - Test Year of Exhibit D2, Tab 1, Schedule 3 of $82,486,620 with the additions of $84,702,000 shown in the 2013 fixed asset continuity schedule in Exhibit B1, Tab 2, Schedule 5.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.3 Is the Test Year 2013 forecast of PILs appropriate? (D2)

RESPONSE:

a) and b) Please refer to Tables EP #37-1 and EP #37-2 below.

Table EP #37-1: CCA Additions - 2012

2012				
CCA Class	**Gross Additions**	**Less: interest Cap**	**SR&ED Deductions**	**Net Capital Additions**
CEC	$ 39,000			$ 39,000
1	$ 1,519,000			$ 1,519,000
8	$ 2,772,000			$ 2,772,000
10	$ 1,958,000			$ 1,958,000
12	$ 1,243,000			$ 1,243,000
13	$ -			$ -
47	$ 59,004,000	$ 330,000	$ 904,600	$ 57,769,400
50	$ 3,758,000			$ 3,758,000
Totals	$ 70,293,000	$ 330,000		$ 69,058,400
			(excluding CEC)	$ 69,019,400

Table EP#37-2: CCA Additions - 2013

2013				
CCA Class	**Gross Additions**	**Less: interest Cap**		**Net Capital Additions**
CEC	$ 41,000			$ 41,000
1	$ 299,000			$ 299,000
8	$ 1,973,000			$ 1,973,000
10	$ 2,893,000			$ 2,893,000
12	$ 4,405,000			$ 4,405,000
13	$ -			$ -
47	$ 73,077,000	$ 1,317,000	$ 904,600	$ 70,855,400
50	$ 2,014,000	$ -		$ 2,014,000
Totals	$ 84,702,000	$ 1,317,000		$ 82,480,400
			(excluding CEC)	$ 82,439,400

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

BOARD STAFF INTERROGATORY #34:

Reference(s): <u>App. 1/S 21/App. 2-L</u>

Appendix 2-L states that for services provided to PowerStream by the City of Vaughan and the Town of Markham that the pricing methodology is "Fully allocated costs w. markup."

a) Please state how the markup for these services is determined and what basis PowerStream has for believing that these costs are reasonable.
b) Please discuss whether or not PowerStream has considered alternative providers for these services. If yes, please state why such providers were not used. If not, please explain why not.

RESPONSE:

a) PowerStream charges the City of Vaughan and the Town of Markham a markup on the services that are provided. Appendix 2-L inadvertently indicates that the reverse is true. The City of Vaughan and the Town of Markham charge PowerStream their costs without a mark-up.

   Prior to occupying the new Head Office, PowerStream leased space from the City of Vaughan in their Joint Operations Centre. At that time, PowerStream was satisfied that the lease cost was reflective of market prices. As indicated in Table 1 in Exhibit A4, Tab 1, Schedule 1, the lease cost for 2013 is $10,758 reflecting that PowerStream uses only a small area of outdoor storage space.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

PowerStream also "groups" JDE Edwards software licences with those of the City of Vaughan in order to get a volume discount from the City's licences.

The cashiering services provided by the Town of Markham (and as defined in the Service Level Agreement) are considered reasonable since PowerStream can reference its own costs for this type of service.

b) PowerStream has not considered alternative providers. As noted in the response to 34a) above, the space from the City of Vaughan is becoming quite small. Also, by combining software licences with the requirements of Vaughan, a pricing discount is achieved.

The cashiering services provided by the Town of Markham to PowerStream are at the Markham Town Centre. This location is a convenient, centralized location and customers may have other business besides electricity, water and sewer billing issues.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

BOARD STAFF INTERROGATORY #35:

Reference(s): <u>App. 1/S 21/App. 2-L</u>

Appendix 2-L states that for services provided by PowerStream to PowerStream Solar, the pricing methodology for such services is "Allocated based on the % time spent," or similar indicators.

Please state why for the provision of these services, PowerStream does not include a weighted cost of capital markup, as is the case for services provided to PowerStream's municipal owners.

RESPONSE:

In designing the Service Level Agreement for PowerStream's solar business, PowerStream followed the methodology of "full cost allocation", as prescribed in Article 340 of the Accounting Procedures Handbook and in the Board's *"Guidelines: Regulatory and Accounting Treatments for Distributor-owned Generation Facilities"*, September 15, 2009. These documents provide guidelines for the proper cost allocation methods for non-rate regulated activities, which shall not result in cross-subsidies between regulated and non-regulated activities. Introducing mark-up to this calculation would not be in compliance with those guidelines.

PowerStream Solar is business unit and is not an affiliate of PowerStream. It is, therefore, not subject to ARC, which regulates the relationships between utilities and affiliates and requires the transfer price to include the mark-up and be comparable to the market prices, where a market exists.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

BOARD STAFF INTERROGATORY #36:

Reference(s): <u>A4/T1/S2</u>

A copy of the shared services agreement between PowerStream and the City of Vaughan is provided, which although it is effective January 1, 2011 has not been executed.

Please state why this agreement has not been executed and when it is expected that it will be.

RESPONSE:

The agreement was executed after PowerStream filed its rate application. A copy is attached as Appendix B to this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

BOARD STAFF INTERROGATORY #37:

Reference(s): A4/T1/S4

A copy of the shared services agreement between PowerStream and the Town of Bradford West Gwillimbury is provided, which although it is effective December 1, 2009 has not been executed.

Please state why this agreement has not been executed and when it is expected that it will be.

RESPONSE:

The agreement was executed after PowerStream filed its rate application. A copy is attached as Appendix C to this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

BOARD STAFF INTERROGATORY #38:

Reference(s): <u>D1/T5/S4/p.3</u>

It is stated that:

"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."

However, Table 1 does not appear to show the corresponding growth in PowerStream's customer base over the same period.

Please provide this information, or clarify the referenced statement.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

RESPONSE:

Please find below a revised Table 1 updated to include PowerStream's customer count:

Table Board Staff #38: Revised 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%**
Customer Growth	**2009**	**2010**	**2011**	**2012 Projected**	**2013 Projected**
Number of customers	320,869	328,589	335,823	343,073	350,324
Increase %		2.4%	2.2%	2.2%	2.1%
Cumulative Increase%		2.4%	4.7%	6.9%	9.2%

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

CCC INTERROGATORY #44:

Reference(s): (A4/T1/S1/p. 1)

The evidence states that although none of the shareholders owns more than 50% of PowerStream and are therefore not affiliates as contemplated by the ARC, PowerStream follows the intent of the ARC by ensuring that there are no cross-subsidies. Please explain how PowerStream "follows the intent of the ARC".

RESPONSE:

PowerStream follows the intent of the ARC by ensuring that the pricing of services is established such that there is no cross subsidization between PowerStream, the City of Vaughan, the Town of Markham or the Town of Bradford West Gwillimbury. There is a mark-up on services.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

CCC INTERROGATORY #45:

Reference(s): (A4/T1/S1/p. 1)

Please explain how PowerStream allocates the costs between it and the City of Vaughan for the JD Edwards Enterprise Software.

RESPONSE:

The cost of JDE Edwards licences is incurred by the City of Vaughan and allocated and charged to PowerStream. By grouping licence requirements with The City of Vaughan, PowerStream and the City both benefit from a volume discount. PowerStream pays the City of Vaughan based on the number of PowerStream licences.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

CCC INTERROGATORY #46:

Reference(s): (A4/T1/S1/p. 3)

Please explain how the payments made to PowerStream by the City of Vaughan for Water and Sewer, Payroll and Cashier Services were all determined. How does PowerStream fairly negotiate these amounts with its shareholders? How are these revenues accounted for in the revenue requirement?

RESPONSE:

Amounts to perform the services are identified as either specifically directly identifiable to Vaughan or shared costs amongst many different departments. Those specifically directly identifiable are fully included in the pricing while those that are shared costs are allocated based on appropriate drivers.

PowerStream and City of Vaughan staff met and reviewed the amounts and allocation methods. Discussion and negotiation between the parties involving these factors resulted in the agreed pricing. Vaughan and Markham staff also meet to discuss pricing to ensure that it is aligned.

These revenues are recorded in account 4375 “Revenues from non-rate regulated utility operations” and have been excluded from the calculation of revenue requirement.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

CCC INTERROGATORY #47:

Reference(s): (A4/T1/S1.p. 5)

Please explain how the payments made to PowerStream by the Town of Markham for Water and Sewer and Street Lighting Services were determined. How does PowerStream fairly negotiate these amounts with its shareholders? How are these revenues accounted for in the revenue requirement?

RESPONSE:

The payment made to PowerStream by the Town of Markham for water and sewer services are determined by the same process as described in the response to IR #46, above

PowerStream provides street light services to the Town of Markham through a third party contract. The Town is charged the actual plus an administration fee.

These revenues are recorded in account 4375 “Revenues from non-rate regulated utility operations” and have been excluded from the calculation of revenue requirement”.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

CCC INTERROGATORY #48:

Reference(s): (A4/T1/S1/p. 5)

What is the impact on the 2013 revenue requirement of eliminating the services PowerStream used to provide to the City of Barrie and Barrie Hydro Energy Services? Does Barrie Hydro Energy Services still exist? If so, what is its relationship with PowerStream?

RESPONSE:

If PowerStream continued to provide those services, both costs and revenues would be recorded in “non-utility” accounts and would not be included in the revenue requirement calculation. Since these services were eliminated in 2011, PowerStream did not budget for those revenues in 2013. The fixed costs of providing the service in 2013 are forecast to be approximately $420,000. This amount represents the portion of fixed costs that that was previously allocated to Barrie water service and paid by the City of Barrie. Those costs include a portion of postage and meter reading costs, as well as allocation of billing system related costs. Consequently, if those services were not eliminated, PowerStream’s revenue requirement would be lower by about $420,000.

Barrie Hydro Energy Services Inc. is owned by the City of Barrie. PowerStream has no further relationship with that entity.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

CCC INTERROGATORY #49:

Reference(s): (A4/T1/S1/p. 6)

Please explain how the payments made to PowerStream by the Town of Bradford West Gwillimbury for water and sewer services are determined.

RESPONSE:

The payment made to PowerStream by the Town of Bradford West Gwillumbury for water and sewer services are determined by the same process as described in the response to CCC IR #46, above.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

CCC INTERROGATORY #50:

Reference(s): (A4/T1/S1)

Has PowerStream ever obtained an independent assessment or audit of its shared services and corporate costs. If so, please provide copies of the independent assessment or audit. If not, why not? If not, how can ratepayers be assured that the payments are justified?

RESPONSE:

PowerStream has not obtained an independent assessment or audit of its shared services and corporate costs. Staff at PowerStream have exercised due diligence to ensure the fees are appropriate.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

CCC INTERROGATORY #51:

Reference(s): (C2/T1/S4/p. 1)

Please list all of the functions performed within the distribution company for CDM, and the costs of those activities. Please provide evidence to support the statement that these activities are not included in the revenue requirement. What is the methodology used to attribute and track these costs in the non-distribution accounts?

RESPONSE:

Please see table below for a listing of all functions performed within the distribution company for CDM as well as the associated costs for the 2013 Test Year.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

Table CCC #51: 2013 CDM Activities

CDM Shared Services	2013 Budget	
Director's Insurance	$	3,839
Vehicle Lease		7,608
IT Resources		72,504
Office Space		104,833
Office Supplies		4,698
Fleet Maintenance		2,796
Executive Support		16,017
Legal Support		4,672
HR Resources		1,321
Accounting & Payroll		5,004
Financial Services		871
Purchasing & Stores		1,217
Communications		108,459
Rates & Regulatory Affairs		113,465
Total Shared Services	$	447,305

These shared service costs are credited against OM&A costs prior to the calculation of the 2013 revenue requirement. The credit is recorded in Account 5620.
New non – distribution accounts were set up to track these costs, using a fully allocated costing methodology in accordance with the Board's CDM Code issued on September 16, 2010.

Dependent on activities, varying methods were used to allocate costs from the distribution core business to CDM, such as square footage of office space, number of PCs and estimates of staff time that will be utilized.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

CCC INTERROGATORY #52:

Reference(s): (D3/T1/S1/p. 3)

Please provide the SLA between PowerStream and PowerStream solar applicable to the test year.

RESPONSE:

The SLA between PowerStream and PowerStream Solar for the Test Year has not yet been finalized. Amounts forecast for 2012 and 2013 are underpinned by and based on the 2011 SLA, adjusted for known increases.

The 2011 SLA is attached as Appendix A.

Table CCC #52: PowerStream Solar 2012 and 2013 Forecast Shared Services Costs

	2011 SLA	2012 Forecast in Rate Application	2013 Forecast in Rate Application
Cost of Shared services - Solar	$370,032	$391,400	$403,142

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

ENERGY PROBE INTERROGATORY #38:

Reference(s): Exhibit A4, Tab 1, Schedule 1

a) Please explain the reduction in the services provided to the Town of Markham for street lighting services shown in Table 4 for 2012 and 2013 as compared to 2011.

b) Please show the most recent year-to-date figures available for 2012, along with the figures for the corresponding period in 2011 for each line item shown in each of the tables shown in Schedule 1.

c) Please quantify the reduction in costs that have been reflected in 2012 and 2013 as a result of the services that were provided to the City of Barrie until the end of 2011. Please indicate how this reduction has been incorporated into the forecast for the bridge and test years.

d) Please provide the revenues and costs associated with the services provided to the City of Barrie for each of 2009 through 2011.

e) Are the figures shown in Table 5 the costs of providing the services or the revenues associated with the provision of the services? If the former, please provide the revenues associated with the provision of the services.

f) Please explain how the costs and revenues associated with the shared services are accounted for in the calculation of the revenue requirement. For example, where are the revenues shown in the rates application, and where are the corresponding costs shown in the rates application?

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

RESPONSE:

a) Please see the response to SEC IR#41 filed in this Exhibit.

b) For all services except street lighting, monthly charges are based on one-twelfth of the yearly total. The amounts charged to the end of June are shown in the table below.

Table EP #38b: Charges to End of June for 2011 and 2012 ($)

To City of Vaughan	**June 2011 YTD**	**June 2012 YTD**
Water and Sewer	573,500	590,705
Payroll	167,465	172,489
Cashier	121,445	125,088
To Town of Markham		
Water and Sewer	568,431	585,086
To Bradford West Gwillimbury		
Water and Sewer	80,000	65,000

Note that in the executed Service Level Agreement filed in the response to Board Staff IR#37, the 2012 price for water and sewer services was reduced to $130,000 (from $160,000)

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

because the town had adopted a lower cost automated meter reading infrastructure. The best estimate for 2013 pricing is $135,000.

For Markham street lighting, billing of the costs has occurred up to May 31, 2012, an amount of $833,195. The May 31, 2011 amount was $489,302.

c) As a result of the City of Barrie assuming responsibility for water and sewer services, PowerStream staff supporting these services for the City of Barrie were redeployed to emerging areas such as FIT/MicroFIT billing requirements, management of MDM/R exceptions and system upgrades, new arrears and account management activities. Had the Barrie engagement continued, PowerStream would have required additional resources to do this work

d) For 2009, the first year after the merger of Barrie Hydro and PowerStream, fees to the City of Barrie continued to be per the former Barrie Hydro methodology of price per billed customer and was based on Barrie Hydro costs only. For 2010 the pricing to the City of Barrie was set at $1,000,000. For 2011 the fees charged to the City of Barrie were $627,012. This represented fees for a partial year, as meter reading fees declined as the City of Barrie assumed more readings throughout the year, billing fees stopped after September, and payment and collection fees declined through the remainder of the year as activities performed for the City of Barrie were completed.

e) Table 5 represents the revenues associated with the provision of the services.

f) These transactions are recorded in non-utility accounts and therefore do not form part of the revenue requirement as calculated in the pre-filed evidence.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

ENERGY PROBE INTERROGATORY #39:

Reference(s): Exhibit A4, Tab 1, Schedule 2

a) Please provide an executed copy of the Shared Services Agreement between PowerStream and the City of Vaughn.

b) How was the 3% escalatory noted in Schedules A through E arrived at?

RESPONSE:

a) Please see response to Board Staff IR #36, filed in this Exhibit.

b) This was a mutually agreed upon inflationary factor by the parties. The main factor from PowerStream's perspective was the 3% increase in PowerStream's labour contract. Establishing a multi-year agreement also allows PowerStream to continue to earn a return on the provision of these services as well as allocate fixed costs and have the certainty of having these contracts in place for a longer time period so that PowerStream can do appropriate resource planning.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

ENERGY PROBE INTERROGATORY #40:

Reference(s): Exhibit A4, Tab 1, Schedule 4

Please provide an executed copy of the Shared Services Agreement between PowerStream and the Town of Bradbury West Gwillimbury.

RESPONSE:

Please see the response to Board Staff IR#37, filed in this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

SEC INTERROGATORY #40:

Reference(s): [A2/1/1/p.7]

Please outline the costs related to the 'increased asset inspections and testing'.

RESPONSE:

Below is the outline of the costs as discussed in Exhibit D1, Tab 1, Schedule 1, pages 5 – 6:

- cable failures, $939,000
- cable condition testing, $361,000
- storm damage and non recoverable accidents and vandalism, $454,000
- soil remediation around stations, $797,000
- building maintenance and security, $413,000

The term "asset inspections and testing" in Exhibit A2, Tab 1, Schedule 1, page 7, line 1 is one component of "asset maintenance", which is the broader cost category referenced in the cost driver table on page 3 and explained on page 5 of Exhibit D1, Tab 1, Schedule 1.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

SEC INTERROGATORY #41:

Reference(s): [A4/1/1/p.5]

Please explain the reduction in services provided to the Town of Markham as shown in Table 4.

RESPONSE:

There is no reduction in services. The water and sewer charges are lower from 2011 to 2013 as compared to 2009 as the pricing reflects an update to PowerStream's costing. The $1,000,000 amounts for street lighting for 2011 and 2012 are estimates. Markham is billed the actual amount plus a management fee. It can be seen from Table 4 that the actual amount varies over the years 2009 to 2011.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.4 Is the proposed allocation of shared services and corporate costs appropriate? (A4)

SEC INTERROGATORY #42:

Reference(s): [D1/1/1/p.3]

Please advise if the costs related to the new Outage Management System/SCADA are included in Table 2.

RESPONSE:

Yes, the costs related to the Outage Management System / SCADA are included in Table 2 as part of the Asset Management increase of $3,539,000. The portion for OMS / SCADA is $375,000, as discussed on page 6 in Exhibit D1, Tab 1, Schedule 1.

THIS SERVICE LEVEL AGREEMENT made as of January 1, 2010 (the **"Effective Date"**)

BETWEEN:

POWERSTREAM INC. ("PowerStream")

and

SOLAR PV DIVISION ("Solar")

WHEREAS, Solar is carrying on non-distribution activities related to the installation and ongoing monitoring and maintenance of solar panels on roof-tops in the Province of Ontario;

AND WHEREAS, Solar desires PowerStream to provide the Shared Services (as defined herein) to it and PowerStream wishes to provide the Shared Services, in the manner set forth herein.

NOW THEREFORE in consideration of the mutual covenants and agreements herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, PowerStream and Solar (the **"Parties"**) agree as follows:

1. PURPOSE

The purpose of this Agreement is to: (i) describe the Shared Services to be provided by PowerStream to Solar; (ii) the charges to be made to Solar for such Shared Services; and, (iii) the working relationship between PowerStream and Solar relating to such Shared Services.

2. INTERPRETATION

2.1 As used in this Agreement, the following terms shall have the following meanings:

"Agreement" means this Service Level Agreement for Shared Services including any attached schedules and appendices, all of which may be amended from time to time.

"Fully Allocated Costing Methodology for Non-Rate Regulated Activities" or **"Full Cost Allocation Methodology"** has the meaning set out in Ontario Energy Board Guideline G-2009-0300 (Regulatory and Accounting Treatment for Distributor-Owned Generation Facilities), as may be amended from time to time.

"Term" shall have the meaning set out in Section 3.1.

"**Parties**" means PowerStream and Solar collectively, and **"Party"** means any one of them.

"Representatives" means any employee, agent, or subcontractor of the Party in question, including without limitation any third party retained to perform any or all of the Shared Services pursuant to Section 4.1 of this Agreement.

"Shared Services" shall have the meaning set out in Section 4.1.

2.2 Unless the context of this Agreement requires otherwise, the singular shall include the plural and vice versa and any gender includes any other gender.

2.3 The following Schedules are attached to and form part of this Agreement:

SCHEDULE	SERVICE AREA
Schedule 1	Corporate Services
Schedule 2	Finance
Schedule 3	Information Services
Schedule 4	Facilities and Procurement

3. TERM AND TERMINATION

3.1 This Agreement will commence as of January 1, 2010 and will remain in effect until terminated by either Party, in whole or in part, upon no less than thirty (30) days' written notice to the other Party, or such other period of time as may be agreed to between the Parties ("**Term**").

3.2 In the event of default in performance of any material covenant in this Agreement, the non-defaulting Party shall be entitled to terminate this Agreement whether in whole or in part on no less than fourteen (14) days prior written notice to the defaulting Party. Any partial termination of this Agreement shall be evidenced by a written agreement as between the Parties specifying the specific Shared Services to be terminated, and the adjustment in Transfer Price pursuant to such partial termination.

4. SHARED SERVICES

4.1 Subject to Section 4.5 of this Agreement, PowerStream shall provide Solar with the services listed in Schedules "1" through "4" hereto and any additional services required by Solar from time to time (collectively, the "**Shared Services**"). Any additional Shared Services required by Solar shall be provided by PowerStream at mutually agreed upon terms, conditions and in accordance with the Transfer Prices.

4.2 PowerStream shall provide the Shared Services at service levels which are mutually acceptable to the Parties, and such service levels shall be reviewed from time to time by the Parties.

4.3 Subject to Sections 4.4 and 4.5 hereof, PowerStream shall have the right, in its sole discretion, to contract with a third party to deliver all or part of the Shared Services, provided however that such third party shall be capable of providing such Shared Services to the same or better quality levels than those set forth in Section 4.2. The Parties agree that PowerStream shall be acting as the agent of Solar in procuring the delivery of such Shared Services.

~~4.4 Where PowerStream has contracted with a third party to provide part or all of the~~ Shared Services pursuant to Section 4.3 above, Solar shall pay the amount charged by such third party for the portion of the Shared Services delivered.

4.5 ~~This Agreement shall be deemed to be an exclusive service agreement as between PowerStream and Solar, and Solar shall not have the right to provide itself, or retain a third party to provide, any of the Shared Services unless agreed to by PowerStream.~~

4.6 No employee shall be shared between PowerStream and Solar; provided that an employee may be transferred or seconded from PowerStream to Solar or from Solar to PowerStream with the prior written approval of a Manager, Director or Vice-President of the relevant departments of PowerStream and Solar. Such approval shall set forth the terms and conditions of such transfer including all appropriate measures required to preserve the confidentiality of customer information. When on a secondment or transfer, the employee will not provide any services whatsoever to the original company during the period of secondment or transfer.

4.7 PowerStream shall bear all costs incurred, and all risk involved in delivering the Shared Services to Solar.

5. TRANSFER PRICING

5.1 All Shared Services provided by PowerStream or its Representatives will be charged to Solar at the transfer prices determined in accordance with Full Cost Allocation Methodology as set out in the attached Schedules (the "**Transfer Price**" or "**Transfer Prices**", collectively). The Transfer Prices do not include GST or any other taxes payable in respect of the Transfer Price, which Solar shall also pay to PowerStream.

5.2 The Parties hereby agree and acknowledge that they shall renegotiate the Shared Services and Transfer Prices described in Schedules hereto at such times as necessary.

5.3 In accordance with Schedules "1" through "4" PowerStream shall allocate to Solar the costs attributable on a monthly basis or such other period of time agreed to between the Parties.

5.4 Solar shall, no later than (45) forty-five days after receipt of a PowerStream invoice, or if such day is not a business day, the immediately preceding business day, render to PowerStream, by any acceptable method agreed to by the Parties, the amount due PowerStream as set forth in the invoice. This Section 5.4 shall survive any termination of this Agreement or the expiry of the Term for a period of twelve (12) months from the date on which the last invoice is rendered to Solar pursuant to this Agreement.

6. NOTICES AND CONTACTS

6.1 Any notice or communication required as between the Parties pursuant to this Agreement shall be delivered to the following individuals, or to such other individual as either Party may stipulate by notice to the other:

For POWERSTREAM:	John Glicksman Executive Vice-President and Chief Financial Officer
For Solar:	Milan Bolkovic Executive Vice-President, Renewable Generation and Conservation

7. AMENDMENTS

7.1 If at any time during the term of this Agreement the Parties deem it necessary or expedient to make any alteration or addition to this Agreement, they may do so by means of a written agreement between them which shall be supplemental and form part of this Agreement.

8. FURTHER ASSURANCES

8.1 The Parties agree that each of them shall, upon reasonable request of the other, do or cause to be done all further lawful acts, deeds and assurances whatever for the better performance of the terms and conditions of this Agreement.

9. SUCCESSORS AND ASSIGNS

9.1 This Agreement shall enure to the benefit of and be binding upon the respective successors and permitted assigns of the Parties, provided however that neither Party may assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld.

10. SEVERABILITY

10.1 If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision and everything else in this Agreement shall continue in full force and effect.

11. COUNTERPARTS

11.1 This Agreement may be executed by the Parties in separate counterparts, each of which when so executed and delivered shall be an original, but all counterparts shall together constitute one and the same instrument.

12. DISPUTE RESOLUTION

12.1 The Parties will use their commercially reasonable efforts to resolve, at an operational level, any disputes which may arise concerning this Agreement. Any issues which remain unresolved for more than fifteen (15) days will be referred to the respective Executive-Vice Presidents of each of the Parties. The parties agree to use their commercially reasonable efforts to resolve all disputes in a timely and professional manner utilizing a process appropriate to the issues involved.

13. CONFIDENTIALITY

13.1 Each party agrees not to disclose any Confidential Information to any person except those of its Representatives who have a need to know such Confidential Information in connection with this Agreement and who are informed of the confidential nature of the Confidential Information and who agree to be bound by the terms of this Section 13.1. The Recipient will not use any Confidential Information relating to the Disclosing Party for any purpose other than in connection with the performance of its obligations, or exercise of its rights, under this Agreement, and will exercise the same security measures normally exercised with respect to its own Confidential Information, and at a minimum a reasonable degree of care, to safeguard the Confidential Information from disclosure to anyone other than as permitted hereby. The provisions of this Section 13.1 shall survive termination of this Agreement. "**Confidential Information**" means all information, whether disclosed orally, in writing, or otherwise, designated as being confidential, which is disclosed by one party (the "**Disclosing Party**") to the other party (the "**Recipient**") relating to the business of the Disclosing Party or in connection with the subject matter of this Agreement and includes, but is not limited to, business, financial, and marketing information, plans and strategies, contractual, customer information, including for the avoidance of doubt such customer's personal information, supplier information, technical information related to hardware, software and firmware, and know-how, trade secrets and any other intellectual property rights, and the terms of this Agreement. Notwithstanding the foregoing, Confidential Information shall not include information which (i) now is, or hereafter properly becomes, generally available to the public other than as a result of disclosure in breach of this Agreement; (ii) is required to be disclosed in compliance with any applicable law, under order of a court of competent jurisdiction or other similar requirement of a governmental agency, so long as the Recipient provides the Disclosing Party with prior written notice of any required disclosure pursuant to such law, order or requirement and cooperates, to the extent permitted by law with the Disclosing Party in seeking an order eliminating or restricting the disclosure or a protective order or otherwise ensuring the confidential treatment of the Confidential Information; (iii) is disclosed with the prior written approval of an authorized officer of the Disclosing Party; (iv) is previously known to the Recipient at the time of disclosure; (v) is discovered by the Recipient without reference to the Confidential Information of the Disclosing Party; or (vi) is lawfully obtained from a third party which was not bound by a confidentiality agreement respecting the disclosure.

[REMAINDER OF PAGE LEFT INTENTIONALLY BLANK]

IN WITNESS WHEREOF, the Parties have entered into this Agreement by their duly authorized signing officers as of the date first written above

POWERSTREAM INC.

Signature:
Name: John Glicksman
Title: Executive Vice-President & Chief Financial Officer

SOLAR PV DIVISION

Signature:
Name: Milan Bolkovic 2010-10-18
Title: Executive Vice-President Renewable Generation and Conservation

[SIGNATURE PAGE – SOLAR SERVICE LEVEL AGREEMENT]

SCHEDULE 1
CORPORATE SERVICES

Function	Services provided	Amount, $
Executive Support	• Strategic review and approval with respect to all business and financial decisions • Director's insurance	$183,180
Legal Support	• Reviewing, drafting and negotiating lease agreements, contracts, letters of intent and related agreements. • Providing ad-hoc legal counsel as it relates to various strategic business decisions • Reviewing and interpreting various legislation, rules and regulations • Participating in negotiations with strategic partners	$16,800
Human Resources	• Support for organizational staff planning/recruitment • Salary administration • Job evaluation, analysis and design	$7,140
Communications	• Communications support /design of marketing/sales materials	Hourly rate ($28 – Junior : $91 – Senior)

SCHEDULE 2
FINANCE

Function	Services provided	Amount, $
Corporate Finance	• Corporate Accounting Policies and Systems • Financial modeling and Analysis, • Developing business' long-term financial outlook, OM&A and capital budgets • Quarterly and annual financial reporting • Decision support • Insurance Management	$39,900
Accounting and Payroll	• Providing accounts payable and accounts receivable functions • Providing general accounting functions / account reconciliations • Providing accurate and timely payroll	$8,960
Financial Services	• Budget application design and maintenance, upload in JDE system • Accounting system set up, including intercompany module • Preparation of monthly and quarterly internal and external financial reports • Tax returns preparation • Audit Service	$4,836
Enterprise Risk & Internal Audit	• Providing assurance that internal controls continue to operate effectively	Included above
Rates and Regulatory Affairs	• Providing government relations support to generation business • Providing various monthly accounting functions (Settlement with IESO) • Assisting with generation business' accounting system set up	$7,420

SCHEDULE 3
INFORMATION SERVICES

Function	Services provided	Amount, $
Information & Technology Services	• Managing communication and telephone systems • Servicing Request for Support services for end users (computer hardware and application support and advices; hardware maintenance; training; data backup) • Production support and administration for all application suites • Infrastructure services for all desktop, server, voice & data platforms • Disaster recovery • Maintaining systems to support all internet, e-mail and security matters	$66,571

SCHEDULE 4
FACILITIES AND PROCUREMENT

Function	Services provided	Amount, $
Head Office	• Occupancy charges for Head office	$25,730
Office supplies	• Office supplies	$1,190
Purchasing	• Assisting in RFI and RFP preparation and tendering process; proposal submission • Contract negotiation • Pre-qualification of vendors and vendor relationship management • Purchase of goods and services • Follow up on warranties	$6,370
Stores	• Consolidate material requirements and material scheduling • Create and update inventory master records • Shipping and receiving, yard and warehouse maintenance	Included above

AMENDING AGREEMENT NO. 1 TO
SERVICE LEVEL AGREEMENT

This Amending Agreement No. 1 is made between PowerStream Inc. (**"PowerStream"**) and Solar PV Division (**"Solar"**) effective January 1, 2011 (the **"Amending Agreement Effective Date"**).

A. PowerStream and Solar entered into a Service Level Agreement (the **"SLA"**) on January 1, 2010.

B. PowerStream and Solar wish to amend PowerStream's cost allocation attributable to Solar on the terms and conditions set out herein.

For good and valuable consideration, the SLA is amended as of the Amending Agreement Effective Date as follows:

1. Schedule 1 through 4 are deleted from the SLA and replaced with Schedule 1 through 4 set out at Appendix 1 to this Amending Agreement No. 1.

Capitalized terms used in this Amending Agreement No.1 which are not defined, shall have the meaning ascribed to such term in the SLA.

All other terms and conditions of the SLA remain in effect.

Executed by the duly authorized representative of the parties on the Amending Agreement Effective Date.

POWERSTREAM INC.

By: ______________________
Name: John Glicksman
Title: Executive Vice-President and Chief Financial Officer

SOLAR DIVISION PV

By: ______________________
Name: Milan Bolkovic
Title: Executive Vice-President Renewable Generation and Conservation

APPENDIX 1

SCHEDULE 1
CORPORATE SERVICES

Function	Services provided	Amount, $
Executive Support	• Strategic review and approval with respect to all business and financial decisions • Director's insurance	$104,165
Legal Support	• Reviewing lease agreements, contracts, letters of intent, etc. • Drafting lease agreements, contracts, letters of intent, etc. • Providing ad-hoc legal counsel on strategic business decisions • Reviewing and interpreting legislation, rules and regulations • Participating in negotiations with strategic partners	$50,400
Human Resources	• Support for organizational staff planning/recruitment • Salary administration • Job evaluation, analysis and design	$2,954
Communications	• Communications support /design of marketing/sales materials	Hourly rate ($22.4 – Junior : $94.9 – Senior)

SCHEDULE 2
FINANCE

Function	Services provided	Amount, $
Corporate Finance	• Corporate Accounting Policies and Systems • Financial modeling and Analysis, • Developing business' long-term financial outlook, OM&A and capital budgets • Quarterly and annual financial reporting • Decision support • Insurance Management	$37,240
Accounting and Payroll	• Providing accounts payable and accounts receivable functions • Providing general accounting functions / account reconciliations • Providing accurate and timely payroll	$12,706
Financial Services	• Budget application design and maintenance, upload in JDE system • Accounting system set up, including intercompany module • Preparation of monthly and quarterly internal and external financial reports • Tax returns preparation • Audit Service	$29,256
Enterprise Risk & Internal Audit	• Providing assurance that internal controls continue to operate effectively	Included above
Rates and Regulatory Affairs	• Providing government relations support to generation business • Providing various monthly accounting functions (Settlement with IESO) • Assisting with generation business' accounting system set up	$7,840

SCHEDULE 3
INFORMATION SERVICES

Function	Services provided	Amount, $
Information & Technology Services	• Managing communication and telephone systems • Servicing Request for Support services for end users (computer hardware and application support and advices; hardware maintenance; training; data backup) • Production support and administration for all application suites • Infrastructure services for all desktop, server, voice & data platforms • Disaster recovery • Maintaining systems to support all internet, e-mail and security matters	$97,350

SCHEDULE 4
FACILITIES AND PROCUREMENT

Function	Services provided	Amount, $
Head Office	• Occupancy charges for Head office	$18,633
Office supplies	• Office supplies	$2,452
Purchasing	• Assisting in RFI and RFP preparation and tendering process; proposal submission • Contract negotiation • Pre-qualification of vendors and vendor relationship management • Purchase of goods and services • Follow up on warranties	$7,036
Stores	• Consolidate material requirements and material scheduling • Create and update inventory master records • Shipping and receiving, yard and warehouse maintenance	Included above

SHARED SERVICES AGREEMENT (Joint 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 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 **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:

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 **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
Primary Contact:

Attention:
Clayton D Harris
City Manager

Fax: 905-832-8143

Email: clayton.harris@vaughan.ca

Attention:	Barbara Cribbett Commissioner of Finance & City Treasurer
Fax:	905-303-2057
E-Mail:	barbara.cribbett@vaughan.ca

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

Attention:	Barry Jackson Director of Financial Services
Fax:	905-832-8566
E-Mail:	barry.jackson@vaughan.ca

For facility issues:

Attention:	Marlon Kallideen Commissioner of Community Services
Fax:	905-303-2033
E-Mail:	marlon.kallideen@vaughan.ca

For information technology services :

Attention:	Dimitri Yampolsky Chief Information Officer
Fax:	905-832-8568
E-mail:	dimitri.yampolsky@vaughan.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 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

THE CORPORATION OF THE CITY OF VAUGHAN

Per: ______________________________

Name: Hon. Maurizio Bevilacqua
Title: Mayor

Per: ______________________________

Name: Jeffrey A. Abrams
Title: City Clerk

CITY OF VAUGHAN
APPROVED BY COUNCIL
DATE JUNE 26,2012
BY-LAW 93-2012
ITEM FINANCE 2(2)
INITIAL

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, Winter 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.

COPY

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

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 <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 **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:

Services Purchased from PowerStream by the Municipality:

Schedule A - Water Meter Reading and Billing

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 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 **Standard of Services.** 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 **Amendments**. 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 **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 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~~ MARK HENDERSON
Title: EVP ~~Corporate Services & Secretary~~ ASSET MGMT + COO

THE CORPORATION OF THE TOWN OF BRADFORD WEST GWILLIMBURY

Per: ______________________________
Name: JAMES B CORRIGAR
Title: TOWN MANAGER.

Per: ______________________________
Name: Ian Goodfellow
Title: Director of Finance/Treasurer

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 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.

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.

Pricing

***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~~ 130,000

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

BOARD STAFF INTERROGATORY #39:

Reference(s): Ref: D1/T5/S4/p.9

Table 6 "Compensation – Average Yearly Base Wages" shows an increase in average compensation to the Board of Directors from $22,027 in 2011 to $30,481 in 2013, an increase of over 38%.

Please provide an explanation for this increase.

RESPONSE:

The 2012 budget made allowance for an anticipated increase in meetings of the Board of Directors, however, this did not materialize. Based on actual for 2012, Board of Directors' costs for 2012 and 2013 will not increase over 2011. A revised Table 6 is listed below.

Table Board Staff #39: (Revised) Table 6: Compensation – Average Yearly Base Wages ($)

	2009 PS Board Approved	2009	2010	2011	2012	2012 Revised	2013	2013 Revised
Board of Directors	30,077	20,396	19,977	22,027	29,593	23,427	30,481	24,130
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	

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

BOARD STAFF INTERROGATORY #40:

Reference(s): D1/T5/S4/p.11

Table 8 "Compensation – Average Yearly Incentive ($)" on this page provides changes in these incentives for the categories of Senior Management, Management and Non-union.

Please provide explanations for the 2011 to 2013 changes for each of these categories including an explanation as to why the senior management incentives increased while the non-union incentives decreased.

RESPONSE:

The Senior Management and Management incentive category increased proportionately to increases in compensation – PowerStream's incentive structure is based on a percent of wages (which have increased), the basis of how the incentive pay is calculated did not change. In 2011, the non union category's actual incentive pay was higher than estimated and therefore, based on historical trends, the 2012 and 2013 budgets should have been higher. The non union incentives are not actually decreasing.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

BOARD STAFF INTERROGATORY #41:

Reference(s): E D1/T1/S2/p.2

Table 1 on this page presents OM&A Cost Productivity Information for PowerStream. This table shows that OM&A Cost per FTE increased by 7.5% in the 2013 Test Year relative to 2011 Actuals under MIFRS. Comparisons between 2011 Actuals under CGAAP compared to 2008 and 2009 Board Approved levels for this statistic also under CGAAP for Barrie Hydro and PowerStream show increases of 43.6% and 17.8% respectively.

a) Please state whether or not PowerStream has undertaken any productivity studies internally, or had any external studies done. If yes, please provide a copy of any such studies. If no, please state why not.
b) Please comment on the increases in the OM&A Cost per FTE noted above.

RESPONSE:

a) PowerStream has not undertaken any productivity studies internally and has not commissioned any such studies externally. In light of the number of mergers and acquisitions since 2004, the focus of the company has been to consolidate the operations of the merged or acquired entity. The company is looking at starting a project within our “Journey to Excellence” initiative that will look at PowerStream’s comparability with not only other utilities but also outside of the utility industry where appropriate. Review and mapping of our key processes are currently being completed. In 2013/2014 the company will be reviewing best practices in these areas.

b) The 7.5% increase in the cost per FTE from 2011 to 2013 is mainly due to increases in compensation, additional staff and an increased need for asset maintenance.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

The increase from 2008(Barrie Hydro-43.6%) and 2009(PowerStream-17.8%) are mainly the result of the clearing of smart meter deferral accounts, increased asset maintenance, increased customer service requirements and an increased demand for locates.

The above can be ascertained by the information shown in the table below which uses data from Exhibit D1, Tab 1, Schedule 1, Exhibit D1, Tab 1, Schedule 2 and Appendix 2-G.

Table Board Staff #41b: OM&A Cost per FTE

OM&A Cost per FTE Change				
Weighted Avg Cost Per Employee 2009		**$ 102,831.4**	**Breakdown by Years**	
			2009 - 2011 CGAAP	**2011 - 2013 MIFRS**
IFRS	$ 23,478.9		$ -	
Compensation	$ 7,744.1		$ 318.6	$ 7,425.5
Additional Staff	$ 4,779.7		$ 1,783.7	$ 2,995.9
Asset Maintenance	$ 6,629.7		$ 3,668.6	$ 2,961.1
Smart Meter	$ 5,233.2		$ 6,863.5	-$ 1,630.2
Customer Services / Regulatory	$ 3,884.1		$ 2,034.8	$ 1,849.3
IS Strategy	$ 2,788.0		$ 913.0	$ 1,875.0
Locates	$ 2,258.1		$ 2,012.5	$ 245.6
Corporate Development	$ 2,305.6		$ 1,107.8	$ 1,197.9
Insurance	$ 1,344.5		$ 716.4	$ 628.1
Other	$ 470.5		-$ 2,053.6	$ 2,524.0
Net Change		**$ 60,916.5**	$ 17,365.4	$ 20,072.2
Adjustment for Changes in FTE Level (Note 1)		**(13,395.0)**		
Ending Balance		**$ 150,352.9**		

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

BOARD STAFF INTERROGATORY #42:

Reference(s): E D1/T1/S2/p.2 and December 1, 2011 Report for Ontario Energy Board *Third Generation Incentive Regulation Stretch Factor Updates for 2012* (EB-2011-0387)

The above referenced Board Report, which is available on the Board's web site, shows in Table 4 "Performance Rankings Based on Econometric Benchmarks" that PowerStream is ranked 52nd of 77 distributors. Table 7 "Performance Rankings Based on Unit Cost Indexes" ranks PowerStream 45th of 76 distributors.

Please comment on these rankings in light of the comparisons noted in the preamble of the preceding interrogatory.

RESPONSE:

PowerStream has always supported the need for the continued development of a fair, transparent and sustainable benchmarking system for Ontario's electricity distributors. Fair benchmarking based on valid, reliable data enables the Ontario Energy Board to respond appropriately with regulatory instruments suitable to the mode of regulation that is being exercised such as the stretch factors in the Third Generation IRM setting.

PowerStream, among other LDCs, has outlined since 2008, the issues with the current methodology that has led to the rankings outlined in the Third Generation Incentive Regulation Stretch Factor Updates for 2012 (EB-2011-0387) as referred to by Board Staff, as well as the previous reports. One of the identified issues with the ranking methodology is the inclusion of OM&A of high voltage transmission assets. The comparison of unadjusted OM&A costs with those of other distributors does not reflect a true comparison of a distributor's performance. Another issue identified is the quality of data sets used. PowerStream has long argued that

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

improved data sets and benchmarking methodology will not only provide for more appropriate classifications of electric utilities but also will avert other implications of the rankings.

The Ontario Energy Board is currently undertaking a consultation on a Renewed Regulatory Framework for Electricity which includes discussions on Performance and Incentives (EB-2010-0379). In the past two years discussions have occurred on what is the fundamental premise of performance measurement. How should performance be measured? (OM&A alone, or the inclusion of capital costs? Peer versus past utility performance comparison?) How should the measurements be used? (The setting of rates for both IRM and cost of service?) PowerStream, as a member of the Distribution Regulation Review Task Force, has participated in the consultation and looks forward to the Board Chair's announcement on next steps.

Although PowerStream ranks in the bottom half of both rankings, PowerStream continues to have one of the lowest OM&A costs per customer. According to the last published Yearbook (2010), PowerStream has the 6th lowest OM&A costs per customer among the 78 ranked LDCs. As well, PowerStream continues to have one of the lower distribution charges when compared to neighbouring utilities.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

BOARD STAFF INTERROGATORY #43:

Reference(s): E D1/T5/S4/p. 12

OMERS has announced a three-year contribution rate increase for its members and employers for the years 2011, 2012, and 2013. Please state whether or not the applicant's proposed pension costs include this increase. If so, please provide the forecasted increase by years and the documentation to support the increases. If not, please state how the applicant proposes to deal with this increase.

RESPONSE:

Due to the timing of the budget process, PowerStream had completed the development of the proposed pension costs prior to OMERS' announcement of contribution rate increase. The rate increase used in arriving PowerStream's proposed pension costs was lower than OMERS' rate increase. The proposed pension costs would have been higher by $340,000 had PowerStream used OMERS' rate increase.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

CCC INTERROGATORY #53:

Reference(s): (A3/T1/S1)

Please provide the impact on the 2013 revenue requirement of reducing the annual increase for union staff to 2.5%. Please provide the impact on the 2013 revenue requirement of reducing the annual increase for non-union staff to 2.5%.

RESPONSE:

If 2013 annual increase for union staff is capped at 2.5%, the overall 2013 compensation would be lower by $113,000. Of this amount, $32,000 would represent lower capital additions and $81,000 would be lower OM&A. These changes would lead to a decrease of $85,000 in the 2013 Test Year revenue requirement.

If 2013 annual increase for non-union staff is capped at 2.5%, the overall 2013 compensation would be lower by $89,000. Of this amount, $13,000 would represent lower capital additions and $76,000 would be lower OM&A. These changes would lead to a decrease of $77,000 in the 2013 Test Year revenue requirement.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

CCC INTERROGATORY #54:

Reference(s): (D1/T1/S1/p. 3)

PowerStream has identified that one of the cost drivers in its OM&A since 2009 has been $4.275 million in Compensation costs. Please provide a detailed break-down of that amount (wage increases , benefits increases etc.) In addition, PowerStream has identified$2.62 million related to additional Staff. Please provide the basis for that calculation and a detailed break-down of that amount.

RESPONSE:

Please see the table below. The amount of $4.275M is broken into the categories of wages and benefits.

Table CCC #54-1: Change in Total Compensation 2009-2013

Change in Total compensation 2009 to 2013

Increase due to Wage	3,451
Increase due to Benefits	824
Total Increase	**4,275**

Below is the table for the breakdown of the cost for additional staff from the period 2010 to 2013. For 2009, additional staffing was not a cost driver as the company was in the process of a merger. The basis for the calculation is the compensation for each staff position, less the portion allocated to capital.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Table CCC #54-2: Change in Total Compensation 2009-2013

OM&A increase from 2009 to 2013 related to additional staff (in 000's)

Year	$ Amount
2010	315
2011	629
2012	646
2013	1,037
Total Increase	**2,626**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

CCC INTERROGATORY #55:

Reference(s): (D1/T5/S1/p. 5)

The evidence states that, in its efforts to improve organizational efficiency and ensure that good governance practices are in place, PowerStream created the PMO office, 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 initiatives. Please identify the 18 roles added and the annual cost of those roles in 2013. Please explain how adding these 18 roles has provided incremental benefits to PowerStream customers.

RESPONSE:

Please see Table CCC #55 below. Please ote that Annual Costs also include miscellaneous expenses, e.g. training, conference, etc and they are annualized. Furthermore, Information Services costs are allocated to either OM&A or capital.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

TABLE CCC #55: ROLES AND ANNUAL COST

	Positions	Annualized Costs
Information Services	Senior Technical Specialist	
	Application Support Analyst	
	Senior Business Analyst	
	Director, Information Services	
	Executive Assistant II	
	Security Administration Analyst	
	Senior Business Analyst	
	Application Support Analyst	
	Application Support Analyst	
	Service Desk Analyst	
	Senior Technical Specialist	
	Supervisor, IS Support Services	
	Total	**1,372,716**
Legal	Administrative Assistant	
	VP General Counsel	
	Total	**376,857**
Project Management Office	PMO Project Manager	
	PMO Project Manager	
	Total	**280,095**
Enterprise Risk and Internal Audit	Manager, Enterprise Risk and Internal Audit	
	Senior Internal Audit	
	Total	**281,932**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Below is a discussion of the incremental benefits to PowerStream customers of the PMO, Enterprise Risk and Internal Audit, the Legal Department and the Technology Strategy.

Project Management Office (PMO)

PowerStream has been and continues to be searching for improvements in the way it operates. In the fall of 2009 it reviewed its capabilities to manage multiple, cross functional projects in a more centralized fashion. As a result of this review it was decided to establish a Project Management Office (PMO). No formal business case was prepared. Prior to the establishment of the PMO, projects were managed on a decentralized basis with the ensuing risks inherent in that approach.

The primary goal of PowerStream's PMO is to make the organization more effective. Staff and other resources will be utilized more effectively, which ultimately benefits customers.

As the PMO matures it will deliver both qualitative and quantitative savings, however during the start-up and implementation phases (2010-2013) quantitative savings are not anticipated.

The PMO is providing value in a number of areas. With centralized management of all projects, there is an increased focus on getting projects completed. Through training and coaching, project management capabilities and expertise have been and will continue to be improved.

Information Services

In 2011, PowerStream developed a comprehensive Information Technology (IT) Strategy with the assistance of KPMG. This strategy has been filed – please refer to this filed at Exhibit J, Tab 2, Schedule 2.3, Appendix D in response to CCC IR #12. The development of this strategy was necessitated by the need to effectively utilize existing and emerging technologies in meeting the customers' current and anticipated needs.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

One of the benefits of the strategy is that IT projects are looked at as a whole, not dissimilar to the PMO concept. With this centralized approach investment decisions are made corporately with less duplication in individual departments, which will benefits the ratepayers. PowerStream also wanted to ensure that IT solutions were driven by the needs of the business rather than by the reverse. Among the new IS staff to be hired is Business Analysts that will bring operations knowledge in the development of IT solutions.

Legal

The Legal Department has several functions, principal of which is the mitigation of risk with third parties and more generally on our day-to-day activities. Mitigating risk principally relates to the negotiation and drafting of an appropriate form of contract with third parties and ensuring both regulatory compliance and the mitigation of reputational risk to the organization.

The Legal Department's focus on managing reputational risk and risk mitigation in both our third party relationships and our day-to-day business has the effect of reducing the risk profile for PowerStream both financial and otherwise, all of which benefits customers.

Enterprise Risk & Internal Audit

The Enterprise Risk and Internal Audit area is responsible for assessing risk throughout the organization and providing guidance on strategies to mitigate risk. An effective risk management strategy reduces the extent to which PowerStream is exposed to adverse effects (monetary or otherwise), which is beneficial to customers.

Further, the Internal Audit function serves as an independent review of the controls and processes throughout the organization, and provides recommendations to improve PowerStream’s effectiveness and efficiency. These operational improvements allow PowerStream to optimize performance and provide a higher level of service to customers given the resources available.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

CCC INTERROGATORY #56:

Reference(s): (D1/T5/S4/p. 3)

Please provide a list of the net 37.2 positions added since 2009.

RESPONSE:

Please refer to the Table below.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Table CCC #56: Net Positions Added since 2009

List of Positions added for New Requirements:	FTE
Application Support Analyst	1
Apprentice Meter Technician	1
Apprentice Power Lineperson	6
Apprentice Station Maintenance Technician	1
Asset Mgmt Project Coordinator	1
Business Analysis	1
Communications Officer	1
Customer Service Analyst	1
Customer Service Clerk	1
Director, Enterprise Risk & Internal Audit	1
Director, Health & Safety	1
Director, Information Service	1
Director, Smart Grid	1
Executive Assistant II	2
Executive Assistant II	1
Financial Analyst	0.5
HR & OE Analyst	1
HR Training Coordinator	1
Human Resources Business Partner	1
Legal Assistant	1
Manager, Communication & CDM Marketing	1
Mgr Facilities	1
Mgr Inventory	1
Mgr Process Mgmt & Continuous Improvement	1
Online Digital Communications Officer	1
PMO Project Manager	1
Regulatory & Gov't Affairs Analyst	0.5
Security Admin Analyst	1
Senior Business Analyst	1
Senior Technical Specialist	1
Service Desk Analyst	0.5

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

List of Positions added for New Requirements:	**FTE**
Sr Business Analyst	1
Sr Technical Specialist	0.5
Sr. Internal Audit	1
Supply Chain Services Admin	1
Supervisor, Collections	0.5
Supervisor, IS Support Services	0.5
Technical Specialist	1
Total Positions Added for New Requirements	41*
Positions Eliminated/Moved from Core Business	-59.3
Positions added for Growth	14.5
Net Reduction	-3.8**

Total Positions Added for New Requirements	41.0*
Less: Net Reduction	-3.8**
Net positions added for new or increased Regulatory and other requirements	37.2

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

CCC INTERROGATORY #57:

Reference(s): (D1/T5/S4/p. 4)

Please provide a list of the individuals that comprise the Senior Management Team and their respective responsibilities.

RESPONSE:

Please find below a table of the Senior Management Team and their responsibilities.

Table CCC #57: PowerStream Senior Management Team

Position	Responsibilities
Director, CIS Project	Responsible for strategic oversight of the new CIS Implementation Project and Transition Team, cost control, system integrator relationship management as well as internal change management.
Director, Corporate Communications	Directs the development, management and execution of external and internal corporate as well as customer communications strategies for the company. Serves as the company's primary media spokesperson.
Director, Customer Credit	Oversees the Payment & Collections function of Customer Service, including responsibility for administration of shared services agreements, credit risk assurance, as well as business process review.
Director, Customer Relations	Provides direction and leadership in managing all aspects of customer relations, including the areas of Customer Care, New Connections and Customer Relations.
Director, Distribution Design	Responsible for the planning and controlling of the Distribution Design programs and initiatives in support of the corporate vision. Oversees the development and design of capital work plans, distribution system changes and expansion proposals. Manages subdivision and new service expansions.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Position	Responsibilities
Director, Health & Safety	Responsible for the planning and controlling of the Health, Safety & Environmental initiatives in support of the corporate vision. Directs and co-ordinates the implementation of all Health and Safety programs, policies and procedures, safety training and WSIB. Monitors and analyzes health and safety key performance indicators to ensure initiatives are successful and the business objectives are being met.
Director, Human Resources	Provides leadership to the organization in delivering innovative and diverse HR services and solutions. In collaboration with the SVP, drives organizational development including performance management, succession and workforce planning and training and development strategy.
Director, Information Services	Manages IS department operational planning, including business requirements, project planning, and organizing and managing the allocation of resources as required. Oversees provision of end user services. Manages and monitors IS Policies and procedures, including but not limited to, architecture, security, disaster recovery, business continuity, and purchasing.
Director, Lines	Works closely with Engineering Services to ensure annual capital programs are completed on time and on budget. Establishes and oversees annual Operating and Maintenance budgets. Ensures system reliability targets are met through effective planning and execution of annual inspection and maintenance programs. Ensures quick and effective response to customer power outages and the safe and expeditious restoration of power to the customer.
Director, Organizational Effectiveness	Responsible for improving organizational effectiveness through the development of the strategic management system and supporting implementation of strategies that prioritize organizational efforts, initiatives and resources that are critical to helping achieve the corporate mission, culture, values strategic objectives and future vision.
Director, Smart Grid	Working collaboratively with senior management in a number of PowerStream departments via the Smart Grid Task Force, is responsible for managing all aspects of PowerStream's Smart Grid activities. Ensures PowerStream prudently deploys Smart Grid technology to its electricity system consistent with the Province's directive to modernize the electricity system.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Position	Responsibilities
Director, Supply Chain Services	Responsible for the overall operation of the Procurement, Materials & Fleet programs and initiatives in support of the corporate vision. Oversees the establishment of user service level agreements as applicable to Inventory Management. Provides contract management expertise and acts as a resource for contract negotiation, review and approval. Directs the effective capital acquisition and maintenance of the corporate fleet.
EVP & Chief Financial Officer	A member of the Executive Management Team, the CFO is responsible for the planning, directing and controlling of PowerStream overall financial plans and policies, and accounting practices. This position provides strategic and financial leadership for the Company. The CFO oversees the general management of the Finance and Customer Service departments.
EVP Asset Mgmt & COO	A member of the Executive Team the COO is responsible for and acts as a leader and change agent in the strategic management of the following areas: Engineering Services, Operations & Construction and Smart Grid.
EVP Corp Services & Secretary	As a member of the Executive Team, is responsible for and acts as a leader and change agent in the strategic management of the following areas; Legal, Human Resources & Organizational Effectiveness, Supply Chain Services, Information Services, and Corporate Communications.
President & CEO	Reporting to the Board of Directors, and working with the Chair as liaison to the Board of Directors, the President and CEO is accountable for the performance of the Corporation. He provides leadership and guidance to the total enterprise, and ensures that high levels of safety, system reliability, customer service and efficiency occur within the enterprise in accordance with the vision, mission, values and strategic objectives established and/or approved by the Board of Directors.
SVP Engineering Services	Responsible for and acts as a leader and change agent in the strategic management of the areas of distribution design, system planning and services and standards. Works collaboratively with the leadership team in Asset Management to optimize divisional business performance.
SVP HR & Organizational Effectiveness	Responsible for and acts as a leader and change agent in the strategic management of the following areas: Human Resources, Health and Safety, Environment, Organizational Effectiveness, and Enterprise Risk & Internal Audit. Drive individual and organizational effectiveness through the superior execution of HR and Health and Safety programs and initiatives.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Position	Responsibilities
SVP Operations & Construction	Responsible for and acts as a leader and change agent in the strategic management of the areas of operations and construction. Oversees operational budgets for the Operations and System Control area. Ensures capital and operation and maintenance projects are delivered in safe and effective manner, on time, within budget, and according to agreed upon standards and specifications.
VP Customer Service	Responsible for and acts as a leader and change agent in the strategic management of the following areas: Customer Credit, Billing and Customer Relations.
VP Engineering Planning	Responsible for the planning and controlling of the Engineering Planning programs and initiatives in support of the corporate vision. Acts as a leader in the following areas: System Planning & Standards, Station Design & Construction, GIS and Agreements.
VP Finance	Supports the vision, strategies and directions to grow the company and meet all performance expectations particularly with respect to financial matters. The position directs and oversees Finance Planning, Accounting, Payroll, Management & Financial Reporting Matters and is the primary lead in working with external auditors to complete the annual financial audit of the Corporation.
VP General Counsel	Responsible for managing and directing the Corporation’s commercial and regulatory legal requirements. Oversees the preparation of various legal documents, reviews documents for completeness and proper form according to applicable laws and regulations. Provides legal technical advice, responds to legal enquires and acts as legal reference for the company
VP Information Services	Responsible for and acts as a leader and change agent in the strategic management of the following areas: IS Operations & Support, Business Administration, Security Administration, and CIS Services. Manages technology infrastructure and supports to align with business needs. Oversees and negotiates service level agreements, technology integration, issues management and service lifecycle management.
VP Operations	Responsible for the planning and controlling of the Operations and Smart Grid programs and initiatives in support of the corporate vision. Oversees the coordination and administration of all aspects of network operations involving System Control, P&C and Smart Grid to ensure the safe, reliable, and efficient delivery of power.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Position	Responsibilities
VP Rates & Regulatory Affairs	Responsible for and acts as a leader and change agent in the strategic management of the following areas: Regulatory & Government Affairs, Rate & Revenue and Rate Applications.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

CCC INTERROGATORY #58:

Reference(s): (D1/T5/S4/pp.4- 6)

Has PowerStream included any assumptions regarding vacancies in the derivation of the 2013 revenue requirement? What is the current staff level in 2012?

RESPONSE:

PowerStream has used half of the anticipated cost for the 2013 vacancies in the derivation of the 2013 revenue requirement. This is to reflect that, practically, the vacancies will be filled over the course of 2013.

The current staff level at June 30, 2012 is noted below:

Table CCC #58: Staff Level as at June 30, 2012

	FTE
Board	13
Executive	27
Management	79
Non-Union	51
Union	319
Temp & Students	44
Total	**533**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

ENERGY PROBE INTERROGATORY #41:

Reference(s): Exhibit A3, Tab 1, Schedule 1, page 5

a) What is the impact on the revenue deficiency if the annual increase for union staff was capped at 2% for each of 2012 and 2013?

b) What is the impact on the revenue deficiency if the annual increase for non-union staff was capped at 2% for each of 2012 and 2013?

RESPONSE:

a) If 2012-2013 annual increase for union staff was capped at 2.0%, the overall 2012 compensation would be reduced by $250,000, and 2013 compensation would be lower by $515,000. For union staff, approximately 28% of this amount is capitalized, resulting in lower capital additions of $70,000 in 2012 and $144,000 in 2013 with lower OM&A of $180,000 in 2012 and $371,000 in 2013. These changes would result in the 2013 Test year revenue requirement decreasing by $390,000.

b) If 2012-2013 annual increase for non-union staff was capped at 2.0%, the 2012 compensation would be reduced by $203,000, and 2013 compensation would be lower by $419,000. For non-union staff, approximately 15% of this amount is capitalized, resulting in lower capital additions of $30,000 in 2012 and $63,000 in 2013 with lower OM&A of $173,000 in 2012 and $356,000 in 2013. These changes would result in the 2013 Test year revenue requirement decreasing by $367,000.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

ENERGY PROBE INTERROGATORY #42:

Reference(s): Exhibit D1, Tab 5, Schedule 4

a) What is the impact on the figures in Table 5 if the 2012 and 2013 increase for employees covered under the collective agreement were reduced to 2.0% in both years?

b) What is the impact on the figures in Table 5 if the 2012 and 2013 increase for management and non-union staff were reduced to 2.0% in both years?

c) Please explain the 38% increase shown in Table 4 for the Board of Directors between 2011 and 2013.

d) Please provide the most recent year-to-date figures available for 2012 and the corresponding figures for the same period in 2011 in the same level of detail as shown in Table 4.

RESPONSE:

a) The impact on the figures in Table 5 if the 2012 and 2013 increase for employees covered under the collective agreement were reduced to 2.0% in both years in listed below:

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Table EP #42a): Table 5: Changes in Total Compensation 2009 to 2013 ($000)

		Original	2% Union Inflationary Increase	
2008 EDR amount (Barrie)		$10,877		$10,877
2009 EDR amount (PS)		$43,743		$43,743
Decrease due to merger savings, hiring lags, other		$-5,345		$-5,345
Contract and inflationary increase	12%	$4,945	11%	$4,502
Increase in number of staff	9%	$4,553	9%	$4,546
Increase in benefits	10%	$4,968	10%	$4,902
Other Changes	4%	$2,141	4%	$2,141
2013 Total Compensation (include Benefit)		$65,882		$65,366

b) The impact on the figures in Table 5 if the 2012 and 2013 increase for management and non-union staff were reduced to 2.0% in both years is listed below:

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Table EP #42b): Table 5: Changes in Total Compensation 2009 to 2013 ($000)

		Original	2% Mgmt Inflationary Increase	
2008 EDR amount (Barrie)		$10,877		$10,877
2009 EDR amount (PS)		$43,743		$43,743
Decrease due to merger savings, hiring lags, other		$-5,345		$-5,345
Contract and inflationary increase	12%	$4,945	11%	$4,596
Increase in number of staff	9%	$4,553	9%	$4,535
Increase in benefits	10%	$4,968	10%	$4,915
Other Changes	4%	$2,141	4%	$2,141
2013 Total Compensation (include Benefit)		$65,882		$65,462

c) Please see response to Energy Probe IR #24, filed at Exhibit J1, Tab 1, Schedule 4.1.

d) Please see table below.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Table EP #42d): Table 4: Total Compensation by Group (4) (including Benefit)

	January 1 to June 30 (Actual)	
	2011	2012
Board of Directors	173,574	169,178
Senior Management	4,227,412	4,577,867
Management	5,862,462	6,151,486
Non-Union	3,372,433	3,494,859
Unionized	16,120,275	16,259,491
Temp & Students	1,226,264	1,582,469
Total	30,982,420	32,235,351

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

ENERGY PROBE INTERROGATORY #43:

Reference(s): Exhibit D1, Tab 5, Schedule 5, Appendix 2-K

a) Please provide a table that shows the performance incentive plan payments made to each group of employees for 2009 through 2011 and the forecast for 2012 and 2013 along with the total payments that could have been paid out in each of those years and the resulting percentage of the total potential payout actually paid out.

b) Please confirm that the total compensation charged to OM&A and the amount capitalized shown for 2011 are based on CGAAP. Please provide the total compensation broken down into the amount charged to OM&A and the amount capitalized in 2011 under IFRS.

c) Please explain why PowerStream believes that it requires 13 members of the Board of Directors.

d) What is the impact on OM&A and capitalized costs if the number of FTEs included for 2013 was maintained at the 2012 level for each category of employees?

RESPONSE:

PowerStream files this response in reference to its evidence on Compensation Costs and Employee levels filed at Exhibit D1, Tab 5, Schedule 4.

a) Please see the table below.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Table EP #43a: Total Yearly Incentive $ - Actual vs Potential Pay Out

	2010			2011			2012			2013		
	Actual	Potential	%	Actual	Potential	%	Budget	Potential	%	Budget	Potential	%
Sr. Mgmt	1,024,391	1,056,669	97%	966,038	1,018,563	95%	956,380	1,384,750	69%	991,343	1,435,673	69%
Mgmt	480,996	710,458	68%	528,233	773,337	68%	586,221	1,083,557	54%	629,699	1,170,038	54%
Non-Union	257,126	370,141	69%	263,232	392,158	67%	229,556	459,112	50%	273,320	546,640	50%
Total	1,762,513	2,137,268	82%	1,757,503	2,184,057	80%	1,772,157	2,927,419	61%	1,894,362	3,152,351	60%

Note that the amounts that have been included in the revenue requirement calculation in the 2013 application are the amounts shown under *Budget*.

b) Yes, the total compensation charged to OM&A and the amount capitalized shown for 2011 are based on CGAAP. Under MIFRS, the amount of compensation charged to OM&A is $38,886,642, and the amount capitalized is $18,892,008.

c) Prior to the Merger of PowerStream and Barrie Hydro PowerStream had ten Directors and Barrie Hydro had three directors. The shareholders determine the number of Directors and have stipulated that the Board shall consist of thirteen directors**.** Note that two of the directors are not compensated for service.

d) Please see the table below.

Table EP #43b: Cost Impact on maintaining the 2013 FTE at 2012 Level

	2013 Budget Original	2013 Budget Maintained at 2012 FTE Level	Impact
OMA Cost	46,262,698	45,871,202	-391,496
Capital Cost	19,619,657	19,254,378	-365,279
Total	**65,882,355**	**65,125,580**	**-756,775**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

SEC INTERROGATORY #43:

Reference(s): [D1/1/1, p. 4]

Please describe the Applicant's succession plan prior to the development of its current apprentice program, and identify the major differences between the former practice and the current practice.

RESPONSE:

Our Apprenticeship program began in 2006 and has continued under the same practice since that time, however, additional consideration has now been given to potential staffing level concerns as a result of retirement and the departure of other employees from the department in recent years. A large majority of the current Journeymen will be eligible to retire over the next decade, along with a significant number of management employees.

As experienced workers retire, knowledge transfer and the mentoring of apprentices will become a greater challenge, along with concerns over safety due to the ratio of journeyman-to-apprentices. Headcount and hiring plans are being considered to balance this. There are also challenges with the large number of management employees in the Lines department which are eligible to retire by 2020. Experienced Union staff are in the same demographic as the eligible-to-retire management employees.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

SEC INTERROGATORY #44:

Reference(s): [D1/3/2, p. 5]

Please provide the annual cost of:

a) Extending "limited employee post-employment benefits" to union employees; and
b) Extending the post-employment benefit plan to management employees.

RESPONSE:

a) The annual cost to extend the post-employment benefits is approximately $98,000 for union employees
b) The annual cost to extend the post-employment benefits is approximately $78,000 for management employees.

The post-employment benefit plan is the same for both union and management employees, but the cost differences are reflective of the number and ages of the additional employees receiving these benefits.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

SEC INTERROGATORY #45:

Reference(s): [D1/5/4, p. 1]

Please advise whether the term "FTE" refers to positions or people, i.e. whether vacancies are deducted or not.

RESPONSE:

The term FTE refers to positions in the budget and people when referring to the actual FTE. The new positions in 2013 budget were budgeted for half a year, indicated as .5 FTE position, although positions will be filled starting January.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

SEC INTERROGATORY #46:

Reference(s): [D1/5/4, p. 2]

Please explain the phrase “excluding new position requirements”.

RESPONSE:

PowerStream set a merger target to reduce headcount to 475 positions and achieved 463.6 positions within the core business. As business evolved PowerStream created ten new positions based on new business requirements that make the total headcount 473.6. These ten positions were not anticipated by either predecessor utility.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

SEC INTERROGATORY #47:

Reference(s): [D1/5/4, p. 3 and 4]

Please restate Tables 1 and 2 deducting vacancies (actual and forecast) from each of the figures.

RESPONSE:

Please see the restated tables below:

Table SEC #47-1: Budgeted Staffing Level (permanent Headcount positions) – Restated

Budgeted Staff Positions	Predecessor LDC's 2009	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
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		-1.2	-1.6	1	
Budgeted Staff level	**519.1**	**473.4**	**481.8**	**495.3**	**515.3**
Less: Vacancy	**62**	**1.5**	**12.7**	**0***	**0***
After Vacancy	**457.1**	**471.9**	**469.1**	**495.3**	**515.3**
Staff increase (decrease)		**-45.7**	**8.4**	**13.5**	**20**
% change		**-8.8%**	**1.8%**	**2.8%**	**4%**

* No vacancies are indicated in 2012 and 2013 as it is anticipated that all the positions will be filled.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

Table SEC #47-2: Full Time Equivalents – Restated

	2009 PS EDR	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	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**
Less: Vacancy	**0***	**0***	**0***	**0***	**0****	**0****
After Vacancy	**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**	**542.8**	**569.5**

*The vacancy is zero as the actual number of staff is reflected.

** No vacancy in 2012 & 2013 as we anticipate that all the positions will be filled.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

SEC INTERROGATORY #48:

Reference(s): [D1/5/4, p. 3]

Please advise how many actual co-op and summer students are included in the 41 FTEs.

RESPONSE:

Please find listed below the FTE's included in the 2013 temps and students category. The temps were missing from the write up on exhibit D1T5S4 page 3.

Table SEC #48: Co-Op and Summer Students in FTE Count

	FTE
Co-op Student	**18**
Summer Student	**9**
Temporary Staff	**14**
Total Temp & Students	**41**

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

SEC INTERROGATORY #49:

Reference(s): [D1/5/4/p.6]

For each of the past 5 years, please provide the percentage of newly eligible employees that did retire in their first year of eligibility.

RESPONSE:

Please refer to the following table for the requested information consistent with the years within this application, up to June 30, 2012.

Table SEC #49: Employee Retirements in First Year of Eligibility

	2009	2010	2011	2012 (up to Jun 30, 2012)
1st Year of Eligibility	6	7	14	4
Retired in 1st Year of Eligibility	1	1	5	0
Percentage	17%	14%	36%	0%

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.5 Are the 2013 compensation costs and employee levels appropriate? (D1)

SEC INTERROGATORY #50:

Reference(s): [D1/5/4, p. 7]

Please explain why, while unionized compensation is increasing about 25% from 2009 to 2013, Senior Management is increasing 40%, Management is increasing 45%, and Non-Union is increasing 70%.

RESPONSE:

A primary reason that management compensation increased more from 2009 to 2013 relative to the union is as noted in Table 8: Compensation – Average Yearly Incentive on page 11 of Exhibit D1, Tab, Schedule 4. Management incentive compensation was not paid out in 2009 as it was paid out in 2008 prior to the merger with Barrie Hydro Distribution Inc. Only management staff is eligible for incentive compensation. As well, in the non union category, increase in headcount is weighted heavier than in the other categories, and as such would increase compensation higher than in comparison to the other categories.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.6 Have the savings due to the merger with Barrie Hydro been properly reflected in the test year? (D1)

BOARD STAFF INTERROGATORY #44:

Reference(s): Ref: D1/T5/S4/p.9

It is stated that:

"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."

Please provide a copy of this report.

RESPONSE:

The consultant (Hay Group) provided guidance to PowerStream to help group various management positions and associate them with appropriate salary ranges. No report was prepared.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.6 Have the savings due to the merger with Barrie Hydro been properly reflected in the test year? (D1)

ENERGY PROBE INTERROGATORY #44:

Reference(s): Exhibit D1, Tab 1, Schedule 1

a) Please explain why there is no cost driver shown in Table 2 to reflect reductions in OM&A costs associated with the merger with Barrie Hydro in 2009.

b) Please provide a cost driver table to reflect the OM&A savings that have resulted from the merger with Barrie Hydro between 2009 and the test year.

RESPONSE:

a) and b)

Please refer to response to Energy Probe IR #45c, filed in this Exhibit. The actuals for 2009 reflect the merger savings; these were reflected in the budgets for each company in 2009 and were not part of the original Board Approved amounts that are shown in Table 2.

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.6 Have the savings due to the merger with Barrie Hydro been properly reflected in the test year? (D1)

ENERGY PROBE INTERROGATORY #45:

Reference(s): Exhibit D1, Tab 1, Schedule 2

The Board approved OM&A cost per customer for Barrie (2008) is $141.4 and for PowerStream (2009) is $174.3.

a) Please explain why the cost per customer for 2009 (combined) is higher than the figures noted above.

b) Please explain why the 2009 combined figure of $188.0 per customer is higher than the 2009 Board approved figure given that the Board approved figures for Barrie were lower.

c) Please show where in Table 2 the savings due to the merger are reflected.

RESPONSE:

a) Although the cost per customer decreased as a result of combining Barrie and PowerStream, the OM&A costs increased by $6.6M for other reasons in 2009 resulting in the net increase to the cost per customer as per the table below:

RESPONSES TO INTERROGATORIES BY ISSUE

4. OPERATING COSTS (Exhibit D)

4.6 Have the savings due to the merger with Barrie Hydro been properly reflected in the test year? (D1)

Table EP #45ab: OM&A Cost per Customer Change from 2009 Approved to Actual

OM&A Cost per Customer Change from 2009 PowerStream Approved to 2009 Actual			
Weighted Average Cost per Customer		**$ 167.0**	*Note 1
Compensation	$ 4.0		
Asset Maintenance	$ 5.2		
Customer Services / Regulatory	$ 4.0		
Locates	$ 1.7		
Other	$ 6.1		
Net Change		**$ 21.0**	
Ending Balance		**$ 188.0**	

∗ Note 1 – The Weighted Average Cost per Customer of $167.0 is based on the Board approved OM&A costs for both Barrie and PowerStream divided by the number of customers for each entity.

b) Please see response to a) above.

c) The actuals for 2009 reflect the merger savings – the 2009 actuals would have been higher if the two companies remained separate. These amounts were reflected in the budgets for each company in 2009 and were not part of the original Board Approved amounts that are shown in Table 2 of Exhibit D1, Tab 1, Schedule 1.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #45:

Reference(s): E I

Where PowerStream's proposals related to deferral and variance accounts are concerned:

a) Has PowerStream made any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis in a previous Cost of Service or IRM proceeding (i.e. balances that were adjusted subsequent to the balance sheet date that were cleared in the most recent rates proceeding)? If yes, please provide explanations for the nature and amounts of the adjustments and include supporting documentation.

b) Please provide breakdowns of energy sales and cost of power expense, as reported in the audited financial statements, by USoA account number. Please tie these numbers to the audited financial statements. If there is a difference between the energy sales and cost of power expense reported numbers, please explain why the applicant is making a profit or loss on the commodity.

c) Please state whether or not PowerStream pro-rates the IESO Global Adjustment Charge into the RPP and non-RPP portions. If this is not the case, please provide an explanation.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

RESPONSE:

a) No, PowerStream has not made any adjustments to the previously approved deferral and variance account balances .

b) Please refer to the tables below. All identified variances are attributable to the differences and timing/implementation between wholesale rates charged by the IESO/Hydro One and retail rates charged by PowerStream to its customers.

<u>Table Board Staff #45-1: 2009 Energy Sales and Cost of Power</u>

					2009
Component	**USoA**	**G/L**	**Sales of Energy per Audited FS**	**Adjustments**	**Explanation**
Commodity	4006-4055	$506,037,537	$506,037,537	$0	
WMS	4062	52,498,015	50,921,155	(1,576,861)	WMS Revenue, allocated to Reg Assets as over-recovery
Transmission Network	4066	40,707,837	40,707,837	0	
Transmission Connection	4068	22,967,619	22,392,162	(575,457)	TC Revenue, allocated to Reg Assets as over-recovery
Low Voltage	4075	2,402,232	1,660,627	(741,605)	Low Voltage Revenue, allocated to Reg Assets as over-recovery
Total per Year		**$624,613,241**	**$621,719,318**	**($2,893,923)**	
		Cost of Power			
Commodity	4,705	$510,181,932	$506,037,537	($4,144,395)	Commodity Cost, allocated to Reg Assets as under-recovery
WMS	4708	50,921,155	50,921,155	(0)	
Transmission Network	4714	41,961,048	40,707,837	(1,253,211)	TN Cost, allocated to Reg Assets as under-recovery
Transmission Connection	4716	22,392,162	22,392,162	0	
Low Voltage	4750	1,660,627	1,660,627	0	
Total per Year		**$627,116,923**	**$621,719,318**	**($5,397,605)**	

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

Table Board Staff #45-2: 2010 Energy Sales and Cost of Power

					2010
Component	**USoA**	**G/L**	**Sales of Energy per Audited FS**	**Adjustments**	**Explanation**
Commodity	4006-4055	$569,807,028	$569,467,839	($339,189)	Commodity Revenue, allocated to Reg Assets as over-recovery
WMS	4062	56,099,048	47,590,790	(8,508,258)	WMS Revenue, allocated to Reg Assets as over-recovery
Transmission Network	4066	47,830,277	47,830,277	0	
Transmission Connection	4068	24,854,395	24,847,123	(7,272)	TC Revenue, allocated to Reg Assets as over-recovery
Low Voltage	4075	1,941,556	1,582,384	(359,172)	Low Voltage Revenue, allocated to Reg Assets as over-recovery
Total per Year		**$700,532,303**	**$691,318,413**	**($9,213,890)**	
			Cost of Power		
Commodity	4,705	$569,467,839	$569,467,839	$0	
WMS	4708	$47,590,790	47,590,790	0	
Transmission Network	4714	$51,006,312	47,830,277	(3,176,035)	TN Cost, allocated to Reg Assets as under-recovery
Transmission Connection	4716	$24,847,123	24,847,123	0	
Low Voltage	4750	$1,582,384	1,582,384	0	
Total per Year		**$694,494,448**	**$691,318,413**	**($3,176,035)**	

As can be seen, there is no difference between the Energy Sales and Cost of Power after the retail settlement variance account entries are made.

c) PowerStream separates the IESO Global Adjustment (GA) Charge into the RPP and non-RPP portion as described below.

PowerStream charges the entire cost of the GA into the Cost of Power. RPP customers are not charged for GA; GA is built into the RPP price. PowerStream reports, via monthly submissions of Form 1598, the portion of Global Adjustment it has been charged for energy used by RPP customers and then credits the Cost of Power for the GA for RPP customers that it gets back from IESO on the monthly invoice. This leaves the GA related to non-RPP customers only, remaining in the Cost of Power.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #46:

Reference(s): E I

In accordance with Section 2.12.2 of the Filing Requirements for the 2013 cost of service rate applications (Harmonized Sales Tax ("HST") Deferral Account), please confirm that PowerStream will not record more amounts in Account 1592 (PILs and Tax Variances, Sub-account HST/OVAT ITCs for the Test Year and going forward, as the impact of the HST and associated ITCs on capital and operating costs in the Test Year should be reflected in the applied-for revenue requirement.

RESPONSE:

PowerStream confirms that it will not be recording any more amounts into Account 1592 (PILs and Tax Variances, Sub-account HST/OVAT ITCs) for the Test Year and going forward, as the impact of the HST and associated ITCs on capital and operating costs in the Test Year will be reflected in the applied-for revenue requirement.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #47:

Reference(s): Ref: E I / T1/ S1/p.5, 12

It is stated that:

"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."

a) Please state whether or not the applicant has followed Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. Please explain if the applicant has not followed Article 490. In other words, please confirm that the higher of, the relevant revenues (i.e. account 4082, Retail Services Revenue and/or account 4084, STR Revenue) and the incremental expenses in the associated expense accounts (i.e. account 5315, Customer Billing, and possibly 5305, Supervision and 5340, Miscellaneous Customer Accounts Expenses) is reduced (i.e. revenues debited or expenses credited) at the end of each period, with an offsetting entry to the variance account. Please explain if the applicant has not followed Article 490, and if so, please quantify the variance.

b) Please confirm that all costs incorporated into the variances reported in Account 1518 and Account 1548 are incremental costs of providing retail services.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

RESPONSE:

a) PowerStream confirms that it has followed the accounting methodology outlined in Article 490 with regards to accounts 1518 and 1548 as described above.

b) PowerStream confirms that it has used the incremental costs of providing retailer services in determining the amounts to be included in accounts 1518 and 1548.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #48:

Reference(s): Ref: E I / T1/ S3

For the Rate Rider calculations for PowerStream South, the Billing Determinant amount used for calculating the rate rider for the Large Use customer class is 187,932 kW (based on projections for the 2013 test year). The actual kW for 2011 for this customer class was 80,298 kW (per sheet 4 of this Schedule). Please provide an explanation for the projection for 2013 to be materially higher than the actuals recorded in 2011.

RESPONSE:

As noted in PowerStream's 2009 COS application (EB-2008-0244, Exhibit H, Tab 1, Schedule 2, page 2), the Large Use class at that time consisted of a single customer using dedicated feeder lines from an adjacent transformer station. Accordingly only the cost of the dedicated assets and some of the Greater than 50 kV assets were allocated to this class. PowerStream noted that the resulting distribution rates were appropriate only for this customer and in the event of additional customers entering the Large Use class, these rates would not reflect the cost of service for these customers. PowerStream noted at that time, that any new or existing customers with average monthly demand greater than 5,000 kW would be treated as General Service Greater than 50 kW (GS>50) customers until such time that the Large Use rate was updated to reflect the cost of service for a broader range of customers.

In its 2010 IRM application (EB-2010-0246), PowerStream noted that there were customers in the GS>50 class, where the average demand was exceeding 5,000 kWs and should be moved to the Large Use class. It was also noted that these customers used more of PowerStream's distribution assets and should be allocated a share of those costs. PowerStream proposed an update to the Large Use rate. The Board decided that updating the Large Use rates should be done after an updated cost allocation study was prepared.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

In this application, PowerStream proposes to update the Large Use class to include a customer currently in the GS>50 kW class that has an average load in excess of 5,000 kW. Accordingly the load and consumption for this customer have been included in the Large Use class throughout the application, and in particular in the 2013 Cost Allocation Study.

This additional customer to be moved to the Large Use class accounts is the reason for the significant increase in the Large Use class projected 2013 billable kWs.

Please see the response to Energy Probe IR 18(d) for a discussion regarding the Large Use forecasted kWs.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #49:

Reference(s): E I / T1/ S5, EI/T1/S6 and EI/T1/S7

The total balance as of December 31, 2011 for account 1562 in the Continuity Schedules does not match the account balance reported under RRR 2.1.7 filing for 2011.

The table below shows the discrepancy between the RRR 2.1.7 filing for 2011 and the balances presented in the Continuity Schedules for account 1562 and 1560.

	Account 1560	Account 1562
Total per Continuity Schedules Exhibit 1/Tab1	$0	$4,591,624
RRR 2.1.7 for 2011	$4,591,624	$0

Please provide an explanation for the discrepancy.

RESPONSE:

At December 31, 2011, the balance in account 1562 was $4,591,624 and there was no balance in account 1560. This is a clerical error that resulted from manually transcribing the amounts from PowerStream's trial balance report into the Board's RRR input screen. PowerStream will correct the RRR filing.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #50:

Reference(s): Ref: EA1 / T2/ S1/p.2, and EI/T1/S10/p.1

In the case of account 1508, sub account IFRS Transitional costs, PowerStream is proposing to dispose the projected balances as at December 31, 2012. PowerStream is proposing to keep the account open so that any variances between the actual and approved amounts can be reviewed by the Board for disposition in the future.

a. The normal practice of the Board is to dispose the audited balances and not to clear the projected or forecasted costs in the deferral and variance accounts. What is the rationale for PowerStream to propose Board approval for disposition of unaudited balances?

b. Please clarify whether PowerStream is proposing to dispose of the projected balances to December 31, 2012 on an interim basis.

RESPONSE:

a) PowerStream is requesting disposal of the forecasted balance in account 1508, sub account IFRS Transitional costs as of December 31, 2012, as it believes that this amount can be forecasted with considerable accuracy. The amount of revenue going into this account is known and over 75% of the projected total costs are in the audited December 31, 2011 amount. As the transition to IFRS will be completed in 2012, PowerStream feels that it is more appropriate to review these costs now and return the projected credit balance to customers rather than waiting until the next cost of service application.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

b) PowerStream is proposing that the amount be reviewed and approved at this time but that the account remain open to track any differences between the actual and forecasted costs. PowerStream is confidential that any differences will be small and can be dealt with expediently in a future application.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #51:

Reference(s): E I Account 1562

Please file the 2003 federal and Ontario PILs tax returns for Aurora. It appears that the 2004 tax returns were filed to support both the 2003 and 2004 SIMPIL models.

RESPONSE:

Please refer to the attached Appendix A for the 2003 Aurora Tax Return.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #52:

Reference(s): E I Account 1562 Continuity Schedules/ Appendix 5/ Schedules 5-1 to 5-5

For each of the service areas, please explain how PowerStream calculated the PILs amounts contained in the unbilled revenue accruals at each December year end from 2002 through 2005 and at April 30, 2006.

RESPONSE:

PowerStream is unable to locate this detailed information regarding the earlier years within the time frame for these IR responses. Some of the predecessor utilities accrued unbilled PILs at year end and some did not. If amounts were accrued these were subsequently reversed leaving what was actually billed in account 1562.

PowerStream's billing system split out the amount billed into the PILs amount and booked this directly to account 1562. In 2006 these billing codes were coded as effective until April 30, 2006 and were applied to any portion of bills related to April 30, 2006 and prior.
At April 30, 2006 PowerStream accrued unbilled PILs. In the following months PowerStream continued to book actual PILs billed related to April 30, 2006 and prior to account 1562.,reverse previous months' accruals and accrue unbilled amounts

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #53:

Reference(s): E I Account 1562 Markham SIMPIL Models for 2003 and 2004: App. 5/Sch 5-14, p.9 and Sch 5-15, p.11

In the 2003 and 2004 SIMPIL models in sheet Reserves as referenced above, Markham shows amounts for holdbacks. Please describe the nature of these reserve amounts and whether they relate to unpaid bonuses.

RESPONSE:

PowerStream was unable to locate the supporting documentation but believes that these are holdbacks on amounts due to suppliers for construction work performed for PowerStream on which an amount, often 15%, is withheld pending satisfactory completion of the project.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #54:

Reference(s): **E I Vaughan 2001 SIMPIL Model: App. 5/Sch. 5-22**

Board staff cannot locate the T2 Schedule 1 that supports the entries in Vaughan's 2001 SIMPIL model. Please file the schedule or identify the evidence page reference.

RESPONSE:

The T2 Schedule 1 is attached as Appendix B.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #55:

Reference(s): E I Vaughan 2002 SIMPIL Model App. 5/Sch 5-23/p. 9 and App. 5/Sch. 5-26/p.30

On the Reserve schedule, an amount of $200,000 has been entered as an allowance for doubtful accounts. This amount trues up to ratepayers. However, on the 2002 Statement of Adjustments, which is the second reference above, the amount of $200,000 was disallowed as a deduction for tax purposes. Immediately above this entry on the Statement of Adjustments, there is an amount of $165,842 related to a disallowance for pre-October 1, 2001 bad debt write-offs. Please explain why this amount of $200,000 should true up to ratepayers when it has been disallowed by the tax authorities. If PowerStream agrees that this amount should not true up to ratepayers, please enter the amount on sheet TAXREC3 and file a revised continuity schedule.

RESPONSE:

PowerStream's bad debt expense was disallowed since the allowance for doubtful accounts was not estimated based on specific accounts. There is no question that bad debt expenses were incurred and the auditors accepted PowerStream's estimate. However for tax purposes, in the absence of a specific account identification, only amounts actual written off are allowed. Accordingly the bad debt expense amount was added back for tax purposes. It is PowerStream's understanding that this is a timing difference between tax and accounting and like other reserve amounts is a valid true-up item that should true-up to ratepayers and thus is shown on TAXREC2. PowerStream submits that no adjustment is required.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #56:

Reference(s): <u>E I 2001 to 2005 SIMPIL Models, Actual and Deemed Interest Expense for Tax Years 2001 to 2005 for True-up Calculations</u>

When the actual interest expense, as reflected in the financial statements and tax returns, exceeds the maximum deemed interest amount approved by the Board, the excess amount is subject to a claw-back penalty and is shown in the TAXCALC worksheet as an extra deduction in the true-up calculations.

For each service area of Markham, Richmond Hill, Vaughan, Aurora and PowerStream South for 2001 through 2005 please respond to the following questions:

a. Please provide a table for the years 2001 to 2005 that shows all of the components of interest expense and the amount associated with each type of interest. For each year, please balance the numbers in the table to the financial statements, to the tax returns and to the amounts used in SIMPIL sheet TAXCALC for the interest true-up calculations.

b. Did the distributor have interest expense related to other than debt that is disclosed as interest expense in its financial statements?

c. Did the distributor net interest income against interest expense in deriving the amount it shows as actual interest expense in the SIMPIL models? If yes, please provide details to what the interest income relates and explain why interest income and expense should be netted to reduce the interest expense used in the true-up calculations.

d. The Board has decided in a number of recent decisions (Hydro One Brampton, EB-2011-0174, December 22, 2011, Kingston Hydro, EB-2011-0178, April 19, 2012 and Innisfil

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

Hydro, EB-2011-0176, April 19, 2012) that interest expense used to calculate the interest claw-back variance should not include interest on customer deposits. Please provide models which exclude interest expense on customer security deposits in interest expense for purposes of the interest true-up calculations.

e. Did the distributor include interest income on customer security deposits in the disclosed amount of interest expense in its financial statements and tax returns?

f. Did the distributor incur interest expense or standby fees or charges on IESO or other prudentials? Please provide a table that lists all of the prudential costs by year for 2001-2005 with the amounts by type of charge for letters or lines of credit whether shown as interest expense or as OM&A. The Board has decided in a number of recent decisions (Burlington Hydro, EB-2011-015, March 20, 2012, Kitchener-Wilmot Hydro, EB-2011-0179, April 4, 2012 and Thunder Bay Hydro Electricity Distribution Inc., EB-2011-0197, April 4, 2012) that prudential costs are interest expense and should be included in the interest claw-back variance calculations.

g. Did the distributor include interest carrying charges on regulatory assets or liabilities in interest expense?

h. Did the distributor include the amortization of debt issue costs, debt discounts or debt premiums in interest expense?

i. Did the distributor deduct capitalized interest in deriving the interest expense disclosed in its financial statements? If the answer is yes, did the distributor add back the capitalized interest to the actual interest expense amount for purposes of the interest true-up

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

calculations? Please explain.

j. If a revision has been made to the SIMPIL interest claw-back calculations, please file the revised SIMPIL models and update the PILs continuity schedule and final balance for disposition in active Excel format.

RESPONSE:

a) PowerStream can find little or no detailed analysis of the financial statement interest expense in the year end working papers for most years prior to 2005. This type of analysis was not required to complete the year-end audited financial statements so it was likely not done.

The attached Table Board Staff #56-1 provides a breakdown of interest expense based on information drawn or inferred from the financial statement, the tax returns and where available any supporting financial analysis on interest expense.

Please note that PowerStream has made some adjustment to expense to reflect the fact that some items included in interest expense are of a non-distribution nature, are not part of the deemed interest included in rates and should not be included in the interest expense for purposes of the interest true-up calculation. A good example of this would be the interest cost on the goodwill (excess of purchase price over net book value (NBV)) on the purchase of Richmond Hill Hydro (RHHI) by Markham Hydro and Hydro Vaughan on December 27, 2001. Rates are based on the NBV of RHHI’s assets so the cost of this is not added to rates but paid for by the shareholder. Since the cost is borne entirely by the shareholder, they should be entitled to any resulting tax benefit.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

PowerStream has also made some adjustments to reflect the fact that due to growth the actual rate base in 2001 through 2005 is larger than the 1999 rate base on which the deemed interest amount is calculated.

b) PowerStream and the predecessor utilities appears to have included interest on overdrafts, interest on customer deposits, fees paid on prudentials, and letters of credit in interest expense, with the exception of Aurora Hydro which has only included interest on long term debt.

c) PowerStream and the predecessor utilities do not appear to have included any significant amounts of interest income in calculating interest expense. PowerStream thinks due to the seasonal nature of the business and variations in the levels of revenue and costs, it may be prudent to keep extra cash available temporarily. In these cases any interest earned on the surplus funds should be offset again the interest expense on debt.

d) PowerStream has estimated or identified the interest expense on customer deposits in Table Board Staff#56-1 in response to part (a). Where it appears that interest on customer deposits has been included in interest expense, these amounts have been deducted in arriving at interest expense for purposes of the interest true-up calculation. Please see the response to part (j) regarding updated models.

e) PowerStream records interest income separately in other income and believes this has been done similarly by its predecessor utilities.

f) Due to the age of the information and staff turnover, PowerStream is unable to complete this request in the time frame for the responses to these IRs. PowerStream is uncertain whether these costs have been included in interest expense. PowerStream submits that based on the Table Board Staff#56-2 in part (j), it is unlikely that adding these amounts would change the outcome of the interest true-up calculation.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

g) PowerStream did include the net interest expense on regulatory assets and liabilities in interest expense and this has been removed in Table Board Staff #56-1 in calculating the amount of interest expense for purposes of the interest true-up calculation. The predecessor utilities do not appear to have included this so no adjustment was made.

h) PowerStream has included the amortization of debt issue costs and debt discounts in interest expense on an accounting basis and adjusted these to a tax basis in filing its tax returns.

i) PowerStream and Richmond Hill Hydro did capitalize interest for accounting purpose and deduct to tax filings. This has been added back in Table Board Staff #56-1 in determining interest expense for purposes of the interest true-up calculation.

j) Table Board Staff #56-2 below summarizes the interest expense for purposes of the interest true-up calculation compared to the deemed interest as per Table Board Staff #56-1.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

Table Board Staff #56-2: Interest Expense vs. Deemed Interest

Summary	Oct 1/2001 to Dec 31/2001	Jan 1/2002 to Dec 31/2002	Jan 1/2003 to Dec 31/2003	Jan 1/2004 to Dec 31/2004	Jan 1/2005 to Oct 31/2005	Nov 1/2005 to Dec 31/2005
Interest for purpose of excess interest calculation						
Aurora Hydro	$ 232,300	$ 923,360	$ 923,360	$ 923,360	$ 770,942	$ -
Markham Hydro	$ 1,216,019	$ 3,721,809	$ 4,361,683	$ 1,729,655	$ -	$ -
Richmond Hill Hydro	$ 1,093,944	$ 2,172,638	$ 3,220,775	$ 1,269,457	$ -	$ -
Hydro Vaughan	$ 1,255,163	$ 4,051,087	$ 5,223,222	$ 2,134,766	$ -	$ -
PowerStream				$ 9,004,218	$ 11,112,795	$ 2,393,333
Total	**$ 3,797,426**	**$ 10,868,894**	**$ 13,729,040**	**$ 15,061,457**	**$ 11,883,737**	**$ 2,393,333**
Deemed Interest						
Aurora Hydro	$ 261,044	$ 1,044,174	$ 1,044,174	$ 1,044,174	$ 870,145	
Markham Hydro	$ 1,270,621	$ 5,082,484	$ 5,082,484	$ 2,116,541	$ -	
Richmond Hill Hydro	$ 1,012,665	$ 4,017,640	$ 4,017,640	$ 1,673,099	$ -	$ -
Hydro Vaughan	$ 1,755,154	$ 6,963,384	$ 6,963,384	$ 2,899,820	$ -	
PowerStream				$ 9,417,470	$ 13,378,089	$ 2,858,925
Total	**$ 4,299,484**	**$ 17,107,682**	**$ 17,107,682**	**$ 17,151,105**	**$ 14,248,234**	**$ 2,858,925**
"Excess" interest	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

PowerStream submits that there is no excess interest to true-up. While there may be some change in the details, the amount of excess interest remains $0, unchanged from the models filed. Accordingly PowerStream does not propose to file updated SIMPIL models or make any changes to the PILs continuity schedule.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #57:

Reference(s): E I App. 5/ Sch. 5-1/ pp. 1-9

Did PowerStream include the retroactive repeal of the Large Corporation Tax as at January 1, 2006 in the PILs continuity schedule? If the answer is yes, please provide the calculations of how the amount was determined and where it appears in the evidence. If the answer is no, please explain why this amount has not been included in the continuity schedule.

RESPONSE:

As noted above, PowerStream was no longer subject to Large Corporations Tax (LCT) retroactive to January 1, 2006., The PILS proxy was adjusted to remove LCT from rates effective May 1, 2007. PowerStream calculated the amount of LCT in its PILs proxy for the period January 1, 2006 to April 30, 2006 as $203,560. This is shown as $50,890 per month in the account1562 continuity schedule for these months. The amount relating to the period May 1, 2006 to April 30, 2007 was recorded in account 1592.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

The LCT amount to be recorded in account 1560 was determined as follows:

Table Board Staff #7-1: 2005 Approved PILs Proxy – Grossed up LCT

Utility	LCT amount
Aurora Hydro	$ -
Markham Hydro	$ 171,090
Richmond Hill Hydro	$ 153,301
Hydro Vaughan	$ 286,284
Total	**$ 610,675**
Per month	**$ 50,890**

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

BOARD STAFF INTERROGATORY #58:

Reference(s): <u>E I 2001 to 2005 Tax Returns</u>

For each service area, please confirm that all tax years from 2001 to 2005 are now statute-barred.

RESPONSE:

PowerStream confirms that the tax years 2001 to 2005 are now statute-barred with one exception. PowerStream signed waivers for 2004 and 2005 with respect to the tax treatment of Retail Settlement Variances (RSVAs).

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

CCC INTERROGATORY #59:

Reference(s): (I/T1/S2/p. 1

Please provide a detailed breakdown of the $13.030 in smart meter costs. What has been the total spent on smart meters to date - total program costs, both operating and capital costs and the amounts already recovered from ratepayers?

RESPONSE:

PowerStream applied for its last smart meter cost recovery in 2011 (EB-2011-0128). This application covered all smart meter installations up to April 30, 2011. In this proceeding two items were identified to be disposed at a later date: (1) stranded meter costs, and (2) the customer premise costs required to resolve installation issues preventing installation of smart meters in a number of cases. PowerStream is now seeking to dispose of these costs.

Table CCC# 59-1: Summary of Smart Meter Costs for Disposition ($000)

Account Description	Account #	December 31, 2011	Explanation
Smart Meter Capital and Recovery	1555	$12,789	Net book value of stranded meters
Smart Meter OMA	1556	$241	Customer premises expenses relating to problematic smart meter installations after April 30, 2011
Total		$13,030	

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

Additional details of these costs are provided in the tables below.

Table CCC #59-2: Stranded Meter Costs ($000)

Year and Type	# of Units	Estimated Unit Cost	Gross Cost	Accumulative Depreciation as of Dec 2011	NBV 2011
Residential					
2007	76,012	$99	$7,558	$(5,066)	$2,492
2008	43,630	$99	$4,338	$(2,889)	$1,449
2009	81,695	$99	$8,124	$(5,369)	$2,755
2010	57,232	$99	$5,690	$(3,726)	$1,964
2011	1,862	$99	$185	$(120)	$65
Total Residential	260,431	n/a	$25,895	$(17,170)	$8,725
General Service <50					
2009	2,453	$299	$733	$(334)	$399
2010	10,738	$293	$3,147	$(1,439)	$1,708
2011	12,200	$295	$3,596	$(1,639)	$1,957
Total GS <50	25,391	n/a	$7,476	$(3,412)	$4,064
Grand Total	**285,822**	**n/a**	**$33,371**	**$(20,582)**	**$12,789**
NOTE: 2012 depreciation was deducted from the above 2011 NBV balance in determining the disposition amount for account 1555					

Table CCC#59-3: OM&A Customer Premises ($000)

Description	Amount, $000
Contract labour	$133
Internal labour	$103
Vehicle costs	$4
Parts	$1
Total	**$241**

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

PowerStream has spent and received approval for smart meter capital costs of $49.6 million and OM&A and depreciation expenses of $8.0 million for a total of $57.6 million. PowerStream has collected a total of $16.0 million in smart meter funding adder from customers. PowerStream does not separately track revenues and expenses related to smart meters after approval.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

CCC INTERROGATORY #60:

Reference(s): (I/T1/S8)

How are the smart meter costs recovered from each of the customer classes?

RESPONSE:

Smart Meters costs remaining in the deferral accounts were tracked by rate zone and allocated by the number of metered customers. The allocation factors can be found in Exhibit I, Tab 1, schedule 3, Sheet 4 Allocators in the South and Barrie rate rider calculation models.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

SEC INTERROGATORY #51:

Reference(s): [A3/1/5, p. 21]

Please provide a detailed breakdown of the costs included in the IFRS Transition Costs Deferral Account.

RESPONSE:

Please see Appendix 2-U IFRS Transition Costs filed in the response to Staff IR#5.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

SEC INTERROGATORY #52:

Reference(s): [A3/1/5, p. 22]

Please confirm that opening balances as at January 1, 2011 and December 31, 2011 year end information were previously audited by your auditors. Please describe the incremental work required to apply those audit results to the MIFRS adjustments.

RESPONSE:

PowerStream's external auditors (Deloitte & Touche) have audited the December 31, 2010 and December 31, 2011 financial statements under CGAAP.

The additional work performed by external auditors for IFRS is as follows:

January 1, 2011 opening IFRS balances:

- Review of white papers that outlined differences between CGAAP and IFRS, along with analysis of PowerStream's current and proposed position for treatment under IFRS;
- Review of new policies, procedures, and process flow documents that were prepared in compliance with the IFRS standards, and instructions provided to departments affected by these changes;
- Property Plant & Equipment (PP&E) – Deemed cost (carry-forward net book value) and change in useful lives in the fixed asset subledger;
- Post Retirement Employee Benefits (PREB) – examine actuarial valuation prepared under IFRS standards;

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit I)

5.1 Is the proposed clearance of deferral and variance account balances appropriate?

- Regulatory assets and liabilities (RAL) – Examination of the mapping used to record the opening RAL balances into retained earnings, PP&E (e.g. smart meter assets), or other balance sheet accounts upon transition to IFRS;
- Future income tax assets – examine calculation for opening balance based on elimination of regulatory accounts and other day one adjustments; and
- System testing on the three ledgers used to track differences between CGAAP, MIFRS, and IFRS in the JD Edwards accounting system, assessing controls and integrity of data.

December 31, 2011 and 2011 comparative balances under IFRS:

- PP&E – Testing of IFRS continuity schedule, including burdens, depreciation, interest capitalization, derecognition and damage claims;
- PREB –actuarial valuation prepared under IFRS standards;
- Regulatory assets and liabilities – Examination of the mapping used to record the fiscal 2011 transactions in RAL to the various income statement or balance sheet accounts;
- System testing on the transactions posted in the three ledgers including system-generated burdens and depreciation calculations;
- System testing on the cutover from entering source transactions in the CGAAP ledger to making the primary ledger MIFRS; and
- Examine draft financial statements and disclosures under IFRS.

Interest Expense 2001-2005

Aurora Hydro	Financials Jan 1/2001 to Dec 31/2001	Split Oct 1/2001 to Dec 31/2001	Financials Jan 1/2002 to Dec 31/2002	Financials Jan 1/2003 to Dec 31/2003	Financials Jan 1/2004 to Dec 31/2004	Financials Jan 1/2005 to Oct 31/2005
Interest Expense per Financial Statements	**$ 5,839**	**$ 1,460**	**$ 1,154,200**	**$ 923,360**	**$ 923,360**	**$ 770,942**
Estimated breakdown:						
Misc. interest expense	$ 5,839	$ 1,460				
Interest on promissory note	$ -		$ 1,154,200	$ 923,360	$ 923,360	$ 770,942
subtotal	**$ 5,839**	**$ 1,460**	**$ 1,154,200**	**$ 923,360**	**$ 923,360**	**$ 770,942**
Accrue promissory note interest re Oct 1 to Dec 31/2001		$ 230,840	$ (230,840)			
Interest for purpose of excess interest calculation	**$ 5,839**	**$ 232,300**	**$ 923,360**	**$ 923,360**	**$ 923,360**	**$ 770,942**
Deemed Interest	$ 1,044,174	$ 261,044	$ 1,044,174	$ 1,044,174	$ 1,044,174	$ 870,145
"Excess" Variance		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Interest per Finanacials		**$ 1,460**	**$ 1,154,200**	**$ 923,360**	**$ 923,360**	**$ 770,942**
tax adjustments - none						
Interest expense for tax purposes		**$ 1,460**	**$ 1,154,200**	**$ 923,360**	**$ 923,360**	**$ 770,942**

Markham Hydro	Financials Jan 1/2001 to Dec 31/2001	Split Oct 1/2001 to Dec 31/2001	Financials Jan 1/2002 to Dec 31/2002	Financials Jan 1/2003 to Dec 31/2003	Financials Jan 1/2004 to May 31/2004
Interest Expense per Consolidated Financial Statements			$ 6,047,000	$ 7,321,000	$ 2,902,000
Less share of interest from RHHI financial statements			$ (1,142,804)	$ (1,696,369)	$ (664,189)
Unconsolidated Interest Expense per Financial Statements	**$ 1,833,000**		**$ 4,904,196**	**$ 5,624,631**	**$ 2,237,811**
Estimated breakdown:					
Interest on promissory note	$ 1,187,655	$ 1,187,655	$ 3,169,342	$ 3,169,342	$ 1,320,559
Interest on old dentures	$ 104,383	$ 26,096	$ 27,913	$ -	
Interest on EDFIN dentures			$ 806,250	$ 1,935,000	$ 806,250
Financing fee & debt issuance cost amortization			$ 12,400		
Short term loan and misc. interest expense	$ 485,190	$ 121,297	$ 778,023	$ 329,460	$ 48,098
Interest on customer deposits	$ 55,773	$ 13,943	$ 110,268	$ 190,829	$ 62,904
subtotal	**$ 1,833,000**	**$ 1,348,991**	**$ 4,904,196**	**$ 5,624,631**	**$ 2,237,811**
Deduct interest above deemed on old dentures at 9.625%		$ (7,117)			
Deduct Interest on deposit re investment in RHHI		$ (93,750)			
Deduct Interest on goodwill on investment in RHHI		$ (33,214)	$ (1,072,119)	$ (1,072,119)	$ (445,252)
Adjust for actual rate base vs. 1999		$ 15,052			
Interest on customer deposits		$ (13,943)	$ (110,268)	$ (190,829)	$ (62,904)
Interest for purpose of excess interest calculation		**$ 1,216,019**	**$ 3,721,809**	**$ 4,361,683**	**$ 1,729,655**
Deemed Interest	$ 5,082,484	$ 1,270,621	$ 5,082,484	$ 5,082,484	$ 2,116,541
"Excess" Variance		**$ -**	**$ -**	**$ -**	**$ -**
Interest per Finanacials		**$ 1,348,991**	**$ 4,904,196**	**$ 5,624,631**	**$ 2,237,811**
Financing fee & debt issuance cost amortization			$ (12,400)	$ (175,388)	$ (73,078)
Deferred finanancing fee		$ 3,596	$ 80,140	$ 80,140	$ 33,283
Interest expense for tax purposes	**$ 5,082,484**	**$ 1,352,587**	**$ 4,971,936**	**$ 5,529,383**	**$ 2,198,016**

Richmond Hill Hydro (RHHI)	Financials Jan 1/2001 to Dec 31/2001	Split Oct 1/2001 to Dec 31/2001	Financials Jan 1/2002 to Dec 31/2002	Financials Jan 1/2003 to Dec 31/2003	Financials Jan 1/2004 to May 31/2004
Interest Expense per Financial Statements	**$ 1,401,595**		**$ 2,285,607**	**$ 3,392,737**	**$ 1,328,377**
Estimated breakdown:					
Interest on promissory note	$ 1,012,665	$ 1,012,665			
Debenture interest	$ 277,426	$ 69,357			
Short term loan and misc. interest expense	$ 47,691	$ 11,923	$ 1,232,013	$ 956,296	$ 322,616
Interest adnd penalites on taxes				$ 6,979	$ 6,216
Interest on EDFIN dentures			$ 940,625	$ 2,257,500	$ 940,625
Interest on customer deposits	$ 63,813	$ 15,953	$ 112,969	$ 171,962	$ 58,920
subtotal	**$ 1,401,595**	**$ 1,109,898**	**$ 2,285,607**	**$ 3,392,737**	**$ 1,328,377**
Interest on customer deposits		$ (15,953)	$ (112,969)	$ (171,962)	$ (58,920)
Interest for purpose of excess interest calculation		**$ 1,093,944**	**$ 2,172,638**	**$ 3,220,775**	**$ 1,269,457**
Deemed Interest	$ 4,017,640	$ 1,012,665	$ 4,017,640	$ 4,017,640	$ 1,673,099
"Excess" Variance		**$ 81,279**	**$ -**	**$ -**	**$ -**
Interest per Finanacials		**$ 1,109,898**	**$ 2,285,607**	**$ 3,392,737**	**$ 1,328,377**
Interest and penaties not allowed				**$ (6,979)**	**$ (6,216)**
Deferred finanancing fee			$ (14,975)	$ (35,726)	$ (68,754)
Sec 20(1)e deduction re debt issuance			$ 71,511	$ 71,511	$ 29,800
Interest capitalized - deduct for tax			$ 56,610		
Interest expense for tax purposes	**$ 4,017,640**	**$ 1,109,898**	**$ 2,398,753**	**$ 3,421,543**	**$ 1,283,207**

Vaughan Hydro	Financials Jan 1/2001 to Dec 31/2001	Split Oct 1/2001 to Dec 31/2001	Financials Jan 1/2002 to Dec 31/2002	Financials Jan 1/2003 to Dec 31/2003	Financials Jan 1/2004 to May 31/2004
Interest Expense per Consolidated Financial Statements			$ 6,769,000		$ 3,432,000
Less share of interest from RHHI financial statements			$ (1,142,804)		$ (664,189)
Unconsolidated Interest Expense per Financial Statements	**$ 3,187,323**		**$ 5,626,196**	**$ 6,810,068**	**$ 2,767,811**
Estimated breakdown:					
Interest on promissory note	$ 787,500	$ 787,500	$ 925,000	$ 320,770	$ -
Interest on Note payable	$ 2,289,789	$ 577,152	$ 3,600,000	$ 3,600,000	$ 1,500,000
Interest on EDFIN dentures			$ 940,625	$ 2,257,500	$ 940,625
Amortization of debt issue costs				$ 257,779	$ 107,407
Short term loan and misc. interest expense	$ (20,973)		$ (62,367)	$ 14,796	$ 96,566
Interest on customer deposits	$ 131,007	$ 32,752	$ 222,938	$ 359,223	$ 123,213
subtotal	**$ 3,187,323**	**$ 1,397,404**	**$ 5,626,196**	**$ 6,810,068**	**$ 2,767,811**
Deduct interest above deemed on old dentures at 9.625%					
Deduct Interest on deposit re investment in RHHI	$ (375,000)	$ (94,521)			
Deduct Interest on goodwill on investment in RHHI			$ (1,054,253)	$ (1,054,253)	$ (437,832)
Adjust for actual rate base vs. 1999		$ (14,968)	$ (297,918)	$ (173,370)	$ (72,000)
Interest on customer deposits		$ (32,752)	$ (222,938)	$ (359,223)	$ (123,213)
Interest for purpose of excess interest calculation		**$ 1,255,163**	**$ 4,051,087**	**$ 5,223,222**	**$ 2,134,766**
Deemed Interest	$ 6,963,384	$ 1,755,154	$ 6,963,384	$ 6,963,384	$ 2,899,820
"Excess" Variance		**$ -**	**$ -**	**$ -**	**$ -**
Interest per Finanacials		**$ 1,397,404**	**$ 5,626,196**	**$ 6,810,068**	**$ 2,767,811**
Finance charge		$ -	**$ (96,667)**	**$ (257,779)**	**$ (107,407)**
Financing fee & debt issuance cost amortization		$ -	$ (314,064)		
Deferred finanancing fee		$ -	$ 463,057	$ 463,057	$ 112,306
Interest expense for tax purposes	**$ 6,963,384**	**$ 1,397,404**	**$ 5,678,522**	**$ 7,015,346**	**$ 2,772,710**

PowerStream Inc.	Financials Jun 1/2004 to Dec 31/2004	Financials Jan 1/2005 to Dec 31/2005	Split Jan 1/2005 to Oct 31/2005	Split Nov 1/2005 to Dec 31/2005
Interest Expense per Financial Statements	$ 11,680,000	$ 19,305,000		
Estimated breakdown:				
EDFIN Debenture interest	$ 3,882,586	$ 6,450,000	$ 5,375,000	$ 1,075,000
EDFIN - amortization of debt discount	$ 233,423	$ 553,964	$ 461,637	$ 92,327
Interest on retailer deposits	$ 5,126			
Other interest expense		$ 3,512,648	$ 2,927,207	$ 585,441
Interest on customer deposits	$ 149,235	$ 312,477	$ 260,398	$ 52,080
Bank Charges and interest	$ 1,458,366			
Amortization of debt discount and expense	$ 3,626			
Interest on promissory notes		$ 9,261,767	$ 7,718,139	$ 1,543,628
Interest on note payable - Markham	$ 2,220,285			
Interest on note payable - Vaughan	$ 2,559,548			
Interest on dividend - Vaughan	$ 813,750			
Interest capitalized (AFUDC)		$ (785,397)	$ (690,734)	$ (94,663)
Miscellaneous interest/overdraft/penalties	$ 375,380			
Interest on income taxes per OEFC	$ (20,538)			
subtotal	**$ 11,680,786**	**$ 19,305,459**	**$ 16,051,646**	**$ 3,253,813**
Deduct Interest on goodwill on investment in RHHI	$ (1,244,080)		$ (1,772,133)	$ (355,593)
Adjust for actual rate base vs. 1999	$ 72,510		$ (607,313)	$ 52,644
Deduct bank charges included in interest	$ (43,852)			
Interest on customer deposits	$ (149,235)		$ (260,398)	$ (52,080)
Interest on PILs	$ 20,538			
Interest expense on regulatory liabilities	$ (1,332,449)		$ (2,989,742)	$ (599,915)
Interest capitalized - deduct for tax			$ 690,734	$ 94,463
Interest for purpose of excess interest calculation	**$ 9,004,218**		**$ 11,112,795**	**$ 2,393,333**
Deemed Interest	$ 9,417,470	$ 16,062,508	$ 13,378,089	$ 2,858,925
"Excess" Variance	**$ -**		**$ -**	**$ -**
Interest per Finanacials	**$ 11,680,000**	**$ 19,305,000**	**$ 16,051,646**	**$ 3,253,813**
Interest and penalties	$ (37,411)		$ (4,851)	
Sec 20(1)e deduction re debt issuance	$ 245,476		$ 351,006	$ 70,432
Interest capitalized - deduct for tax			$ 690,734	$ 94,663
Interest expense for tax purposes	**$ 11,888,065**		**$ 17,088,535**	**$ 3,418,908**

2003 PowerStream Aurora Tax Return

Canada Customs and Revenue Agency | Agence des douanes et du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

Schedule 200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporate return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing. If you need more information about items on the return, see the corresponding items in the *T2 Corporation - Income Tax Guide (T4012)*.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax services office or tax centre. You have to file the return within six months after the end of the corporation's taxation year. For more information on when and how to file T2 returns, see items 1 to 5 in the guide.

055 Do not use this area

Identification

Business number (BN) (item 11) 001 86368 3165 RC 0001

Corporation's name (item 12)

002 Aurora Hydro Connections Limited

Has the corporation changed its name since the last time we were notified? 003 ☐ Yes ☒ No

If *yes*, do you have a copy of the articles of amendment? 004 ☐ Yes ☐ No

Address of head office (item 13)

Has the address changed since the last time we were notified? 010 ☐ Yes ☒ No

011 215 Industrial Parkway South

012 PO Box 157

City 015 Aurora — Province, territory, or state 016 ON

Country (other than Canada) 017 ____ — Postal code/Zip code 018 L4G 3H3

To which taxation year does this return apply? (item 17)

From 060 2003/01/01 to 061 2003/12/31

Has there been an acquisition of control to which subsection 249(4) applies since the previous taxation year? 063 ☐ Yes ☒ No

If *yes*, provide date control was acquired 065 ____

Is the corporation a professional corporation that is a member of a partnership? (item 18) 067 ☐ Yes ☒ No

Mailing address (if different from head office address) (item 14)

Has the address changed since the last time we were notified?

020 Yes ☐ No ☒

021 C/o ____

022 215 Industrial Parkway South

023 PO Box 157

City 025 Aurora — Province, territory, or state 026 ON

Country (other than Canada) 027 ____ — Postal code/Zip code 028 L4G 3H3

Is this the first year of filing after:

Incorporation? (item 19) 070 ☐ Yes ☒ No

Amalgamation? (item 20) 071 ☐ Yes ☒ No

If *yes*, complete Schedule 24

Has there been a wind-up of a subsidiary under section 88 during the current taxation year?(item 21)

If *yes*, complete Schedule 24 072 ☐ Yes ☒ No

Location of books and records (item 15)

031 215 Industrial Parkway South

032 PO Box 157

City 035 Aurora — Province, territory, or state 036 ON

Country (other than Canada) 037 ____ — Postal code/Zip code 038 L4G 3H3

Is this the final taxation year before amalgamation? (item 22) 076 ☐ Yes ☒ No

Is this the final return up to dissolution? (item 23) 078 ☐ Yes ☒ No

Is the corporation a resident of Canada? (item 24) 080 ☒ Yes ☐ No

If *no*, give the country of residence. 081 ____

040 Type of corporation at end of taxation year (item 16)

1 ☒ Canadian controlled private corporation (CCPC)

2 ☐ Other private corporation

3 ☐ Public corporation

4 ☐ Corporation controlled by a public corporation

5 ☐ Other corporation (please specify, below)

____

If the type of corporation changed during the taxation year, provide the effective date of the change 043 ____

Is the non-resident corporation claiming an exemption under an income tax treaty? (item 24) 082 ☐ Yes ☒ No

If *yes*, complete Schedule 91

If the corporation is exempt from tax under section 149, tick one of the following boxes: (item 25)

085 1 ☐ Exempt under 149(1)(e) or (l)

2 ☐ Exempt under 149(1)(j)

3 ☐ Exempt under 149(1)(t)

4 ☐ Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
097					

Attachments

Guide item		Line	Yes	Schedule
27	Is the corporation related to any other corporations?	150	X	9
28	Does the corporation have any non-resident shareholders?	151		19
29	Is the corporation an associated Canadian-controlled private corporation (CCPC)?	160	X	23
30	Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
32	Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
33	If you answered *yes* to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
34	Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
35	Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
37	Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
38	Is the corporation a member of a partnership for which an identification number has been assigned?	167	X	T5013
40	Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
41	Did the corporation have any foreign affiliates during the year?	169		25
42	Has the corporation made any payments to non-residents of Canada under subsections 202(1) and 105(1) of the federal *Income Tax Regulations*?	170		29
43	Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
47	Has the corporation made payments to, or received amounts from a retirement compensation arrangement?	172		-----
46	Does the corporation (private corporations only) have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
55	Is the net income/loss shown on financial statements different from the net income for income tax purposes?	201	X	1
78-81	Has the corporation made any charitable donations, gifts to Canada, a province, or a territory, or gifts of cultural or ecological property?	202		2
82,104	Has the corporation received dividends or paid taxable dividends for purposes of the dividend refund?	203		3
69-76	Is the corporation claiming any type of losses?	204	X	4
132	Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
56	Has the corporation realized any capital gains or incurred any capital losses during the taxation year?	206		6
103	(i) Is the corporation claiming the small business deduction and reporting income from : (a) property (other than dividends), (b) a partnership, (c) a foreign business, or (d) a personal services business; or (ii) is the corporation claiming the refundable portion of Part I tax?	207	X	7
57	Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
58	Does the corporation have any property that is eligible capital property?	210	X	10
59	Does the corporation have any resource-related deductions?	212		12
60	Is the corporation claiming reserves of any kind?	213	X	13
61	Is the corporation claiming a patronage dividend deduction?	216		16
62	Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
150	is the corporation an investment corporation or a mutual fund corporation?	218		18
131	Was the corporation carrying on business in Canada as a non-resident corporation?	220		20
118	Is the corporation claiming any federal or provincial foreign tax credits, or logging tax credits?	221		21
155	Is the corporation a non-resident-owned investment corporation claiming an allowable refund?	226		26 *
111	Does the corporation have any Canadian manufacturing and processing profits?	227		27
121	Is the corporation claiming an investment tax credit?	231		31
63	Is the corporation claiming any scientific research and experimental development expenditures?	232		T661/T665
124	Is the corporation subject to Part 1.3 tax?	233	X	33/34/35
124	Is the corporation a member of a related group with one or more members subject to gross Part 1.3 tax?	236	X	36
124	Is the corporation claiming a surtax credit?	237		37
128	Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
128	Is the corporation claiming a Part I tax credit?	242		42
129	Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
129	Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
125	Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
128	For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
128	For life insurance corporations: Is the corporation a member of a related group of insurance corporations with one or more members subject to the additional gross Part VI tax?	251		40

Attachments - Continued from page 2

Guide item		Yes	Schedule
128	For deposit-taking institutions: Is the corporation a member of a related group of financial institutions (other than life insurance corporations) with one or more members subject to the additional Part VI tax?	252 ☐	41
152	Is the corporation claiming a Canadian film or video production tax credit refund?	253 ☐	T1131
130	Is the corporation subject to Part XIII.1 tax?	☐	92 *
153	Is the corporation claiming a film or video production services tax credit refund?	☐	T1177
44	Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	☐	T1134-A
44	Did the corporation have any controlled foreign affiliates?	☐	T1134-B
44	Did the corporation own specified foreign property in the year with a cost amount over $100,000?	☐	T1135
44	Did the corporation transfer or loan property to a non-resident trust?	☐	T1141
44	Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	☐	T1142
-	Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	☐	T1145
-	Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	☐	T1146
-	Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	☐	T1174

Additional information

Is the corporation inactive? (item 48)	280	1 Yes ☐	2 No ☒
Has the major business activity changed since the last return was filed? (enter yes for first time filers) (item 49)	281	1 Yes ☐	2 No ☒
What is the corporation's major business activity? (item 50) (Only complete if *yes* was entered at line 281.)	282		
If the major activity involves the resale of goods, indicate whether is is wholesale or retail (item 51)	283	1 Wholesale ☐	2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or service provided, giving the approximate percentage of the total revenue that each product or service represents. (item 52)

284	Hydro electricity	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the taxation year? (item 53)	291	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the taxation year? (item 54)	292	1 Yes ☐	2 No ☒

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements or GIFI (item 77)			300	723,132	A
Deduct: Charitable donations from Schedule 2 (item 78)	311				
Gifts to Canada or a province, or a territory from Schedule 2 (item 79)	312				
Cultural gifts from Schedule 2 (item 80)	313				
Ecological gifts from Schedule 2 (item 81)	314				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3 (item 82)	320				
Part VI.1 tax deduction from Schedule 43 (item 83)*	325				
Non-capital losses of preceding taxation years from Schedule 4 (item 84)	331	669,335			
Net capital losses of preceding taxation years from Schedule 4 (item 85)	332				
Restricted farm losses of prior taxation years from Schedule 4 (item 86)	333				
Farm losses of prior taxation years from Schedule 4 (item 87)	334				
Limited partnership losses of prior years from Schedule 4 (item 88)	335	636			
Taxable capital gains or taxable dividends allocated from a central credit union (item 89)	340				
Prospector's and grubstaker's shares (item 90)	350				
Subtotal		669,971	▶	669,971	B
Subtotal (amount A minus amount B) (if negative, enter "0")				53,161	C
Add: Section 110.5 additions and/or subparagraph 115(1)(a)(vii) additions (item 91)			355		D
Taxable income (amount C plus amount D) (item 92)			360	53,161	
Income exempt under paragraph 149(1)(t) (item 93)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 minus line 370) (item 94)					Z

* If the taxation year ends after December 31, 2002, use "3" Instead of "9/4" in the calculation of the Part VI.1 tax deduction indicated in item 83 of the *T2 Corporation Income Tax Guide*.

Small business deduction

Canadian-controlled private corporations throughout the taxation year

Income from active business carried on in Canada from Schedule 7 (item 95)	**400**	648,907	A
Taxable income from line 360 on page 3, **minus** 10/3 the amount at line 632* on page 7, **minus** 3 times the amount at line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax (item 96)	**405**	53,161	B

Calculation of the business limit: (item 97)

For all CCPCs, calculate the amount at line 4 below

$200,000 x	Number of days in the taxation year before 2003 / Number of days in the taxation year	/ 365	=		1
$225,000 x	Number of days in the taxation year in 2003 / Number of days in the taxation year	365 / 365	=	225,000	2
$250,000 x	Number of days in the taxation year in 2004 / Number of days in the taxation year	/ 365	=		3
	Add amounts at line 1, 2, and 3			225,000	4

Business limit (see notes 1 and 2 below)	**410**	222,750	C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 at line 410. However, if the corporation's taxation year is less than 51 weeks, prorate the amount from line 4 by the number of days in the taxation year divided by 365, and enter the result on like 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered at line 410

Business limit reduction: (item 98)

Amount C 222,750 X **415 ***** 39,173 D / 11,250 = 775,625 E

Reduced business limit (amount C minus amount E) (if negative, enter "0")	**425**	0	F
Small business deduction - 16% of the least of amounts A, B, C, and F	**430**	0	G

(enter amount G of line 9 on page 7)

Accelerated tax reduction (item 99)

Canadian-controlled private corporations throughout the taxation year that claimed the small business deduction

Reduced business limit (amount from line 425)	_______ x _______ =		A
Net active business income (amount from line 400)*			B
Taxable income from line 360 on page 3 **minus** 3 times the amount at line 636** on page 7, and minus any amount that, because of federal law, is exempt from Part I tax (item 96)		C	
Deduct:			
Aggregate investment income (amount from line 440 of page 6)		D	
Amount C minus amount D (if negative, enter "0")		▶	E
Amount A, B, or E above, whichever is less			F
Amount Z from Part 9 of Schedule 27	_______ x 100 / 7 =	G	
Amount QQ from Part 13 of Schedule 27		H	
Taxable resource income from line 435 on page 5		I	
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)		J	
Amount on line 400, 405, 410 or 425, whichever is less		K	
Total of amounts G, H, I, J, and K		▶	L
Amount F minus amount L (if negative, enter "0")			M
Accelerated tax reduction - 7% of amount M			N

(Enter amount N on line 637 of page 7)

* If the amount at line 450 of Schedule 7 is positive, members of partnerships need to use Schedule 70 to calculate net active business income.

** Calculate the amount of foreign business income tax credit deductible at line 636 without reference to the corporate tax reductions under section 123.4.

Resource deduction (item 100)

Taxable resource income			435		A
Amount A ______ x	Number of days in the taxation year in 2003 / Number of days in the taxation year	365 / 365	x 1% =		B
Amount A ______ x	Number of days in the taxation year in 2004 / Number of days in the taxation year	____ / 365	x 2% =		C
Resource deduction - amount B plus amount C (enter amount D on line 10 of page 7)			438		D

General tax reduction for Canadian-controlled private corporations (item 101)

Canadian-controlled private corporations throughout taxation year

Taxable income from line 360 page 3			53,161	A
Amount Z from Part 9 of Schedule 27 ______ x 100 / 7 =		B		
Amount QQ from Part 13 of Schedule 27		C		
Taxable resource income from line 435 above		D		
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)		E		
Amounts on lines 400, 405, 410, and 425 on page 4, whichever is less		F		
Aggregate investment income from line 440 of page 6	74,225	G		
Amount used to calculate the accelerated tax reduction (amount M of page 4)		H		
Total of amounts B, C, D, E, F, G, and H	74,225	▶	74,225	I
Amount A minus amount I (if negative, enter "0")				J

Amount J ______ x	Number of days in the taxation year in 2001 / Number of days in the taxation year	____ / 365	x 1% =		K
Amount J ______ x	Number of days in the taxation year in 2002 / Number of days in the taxation year	____ / 365	x 3% =		L
Amount J ______ x	Number of days in the taxation year in 2003 / Number of days in the taxation year	365 / 365	x 5% =		M
Amount J ______ x	Number of days in the taxation year after 2003 / Number of days in the taxation year	____ / 365	x 7% =		N

General tax reduction for Canadian-controlled private corporations - total of amounts K, L, M and N (enter amount O on line 638 of page 7) ______ O

General tax reduction (item 102)

Corporations other than a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or a non-resident-owned investment corporation

Taxable income from line 360 on page 3				A
Amount Z from Part 9 of Schedule 27 ______ x 100 / 7 =		B		
Amount QQ from Part 13 of Schedule 27		C		
Taxable resource income from line 435 above		D		
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)		E		
Total of amounts B, C, D and E		▶		F
Amount A minus amount F (if negative, enter "0")				G

Amount G ______ x	Number of days in the taxation year in 2001 / Number of days in the taxation year	____	x 1% =		H
Amount G ______ x	Number of days in the taxation year in 2002 / Number of days in the taxation year	____	x 3% =		I
Amount G ______ x	Number of days in the taxation year in 2003 / Number of days in the taxation year	____	x 5% =		J
Amount G ______ x	Number of days in the taxation year after 2003 / Number of days in the taxation year	____	x 7% =		K

General tax reduction - total of amounts H, I, J and K (enter amount L on line 639 of page 7) ______ L

Refundable portion of Part I tax (item 103)

Canadian-controlled private corporations throughout the taxation year

Aggregate investment income (Amount P from Part 1 of Schedule 7)	440	74,225 X 26 2/3 % =		19,793 A
Foreign non-business income tax credit from line 632 on page 7				
Deduct:				
Foreign investment income (Amount O from Part 1 of Schedule 7)	445	X 9 1/3 % = (if negative, enter "0")		B
Amount A **minus** amount B (if negative, enter "0")				19,793 C
Taxable income from line 360 on page 3			53,161	
Deduct:				
Least of amounts on lines 400, 405, 410, and 425 on page 4				
Foreign non-business income tax credit from line 632 on page 7		x 25/9 =		
Foreign business income tax credit from line 636 on page 7		x 3 =		
			53,161 X 26 2/3% =	14,176 D
Part I tax payable minus investment tax credit refund (line 700 minus line 780 on page 8)			19,024	
Deduct corporate surtax from line 600 on page 7			595	
Net amount			18,429	18,429 E
Refundable portion of Part I tax - the least of amounts C, D, and E	450			14,176 F

Refundable dividend tax on hand (item 104)

Refundable dividend tax on hand at the end of the preceding tax year	460	57	
Deduct dividend refund for the previous taxation year	465		
		57	57 A
Add the total of:			
Refundable portion of Part I tax from line 450 above		14,176	
Total Part IV tax payable from line 360 on page 2 of Schedule 3			
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480		
		14,176	14,176 B
Refundable dividend tax on hand at the end of the taxation year - amount A plus amount B	485		14,233

Dividend refund (item 105)

Private and subject corporations at the time taxable dividends were paid in the taxation year

Taxable dividends paid in the taxation year from line 460 on page 2 of Schedule 3	X 1/3	A
Refundable dividend tax on hand at the end of the taxation year from line 485 above		14,233 B
Dividend refund - Lesser of amounts A and B (enter this amount on line 784 on page 8)		0

Part I tax

Base amount of Part I tax - 38% of taxable income (line 360 or amount Z, whichever applies) from page 3 (item 106)				550	20,201	A
Corporate surtax calculation (item 107)						
Base amount from line A above		20,201	1			
Deduct:						
10% of taxable income (line 360 or amount Z, whichever applies) from page 3		5,316	2			
Investment corporation deduction from line 620 below			3			
Federal logging tax credit from line 640 below			4			
Federal qualifying environment trust tax credit from line 648 below			5			
For a mutual fund corporation or an investment corporation throughout the taxation year, enter the least of a, b and c below on line 6:						
28% of taxable income from line 360 on page 3		(a)				
28% of taxed capital gains		(b)	6			
Part I tax otherwise payable (line A **plus** line C and D **minus** line F)		14,885 (c)				
Total of lines 2 to 6		5,316	7			
Net amount (line 1 minus line 7)		14,885	8			
Corporate surtax - 4% of the amount on line 8				600	595	B
Recapture of investment tax credit from line PPP in Part 21 on page 8 of Schedule 31 (item 108)				602		C
Calculation for the refundable tax on Canadian-controlled private corporation's investment income (for a CCPC throughout the taxation year) (item 109)						
Aggregate investment income from line 440 on page 6		74,225	i			
Taxable income from line 360 on page 3	53,161					
Deduct: The least of amounts on lines 400, 405, 410, and 425 on page 4						
Net amount	53,161 ▶	53,161	ii			
Refundable tax on CCPC's investment income - 6 2/3 % of the lesser of amounts i or ii				604	3,544	D
Subtotal (add lines A, B, C, and D)					24,340	E
Deduct:						
Small business deduction from line 430 on page 4			9			
Federal tax abatement (item 110)	608	5,316				
Manufacturing and processing profits deduction from amount BB of Schedule 27 (item 111)	616					
Investment corporation deduction (item 112)	620					
(Taxed capital gains **624**)						
Additional deduction - credit unions from Schedule 17 (item 113)	628					
Federal foreign non-business income tax credit from Schedule 21 (item 114)	632					
Federal foreign business income tax credit from Schedule 21 (item 115)	636					
Accelerated tax reduction from amount N of page 4 (item 116)	637					
Resource deduction from line 438 of page 5			10			
General tax reduction for CCPC's from amount O of page 5 (item 117)	638					
General tax reduction from amount L of page 5 (item 117)	639					
Federal logging tax credit from Schedule 21 (item 118)	640					
Federal political contribution tax credit (item 119)	644					
Federal political contributions **646**						
Federal qualifying environmental trust tax credit (item 120)	648					
Investment tax credit from Schedule 31 (item 121)	652					
Subtotal		5,316 ▶			5,316	F
Part I tax payable - Line E minus line F (enter amount G on line 700 on page 8) (item 122)					19,024	G

Summary of tax and credits

Federal tax

Part I tax payable from page 7 (item 123)	700	19,024
Part I.3 tax payable from Schedule 33, 34, or 35 (item 124)	704	36,027
Part II surtax payable from Schedule 46 (item 125)	708	
Part IV tax payable from Schedule 3 (item 126)	712	
Part IV.1 tax payable from Schedule 43 (item 127)	716	
Part VI tax payable from Schedule 38 (item 128)	720	
Part VI.1 tax payable from Schedule 43 (item 129)	724	
Part XIII.1 tax payable from Schedule 92 (item 130)	727	
Part XIV tax payable from Schedule 20 (item 131)	728	
Total federal tax		55,051

Add provincial and territorial tax

Provincial or territorial jurisdiction (item 132) 750 ON

(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial and territorial tax payable (except Quebec, Ontario and Alberta) (item 133)	760			
Provincial tax on large corporations (New Brunswick and Nova Scotia) (item 147)	765			
		Total tax payable	770	55,051 A

Deduct other credits

Investment tax credit refund from Schedule 31 (items 148)	780		
Dividend refund from Page 4 (items 149)	784		
Federal capital gains refund from Schedule 18 (item 150)	788		
Federal qualifying environmental trust tax credit refund (item 151)	792		
Canadian film or video production tax credit refund from Form T1131 (item 152)	796		
Film or video production services tax credit refund from Form T1177 (item 153)	797		
Tax withheld at source (item 154)	800		
Total payments on which tax has been withheld (item 154) 801			
Allowable refund for non-resident-owned investment corporations - Schedule 26 (item 155)	804		
Provincial and territorial capital gains refund from Schedule 18 (item 156)	808		
Provincial and territorial refundable tax credits from Schedule 5 (item 157)	812		
Royalties deductible under Syncrude Remission Order 815			
Tax remitted under Syncrude Remission Order (item 158)	816		
Tax instalments paid (item 159)	840	55,051	
Total credits	890	55,051	55,051 B

Refund Code (item 160) 894 ☐ Overpayment (item 163) ______

Balance (line A minus line B) 0 I

Direct Deposit Request (item 164)

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below.

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
We do not charge or refund a difference of less than $2.

Balance unpaid (item 163) ______

Enclosed payment (item 162) 898 ______

If the corporation is a Canadian-controlled private corporation throughout the taxation year, does it qualify for the one-month extension of the date the balance is due? (item 161) 896 1 Yes ☐ 2 No ☒ NA ☐

Certification (item 165)

950 Barrett (Surname) 951 Tom (First name) 954 Chief Financial Officer (Position, office or rank)

955 2004/06/24 (Date) 956 (905) 727-4612 (Telephone number)

Is the contact person the same as the authorized signing officer? If *no*, complete the information below. 957 1 Yes ☒ 2 No ☐

958 ______ Name 959 (   )   - Telephone number

Language of correspondence - Langue de correspondance (item 166)

990 Language of choice/Langue de choix 1 English / Anglais ☒ 2 Français / French ☐

Canada Customs and Revenue Agency | Agence des douanes et du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Schedule 1

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes.

Net income (loss) after taxes and extraordinary items per financial statements		A 348,142
Add:		
Provision for income taxes - current	101 110,000	
Interest and penalties on taxes	103 1,141	
Amortization of tangible assets	104 1,624,365	
Income/loss for tax purposes - joint ventures/partnerships	109 3,166	
Non-deductible meals and entertainment expenses 4,091 X 50%	121 2,046	
Tax reserves deducted in prior year - Schedule 13	125 230,000	
Reserves from financial statements - balance at the end of the year	126 262,000	
Total of fields 201 to 294	199 3,216,040	
Total of fields 101 to 199	500 5,448,758	5,448,758
Deduct:		
Capital cost allowance - Schedule 8	403 1,343,913	
Cumulative eligible capital deduction - Schedule 10	405 52,330	
Tax reserves claimed in current year - Schedule 13	413 162,000	
Reserves from financial statements - balance at the beginning of the year	414 230,000	
Total of fields 300 to 394	499 3,285,525	
Total of fields 401 to 499	510 5,073,768	5,073,768
Net income (loss) for income tax purposes (enter on line 300 of the T2 return)		723,132
Add:		
Other additions:		
604 Par. 12 (1)(x) contributions capitalized on F/S	3,216,040	
Other additions		
Total of fields 201 to 294 (Enter this amount at line 199)	3,216,040 294	3,216,040
		3,216,040
Deduct:		
Other deductions:		
700 Ss. 13(7.4) election re Contributions in aid of construction	390	3,216,040
701 Ontario Capital Tax in 2003 per CT 23	391	67,227
702 Ontario Capital Tax in 2002, not previously deducted	392	2,258
Total of fields 300 to 394 (Enter this amount at line 499)		3,285,525

Ontario

Ministry of Finance
Corporations Tax Branch
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

2003 CT23 Corporations Tax and Annual Return

For taxation years commencing after September 30, 2001

Corporations Tax Act - Ministry of Finance (MOF)
Corporations Information Act - Ministry of Consumer and Business Services (MCBS)

This return is a combination of the Ministry of Finance (MOF) CT23 Corporations Tax Return and the Ministry of Consumer and Business Services (MCBS) Annual Return. Page 1 is a common page required for both returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17, together with the applicable schedules on pages 18-21. **Corporations that do not meet the EFF criteria but do meet the Short-Form criteria, may request and file th CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MCBS Schedule A on pages 22 and 23, and Schedule K on page 24) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

MCBS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* ☐ Yes ☒ No

Ministry Use

Corporation's Legal Name *(including punctuation)* Aurora Hydro Connections Limited	Ontario Corporations Tax Account No. (MOF) 1800045
Mailing address 215 Industrial Parkway South PO Box 157 City: Aurora — Province: ON — Country: — Postal code: L4G 3H3	This CT23 Return covers the Taxation Year Start 2003/01/01 End 2003/12/31
Has the mailing address changed since last filed CT23 Return? ☐ Yes — Date of change:	Date of Incorporation or Amalgamation 2000/09/15
Registered/Head Office Address 215 Industrial Parkway South PO Box 157 City: Aurora — Province: ON — Country: — Postal code: L4G 3H3	Ontario Corporation No. (MCBS) 1439583
Location of Books and Records 215 Industrial Parkway South PO Box 157 City: Aurora — Province: ON — Country: — Postal code: L4G 3H3	Canada Customs and Revenue Agency Business No. 863683165RC0001
Name of person to contact regarding this CT23 Return: Tom Barrett — Telephone No.: (905) 727-4612 — Fax No.: ( ) -	Jurisdiction Incorporated: Ontario
Address of Principal Office in Ontario (*Extra-Provincial Corporations only*) (MCBS) City — Province — Country — Postal code	If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased: Commenced Ceased ☒ *Not Applicable*
Former Corporation Name (*Extra-Provincial Corporations only*) ☐ ***Not applicable*** (MCBS)	
Information on Directors/Officers/Administrators must be completed on MCBS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MCBS). ▸ No. of Schedule(s): 0	Preferred Language / *Langue de préférence* ☒ English anglais ☐ French français
If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MCBS, please check ☑ this box. Schedule(s) A and K are not required (MCBS). ▸ ☐ No Change	Ministry Use

Certification (MCBS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person
Tom Barrett

Title: D ☐ Director O ☐ Officer P ☐ Other individual having knowledge of the affairs of the Corporation

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)

I, ______________________________ declare that:

The above corporation satisfies **all** of the exempt from filing criteria (a) through (f) below for the taxation year and therefore qualifies under the *orporations Tax Act* as exempt from filing an Ontario Corporations Tax Return.

Criteria for exempt from filing status:

a) has filed a federal income tax return (T2) with Canada Customs and Revenue Agency for the taxation year;
b) had no Ontario taxable income for the taxation year (subject to the provisions in NOTE 2 below);
c) had no Ontario Corporations Tax payable for the taxation year;
d) was a Canadian-controlled private corporation throughout the taxation year (i.e. generally a private corporation with 50% or more shares owned by Canadian residents as defined by the *Income Tax Act* (Canada));
e) had provided its Canada Customs and Revenue Agency business number to the Ministry of Finance, Corporations Tax Branch; and
f) is NOT subject to the Corporate Minimum Tax (i.e. alone or as part of an associated group whose total assets exceed $5 million or whose total revenues exceed $10 million for the taxation year).

Signature	Title/Relationship to Corporation	Telephone number	Date
		( ) -	

Please note that making a false statement to avoid compliance with the *Corporations Tax Act* is an offence which can result in a penalty and/or fine.

NOTE 1: Filing of this declaration and the Annual Return does not constitute the filing of a Corporations Tax Return under section 75 of the *Corporations Tax Act.*

NOTE 2: The following loss situations will require otherwise EFF corporations to file a CT23 tax return complete with all related schedules and financial statements:

1. If a corporation has a loss in the current taxation year that is to be carried back and applied to a previous taxation year(s), regardless of whether the loss is the same as for federal purposes or not, a CT23 tax return is required for the current taxation year. The corporation must also provide information indicating that the loss is to be carried back and specify the year and the amount of loss to be carried back to each taxation year.
2. If a corporation has a prior year loss, that is not the same for both federal and Ontario purposes and the corporation is applying a loss carryforward from the prior year to the current year, a CT23 tax return is required for the current taxation year, and if not previously filed, a CT23 tax return for the prior taxation year in which the loss was incurred is also required. Although a tax return for the loss year is not required where the loss is not being applied, the Corporations Tax Branch will accept the filing of a tax return for a loss year at the time the loss is incurred.
3. If a corporation has a prior year loss, that is the same for both federal and Ontario purposes, but in the current taxation year the corporation is applying a different amount of loss for Ontario than the loss amount being applied for federal income tax purposes, the corporation is required to file a CT23 tax return for the current taxation year only.

The following 3 items MUST be completed if the EFF declaration only is being submitted at this time. In cases where the annual return, which includes page 1, is **also** being filed, completion of these fields is NOT necessary.

1. Corporation's Mailing Address

City	Province	Country	Postal code

2. Ontario Corporation No. (MCBS)

3. Canada Customs and Revenue Agency Business No. RC

A corporation **must file** an **Exempt From Filing Corporations Tax Return Declaration** form for each taxation year that the corporation is exempt from filing, **within 6 months** after the end of its taxation year, to the address shown at the top of Page 1.

If you check "Yes" to ALL of the following criteria, you are eligible to file the CT23 Short-Form Corporation Tax Return. To obtain a copy, contact the Ministry Information Centre at the numbers listed on page 2 of the Guide.

Yes	No	
X		(a) The corporation is a Canadian-controlled private corporation (CCPC) throughout the taxation year. Indicate Share Capital with full voting rights owned by Canadian Residents (nearest whole percentage) 100 %
X		(b) The corporation's taxable income for the taxation year is $200,000 or less. For a taxation year with less than 51 weeks, taxable income must be grossed-up. (*Refer to guide)*
	X	(c) The corporation is NOT a member of a partnership/joint venture or a member of an associated group of corporations during the taxation year.
	X	(d) The corporation's taxation year ends on or after January 1, 2001, and its gross revenue and total assets are each $1,500,000 or less and the corporation is not a financial institution; OR The corporation's taxation year commences after September 30, 2001, and its gross revenue and total assets are each $3,000,000 or less and the corporation is not a financial institution.
	X	(e) The corporation is NOT claiming a tax credit other than the Incentive Deduction for Small Business Corporations (IDSBC), Co-operative Education Tax Credit (CETC) or Graduate Transitions Tax Credit (GTTC).
X		(f) The corporation's Ontario allocation factor is 100%.

NOTE: Family Farm or Fishing corporations that have a taxation year ending on or after January 1, 2000 and that are NOT subject to the Corporate Minimum Tax, may also use the **CT23 Short-Form Corporations Tax Return** if the corporation checks "Yes" to (a), (b), (c), (e) and (f) above.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Type of Corporation - Please check (✓) box(es) if applicable in sections 1 & 2

1 [X] Canadian-controlled private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other (specify)

Share Capital with full voting rights owned by Canadian residents. (nearest %) 100 %

Ontario Retail Sales Tax Vendor Permit No.
(Use Head Office No.)

Ontario Employer Health Tax Account No.
(Use Head Office No.)

Specify major business activity
Distribution of Hydro Electricity

2

1 [ ] Family Farm Corporation s.1(2)
2 [ ] Family Fishing Corporation s.1(2)
3 [ ] Mortgage Investment Corp s.47
4 [ ] Credit Union s.51
5 [ ] Bank Mortgage Subsidiary s.61(4)
6 [ ] Bank s.1(2)
7 [ ] Loan and Trust Corporation s.61(4)
8 [ ] Non-resident Corp s.2(2)(a) or (b)
9 [ ] Non-resident Corporation s.2(2)(c)
10 [ ] Mutual Fund Corporation s.48
11 [ ] Non-resident owned investment Corp s.49
12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)
14 [ ] Bare Trustee Corporation
15 [ ] Branch of Non-resident s.63(1)
16 [ ] Financial institutions prescribed by Regulation only
17 [ ] Investment Dealer
18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale
19 [X] Hydro successor, Municipal Electrical Utility or subsidary of either
20 [ ] Producer and seller of steam for uses other than for the generation of electricity
21 [ ] Insurance Exchange s.74.4
22 [ ] Farm Feeder Finance Co-operative Corporation
23 [ ] Professional Corporation (incorporated professionals only)

Please check (✓) box(es) if applicable:

[ ] First Year of Filing

[ ] Final Taxation Year up to Dissolution(wind-up) (Note: For discontinued businesses, see Guide.)

[ ] Transfer or Receipt of Asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] Amended Return

[ ] Final Taxation Year before Amalgamation

[ ] Acquisition of Control fed s.249(4)

Date control was acquired: ______

[ ] Taxation Year End has changed - Canada Customs and Revenue Agency approval required

[ ] Floating Fiscal Year End

Was the corporation inactive throughout the taxation year?	Yes [ ]	No [X]
Has the corporation's Federal T2 Return been filed with the Canada Customs and Revenue Agency (CCRA)?	Yes [X]	No [ ]
Are you requesting a refund due to: the Carry-back of a Loss?	Yes [ ]	No [X]
an Overpayment?	Yes [ ]	No [X]
a Specified Refundable Tax Credit?	Yes [ ]	No [X]
Are you a Member of a Partnership or a Joint Venture?	Yes [X]	No [ ]

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction, to that jurisdiction (s.39) (Int.B. 3008).

Net income (loss) for Ontario purposes (per reconciliation schedule, page 15)	From 690 ±	723,132
Subtract: Charitable donations	1 -	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	2 -	
Subtract: Taxable dividends deductible, per federal T2 SCH 3	3 -	
Subtract: Ontario political contributions *(Attach schedule* 2A) (Int.B. 3002)	4 -	
Subtract: Federal Part VI.1 tax ______ X 9/3	5 -	
Subtract: Prior years' losses applied - Non-capital losses	From 704 -	669,335
Net capital losses (page 16) From 715 ______ X inclusion rate 50.000000 % =	714 -	
Farm losses	From 724 -	
Restricted farm losses	From 734 -	
Limited partnership losses	From 754 -	636
Taxable income (Non-capital loss)	10 =	53,161
Addition to taxable income for unused foreign tax deduction for federal purposes	11 +	
Adjusted taxable income 10 + 11 (if **10** is negative, enter **11**)	20 =	53,161

Taxable Income — **Number of days in Taxation Year**

From **10** (or **20**) 53,161 X30 100.0000 % X 12.5 % X **33** 365 ÷ **73** 365 = **29** + 6,645
(Ontario Allocation; Days after Sept 30, 2001 and before Jan 1, 2004; Total days)

From **10** (or **20**) 53,161 X30 100.0000 % X 14.0 % X **34** ______ ÷ **73** 365 = **32** + ______
(Ontario Allocation; Days after Dec 31, 2003; Total days)

Income Tax Payable (before deduction of tax credits) **29 + 32** — **40** = 6,645

Incentive Deduction for Small Business Corporations (IDSBC)(s.41) *(If this section is not completed, the IDSBC will be denied.)*

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the year? (✓) ☒ Yes ☐ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))			50	648,907
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	51 +	53,161		
Add: Losses of other years deducted for federal purposes (fed.s.111)	52 +	669,971		
Subtract: Losses of other years deducted for Ontario purposes (s.34)	53 -	669,971		
	=	53,161 ▶	54	53,161
Federal Business limit (line 410 of the T2 return) for the year before application of fed.s.125(5.1)	55 +	222,750		

Ontario Business Limit Calculation

280,000 X **28** ______ (Days after Sept. 30, 2001 and before Jan. 1, 2003) ÷ ** 365 =+ **43** ______

320,000 X **31** 365 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ ** 365 =+ **46** 320,000

400,000 X **34** ______ (Days after Dec. 31, 2003) ÷ ** 365 =+ **47** ______

Business limit for Ontario purposes **43 + 46 + 47** = **44** 320,000 X **48** 99.0000 % = **45** 316,800

*** Percentage of Federal Business limit (from T2 Sch. 23). Enter 100% if not associated

Income eligible for the IDSBC From **30** 100.0000 % X **56** 53,161 **60** = 53,161
(****Ontario Allocation; Least of 50, 54 or 45)

* ***Note***: *Modified by s.41(6) and (7) for corporations that are members of a partnership.* ***(Refer to Guide.)***

** ***Note***: *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note***: *For a taxation year ending before Jan 1, 2003, use your proportion of the associated group business limit.*

**** ***Note***: *Ontario Allocation for IDSBC purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

Income Tax *continued from Page 4*

Year

Number of Days in Taxation

		Days after Sept 30, 2001 and before Jan 1, 2003		Total Days		
Calculation of IDSBC Rate	6.5 % X 28		÷ 73	365	= 79 +	
		Days after Dec 31, 2002 and before Jan 1, 2004		Total Days		
	7.0 % X 31	365	÷ 73	365	= 89 +	7.0000
		Days after Dec 31, 2003		Total Days		
	8.5 % X 34		÷ 73	365	= 90 +	
IDSBC Rate for Taxation Year 79 + 89 + 90					78 =	7.0000
Claim	From 60	53,161	X From 78	7.0000 %	70 =	3,721

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount in **114** below.

Surtax on Canadian-controlled private corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

***** Short Taxation Years*** **-** Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

Associated corporation **-** The taxable income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

**** Taxable Income of the corporation**	From **10** (or **20** if applicable)	**80 +**	53,161
If you are a member of an associated group (✓)	**81** ☒ (Yes)		
Taxable income of associated corporations *(Attach schedule)*		**82 +**	1,000,000
Aggregate Taxable Income		**85 =**	1,053,161

Number of days in Taxation Year

		Days after Sept 30, 2001 and before Jan 1, 2003		Total Days				
Subtract: 280,000 X	28		÷ 73	365	= 113 +			
		Days after Dec 31, 2002 and before Jan 1, 2004		Total Days				
320,000 X	31	365	÷ 73	365	= 115 +	320,000		
		Days after Dec 31, 2003		Total Days				
400,000 X	34		÷ 73	365	= 116 +			
				113 + 115 + 116	=	320,000	114 -	320,000
(If negative, enter nil)							86 =	733,161

Number of Days in Taxation Year

		Days after Sept 30, 2001 and before Jan 1, 2003		Total Days		
Calculation of Specified Rate for Surtax	4.333% X 28		÷ 73	365	= 95 +	
		Days after Dec 31, 2002 and before Jan 1, 2004		Total Days		
	4.667% X 31	365	÷ 73	365	= 96 +	4.6670
		Days after Dec 31, 2003		Total Days		
	4.667% X 34		÷ 73	365	= 97 +	

Specified rate of surtax for Taxation Year **95 + 96 + 97**					**94 =**	4.6670
From **86**	733,161	X From **94**	4.6670 % =		**87 =**	34,217
From **87**	34,217	X From **60**	53,161	÷ From **114** 320,000	**88 =**	5,684
Surtax: Lesser of **70** or **88**					**100 =**	3,721

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)* 110

Manufacturing and Processing Profits Credit (M&P) (s.43)

plies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as .ermined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing, is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits		120+	
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	From 56	-	53,161

Add: Adjustment for Surtax on Canadian-controlled private corporations
From **100** 3,721 ÷ From **30** 100.0000 % ÷ From **78** 7.0000 % = **121** 53,157
*Ontario Allocation

Lesser of **56** or **121**		122+	53,157
120 - 56 + 122		130=	
Taxable income	From 10	+	53,161
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	From 56	-	53,161
Add: Adjustments for Surtax on Canadian-controlled private corporations	From 122	+	53,157
Subtract: Taxable income **10** X Allocation % to jurisdictions outside Canada		140-	
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses		141-	74,225
10 - 56 + 122 - 140 - 141		142=	

Claim — **Number of Days in Taxation Year**

143 ______ X From **30** 100.0000 % X 1.5% X **33** 365 ÷ **73** 365 = **154**+
Lesser of **130** or **142** — *Ontario Allocation — Days after Sept 30, 2001 and before Jan 1, 2004 — Total Days

143 ______ X From **30** 100.0000 % X 2.0% X **34** ______ ÷ **73** 365 = **156**+
Lesser of **130** or **142** — *Ontario Allocation — Days after Dec 31, 2003 — Total Days

M&P claim for taxation year **154 + 156** 160=

Note*: Ontario Allocation for M&P Credit purposes may differ from **30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1)).*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations 161=

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity 162=

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001) *(Attach schedule)*. 170

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former Small Business Development Corporations Act)

Eligible credit **175** ______ Credit claimed **180**

Subtotal of Income Tax 40 - 70 + 100 - 110 - 160 - 161 - 162 -170 - 180 190= 6,645

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to research and development in Ontario.
Eligible credit from **5620** OITC claim form *(Attach original Claim Form)* — **191 +**

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible credit from **5798** Summary Schedule F — **192 +** 806

Ontario Film and Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions.
Eligible credit from **5899** either Claim Form from Ontario Media Development Corporation (OMDC)
or Ministry of Finance (MFO) CT Schedule 193/199, as applicable.
(Attach the original Certification/Claim Form received from the OMDC ***or*** *the original Certification Form received from the OMDC along with a completed MOF CT Schedule 193/199, as applicable.)* — **193 +**

Graduate Transitions Tax Credit (GTTC) (s.43.6)
Applies to employment of eligible unemployed post secondary graduate.
No. of Graduates from **6596** — **194**
Eligible Credit from **6598** Summary Schedule G — **195 +**

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit from **6900** OBPTC Claim Form *(Attach* ***both*** *the original Claim Form and the Certification Form)* — **196 +**

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit from **6700** Claim Form Certified by Ontario Media Development Corporation
(Attach the original Claim/Certification Form with the CT23 Tax Return.) — **197 +**

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit from **7100** OBRITC Claim Form *(Attach original Claim Form)* — **198 +**

Ontario Production Services Tax credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit from **7300** either Claim Form from Ontario Media Development Corporation (OMDC)
or Ministry of Finance (MFO) CT Schedule 193/199, as applicable
(Attach the original Certification/Claim Form received from the OMDC ***or*** *the original Certification Form received from the OMDC along with a completed MOF CT Schedule 193/199, as applicable.)* — **199 +**

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit from **7400** Claim Form certified by Ontario Media Development Corporation
(Attach original Claim/Certification Form.) — **200 +**

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit from **7500** OSRTC Claim Form *(Attach* ***both*** *the original Claim Form and the Certification Form)* — **201 +**

Total Specified Tax Credits: 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 — **220 =** 806

Specified Tax Credits ***Applied to reduce Income Tax*** — **225 =** 806

Income Tax 190 - 225 OR Enter NIL if reporting Non-Capital Loss (amount cannot be negative) — **230 =** 5,839

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see ***Determination of Applicability*** section for the CMT on ***Page 8***. If CMT is not applicable, transfer amount in **230** to Income Tax in **Summary** section on ***Page 17***.

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the ***Application of CMT Credit Carryovers*** section part B on ***Page 8***.

Corporate Minimum Tax (CMT)

Determination of Applicability

Applies if *either* Total Assets **249** exceeds $5,000,000 *or* Total Revenue **250** exceeds $10,000,000.
* These amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

Short Taxation Years - Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation - The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

*** Total Assets of the corporation**	**240** +	33,260,832		
*** Total Revenue of the corporation**			**241** +	33,630,919
If you are a member of an associated group (✓) **242** ☒ (Yes)				
Total Assets of associated corporations *(Attach schedule)*	**243** +	12,385,677		
Total Revenue of associated corporations *(Attach schedule)*			**244** +	180,000
Aggregate Total Assets	**249** =	45,646,509		
Aggregate Total Revenue			**250** =	33,810,919

If CMT is applicable to current taxation year, complete section ***Calculation: CMT*** below and ***Corporate Minimum Tax Schedules A through E on pages 18, 19 and 20 of CT23.***

Calculation: CMT *(Attach Schedule A: Calculation of CMT Base on page 18.)*

Gross CMT Payable	CMT Base From **2135** ____ X (If negative, enter zero)	From **30** 100.0000 % X 4% (Ontario Allocation)	**276** =	
Subtract: Foreign Tax Credit for CMT purposes *(Attach schedule)*			**277** -	
Subtract: Income Tax			From **190** -	6,645
Net CMT Payable (if negative, enter Nil on page 17.)			**280** =	

If **280** is less than zero and you do not have a CMT credit carryover, transfer **230** from ***Page 7 to Income Tax Summary, on Page 17.***

If **280** is less than zero and you have a CMT credit carryover, complete A & B below.

If **280** is greater than or equal to zero, transfer **230** to ***Page 17*** and transfer **280** to ***Page 17, and to Schedule D: Continuity of CMT Credit Carryovers,*** on ***Page 20.***

CMT Credit Carryover available	From **2307**	

Application of CMT Credit Carryovers

A.	Income Tax (before deduction of specified credits)		From **190** +	6,645
	Gross CMT payable	From **276** +		
	Subtract: Foreign Tax Credit for CMT purposes	From **277** -		
	If **276** - **277** is negative, enter NIL in **290**	=	**290** -	
	Income Tax eligible for CMT Credit		**300** =	6,645
B.	Income Tax (after deduction of specified credits)		From **230** +	5,839
	Subtract: CMT credit used to reduce income taxes		**310** -	
	Income Tax		**320** =	5,839
				Transfer to Page 17

***If A & B apply,* 310 *cannot exceed the lesser of* 230, 300 *and your CMT credit carryover available* 2307.**

If only B applies,* 310 *cannot exceed the lesser of* 230 *and your CMT credit carryover available 2307.

Capital Tax *(Refer to Guide and Int.B. 3011)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 and 430 on page 10 then proceed to page 13.

If your corporation is not a member of an associated group and/or partnership and (1) the Gross Revenue and Total Assets as calculated on Page 10 in 480 and 430 are both $1,500,000 or less and the taxation year ends on or after January 1, 2001, or (2) the Gross Revenue and Total Assets as calculated on Page 10 in 480 and 430 are both $3,000,000 or less and the taxation year commences after September 30, 2001, your corporation is exempt from Capital Tax for the taxation year. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in 550 on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation.

If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(a) or (b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012 and 3015)	350 +	12,385,600
Retained earnings (if deficit, deduct) (Int.B. 3012)	351 ±	1,757,296
Capital and other surpluses, excluding appraisal surplus (Int.B. 3012)	352 +	
Loans and advances *(Attach schedule)*(Int.B. 3013)	353 +	15,125,910
Bank loans (Int.B. 3013)	354 +	
Bankers acceptances (Int.B. 3013)	355 +	
Bonds and debentures payable (Int.B. 3013)	356 +	
Mortgages payable (Int.B. 3013)	357 +	
Lien notes payable (Int.B. 3013)	358 +	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013)	359 +	
Contingent, investment, inventory and similar reserves (Int.B. 3012)	360 +	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012)	361 +	874,754
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017)	362 +	5,516
Subtotal	370 =	30,149,076
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012)	371 -	
Deductible R&D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015)	372 -	
Total Paid-up Capital	380 =	30,149,076
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015)	381 -	
Electrical Generating Corporations Only - All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the Corporations Tax Act, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	382 -	
Net Paid-up Capital	390 =	30,149,076

Eligible Investments *(Refer to Guide and Int.B. 3015)*

Attach computations and list of corporations' names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	402 +	
Mortgages due from other corporations	403 +	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	404 +	
Loans and advances to unrelated corporations	405 +	3,092,460
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	406 +	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	407 +	756
Total Eligible Investments	410 =	3,093,216

Capital Tax *continued from Page 9*

Total Assets (Int.B. 3015)

Total Assets per balance sheet	420 +	33,260,832
Mortgages or other liabilities deducted from assets	421 +	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	422 +	
Subtract: Investment in partnership(s)/joint venture(s)	423 -	
Total Assets as adjusted	430 =	33,260,832
Amounts in **360** and **361** (if deducted from assets)	440 +	774,754
Subtract: Amounts in **371**, **372** and **381**	441 -	
Subtract: Appraisal surplus if booked	442 -	
Add or Subtract: Other adjustments (specify on an attached schedule)	443 ±	
Total Assets	450 =	34,035,586

Investment Allowance (410 ÷ 450) X 390	Not to exceed 410	460 =	2,740,003
Taxable Capital 390 - 460		470 =	27,409,073

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)

Gross Revenue of the corporation	33,630,919		
Corporation's Share of partnership(s)/joint venture(s) Gross Revenue *(Attach schedule)*			
Aggregate of Gross Revenue	33,630,919	480	33,630,919
Total Assets (as adjusted)	From	430	33,260,832

Calculation of Capital Tax for all corporations except Financial Institutions

Note: This version (2003) of the CT23 may only be used for a taxation year that commenced after September 30, 2001.

(Financial Institutions use calculations on page 13.)

Important: **If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.**

OR **If the corporation is NOT a member of an associated group and/or partnership, review only the capital tax calculations in Section B below and select and complete the one specific subsection (e.g. B3) that applies to the corporation.**

OR **If the corporation IS a member of an associated group and/or partnership, complete Section C on page 11. and if applicable, complete Section D or Section E on page 12. Note: if the corporation is a member of a connected partnership, please refer to the 2003 CT23 guide for additional instructions before completing the capital tax section.**

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in **550** on page 12 and complete the return from that point.

SECTION B

This section applies if the corporation is NOT a member of an associated group and/or partnership

B1. If the taxation year commences after September 30, 2001 and **430** and **480** on page 10 are both $3,000,000 or less, enter NIL in **550** on page 12 and complete the return from that point.

B2. If taxable capital, **470** on page 10, is **$5,000,000 or less**, enter NIL in **550** on page 12 and complete the return from that point.

B3. If taxable capital, **470** on page 10 exceeds **$5,000,000**, complete the following calculation and transfer the amount from **523** to **543** on page 12, and complete the return from that point.

+ From **470** ______

\- ______

= **471** ______ x From **30** 100.0000 (Ontario Allocation) x 0.3% x **555** 365 (Days in taxation year / **365/366) = **523** + ______

Transfer to 543 on page 12 and complete the return from that point

*** If floating taxation year, refer to Guide.**

continued on Page 11

Capital Tax Calculation *continued from page 10*

SECTION C

This section applies ONLY to a corporation that is a member of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your capital tax calculation under either Section D or Section E.

C1. ☐ **509** (✓ if applicable) **All corporations that you are associated with do not have a permanent establishment in Canada.**
If taxable capital **470** on page 10 is $5,000,000 or less, enter NIL in **550** on page 12 and complete the return from that point.
If taxable capital **470** on page 10 exceeds $5,000,000 proceed to **Section D**, enter $5,000,000 in **542** Section D, and complete Section D and the return from that point

C2. ☒ **524** (✓ if applicable) **One or more of the corporations that you are associated with maintains a permanent establishment in Canada**
If the taxation year **ends before January 1, 2003**, you must complete the *Calculation* below.
If the taxation year **ends after December 31, 2002**, you and your associated group may continue to allocate the $5,000,000 taxable capital exemption by completing the *Calculation* below. Or, the associated group **may file an election** under subsection 69(2.1) of the Corporations Tax Act, whereby total assets are used to allocate the taxable capital exemption among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the $15,000 capital tax effect, relating to the $5,000,000 taxable capital exemption, to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

Calculation ***Do NOT complete this calculation if ss.69(2.1) election is filed***

Taxable Capital form **470** on page 10 — From **470** + ________

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Taxable Capital of associated corporations *(Attach schedule)* — **531** + ________
Total Aggregate Taxable Capital **470 + 531** — **540** = ________

If **540** above is $5,000,000 or less, the corporation's Capital Tax for the taxation year, is NIL.
Enter NIL in **523** in section D on page 12, as applicable.
If **540** above is greater than $5,000,000, the corporation must compute its share of the $5,000,000 exemption below in order to calculate its Capital Tax for the taxation year under Section D on page 12.

From **470** ________ ÷ From **540** ________ X 5,000,000 — **541** = ________
Transfer to Section 542 in D on page 12

Ss.69(2.1) Election Filed

☒ **591** (✓ if applicable) **Election filed.** ***Attach a copy of the election with this CT23 Return.***
Proceed to **Section E** on page 12.

Capital Tax Calculation *continued from page 11*

SECTION D

This section applies if the corporation IS a member of an associated group and/or partnership whose total AGGREGATE taxable capital, 540 on *page 11* exceeds $5,000,000.

Complete the following calculation and transfer the amount From **523** to **543**, and complete the return from that point.

+ From **470** ______
\- **542** ______
= **471** ______ x From **30** 100.0000 % x 0.3% x **555** 365 = **523** + ______

Ontario Allocation; Days in the taxation year ** (365/366); **Total Capital Tax for the taxation year**

Transfer to 543 and complete the return from that point

SECTION E

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

\+ From **470** 27,409,073 X From **30** 100.0000 x 0.3% = **561** + 82,227

\- Capital tax deduction relating to your corporation's capital tax deduction, on ss.69(2.1) election form From **995** - 15,000

562 = 67,227

Capital Tax **562** 67,227 X Days in taxation year **555** 365 ** (365/366) = **563** + 67,227

Transfer to 543 and complete the return from that point

**** If floating taxation year, refer to Guide**

Capital Tax *before application of specified credits*	**543** =	67,227
Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)*	**546** -	
Capital Tax 543 - 546 *(amount cannot be negative)*	**550** =	67,227

Transfer to page 17

Capital Tax *continued from page 12*

Calculation of Capital Tax for Financial Institutions

I.1. Credit Unions Only

r taxation years commencing **after May 4, 1999** enter NIL in **550** on page 12, and complete the return from that point.

I.2 Other than Credit Unions

*(Retain details of calculations for amounts in boxes **565** and **570**. Do not submit with this tax return.)*

565 ______ x 0.6% x From **30** ______ % x **555** ______ (Days in taxation year) ÷ **365/366 = **569**+ ______

Lesser of adjusted TPUC and Basic Capital Amount in accordance with Division B.1 — Ontario Allocation

570 ______ x**571** ______ x From **30** ______ % x **555** ______ (Days in taxation year) ÷ **365/366 = **574**+ ______

Adjusted TPUC in accordance with Division B.1 in excess of Basic Capital Amount — Capital Tax Rate *(Refer to Guide)* — Ontario Allocation

Capital Tax for Financial Institutions - other than Credit Unions (before Section II) 569 + 574 **575**= ______

***** If floating taxation year, refer to Guide.***

II. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments **585**- ______

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)?(✓) ☐ Yes

pital Tax - Financial Institutions 575 - 585 **586**= ______

*Transfer to **543** on Page 1*

Premium Tax (s.74.2 & 74.3) *(refer to Guide)*

(1) Uninsured Benefits Arrangements **587** ______ x 2% **588**= ______
Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in **588** and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in **588**.)
Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to guide)* **589**- ______

Premium Tax 588 - 589 **590**= ______

Transfer to Page 17

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 SCH 1 600± 723,132

Transfer to Page 15

Add:

Federal capital cost allowance	601+	1,343,913
Federal cumulative eligible capital deduction	602+	52,330
Ontario taxable capital gain	603+	
Federal non-allowable reserves. Balance beginning of year	604+	230,000
Federal allowable reserves. Balance end of year	605+	162,000
Ontario non-allowable reserves. Balance end of year	606+	262,000
Ontario allowable reserves. Balance beginning of year	607+	230,000
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	608+	
Federal resource allowance	609+	
Federal depletion allowance	610+	
Federal foreign exploration and development expenses	611+	

Management fees, rents, royalties and similar payments to non-arms' length non-residents

Number of days in Taxation Year

612 ______ X 5/12.5 X **33** 365 (Days after Sept. 30, 2001 and before Jan. 1, 2004) ÷ **73** 365 (Total days) = **633**+ ______

612 ______ X 5/14.0 X **34** ______ (Days after Dec. 31, 2003) ÷ **73** 365 (Total days) = **634**+ ______

Total add-back amount for Management fees, etc. **633 + 634** =	613+			
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in **473** from Ont. CT23 schedule 161	615+			
Add any negative amount in **473** from Ont. CT23 Schedule 161	616+			
Federal allowable business investment loss	620+			
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	614+			
Sub Total of Additions 601 to 611 + 613 + 615 + 616 + 620 + 614	=	2,280,243	640	2,280,243

Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under **675**)	650+	1,343,913
Ontario cumulative eligible capital deduction	651+	52,330
Federal taxable capital gain	652+	
Ontario non-allowable reserves. Balance beginning of year	653+	230,000
Ontario allowable reserves. Balance end of year	654+	162,000
Federal non-allowable reserves. Balance end of year	655+	262,000
Federal allowable reserves. Balance beginning of year	656+	230,000
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	657+	
Ontario depletion allowance	658+	
Ontario resource allowance	659+	
Ontario current cost adjustment *(Attach schedule)*	661+	
Incentive for new electricity supply (section 13.6 deduction from income) (*Applies* only to electrical generating corporations.)	674+	
CCA for investments in qualifying energy-efficient equipment and for assets used to generate electricity from natural gas, alternative or renewable resources.	675+	
Subtotal of deductions for this page 650 to 659 + 661 + 674 + 675	681	2,280,243

Transfer to Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Continued from page 14

income (loss) for federal income tax purposes, per federal T2 SCH 1			From 600 ±	723,132
Sub Total of Additions			From 640 =	2,280,243
Sub Total of deductions on page 14	From 681 =	2,280,243		

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(*Applies* only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year **662** ______

ONTTI Gross-up deduction calculation:

From **662** ______ x 100/ 30 100.0000 (Ontario allocation) - From **662** ______ (Gross-up of CCA) **663** =

Workplace Child Care Tax Incentive

Qualifying expenditures: **665** ______ x 30% x 100/ 30 100.0000 (Ontario Allocation) **666** =

Workplace Accessibility Tax Incentive

Qualifying expenditures: **667** ______ x 100% x 100/ 30 100.0000 (Ontario Allocation) **668** =

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI): (*Applies* to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures **670** ______ x 30% x 100/ 30 100.0000 (Ontario Allocation) **671** =

Educational Technology Tax Incentive (*Applies* to qualifying amounts incurred after May 2, 2000.)

Qualifying expenditures **672** ______ x 15% x 100/ 30 100.0000 (Ontario Allocation) **673** =

Ontario allowable business investment loss	**678** +	
Ontario Scientific Research Expenses claimed in year in 477 from Ont. CT23 Schedule 161	**679** +	
Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003)	**677** +	
Total of other deductions allowed by Ontario *(Attach schedule)*	**664** +	
Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664	= 2,280,243	**680** 2,280,243

Net income (loss) for Ontario purposes 600 + 640 - 680 **690** = 723,132

Transfer to Page 4

Continuity of Losses Carried Forward

	Non-Capital Losses (1)	Total Capital Losses (9) (10)	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year	700 (2) 669,335	710 (2)	720 (2)	730	740	750 636
Add: Current year's losses (7)	701	711	721	731	741	751
Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal	703	713	723	733	743	753
Subtract: Utilized during the year to reduce taxable income	704 (2) 669,335	715 (2)(4)	724 (2)	734 (2)(4)	744 (4)	754 (4) 636
Expired during the year	705		725	735	745	
Carried back to prior years to reduce income (5)	706 (2) To Pg 17	716 (2) To Pg 17	726 (2) To Pg 17	736 (2) To Pg 17	746	
Subtotal	707 669,335	717	727	737	747	757 636
Balance at End of Year	709 (8)	719	729	739	749	759

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5) as made applicable by s.34.

(3) Include losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amounts from **11** if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in **709** must equal total of **829** + **839**.

(9) Total Capital Losses for a year is the excess of 100% of the Capital Losses in the taxation year minus 100% of the Capital Gains (less any reserves) in the taxation year. Total Capital Losses is before the inclusion rate has been applied.

(10) Commencing in the 2001 CT23 this column now refers to Tota Capital Losses (100% of loss), whereas previously the column referred to Net Capital Losses (75% of loss or after the inclusion rate has been applied). Loss amounts that are not carried at 100% of the loss must be grossed back up to 100% by multiplying the balance by 1.333333. No adjustment is required where losses are carried at 100% of the loss amount.

Analysis of Balance by Year of Origin

Year of Origin (oldest year first)	Non Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only (9) (10)	Farm Losses	Restricted Farm Losses
800				850	870
801				851	871
802				852	872
803	820	830	840	853	873
804	821	831	841	854	874
805	822	832	842	855	875
806 2000/12/31	823	833	843	856	876
807 2001/12/31	824	834	844	857	877
808 2002/12/31	825	835	845	858	878
809 2003/12/31	826	836	846	859	879
Total	829	839	849	869	889

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carryback adjustment may be applied by the Minister of Finance to amounts owing under ***any Act administered by the Minister of Finance***.
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses	**Non-Capital Losses**	**Total Capital Losses**	**Farm Losses**	**Restricted Farm Losses**
Total amount of loss	910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income. — **Predecessor Corporation's Account No. (MOF)** / **Taxation Year Ending**				
i) 3rd preceding — 901 2000/12/31	911	921	931	941
ii) 2nd preceding — 902 2001/12/31	912	922	932	942
iii) 1st preceding — 903 2002/12/31	913	923	933	943
Total loss to be carried back	From **706**	From **716**	From **726**	From **736**
Balance of loss available for carryforward	919	929	939	949

Summary

Income Tax	From 230 or 320	+	5,839
Corporate Minimum Tax	From 280	+	
Capital Tax	From 550	+	67,227
Premium Tax	From 590	+	
Total Tax Payable	950	=	73,066
Subtract: **Payments**	960	-	55,420
Capital Gains Refund (s.48)	965	-	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	985	-	
Specified Tax Credits *(Refer to Guide)*	955	-	
Balance	970	=	17,646
If payment due Enclosed *	990		
If overpayment: Refund *(Refer to Guide)*	975	=	
Apply to	980		

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, ***payable to the Minister of Finance*** and print your Ontario Corporation's Tax Account No. (MOF) on the back of the cheque or money order. (Refer to guide for other payment methods.)

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name
Tom Barrett

Title
Chief Financial Officer

Full Residence Address
215 Industrial Parkway South
PO Box 157

City
Aurora

Province	Country	Postal Code
ON		L4G 3H3

Signature	Date
	2004/06/24

Note: Section 76 of the Corporations Tax Act provides penalties for making false or misleading statements or omissions.

Corporate Minimum Tax - Schedule A: Calculation of CMT Base

Banks - Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

income/(loss) (unconsolidated, determined in accordance with GAAP)			2100 ±	348,142
Subtract (to the extent reflected in net income/loss):				
Provision for recovery of income taxes / benefit of current income taxes	2101 +			
Provision for deferred income taxes (credits) / benefit of future income taxes	2102 +			
Equity income from corporations	2103 +			
Share of partnership(s)/joint venture(s) income	2104 +			
Dividends received/receivable deductible under fed.s.112	2105 +			
Dividends received/receivable deductible under fed.s.113	2106 +			
Dividends received/receivable deductible under fed.s.83(2)	2107 +			
Federal Part VI.1 tax on dividends declared and paid, under fed.s.191.1(1) ______ x 9/3 =	2108 +			
Subtotal	=		▶ 2109 -	
Add (to extent reflected in net income/loss):				
Provision for current taxes / cost of current income taxes	2110 +	110,000		
Provision for deferred income taxes (debits) / cost of future income taxes	2111 +			
Equity losses from corporations	2112 +			
Share of partnership(s)/joint venture(s) losses	2113 +			
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	2114 +			
Subtotal	=	110,000	▶ 2115 +	110,000

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

** Fed.s.85	2116 +		or	2117 -		
** Fed.s.85.1	2118 +		or	2119 -		
** Fed.s.97	2120 +		or	2121 -		
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	2122 +		or	2123 -		
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	2124 +		or	2125 -		
** Amounts relating to s.57.10 election/ regulations for replacement re fed.s.13(4), 14(6) and 44 for current/prior years	2126 +		or	2127 -		
Interest allowable under ss. 20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income				2150 -		
Subtotal (Additions)	=		▶		2128 +	
Subtotal (Subtractions)				=	▶ 2129 -	
** Other adjustments					2130 ±	
Subtotal ± 2100 - 2109 + 2115 + 2128 - 2129 ± 2130					2131 =	458,142
** Share of partnership(s)/joint venture(s) **adjusted** net income/loss					2132 ±	
Adjusted net income (loss) (if loss, transfer to **2202** in **Schedule B**)					2133 =	458,142
Deduct: CMT losses: pre-1994 Loss *			From	2210 +		
CMT losses: other eligible losses *				2211 + 458,142		
				= 458,142	▶ 2134 -	458,142

* CMT losses applied cannot exceed adjusted net income or increase a loss
** Retain calculations. Do not submit with this tax return.

CMT Base	2135 =	

Transfer to CMT Base on page

Corporate Minimum Tax (CMT)

Schedule B: Continuity of CMT Losses Carried Forward

CMT loss continuity by year

Year of origin	Beginning balance	Transfers on amalgamation	Transfers on wind-up	Adjustments	Current year loss	Applied	Ending balance
							Expired
2000/12/31							
2001/12/31	627,869					458,142	169,727
2002/12/31							
2003/12/31							
Totals	627,869					458,142	169,727

Balance at Beginning of year (1), (2) — **2201** + 627,869

Add:
- Current year's losses — **2202** +
- Losses from predecessor corporations on amalgamation (3) — **2203** +
- Losses from predecessor corporations on wind-up (3) — **2204** +
- Amalgamation (✓) **2205** ☐ Yes Wind-up (✓) **2206** ☐ Yes

Subtotal = ▶ **2207** +

Adjustments (attach schedule) — **2208** ±

CMT losses available 2201 + 2207 ± 2208 — **2209** = 627,869

Subtract:
- Pre-1994 loss utilized during the year to reduce adjusted net income — **2210** +
- Other eligible losses utilized during the year to reduce adjusted net income (4) — **2211** + 458,142
- Losses expired during the year — **2212** +

Subtotal = 458,142 ▶ **2213** - 458,142

Balances at End of Year (5) **2209 - 2213** — **2214** = 169,727

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisitions of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and s.57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income **2133** and CMT losses available **2209**.

(5) Amount in **2214** must equal sum of **2270** and **2290**.

Schedule C: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year-end before your corporation's first taxation year commencing after 1993.

Year of Origin (oldest year first)	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	2260	2280
2241	2261	2281
2242	2262	2282
2243	2263	2283
2244	2264	2284
2245	2265	2285
2246 2000/12/31	2266	2286
2247 2001/12/31	2267 169,727	2287
2248 2002/12/31	2268	2288
2249 2003/12/31	2269	2289
Totals	2270 169,727	2290

The sum of amounts 2270 + 2290 must equal amount in 2214.

Corporate Minimum Tax (CMT)

Schedule D: Continuity of CMT Credit Carryovers

CMT credit continuity by year

Year of origin	Beginning balance	Transfers on amalgamation or wind-up	Adjustments	Current year credit	Applied	Expired	Ending balance
2001/12/31							
2002/12/31							
2003/12/31							
Totals							

Balance at Beginning of year (1) **2301** +

Add: Current year's CMT Credit (**280** on page 8. If negative, enter NIL) From **280** +

CMT Credit Carryovers from predecessor corporations (2) **2302** +

Amalgamation (✓) **2303** ☐ Yes Wind-up (✓) **2304** ☐ Yes

Subtotal = ▶ **2305** +

Adjustments *(Attach schedule)* **2306** ±

CMT credit carryover available 2301 + 2305 ± 2306 **2307** =

Transfer to Page 8

Subtract: CMT credit utilized during the year to reduce income tax (Page 8) From **310** +

CMT credit expired during the year **2308** +

Subtotal = ▶ **2309** -

Balance at End of Year (3) **2307 - 2309** **2310** =

Notes:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))

(2) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))

(3) Amount in **2310** must equal the sum of **2370** + **2390**.

Schedule E: Analysis of CMT Credit Carryovers Year-End Balance by Year of Origin

Year of Origin (oldest year first)	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporations
2340	**2360**	**2380**
2341	**2361**	**2281**
2342	**2362**	**2382**
2343	**2363**	**2383**
2344	**2364**	**2384**
2345	**2365**	**2385**
2346	**2366**	**2386**
2347 2001/12/31	**2367**	**2387**
2348 2002/12/31	**2368**	**2388**
2349 2003/12/31	**2369**	**2389**
Totals	**2370**	**2390**

The sum of amounts 2370 and 2390 must equal the amount in 2310.

Schedule F: Summary of Co-operative Education Tax Credit Claimed

...nplete a separate entry for each student work placement which ...ded during the corporation's taxation year. The tax credit is for co-op work placements and leading-edge technology work placements. A work placement is generally considered to be a full-time work assignment for up to 4 months in duration.

Example: If a corporation, with a December 31, 2001 taxation year end, hires an eligible student from September 1, 2001 until April 30, 2002, this would be considered 2 work placements. The first work placement is September 1, 2001 to December 31, 2001 and would be claimed in the 2001 taxation year. The second placement is January 1, 2002 to April 30, 2002 and must be claimed in the 2002 taxation year.

Qualifying work placements

Name of University / College and Education Program	Name of Student	SIN of Student	Work Term Start and End Dates	Eligible Costs of Placement (ECP)	*Credit Claimed (See notes below) (ma... $1000 per work placement)
University/College Georgian College Name of program Electrical Engineering Automated Systems	Kevin Philp	509 791 513	From 2003/05/01 To 2003/08/31	8,061	806
University/College Name of program			From To		
			Totals	5774 8,061	5798 806

*Transfer to **192** on Page 7 of the Tax Retur...*

Note: Enter corporation's salaries & wages paid in the preceding taxation year **A** 1,305,125 .

If **A** is $600,000 or greater use 10%. If **A** is $400,000 or less use 15%.

If **A** is over $400,000 but less than $600,000 use the following formula to calculate the rate:
Rate: = .15 - [.05 (From **A** ______________ - $400,000) ÷ $200,000]

...icate rate used: 10.0000 %. *** Credit claimed equals ECP multiplied by rate.**

Schedule G: Summary of Graduate Transitions Tax Credit Claimed

Complete a separate entry for each graduate, that is unrelated to the employer, that has worked full-time for a minimum of a six-month period. This credit applies to new hires for a maximum credit of $4,000 each and may only be claimed once.

Example: A taxpayer, with a December 31, 2001 taxation year end, hires an otherwise eligible graduate on June 1, 2001 who is still employed on December 31, 2002 at a salary of $3,500 per month. The salaries and wages in the taxpayer's preceding taxation year was $700,000. The taxpayer may only make one tax credit clai... for each graduate employed. Although the graduate is employed for 7 months during the 2001 taxation year, the taxpayer must claim the full credit in the taxation year in which the first 12 months of employment falls or when employment is ended if less than 12 months. In this example, the credit must be claimed in the 2002 taxation year. The credit claimed is the lesser of 10% of salary for the maximum 12 months of employment (10% X $3,500 X 12 = $4,200) or $4,000.

Qualifying Employment

Name of University / College and Date Program Completed	Name of Graduate	SIN of Graduate	Employment period	Qualified Eligible Expenditures (QEE)	*Credit Claimed (See notes below) (max $4,000 per graduate)
University/College Date program completed	Name		From To		
			Totals	6574	6598

*Transfer to **195** Page 7 of the Tax Return*

Note: Enter corporation's salaries & wages paid in the preceding taxation year **A** 1,305,125 .

If **A** is $600,000 or greater use 10%. If **A** is $400,000 or less use 15%.

...is over $400,000 but less than $600,000 use the following formula to calculate the rate:
Rate: = .15 - [.05 (From **A** ______________ - $400,000) ÷ $200,000]

Indicate rate used: 10.0000 %. *** Credit claimed equals QEE multiplied by rate.**

Total Number of Graduates **6596** = ______

*Transfer to **194** Page 7 of the Tax Return*

Canada Customs and Revenue Agency Agence des douanes et du revenu du Canada

CONTINUITY OF RESERVES

Schedule 1

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.

Part 1 - Capital gains reserves

Description of property 001	Balance at the beginning of the year 002	Transfer on wind-up or amalgamation 003	Balance at the end of the year 004
Totals	008	009	010

The total capital gains reserve at the beginning of the taxation year plus the total transfer on wind-up or amalgamation should be entered on line 880, and the total capital gains reserve at the end of the taxation year should be entered on line 885 of Schedule 6.

Part 2 - Other reserves not deducted for accounting purposes

Description of property	Balance at the beginning of the year	Transfer on wind-up or amalgamation	Balance at the end of the year
Reserve for doubtful debt	110 230,000	115	120 162,000
Reserve for undelivered goods and services not rendered	130	135	140
Reserve for prepaid rent	150	155	160
Reserve for December 31, 1995 income	170	175	180
Reserve for returnable containers	190	195	200
Reserve for unpaid amounts	210	215	220
Other tax reserves	230	235	240
Totals	270 230,000	275	280 162,000

The amount from line 270 plus the amount from line 275 should be included on line 125 of Schedule 1 as an addition.
The amount from line 280 should be included on line 413 of Schedule 1 as a deduction.

Part 3 - Accounting reserves not deductible for tax purposes

Description of property	Balance at the beginning of the year	Balance at the end of the year
Allowance for doubtful accounts	230,000	162,000
Employment litigation accrual		100,000
Totals	A 230,000	B 262,000

Enter amount A on line 414 of Schedule 1 as a deduction.
Enter amount B on line 126 of Schedule 1 as an addition.

Canada Customs and Revenue Agency / Agence des douanes et du revenu du Canada

PART I.3 TAX ON LARGE CORPORATIONS

Schedule 3:

- This schedule is for use by corporations (other than financial institutions and insurance corporations) that have Part I.3 tax payable before deducting surtax credits (line 820 in Part 5). You should also use and file this schedule if you calculate a **gross Part I.3 tax for the purposes of unused surtax credit** (line 821 in Part 6) and a **current-year unused surtax credit** (line 850 in Part 8).
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act* and the *Income Tax Regulations.*
- Subsection 181(1) defines the terms "financial institution", "long-term debt" and "reserves".
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- No Part I.3 tax is payable for a taxation year by a corporation that was:
  1) a non-resident-owned investment corporation throughout the year;
  2) bankrupt [as defined by subsection 128(3)] at the end of the year;
  3) a deposit insurance corporation throughout the year, as defined by subsection 137.1(5), or deemed to be a deposit insurance corporation by subsection 137.1(5.1);
  4) exempt from tax under section 149 throughout the year on all of its taxable income;
  5) neither resident in Canada nor carrying on a business through a permanent establishment in Canada at any time in the year; or
  6) a corporation described in subsection 136(2) throughout the year, the principal business of which was marketing (including any related processing) natural products belonging to or acquired from its members or customers.
- File the completed Schedule 33 with the *T2 Corporation Income Tax Return* no later than six months from the end of the taxation year.
- This schedule may contain changes that had not yet become law at the time of printing.

Complete the following areas to determine the amounts needed to calculate Part I.3 tax. If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 - Capital

	Line	Amount	Line	Total	
Add the following amounts at the end of the year:					
Reserves that have not been deducted in computing income for the year under Part I	101				
Capital stock (or members' contributions if incorporated without share capital)	103	12,385,600			
Retained earnings	104	1,757,219			
Contributed surplus	105				
Any other surpluses	106	100,000			
Deferred unrealized foreign exchange gains	107				
All loans and advances to the corporation	108	12,736,000			
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109				
Any dividends declared but not paid by the corporation before the end of the year	110				
All other indebtedness of the corporation (other than any indebtedness in respect of a lease) that has been outstanding for more than 365 days before the end of the year	111	2,389,910			
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112				
Subtotal		29,368,729	▸	29,368,729	A
Deduct the following amounts:					
Deferred tax debit balance at the end of the year	121				
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122				
Any amount deducted under subsection 135(1) in computing income under Part I for the year, to the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123				
The amount of deferred unrealized foreign exchange losses at the end of the year	124				
Subtotal			▸		B
Capital for the year (amount A minus amount B) (if negative, enter "0")			190	29,368,729	

PART I.3 TAX ON LARGE CORPORATIONS

Part 2 - Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	3,092,460
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 (other than by reason of paragraph 181.1(3)(d))	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year	490	3,092,460

Part 3 - Taxable capital

Capital for the year (line 190)		29,368,729	C
Deduct: Investment allowance for the year (line 490)		3,092,460	D
Taxable capital for the year (amount C minus amount D) (if negative, enter "0")	500	26,276,269	

Part 4 - Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500)			Taxable income earned in Canada / Taxable income				Taxable capital employed in Canada
	26,276,269	x		610	53,161 / 53,161	= 690	26,276,269

Notes: 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a taxation year is "0" it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business it carried on during the year through a permanent establishment in Canada			701	
Deduct the following amounts:				
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711			
Total of all amounts each of which is the carrying value at the end of the year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business it carried on during the year through a permanent establishment in Canada	712			
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713			
Total deductions (add lines 711, 712, and 713)				E
Taxable capital employed in Canada (line 701 minus amount E) (if negative, enter "0")			790	

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

PART I.3 TAX ON LARGE CORPORATIONS

Part 5 - Calculation of gross Part I.3 tax

Taxable capital employed in Canada (line 690 or 790, whichever applies)		26,276,269
Deduct: Capital deduction claimed for the year (enter $10,000,000 or, for related corporations, the amount allocated on Schedule 36)	801	9,999,923
Excess of taxable capital employed in Canada over capital deduction	811	16,276,346

Line 811 16,276,346 x Number of days in the taxation year before 2004 (365) / Number of days in the taxation year (365) x 0.00225 = 36,622 F

Line 811 16,276,346 x Number of days in the taxation year in 2004 ( ) / Number of days in the taxation year (365) x 0.002 = ______ G

Note: The Part I.3 tax rate is reduced to 0% for the days in the taxation year that are after 2007.

Subtotal (add amounts F and G) 36,622 K

Where the taxation year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax as follows:

Amount K ______ X Number of days in the year (______) / 365 = ______ L

Gross Part I.3 tax (amount K or L, whichever applies) 820 36,622

Part 6 – Calculation of gross Part I.3 tax for purposes of the unused surtax credit

Taxable capital employed in Canada (line 690 or 790, whichever applies)	26,276,269	M
Deduct: Line 801 above 9,999,923	9,999,923	N
Excess (amount M minus amount N) (if negative, enter "0")	16,276,346	O
Amount O 16,276,346 x 0.00225 =	36,622	P

Where the taxation year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax for purposes of the unused surtax credit as follows:

Amount P ______ x Number of days in the year (______) / 365 = ______ Q

Gross Part I.3 tax for purposes of the unused surtax credit (amount P or Q, whichever applies) 821 36,622

PART I.3 TAX ON LARGE CORPORATIONS

Part 7 - Calculation of current year surtax credit available

- Corporations can claim a credit against their Part I.3 tax for the amount of Canadian surtax payable for the year. This is called the surtax credit.
- Any unused surtax credit can be carried back three years or carried forward seven years. Unused surtax credits must be applied in order of the oldest first.
- Refer to subsection 181.1(7) of the Act when calculating the amount deductible for a corporation's unused surtax credits where control of the corporation has been acquired between the year in which the credits arose and the year in which you want to claim them.

For a corporation that was a non-resident of Canada throughout the year, enter amount **a** or **b** at line R, whichever is less:

a) line 600 from the T2 return		**a**		
b) line 700 from the T2 return		**b**		R

In any other case, enter amount **c** or **d** at line S, whichever is less:

c) line 600 from your T2 return 595 x (line 690 ÷ line 500) =	595	**c**		
d) line 700 from the T2 return	19,024	**d**	595	S
Current year surtax credit available (amount R or S, whichever applies)		**830**	595	

Part 8 - Calculation of current-year unused surtax credit

Current-year surtax credit available (line 830)		595
Less: Gross Part I.3 tax for purposes of the unused surtax credit (line 821)		36,622
Current-year unused surtax credit (if negative, enter "0")	**850**	

Enter this amount at line 600 on Schedule 37.

Part 9 - Calculation of net Part I.3 tax payable

Gross Part I.3 tax (line 820)			36,622	T
Deduct:				
Current-year surtax credit applied (line 820 or 830, whichever is less)	**861**	595		
Unused surtax credit from previous years applied (amount from line 320 on Schedule 37)	**862**			
Subtotal (cannot be more than amount on line 820)		595	595	U
Net Part I.3 tax payable (amount T minus amount U)	**870**		36,027	

Enter this amount at line 704 of the T2 return.

Client: Aurora Hydro Connections Limited CRA Business # 863683165 Year-end: 2003/12/31 Printed: 2004/06/24 14:44

Canada Customs and Revenue Agency · Agence des douanes et du revenu du Canada

AGREEMENT AMONG RELATED CORPORATIONS - PART I.3 TAX

Schedule

- Members of a related group of corporations should use this schedule to allocate the capital deduction among the members of the relate group. **Do not file this agreement if no members of the related group have to pay Part I.3 tax.**
- In cases where a related corporation has more than one taxation year ending in a calendar year, it has to file an agreement for each of those taxation years.
- A corporation that is related to any other corporation at any time in a taxation year of the corporation that ends in a calendar year may fil such an agreement.
- In accordance with subsection 181.5(7) of the federal *Income Tax Act*, a Canadian-controlled private corporation is not considered to be related to another corporation for purposes of the capital deduction unless it is also associated with that corporation.

Agreement

Date filed (for departmental use only) 010 ____________

Is this an amended agreement? 020 ☐ 1 Yes ☒ 2 No

Calendar year to which the agreement applies 030 2003

Note: This agreement must include all the information indicated below for all members of the related group, including members to which no amount of capital deduction is allocated for the year. However, any member that is exempt from Part 1.3 tax under subsection 181.1(3) does not have to be included.

Names of all corporations which are members of the related group 200	Business number (if a corporation is not registered, enter "NR") 300	Allocation of capital deduction for the year $ 400	Taxation year end to which thi agreement applies * 500
Aurora Hydro Connections Limited	86368 3165 RC 0001	9,999,923	yyyy/mm/dd
Borealis Hydro Electric Holdings Inc.	86550 8196 RC 0001	77	yyyy/mm/dd
	RC	0	yyyy/mm/dd
	Total	10,000,000	

* Entries are only required in this column for a corporation that has more than one taxation year ending in the same calendar year and is related in two or more of those taxation years to another corporation that has a taxation year ending in that calendar year. The capital deduction of the first corporation for each such taxation year at the end of which it is related to the other corporation is an amount equal to its capital deduction for the first such taxation year. Enter the taxation year end to which this agreement applies.

Canada Customs and Revenue Agency/Agence des douanes et du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to an this schedule are from the "Income Tax Act."
- For more information, see the "T2 Corporation Income Tax Guide."

Net income (loss) after taxes and extraordinary items per financial statements			-2,851,002	A

Additions:

Provision for income taxes - current	101	112,000		
Amortization of tangible assets	104	2,400,206		
Subtotal of additions		2,512,206	2,512,206	
Other Additions:				
Miscellaneous Other Additions:				
Subtotal of Other Additions	199	0	0	
Total Additions	500		2,512,206	

Deductions:

Subtotal of Deductions		0	0

Other Deductions:

Miscellaneous Other Deductions:

Subtotal of Other Deductions	499	0	0
Total Deductions	510		0

Net income (loss) for income tax purposes (enter on line 300 on the T2 return)	-338,796

PS - Vaughan
Taxation Period : 2001

	Per T2 Sch 1	Posted To TaxRec	Posted To TaxRec2	Posted to Taxrec3	Posted to Reserve
Net Income (Loss) After Taxes	($2,851,002)	($2,851,002)			
Additions					
Provision For Income Taxes - Current	$112,000	$112,000			
Provision For Income Taxes - Deferred		$0			
Amortization of tangible assets	$2,400,206	$2,400,206			
Amortization of intangible assets		$0			
Other Additions					
Reserves - OPEB	$986,000				$986,000
				$0	
				$0	
Total Additions	$3,498,206	$2,512,206	$0	$0	$986,000
Deductions					
Capital Cost Allowance	$2,539,925	$2,539,925			
Cummulative Eligible Capital	$52,402	$52,402			
Other Deductions					
Reserves - OPEB	$860,000				$860,000
				$0	
				$0	
				$0	
				$0	
Total Deductions	$3,452,327	$2,592,327	$0	$0	$860,000
Net Income (Loss) for income tax purposes	($2,805,123)	($2,931,123)	$0	$0	$126,000

Fed Income Tax	
FCT	$111,974
	$111,974
Prov Income Tax	
OCT	$159,211
	$159,211
	$271,185
Reassessment	$273,518
Difference	($2,333)

PS - Vaughan
Taxation Period : 2001

	Per T2 Sch 1		Posted To TaxRec		Posted To TaxRec2	Posted to Taxrec3		Posted to Reserve
Net Income (Loss) After Taxes		($2,851,002)		($2,851,002)				
Additions								
Provision For Income Taxes - Current	$112,000		$112,000					
Provision For Income Taxes - Deferred			$0					
Amortization of tangible assets	$2,400,206		$2,400,206					
Amortization of intangible assets			$0					
Other Additions								
			$0					
						$0		
						$0		
Total Additions		$2,512,206		$2,512,206	$0		$0	$0
Deductions								
Capital Cost Allowance			$0					
Cummulative Eligible Capital			$0					
Other Deductions								
						$0		
						$0		
						$0		
						$0		
						$0		
Total Deductions		$0		$0	$0		$0	$0
Net Income (Loss) for income tax purposes		($338,796)		($338,796)	$0		$0	$0

Fed Income Tax	
FCT	$111,974
	$111,974
Prov Income Tax	
OCT	$159,211
	$159,211
	$271,185
Reassessment	$273,518
Difference	($2,333)

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

BOARD STAFF INTERROGATORY #59:

Reference(s): E I / T1/ S4, EA3/T1/S5/p.20 and p. 26, *Accounting Procedures Handbook For Electricity Distributors* (“APH”), Article 220, p.31 and *Addendum to the Report of the Board*, EB-2008-0408, June 13, 2011, Issue 6, pp. 22-23

PowerStream is requesting a new 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.

On page 26 of the second reference, PowerStream stated that:

> “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.”

The Board has established guidelines for Z-factors claims related to unforeseen events outside of a distributor’s management control such as storms. The Board also established Account 1572, Extraordinary Event Costs, to be used to record extraordinary event costs, e.g., costs arising from storms, etc. that meet the qualifying criteria established by the Board, as contained in the APH.

a) Please clarify why PowerStream did not choose to file a Z-factor application for the storm related costs and follow accounting treatment as established by the Board using Account 1572 while meeting the IFRS accounting requirements, i.e., recognize gains or losses on retirement (“derecognition”) in other income.

b) Please state whether or not PowerStream is aware of any regulatory precedents for the proposed variance account?

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

c) As per the *Addendum to the Report of the Board*, utilities can apply to the Board for a utility specific variance account if they can demonstrate the probability of significant ongoing volatility. PowerStream has stated that it has not tracked this expense in the past and has very little data on which to base an estimate. Please provide justification for this account by demonstrating the probability of significant volatility for PP&E derecognition expense.

d) Given the fact that PowerStream has not tracked this expense in the past and has very little data to forecast it with precision, please explain how PowerStream can justify the inclusion of the PP&E derecognition expense in its 2013 forecast revenue requirement.

e) As per the *Addendum to the Report of the Board*, the Board may grant a variance account, for utilities that have rebased under modified IFRS, to mitigate volatility in certain expenses that may arise from the application of IFRS rules. Please explain why in PowerStream's view the PP&E derecognition costs that are due to mainly storm and accident damage requiring assets to be retired prematurely may arise from the application of IFRS rules.

RESPONSE:

a) PowerStream did not consider a Z-factor claim for derecognition costs as this was specifically dealt with by the Board in Transition to International Financial Reporting Standards ("IFRS") "*Addendum to the Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*" dated June 13, 2011 (EB-2008-0408) ("IFRS Addendum"). On page 22 under "Issue 6" the Board

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

considered the use of a generic variance account for "gains and losses arising from early retirement of in-service assets".

On page 23, the Board states in part,

> *At the first cost of service application after the transition, a utility will be expected to provide a forecast of asset useful lives, and gains and losses from retirements, as part of its application. This forecast will be reviewed by the Board and the likelihood of large variances from the forecast can be assessed. Utilities can apply to the Board for a utility-specific variance account if they can demonstrate the probability of significant ongoing volatility*.

PowerStream considers the use of a variance account to be a more appropriate way to deal with the issue of derecognition of assets, than account 1572 in combination with a Z-factor application. A storm-related event is not "unique" as described in account 1572 Extraordinary Event Costs. Every year assets are prematurely replaced due to storm damage or premature aging; a Z-factor application is not an appropriate way to deal with a recurring item. The issue is that the amount fluctuates widely from year to year and the estimate is based on one year of recorded history. As a recurring item it should be included in rates. Due to the limited history on which to base the amount, PowerStream proposes that a variance account, to track the difference between actual costs and the estimated cost used to set rates, is reasonable to protect both customers and the utility.

b) As discussed in the response to part (a) and noted in part (c) of this interrogatory, the Board has indicated that the proposed variance account is an approach that may be applicable to this situation.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

PowerStream compares the variance account treatment it is proposing in respect of derecognition expense to the variance account (1508 sub account) treatment the Board used for IFRS Transitional Costs. In the case of IFRS, due to the newness of the situation, there was uncertainty regarding the estimated costs so a variance account was established to track the differences between the actual costs and the costs used to set rates.

c) Early or premature retirement of assets due to storm damage or equipment failure is not new. Another driver of early retirement of assets is road widening and relocation projects. What is new is the requirement under IFRS and modified IFRS (MIFRS) to remove these assets from the asset accounts and record a derecognition expense equal to the remaining net book value (NBV) of assets removed from service. Prior to implementation of IFRS/MIFRS, these assets remained in the asset accounts until fully depreciated. Costs were recovered through the assets remaining in rate base and continued depreciation in rates. There was no need to track the remaining NBV of the assets removed from service.

PowerStream does track the capital cost of the new assets that are replacing the assets that are removed from service. The capital spending categories of “Emergency/ Restoration” and “Road Authority Projects” will provide an indication of the volatility of the amount of assets being replaced. These two categories will capture much of the cost of replacing failed plant (storm / equipment failure) and assets replaced due to road widening and relocation. The following table summarizes actual capital spending in these areas for the years 2007 to 2011 (all amounts in CGAAP):

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

Table Board Staff #59-1: Historical Capital Costs related to Derecognition Expense ($000)

DESCRIPTION	2007	2008	2009	2010	2011
Emergency/Restoration	$ 3,114	$ 3,590	$ 4,204	$ 8,673	$ 7,504
Road Authority Projects	$ 3,697	$ 1,089	$ 3,942	$ 5,923	$ 8,910
Total	**$ 6,811**	**$ 4,679**	**$ 8,146**	**$ 14,596**	**$ 16,414**

Based on this experience PowerStream considers it reasonable to expect that in some years there will be a small amount of derecognition expense and that in other years there will be considerable derecognition expense. However, this does not measure the underlying derecognition cost. Derecognition cost will vary with the amount of assets replaced and the age of assets replaced (the age will affect the remaining NBV). There is only one year of actual derecognition cost and this is not enough history to establish an average to use over an IRM period or to tell if 2011 costs were above or below average.

d) PowerStream has tracked the derecognition cost of premature retirement of assets for 2011 as required under MIFRS. The actual derecognition expense for 2011 was $1.2 million. This has been estimated as $1.4 million for 2012 and 2013. PowerStream submits that an amount should be in rates as there will be derecognition expense and the proposed amount is reasonable based on the very limited history. Rate payers are protected by the proposed variance account that in the event actual costs are below the estimated level of $1.4 million per year, the difference is tracked and will be returned to ratepayers. This variance account would operate similarly to the IFRS transition cost variance account where PowerStream is proposing in this application to refund to customers the excess of IFRS costs over actual costs collected in rates.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

e) Please see the response to part (c) above which explains how the treatment of premature retirement of assets under MIFRS compares to past regulatory treatment and must now be recovered as a current period cost rather than continued inclusion in rate base and depreciation expense.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

BOARD STAFF INTERROGATORY #60:

Reference(s): E I / T1/ S4, EA3/T1/S5, pp. 26-27, EA3/T1/S5/p.10 and *Addendum to the Report of the Board*, EB-2008-0408, June 13, 2011, Issue 2, p. 15

PowerStream is requesting a new deferral account for the changes in the Post Retirement Employee Benefits ("PREB") liability and costs under MIFRS compared to CGAAP up to this cost of service rebasing. In its application, PowerStream stated on page 26 of the second reference:

> "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."

In the third reference, PowerStream stated that:

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

a) Please provide a copy of the report by Dion Durrell and refer specifically to the evidence with respect to the PREB liability increase of $1.7 million as result of recognizing "Unrecognized Losses", "Unrecognized Past Service Cost" and "Unrecognized Transitional Obligation" amounts.

b) Please state whether or not PowerStream is aware of any regulatory precedents for the proposed deferral account and, if so, what they are?

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

c) As per the *Addendum to the Report of the Board*, the option is available for utilities to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS. Please state whether or not PowerStream is aware of any new or additional information that would be useful to the Board in making a decision on the proposed deferral account?

RESPONSE:

a) Please see attached Appendix A, a Memorandum from Dion Durrell dated June 23, 2011, regarding the Post-Retirement Non-Pension Benefit Plan Results under IFRS ("Actuarial Memo"). In Section E, the table on the top of page 3 titled "Prepaid Benefit liability as at January 1, 2011" shows that under IFRS (IAS 19), there is immediate recognition on transition to IFRS of the Unrecognized Loss of $5,284,894, Unrecognized Past Service cost of $1,215,577 and the Unrecognized Transitional Obligation of $417,032 offset by a reduction in the valuation of the Accrued Benefit Obligation (ABO) under IFRS of $5,239,650. This results in a net increase in the outstanding liability of $1,677,853 and a corresponding reduction in retained earnings. Under CGAAP these amounts would have been amortized over a number of years and this cost would have been factored into rates. As shown in Exhibit A3, Tab 1, Schedule 5, Table 11 (page 27), PowerStream has added this amount to the deferral account so that this cost which is not in current rates can be recovered in future rates.

As a result of the immediate recognition at January 1, 2011 in IFRS of amounts amortized over a period in CGAAP, the expense in 2011 under IFRS was estimated to be lower by $130,000 than it was under CGAAP. PowerStream has assumed the same difference for

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

2012. As current rates are based on CGAAP, these cost reductions under MIFRS for 2011 and 2012 have been deducted from the initial amount in the proposed deferral account. Table Board Staff #60-1 below, shows the amounts in dollars at January 1, 2011 as per the Actuarial Memo, and the amounts per the IFRS and CGAAP December 31, 2011 Actuarial reports, attached respectively as Appendix B and Appendix C. As can be seen, the actual difference for 2011 was $131,490 resulting in a small rounding difference of $2,980 from the amount of $1,418,000 in Table 11 at Exhibit A3, Tab 1, Schedule 5, pp. 26-27.

Table Board Staff #60-1: Change in Net Defined Benefit Liability (PREB) under IFRS

Net Defined Benefit Liability	CGAAP	IFRS	Difference
January 1, 2011	$ 13,379,126	$ 15,056,979	$ 1,677,853
2011 Change	$ 1,885,730	$ 1,754,240	$ (131,490)
December 31, 2011	$ 15,264,856	$ 16,811,219	$ 1,546,363
2012 Projected change			$ (131,490)
December 31, 2012			$ 1,414,873
Rounding difference			$ 2,980
Projected Difference to December 31, 2012			$ 1,417,853

b) PowerStream notes that the issue of a proposed IFRS deferral account was specifically dealt with by the Board in Transition to International Financial Reporting Standards ("IFRS") "*Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment*" dated June 13, 2011 (EB-2008-0408) ("IFRS Addendum"). On page 15, regarding a deferral account for pension and other post retirement benefits (P&OPEB), the Board states, in part:

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

> *"As acknowledged by the CLD, the impacts are anticipated to be significant for only a few large utilities. The option remains for these utilities to seek an individual account if they can demonstrate the likelihood of a large cost impact on the transition to IFRS."*

PowerStream submits that the amount of $1.4 million is significant compared to a Z-factor threshold of approximately $0.9M (i.e. 0.5% of the 2013 revenue requirement).

c) The amounts identified in its Application and parts a) and b) of this response, represent the best information that PowerStream has on the impact of IFRS on PREB.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

BOARD STAFF INTERROGATORY #61:

Reference(s): <u>E I / T1/ S4, EA3/T1/S5, p. 27 and *Addendum to the Report of the Board*, EB-2008-0408, June 13, 2011, Issue 6, p. 23</u>

PowerStream is requesting a new variance account for PREB expense included in the approved 2013 rates and the actual costs in each year until the next setting of cost of service rates.

a) What is the regulatory precedent for the proposed variance account?

b) Please confirm that PowerStream's request for a new variance account for PREB is due to adoption of IAS 19, Employee Benefits, which eliminates the corridor method effective January 1, 2013.

c) As per the *Addendum to the Report of the Board*, utilities can apply to the Board for a utility specific variance account if they can demonstrate the probability of significant ongoing volatility. Please provide information to demonstrate the probability of significant ongoing volatility with respect to the PREB expense included in the proposed 2013 rates.

RESPONSE:

a) PowerStream notes that this was specifically dealt with by the Board in Transition to International Financial Reporting Standards ("IFRS") "*Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment*" dated June 13, 2011 (EB-2008-0408) ("IFRS Addendum"). On pages 23-24, regarding a variance account to deal with

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

the volatility of pension and other post retirement benefits (P&OPEB) expense after rebasing under MIFRS, the Board states, in part:

> *"With respect to P&OPEB items, the Board is not persuaded that a generic account is necessary. It is not clear that the impact of the transition to IFRS on P&OPEB items will be consistent among Ontario utilities. Individual utilities that can demonstrate the likelihood of large variances can seek an individual variance account from the Board."*

b) PowerStream confirms that its request for a new variance account for PREB is due to adoption of IAS 19, Employee Benefits, which eliminates the corridor method, with its transition to IFRS. As a result, actuarial gains and losses would be recognized immediately in the income statement.

c) The probability of significant ongoing volatility with respect to the PREB expense included in the proposed 2013 rates is demonstrated by the sensitivity analysis performed in note 12, Employee Future Benefits, in PowerStream's 2011 Audited Financial Statement (Appendix 1, Schedule 16 of the Application). This is reproduced below:

Sensitivity analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2011:

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

	Increase	Decrease
	$	$
Total service and interest cost	**293**	**(230)**
Accrued benefit obligation	**2,819**	**(2,292)**
	3,112	**(2,522)**

The above note appears in the 2011 CGAAP financial statements. Under IFRS the change shown for the Accrued benefit obligation would be recognized immediately in the income statement. A range of -$2.3 to +$2.8 million for a small change in the assumed cost increase rate has an impact that is several times PowerStream's Z-factor threshold of approximately $0.9 million or 0.5% of the proposed revenue requirement. PowerStream submits that this clearly demonstrates the volatility that can happen under IFFRS.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.2 Are the proposed new and existing deferral and variance accounts for the test year appropriate?

SEC INTERROGATORY #53:

Reference(s): [Ex. A3/1/5, p. 27]

Please explain why the Applicant is proposing to clear the proposed Post Retirement Employee Benefit Expense Variance Account periodically, rather than using it as a method of achieving a result akin to the corridor method over the remaining service lives of the employees. Please discuss the pros and cons of each approach, and the impact of volatility differences on both the Applicant and the ratepayers.

RESPONSE:

PowerStream is not proposing that Post Retirement Employee Benefit (PREB) Expense Variance Account necessarily be cleared in full periodically but that consideration is given to the accumulating balance and how it should be incorporated in rates.

PowerStream agrees that SEC's suggestion that a disposition based the corridor method over the remaining service lives of the employees has merit. This approach smoothes these changes to minimize rate impacts to customers. As these costs and liabilities are subject to a number of economic assumptions it is likely that the expense will move both up and down over the service lives of the employees. In PowerStream's view, a method, such as that suggested by SEC, provides a better matching of the long term cost to the current period.

Dion Durrell
Actuaries and Consultants

Dion, Durrell + Associates Inc.
250 Yonge Street, Suite 2900
Toronto, Ontario, Canada M5B 2L7
dion-durrell.com

T 41
F 416 408 3721

MEMORANDUM

DATE: June 23, 2011
TO: Heather Clark (Powerstream Inc.)
FROM: Stanley Caravaggio
RE: Powerstream Inc. – Post-Retirement Non-Pension Benefit Plan Accounting Results under International Financial Reporting Standards (IFRS)
COPY: Adam Chiarandini (Powerstream Inc.), Patrick Kavanagh, Connie Cheung

The purpose of this memo is to provide Powerstream Inc. (the "Corporation") with projected FY 2011 accounting results in respect of its post-retirement non-pension benefits based on the application of IFRS.

We understand that the Corporation is required to prepare its financial statements in accordance with IFRS effective January 1, 2012. In addition, although the Corporation will continue to report 2011 results under current Canadian Generally Accepted Accounting Principles ("CGAAP"), it is required to present 2011 comparable financial statements under IFRS.

Previous actuarial valuation reports and disclosures for your post-retirement non-pension benefits were prepared in accordance with Section 3461 of the Canadian Institute of Chartered Accountants Accounting Handbook ("CICA 3461"). Under IFRS, these same post-retirement non-pension benefits are to be valued in accordance with International Accounting Standard 19 Employee Benefits (IAS 19).

Below you will find projected 2011 accounting entries for your post-retirement non-pension benefit plan using IAS 19. Please note that these results are for informational purposes only as significant changes to the information including re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review for 2011. The supporting calculations are summarized in the accounting worksheets hereby attached.

FY2011—PROJECTED BENEFIT EXPENSE (IAS 19)

A. Amounts Recognized in Balance Sheet

Net liability, January 1	$15,056,979
Net expense recognized in income statement	$ 1,782,042
Benefits paid by the employer	$ (477,133)
Net liability, December 31	$16,361,888

B. Amounts Recognized in Income Statement

Current Service Cost	$ 991,544
Interest Cost	$ 790,498
Expected Return on Plan Assets	$ -
Past Service Cost – Non-vested benefits	$ -
Past Service Cost – Vested benefits	$ -
Transitional Obligation	$ -
Net Actuarial (Gain) / Loss Recognized in Year	$ -
Expense Recognized in Income Statement	$ 1,782,042

C. Change in the Present Value of the Defined Benefit Obligation

Present Value of Obligation at January 1, 2011	$ 15,056,979
Current Service Cost	$ 991,544
Interest Cost	$ 790,498
Past Service Cost – non vested benefits	$ -
Past Service Cost – vested benefits	$ -
Benefits Paid	$ (477,133)*
Actuarial (Gain)/Loss	$ -
Present Value of Obligation at December 31, 2011	$ 16,361,888

* based on estimated employer benefit payments for those expected to be eligible for post-retirement non-pension benefits in 2011.

FY2011—RECONCILIATION BETWEEN PROJECTED CICA 3461 AND IAS 19 FIGURES

D. 2011 Projected Benefit Expense

	CGAAP (CICA 3461)	Change	IFRS (IAS 19)
Current Service Cost	$ 595,634	395,910	$ 991,544
Interest on Benefits	$ 1,032,685	(242,187)	$ 790,498
Past Service Cost/(Gain)	$ 77,330	(77,330)	-
Transitional Obligation/(Asset)	$ 72,000	(72,000)	-
Actuarial (Gain)/Loss	$ 422,953	(422,953)	-
Benefit Expense	$ 2,200,601	(418,560)	$ 1,782,042

E. Prepaid Benefit Liability as at January 1, 2011

	CGAAP (CICA 3461)	Change	IFRS (IAS 19)
Unfunded ABO	$ 20,296,629	(5,239,650)	$ 15,056,979
Unrecognized (Loss)/Gain	$ (5,284,894)	5,284,894	-
Unrecognized Past Service (Cost)/Gain	$ (1,215,577)	1,215,577	-
Unrecognized Transitional (Obligation)/Asset	$ (417,032)	417,032	-
Prepaid Benefit Liability	$ 13,379,126	1,677,853	$ 15,056,979

Pursuant to Appendix section D10 of IFRS 1 (First-Time Adoption of IFRS), the results above are based on the Corporation's election to recognize all cumulative actuarial gains and losses at the date of transition to IFRSs. We note that this election does not impact the Corporation's choice of approach to recognizing future actuarial gains or losses under IFRS when they occur.

The following is noted in regards to the figures above:

- The employee data is as detailed in the Report on the Actuarial Valuation of Post-Retirement Non-Pension Benefits as at December 31, 2009 ("Valuation Report") for the Former Aurora, Former Richmond Hill, Former Barrie, Former Markham, and Former Vaughan Hydro members. Employee data for the new Union employees with dates of hire prior to June 21, 2010 were reflected in our calculation of the December 31, 2010 ABO
- The methodology used in the calculation of the present value of the defined benefit obligation and current service cost is the same as outlined in the Valuation Report, with the exception of changes made in respect of the application of the provisions in Sections 67-71 of IAS 19 regarding attributing benefits to periods of service. More specifically, the following changes were made to the attribution period for post-retirement non-pension benefits for Former Richmond Hill, Former Barrie, Former Markham, Former Vaughan Hydro, and new Union employees to reflect underlying post-retirement benefit service eligibility requirements under these plans and the application of Section 70 of IAS 19 to same:
  - **Former Richmond Hill Hydro employees** (20 year service requirement to be eligible for post-retirement health and dental benefits) – the attribution period under IFRS for the aforementioned benefits would commence at the later of the date of hire and age 35 and would cease at the later of age 55 or the date at which 20 years of service is reached.
  - **Former Barrie Hydro employees** (15 year service requirement to be eligible for post-retirement health and dental benefits) – the attribution period under IFRS for the aforementioned benefits would commence at the later of the date of hire and age 40 and would cease at the later of age 55 or the date at which 15 years of service is reached.
  - **Former Vaughan Hydro employees** (5 year service requirement to be eligible for post-retirement life, health, and dental benefits) – the attribution period under IFRS for the aforementioned benefits would commence at the later of the date of hire and age 50 and would cease at the later of age 55 or the date at which 5 years of service is reached.

- **Former Markham Hydro employees** (5 year service requirement to be eligible for post-retirement health and dental benefits) – the attribution period under IFRS for the aforementioned benefits would commence at the later of the date of hire and age 50 and would cease at the later of age 55 or the date at which 5 years of service is reached.
- **New Union employees** (15 year service requirement to be eligible for post-retirement life, health, and dental benefits) – the attribution period under IFRS for the aforementioned benefits would commence at the later of the date of hire and age 40 and would cease at the later of age 55 or the date at which 15 years of service is reached.

➢ The assumptions used are the same as those detailed in the Valuation Report, with the exception of the discount rate assumption which has been updated to 5.00% per annum as at December 31, 2010 to reflect management's best estimate assumption for the calculation of the Corporation's accrued benefit obligation as at December 31, 2010.

➢ Benefit plan provisions reflect those outlined in the Valuation Report for the Former Aurora, Former Richmond Hill, Former Barrie, Former Markham, and Former Vaughan Hydro members. Plan provisions for the new Union employees, effective June 21, 2010, are summarized in the correspondence provided under separate cover relating to the FY 2010 accounting disclosures.

➢ Our calculations conform to the standards as set out in International Accounting Standard 19 in Employee Benefits.

If you have any questions regarding the above or any other queries regarding the impact of IFRS on the accounting results of your post-retirement non-pension benefit plan, please do not hesitate to give us a call.

Dion Durrell

Powerstream Inc. (Total)
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	CY 2011	Projected** CY 2012	Projected** CY 2013
Discount Rate at January 1	5.00%	4.50%	4.50%
Discount Rate at December 31	4.50%	4.50%	4.50%
Health Benefit Cost Trend Rate at December 31			
Initial Rate	8.00%	7.63%	7.25%
Ultimate Rate	5.00%	5.00%	5.00%
Year Ultimate Rate Reached	2020	2020	2020
Dental Benefit Cost Trend Rate	5.00%	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%	2.00%
Assumed Increase in Employer Contributions	actual	expected*	expected*

A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet

	CY 2011	CY 2012	CY 2013
Net Defined Benefit Liability/(Asset) as at January 1	15,056,979	16,811,219	18,048,314
Defined Benefit Cost Recognized in Income Statement	1,066,923	1,795,103	1,896,827
Defined Benefit Cost Recognized in Other Comprehensive Income	1,006,147	-	-
Benefits Paid by the Employer	(318,829)	(558,008)	(627,769)
Net Defined Benefit Liability/(Asset) as at December 31	16,811,219	18,048,314	19,317,373

B. Determination of Defined Benefit Cost
B1. Determination of Defined Benefit Cost Recognized in Income Statement

	CY 2011	CY 2012	CY 2013
Service Cost			
- Current Service Cost	991,544	1,051,153	1,098,778
- Past Service Cost	(669,500)	-	-
Net Interest Cost	744,878	743,950	798,049
Defined Benefit Cost Recognized in Income Statement	1,066,923	1,795,103	1,896,827

B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income

	CY 2011	CY 2012	CY 2013
Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	1,006,147	-	-
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	-	-	
Return on Plan Assets (excluding amounts included in net interest cost)	-	-	-
Change in effect of asset ceiling	-	-	-
Defined Benefit Cost Recognized in Other Comprehensive Income	1,006,147	-	-
Total Defined Benefit Cost	2,073,069	1,795,103	1,896,827

C. Change in the Present Value of Defined Benefit Obligation

	CY 2011	CY 2012	CY 2013
Present Value of Defined Benefit Obligation as at January 1	15,056,979	16,811,219	18,048,314
Current Service Cost	991,544	1,051,153	1,098,778
Past Service Cost	(669,500)	-	-
Interest Cost	744,878	743,950	798,049
Benefits Paid	(318,829)	(558,008)	(627,769)
Net Actuarial Loss/(Gain)	1,006,147	-	-
Present Value of Defined Benefit Obligation as at December 31	16,811,219	18,048,314	19,317,373

* based on estimated employer benefit payments for those expected to be eligible for benefits

** For informational purposes only. Significant changes in 2012-13 such as re-negotiated benefits, increased benefit costs, changes to best estimate assumptions, or significant demographic swings may require revised projections/a full actuarial review.

Dion Durrell

4/12/2012

Powerstream Inc. (Total)
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	CY 2011	Projected** CY 2012	Projected** CY 2013
Discount Rate at January 1	5.00%	4.50%	4.50%
Discount Rate at December 31	4.50%	4.50%	4.50%
Health Benefit Cost Trend Rate at December 31			
Initial Rate	8.00%	7.63%	7.25%
Ultimate Rate	5.00%	5.00%	5.00%
Year Ultimate Rate Reached	2020	2020	2020
Dental Benefit Cost Trend Rate	5.00%	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%	2.00%
Assumed Increase in Employer Contributions	actual	expected*	expected*

D. Calculation of Component Items

	CY 2011	CY 2012	CY 2013
Service Cost			
- Current Service Cost	991,544	1,051,153	1,098,778
- Past Service Cost	(669,500)	-	-
Interest Cost			
- Net Defined Benefit Liability/(Asset) as at January 1	15,056,979	16,811,219	18,048,314
- Benefits Paid	(159,414)	(279,004)	(313,884)
- Accrued Benefits	14,897,564	16,532,215	17,734,430
- Interest Cost	744,878	743,950	798,049
Expected Present Value of Defined Benefit Obligation as at December 31			
- Present Value of Defined Benefit Obligation as at January 1	15,056,979	16,811,219	18,048,314
- Current Service Cost	991,544	1,051,153	1,098,778
- Interest Cost	744,878	743,950	798,049
- Benefits Paid	(318,829)	(558,008)	(627,769)
- Expected Present Value of Defined Benefit Obligation as at December 31	16,474,573	18,048,314	19,317,373

E. Net Actuarial Loss/(Gain)

	CY 2011	CY 2012	CY 2013
Net Actuarial Loss/(Gain) on Present Value of Defined Benefit Obligation as at December 31			
- Expected Present Value of Defined Benefit Obligation	16,474,573	18,048,314	19,317,373
- Past Service Cost	(669,500)	-	-
- Expected Present Value of Defined Benefit Obligation (after Past Service Cost)	15,805,073	18,048,314	19,317,373
- Actual Present Value of Defined Benefit Obligation	16,811,219	18,048,314	19,317,373
- Net Actuarial Loss/(Gain) on Present Value of Defined Benefit Obligation	1,006,147	-	-

* based on estimated employer Benefits Paid for those expected to be eligible for benefits.

** For informational purposes only. Significant changes in 2012-13 such as re-negotiated benefits, increased benefit costs, changes to best estimate assumptions, or significant demographic swings may require revised projections/a full actuarial review.

Dion Durrell

Powerstream Inc. (Total)

Filed: August 31, 2012

ESTIMATED BENEFIT EXPENSE (CICA Section 3461)

FINAL

	Calendar Year 2011 Jan 1 - Dec 31
Discount Rate - January 1	5.00%
Discount Rate - December 31	4.50%
Withdrawal Rate	2.00%
Assumed increase in Employer Contributions	actual

A. Determination of Benefit Expense

Current Service Cost	595,634
Interest on Benefits	1,036,642
Expected Interest on Assets	-
Past Service Cost/(Gain)	77,330
Transitional Obligation/(Asset)	72,000
Actuarial (Gain)/Loss	422,953
Benefit Expense	2,204,560

B. Reconciliation of Prepaid Benefit Asset (Liability)

Accrued Benefit Obligation (ABO) at end of period	21,832,610
Assets at end of period	-
Unfunded ABO	(21,832,610)
Unrecognized Loss/(Gain)	5,507,374
Unrecognized Past Service Cost/(Gain)	715,347
Unrecognized Transition	345,032
Prepaid Benefit Asset (Liability)	(15,264,857)
Prepaid Benefit/(Liability) beginning of period	(13,379,126)
Benefit Income/(Expense)	(2,204,560)
Contributions/Benefit Payments by the Employer*	318,829
Prepaid Benefit Asset (Liability)	(15,264,857)

Dion Durrell

4/12/2012

Powerstream Inc. (Total)
ESTIMATED BENEFIT EXPENSE (CICA Section 3461)
FINAL

	Calendar Year 2011 Jan 1 - Dec 31
Discount Rate - January 1	5.00%
Discount Rate - December 31	4.50%
Withdrawal Rate	2.00%
Assumed increase in Employer Contributions	actual

C. Calculation of Component Items

Calculation of the Service Cost	
- Current service cost	595,634
Interest on Benefits	
- ABO at beginning of period	20,296,629
- Current service cost	595,634
- Benefit payments	(159,414)
- Accrued benefits	20,732,849
- Interest	1,036,642
Expected Interest on Assets	
- Assets at beginning of period	-
- Funding	159,414
- Benefit payments	(159,414)
- Expected assets	-
- Interest	-
Expected ABO at end of Period	
- ABO at beginning of period	20,296,629
- Current service cost	595,634
- Interest on benefits	1,036,642
- Benefit payments	(318,829)
- Expected ABO at end of period	21,610,077
Expected Assets at end of Period	
- Assets at beginning of period	-
- Funding	318,829
- Interest on assets	-
- Benefit payments	(318,829)
- Expected Assets at end of period	-

4/12/2012

Dion Durrell

Powerstream Inc. (Total)
ESTIMATED BENEFIT EXPENSE (CICA Section 3461)
FINAL

	Calendar Year 2011 Jan 1 - Dec 31
Discount Rate - January 1	5.00%
Discount Rate - December 31	4.50%
Withdrawal Rate	2.00%
Assumed increase in Employer Contributions	actual

D. Actuarial (Gain)/Loss

(Gain)/Loss on ABO at beginning of period	
- Prepaid Benefit/(Liability)	13,379,126
- Unamortized Past Service Cost/(Gain) From Prior Year	1,215,577
- Unamortized Transition From Prior Year	417,032
- Unamortized (Gain)/Loss From Prior Year	5,284,894
- Expected ABO	20,296,629
- Actual ABO	20,296,629
- (Gain)/Loss on ABO	-
(Gain)/Loss on assets at beginning of period	
- Expected assets	-
- Actual assets	-
- (Gain)/Loss on assets	-
Total (Gain)/Loss as at beginning of period	5,284,894
10% of ABO as at beginning of period	2,029,663
Total (Gain)/Loss in Excess of 10%	3,255,231
Expected Average Remaining Service Life (Years)	8
Actual Amortization for current period	422,953
(Gain)/Loss on ABO at December 31 due to actuarial valuation	
- Expected ABO - December 31	21,610,077
- Correction to 'Past Service Cost arising in CY 2010'*	(598,000)
- Past Service Cost arising in CY 2011	175,100
- Actual ABO - December 31	21,832,610
- (Gain)/Loss on ABO at December 31	645,433
Unamortized (Gain)/Loss*	5,507,374

4/12/2012

Dion Durrell

Powerstream Inc. (Total)
ESTIMATED BENEFIT EXPENSE (CICA Section 3461)
FINAL

	Calendar Year 2011 Jan 1 - Dec 31
Discount Rate - January 1	5.00%
Discount Rate - December 31	4.50%
Withdrawal Rate	2.00%
Assumed increase in Employer Contributions	actual

E. Amortization of Past Service Costs

Unamortized past service costs as at beginning of period	
Arising in CY 2005	(5,540)
Arising in CY 2010	1,221,117
Total	1,215,577
Period over which past service costs are to be amortized (years)	
Past Service Cost arising in CY 2005	4
Past Service Cost arising in CY 2010	15
Actual Amortization for current period	
Past Service Cost arising in CY 2005	(1,452)
Past Service Cost arising in CY 2010	78,782
Unamortized past service costs as at the end of period	
Past Service Cost arising in CY 2005	(4,088)
Past Service Cost arising in CY 2010	1,142,335
Correction to 'Past Service Cost arising in CY 2010'*	(598,000)
	544,335
Past Service Cost arising in CY 2011	175,100
Total	715,347

* Past Service Cost arising in CY 2010 to be adjusted for new information on actual benefit provisions provided by PowerStream. This adjustment will impact final Unamortized Loss at December 31, 2011

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.3 Is the proposal related to the recovery of stranded meter costs appropriate?

VECC INTERROGATORY #51:

Reference(s): Exhibit I, Tab 1, Schedule 8

a) Please provide a summary table showing the derivation of the rate rider (including allocators) for account 1555

RESPONSE:

Preamble:

In its Issues List Decision and Procedural Order No. 2 dated July 25, 2012, the Board approved a Final Issues List and made provision for written interrogatories to reference the pre-filed evidence and to be filed by issue. Contrary to Board direction, for purposes of this interrogatory VECC has created "Issue 10.1: Are the proposed quanta and nature of smart meter costs, including the allocation and recovery methodologies appropriate?" PowerStream finds the Board-approved issue most closely related to this interrogatory to be "Issue 5.3: Is the proposal related to the recovery of stranded meter costs appropriate?" and has so responded.

a) PowerStream has included recovery of account 1555 deferred costs in the deferral and variance account models filed in Exhibit I, Tab 1, Schedule 3. These amounts represent the remaining unamortized cost of stranded meters at December 31, 2012. The amounts are split by rate zone and entered into the South and Barrie models on "Sheet 1 – Rate Rider Calculation" of the respective models. As shown on Sheet 1, these costs were allocated based on the number of metered customers, which can be found on "Sheet 4- Allocators" of the respective models under "Metered Customers". The amounts allocated to the customer classes are summarized in Table VECC#51-1 below.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.3 Is the proposal related to the recovery of stranded meter costs appropriate?

Table VECC#51-1: Smart Meter Account 1555 Class Allocation

	South		Barrie		Total	
Class	**Amount**	**%**	**Amount**	**%**	**Amount**	**%**
Residential	$ 7,803,817	89.1%	$ 2,534,200	90.7%	$ 10,338,017	89.5%
GS<50 kW	$ 822,703	9.4%	$ 228,923	8.2%	$ 1,051,626	9.1%
GS>50 kW	$ 127,781	1.5%	$ 31,327	1.1%	$ 159,108	1.4%
Large Use	$ 34	0.0%		0.0%	$ 34	0.0%
Unmetered		0.0%		0.0%	$ -	0.0%
Sentinel Lighting		0.0%		0.0%	$ -	0.0%
Street Lighting		0.0%		0.0%	$ -	0.0%
Total	**$ 8,754,335**	**100.0%**	**$ 2,794,450**	**100.0%**	**$ 11,548,785**	**100.0%**

Each of the Deferral and Variance Account Rate Rider Calculation models determine a single rate rider for each customer class covering the entire amount to be disposed. Table VECC#51-2 shows the portion of the rate rider attributable to the account 1555 amounts shown in Table VECC#51-1.

Table VECC#51-2 Deferral & Variance Rate Rider – Account 1555 Portion

	South			Barrie			
Class	**Amount**	**Billing Determinant**	**Rate Rider**	**Amount**	**Billing Determinant**	**Rate Rider**	**Per**
Residential	$ 7,803,817	2,156,279,348	$ 0.0036	$ 2,534,200	571,622,363	$ 0.0044	kWh
GS<50 kW	$ 822,703	840,157,445	$ 0.0010	$ 228,923	209,719,823	$ 0.0011	kWh
GS>50 kW	$ 127,781	10,195,076	$ 0.0125	$ 31,327	1,935,649	$ 0.0162	kW
Large Use	$ 34	187,932	$ 0.0002		-		kW
Unmetered							kWh
Sentinel Lighting							kW
Street Lighting							kW
Total	**$ 8,754,335**			**$ 2,794,450**			

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.3 Is the proposal related to the recovery of stranded meter costs appropriate?

VECC INTERROGATORY #52:

Reference(s): Exhibit I, Tab 1, Schedule 8

a) Please provide a summary table showing the derivation of the rate rider (including allocator) for account 1556

RESPONSE:

Preamble:

In its Issues List Decision and Procedural Order No. 2 dated July 25, 2012, the Board approved a Final Issues List and made provision for written interrogatories to reference the pre-filed evidence and to be filed by issue. Contrary to Board direction, for purposes of this interrogatory VECC has created "Issue 10.1: Are the proposed quanta and nature of smart meter costs, including the allocation and recovery methodologies appropriate?" PowerStream finds the Board-approved issue most closely related to this interrogatory to be "Issue 5.3: Is the proposal related to the recovery of stranded meter costs appropriate?" and has so responded.

a) PowerStream has included recovery of account 1556 deferred costs in the deferral and variance account models filed in Exhibit I, Tab 1, Schedule 3. These amounts represent mainly customer premise costs related to smart meters installed after the final recovery cut-off of April 30, 2011. The amounts are split by rate zone and entered into the South and Barrie models on "Sheet 1 – Rate Rider Calculation" of the respective models. As shown on Sheet 1, these costs were allocated based on the number of metered customers, which can be found on "Sheet 4- Allocators" of the respective models under "Metered Customers". The amounts allocated to the customer classes are summarized in Table VECC #52-1 below.

RESPONSES TO INTERROGATORIES BY ISSUE

5. DEFERAL AND VARIANCE ACCOUNTS (Exhibit I)

5.3 Is the proposal related to the recovery of stranded meter costs appropriate?

Table VECC #52-1: Smart Meter Account 1556 Class Allocation

	South		Barrie		Total	
Class	**Amount**	**%**	**Amount**	**%**	**Amount**	**%**
Residential	$ 80,180	89.1%	$ 140,031	90.7%	$ 220,211	90.1%
GS<50 kW	$ 8,453	9.4%	$ 12,649	8.2%	$ 21,102	8.6%
GS>50 kW	$ 1,313	1.5%	$ 1,731	1.1%	$ 3,044	1.2%
Large Use		0.0%		0.0%	$ -	0.0%
Unmetered		0.0%		0.0%	$ -	0.0%
Sentinel Lighting		0.0%		0.0%	$ -	0.0%
Street Lighting		0.0%		0.0%	$ -	0.0%
Total	**$ 89,946**	100.0%	**$ 154,411**	100.0%	**$ 244,357**	100.0%

Each of the Deferral and Variance Account Rate Rider Calculation models determines a single rate rider for each customer class covering the entire amount to be disposed. Table VECC #52-2 shows the portion of the rate rider attributable to the account 1556 amounts shown in Table VECC #52-1.

Table VECC #52-2 Deferral & Variance Rate Rider – Account 1555 Portion

	South			Barrie			
Class	**Amount**	**Billing Determinant**	**Rate Rider**	**Amount**	**Billing Determinant**	**Rate Rider**	**Per**
Residential	$ 80,180	2,156,279,348	$ 0.0000	$ 140,031	571,622,363	$ 0.0002	kWh
GS<50 kW	$ 8,453	840,157,445	$ 0.0000	$ 12,649	209,719,823	$ 0.0001	kWh
GS>50 kW	$ 1,313	10,195,076	$ 0.0001	$ 1,731	1,935,649	$ 0.0009	kW
Large Use	$ -	187,932	$ -	$ -	-		kW
Unmetered	$ -			$ -			kWh
Sentinel Lighting	$ -			$ -			kW
Street Lighting	$ -			$ -			kW
Total	**$ 89,946**			**$ 154,411**			

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

BOARD STAFF INTERROGATORY #62:

Reference(s): <u>Ref: E E/ T1/ S1/p.4</u>

It is stated that:

"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."

a) Please provide an update on the status of this refinancing.
b) Please state whether financing from Infrastructure Ontario is among the options being considered by PowerStream and its financial advisors. If not, please explain why not.

RESPONSE:

a) The $125 million EDFIN debenture refinancing has been completed. A new $200 million 30-year debenture was issued on July 30, 2012 at a rate of 3.958%.

b) PowerStream did have some initial discussions with Infrastructure Ontario on refinancing the EDFIN debenture with debt provided by Infrastructure Ontario. PowerStream elected not to proceed with Infrastructure Ontario for several reasons some of which are noted below.

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

Infrastructure Ontario's covenants and reporting requirements were too restrictive and stringent for PowerStream. For example, Infrastructure Ontario requires issuers to file monthly project management reports which require a lot of time and effort.
Infrastructure Ontario has several financial covenants which are cumbersome and restrictive for an entity the size of PowerStream. Infrastructure Ontario requires that entities maintain an interest coverage ratio of 1:1. a current ratio of 1:1, and a debt to total capital ratio of 70%. These ratios are tested quarterly and at year-end, and in the company's view, have the potential risk that the company would not be compliant.

Based on PowerStream's past experiences issuing debt (Bank debt, EDFIN) as well as the discussions the company has had with financial advisors, there has never been a requirement to maintain a current ratio. Comparatively, the two hundred million dollar bond that PowerStream issued in July 2012 has no monthly reporting requirements and no quarterly or annual financial covenant tests.

In addition there is an advantage to being known in the debt markets, such that lower interest rate spreads occur when the financing community is knowledgeable of the Issuer of the debt. Because PowerStream was required to borrow two hundred million dollars and will require further funds in the future, PowerStream took the opportunity to issue debt through a private issue. The issue will help PowerStream become established in the financial marketplace which will help the next time PowerStream has to raise capital, reduce the spread and subsequently the interest rate on future debt issues.

As of August 14, 2012 the comparable 30-year rate with Infrastructure Ontario was 3.94%. The two hundred million dollar bond that PowerStream issued in July 2012 was at an all-in coupon rate of 3.958%.

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

BOARD STAFF INTERROGATORY #63:

Reference(s): <u>E E/ T1/ S1/p.5, 12</u>

It is stated that:

"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."

On page 12, the issuance dates for these promissory notes is shown as June 1, 2004 for Vaughan and Markham and January 1, 2009 for Barrie.

Please state how the 5.58% rate was determined on June 1, 2004 and why it was considered appropriate to apply to the Barrie promissory notes which were issued four and a half years later.

RESPONSE:

The interest rate of 5.58% used for the original promissory notes for the Cities of Vaughan and Markham was reviewed and approved in PowerStream's 2006 rate application. The debt was originally issued when the OEB deemed rate was 6.9%.

The Barrie Hydro Distribution Inc. (BHDI) promissory note was originally issued in 2000 and had its rate of interest approved through a Cost of Service rate application in 2006. When PowerStream merged with Barrie Hydro in 2009 there was an adjustment to the interest rate of the legacy promissory note when it was brought forth into the merged entity; no other changes

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

were made. At the time of the merger it was requested by the City of Vaughan and Markham that the interest rates are consistent between shareholders and the City of Barrie agreed to lower the interest rate on its promissory note from 6.5% to 5.58% to match the City of Vaughan and Markham's interest rate.

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

CCC INTERROGATORY #61:

Reference(s): (E/T1)

Please provide the actual ROE achieved by PowerStream in each year 2009-2011. Please provide the most current forecast for 2012.

RESPONSE:

Please see table below. The most current ROE forecast for 2012 remains the same as in the 2012 budget

Table CCC #61: PowerStream ROE 2009-2012

2009	2010	2011	2012
Actual	Actual	Actual	Budget
8.17%	9.89%	10.07%	8.00%

Note: The calculation is based on the financial statements for 2009 to 2011 and on the budget for 2012.

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

CCC INTERROGATORY #62:

Reference(s): (E/T1/S1/p. 3)

What is the current status of the EDFIN refinancing, expected in August 2012. What steps does PowerStream take to ensure that its debt costs are in the best interests of its ratepayers?

RESPONSE:

The $125 million EDFIN debenture refinancing has been completed. The new $200 million 30-year debenture was issued on July 30, 2012 with a rate of 3.958%. PowerStream went through a thorough review and analysis of the financing options that were available in the capital markets including looking at debt maturity terms of 5, 10, 20, and 30 years to ensure that the debt costs were in the best interest of the ratepayers. Based on the long-term interest rates at the time of the refinancing, PowerStream elected to issue debt for a 30-year term which is better aligned with the life of the distribution assets.

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

CCC INTERROGATORY #63:

Reference(s): (E/T1/S1/p. 4)

Please provide a copy of the Financing Plan approved by the Board of Directors on January 25, 2012. Please include all material presented to the Board of Directors.

RESPONSE:

PowerStream declines to file this document which addresses business planning matters including information beyond the Test Year, as it is not relevant to this proceeding.

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

CCC INTERROGATORY #64:

Reference(s): (E/T1/S1/p. 6)

Please provide a copy of the current dividend policy.

RESPONSE:

Please see the attached Dividend Policy – Appendix D.

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

ENERGY PROBE INTERROGATORY #46:

Reference(s): Ref: Exhibit E, Tab 1, Schedule 1

a) The evidence on page 2 indicates that the cost of capital parameters used have been taken from the OEB letter dated March 2, 2012 for rates effective May 1, 2012 and that "this calculation may require updating when the Board releases the Cost of Capital parameters for rates effective January 1, 2013". Please confirm that PowerStream will update the cost of capital parameters based on the letter that the Board is expected to release later this year for rates effective January 1, 2013.

b) Has the refinancing of the $125 million EDFIN debenture, which comes due in August 2012, been completed? If so, please provide the details including the applicable rate. If not, please provide an update as to when this refinancing is expected to be completed and provide the best forecast available at the current time for the associated rate.

c) Has PowerStream attempted to obtain funding from Infrastructure Ontario? Please explain.

d) What at the current rates available from Infrastructure Ontario for terms of 5, 10 and 20 years?

e) PowerStream has a current bank loan of $50 million at a rate of 5.08% that comes due in February 2013. What are the plans to replace this debt and what is the forecast rate for the replacement loan?

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

f) PowerStream has a number of other loans that expire at the beginning of 2013 or in October 2013 (lines 4 through 9) in the long-term debt cost table for the 2013 test year shown on page 12. What are the plans to replace this debt and what is the current forecast of the rates to be used for this replacement debt?

g) Please provide copies of the letters confirming that the shareholders intent not to demand payment within the next year that are referenced on page 5.

RESPONSE:

a) Confirmed. PowerStream will update Cost of Capital parameters based on the OEB letter expected to be released later in 2012.

b) Yes, the $125 million EDFIN debenture refinancing has been completed. The new $200 million 30-year debenture was issued on July 30, 2012 with a rate of 3.958%.

c) The funding that PowerStream has obtained from Infrastructure Ontario is to fund the construction of PowerStream Solar projects. As for using Infrastructure Ontario for funding other capital requirements, please see response to Board Staff IR #62b, filed with this Exhibit.

d) As of August 9 2012 the rates are:

5 year	2.38%
10 year	3.02%
20 year	3.67%

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

e) The plan is to refinance this debt when it comes due. At this time PowerStream does not have a forecast rate for the replacement loan as market conditions for next year are still uncertain. The current rate is used in the calculation of cost of capital.

f) The funding arrangement with two of the three shareholders involving deferred interest is due in October 2013. At that time the debt will be either renewed or be repaid and refinanced with new debt. At this time PowerStream has not determined the appropriate rate. The current rate is used in the calculation of cost of capital.

g) Please see signed letters from each of the three municipalities, Barrie, Markham and Vaughan, attached as Appendices A, B, and C respectively.

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

SEC INTERROGATORY #54:

Reference(s): [E1/1/1, p. 4] Please provide a copy of the most current Financing Plan.

RESPONSE:

The 2012-2016 Financing Plan dated January 11, 2012 is attached as Appendix E.

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

SEC INTERROGATORY #55:

Reference(s): [E1/1/1, p. 5]

Please provide full details of all dividends, if any, paid in the period 2006 through 2012 to date.

RESPONSE:

Please see the table below. Dividends are paid on the prior year's net income.

Table SEC #55: 2006-2012 Paid Dividends

	Regular Dividend	Special Dividend
2006	$6,555,000	
2007	$4,140,000	$596,400*
2008	$4,140,000	$4,373,868**
2009	$11,279,523	$19,808,119***
2010	$10,532,000	
2011	$13,857,000	
2012	$16,087,305	

* - special dividend relates to the sale of PowerStream's water heater assets.
** - special dividend relates to the sale of PowerStream's fibre optics assets.
*** - special dividend relates to final closing adjustment for the amalgamation of PowerStream Inc. and Barrie Hydro Distribution Inc.

RESPONSES TO INTERROGATORIES BY ISSUE

6. COST OF CAPITAL (Exhibit E)

6.1 Are the proposed Test Year cost of capital parameters appropriate?

VECC INTERROGATORY #41:

Reference(s): Exhibit E, Tab 1, Schedule 1, page 4

a) Please explain how the 4.41% rate for the deemed long-term debt was estimated?

RESPONSE:

a) PowerStream assumed the 4.41% Deemed Long-term Debt rate for 2012 Cost of Service Applications[1] in its calculation of weighted cost of capital for the 2013 Test Year. This rate is a placeholder and will be updated later in 2012, when the OEB issues the Cost of Capital Parameter Updates for 2013 Cost of Service Applications for Rates Effective January 1, 2013.

[1] OEB March 2, 2012 Letter: *Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012*

CITY HALL
70 COLLIER STREET
TEL. (705) 726-4204
FAX (705) 739-4243

The City of
BARRIE

THE CORPORATION OF THE CITY OF BARRIE
CITY CLERK'S OFFICE
"Committed to Service Excellence"

P.O. BOX 400
BARRIE, ONTARIO
L4M 4T5

April 20, 2012

File: A00- PowerStream

Mr. Daniel Miller, MBA
Manager, Strategic Support and Planning
PowerStream Inc.
161 Cityview Boulevard
Vaughan, ON L4H 0A9

Reference: Promissory Notes

Further to correspondence received on March 12, 2012 regarding the promissory notes held by the City of Barrie with PowerStream, this will confirm that the City of Barrie is not intending on calling the Shareholder debt in 2012.

If you require any further information, please do not hesitate to contact me.

Yours truly,

Dawn McAlpine
City Clerk

cc: Brian Bentz, President & CEO, PowerStream Inc.
Dennis Nolan, EVP Corporate Services & Secretary, PowerStream Inc.

MARKHAM

Andy Taylor
Chief Administrative Officer

March 19, 2012

EB-2012-0161
PowerStream Inc.
Exhibit J1
Tab 6
Schedule 6.1
Appendix B
1 Page
Filed: August 31, 2012

Mr. John Glicksman
EVP & Chief Financial Officer
PowerStream
161 Cityview Boulevard
Vaughan, ON L4H 0A9

Subject: Promissory Notes

Dear John:

In response to your letter dated March 12, 2012, this letter is to confirm that the Council of the Town of Markham has not authorized the acceleration of promissory note payments.

Sincerely,

Corporation of the Town of Markham

Andy Taylor
Chief Administrative Officer
AT:kb

VAUGHAN

March 28, 2012

Mr. John Glicksman
EVP & CFO
PowerStream Inc.
161 Cityview Blvd.
Vaughan, ON L4H 0A9

Dear Mr. Glicksman:

Re: Amended and Restated Promissory Note Date June 1, 2004

This is to confirm that:

1) the Corporation of the City of Vaughan has no intent to demand accelerated payment of the promissory note in accordance with section 3 of the "Amended and Restated Promissory Note" dated June 1, 2004 within a year of the date of this letter;

2) the callable feature of the note will not be exercised on or before January 1, 2013; and

3) the principal balance of the Promissory Note as of December 31, 2011 was $78,236,285.

Please contact me at 905-832-8585, ext. 8475 should you or your Auditors require further clarification on this subject matter.

Sincerely,

Barbara Cribbett, CMA
Commissioner of Finance & City Treasurer

c: Clayton Harris, City Manager
Barry Jackson, Director of Financial Services

SCHEDULE "D"

DIVIDEND POLICIES

COMMON SHARES DIVIDEND POLICY

Purpose

Consistent with the Objectives and Guiding Principles set forth in Section 2.07, the Corporation will endeavor to earn the maximum rate of return allowable by the OEB. The purpose of this policy is to provide Shareholders with a steady income stream from dividends while providing the Corporation with an appropriate capital structure and working capital level in order to operate as a viable business.

Determination of Dividends

Dividends on the Common Shares will be determined as follows:

- The Corporation shall pay a minimum of 50% of net income, excluding the Permitted Generation Business income, with consideration given to the following:
    - Cash position at the beginning of the current year;
    - Working capital requirements for the current year; and
    - Net capital expenditures required for the current year.

Criteria for Determination of Dividends

Dividends will be declared after due consideration is 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 (2 year) plans of capital expenditures

CLASS A COMMON SHARES DIVIDEND POLICY

PowerStream Permitted Generation Business Unit Dividend Policy for Class A Common Shares

Definitions used in respect of the Class A Common Shares Dividend Policy include:

"Post-Construction Period" for each Solar PV project, for purposes of determination of dividends on Class A Common Shares, starts on the Commercial Operation date of the project under the terms of the contract between the Corporation and the Ontario Power Authority in respect of that project. For reporting purposes related to projects in the construction and Post-Construction Period, the Corporation shall provide to the Shareholders on a semi-annual basis a status report of Solar PV projects for which the Corporation has entered into a contract with the Ontario Power Authority, showing: date of contract; generation capacity of the project; estimated capital cost; projected completion date; actual capital cost (if completed); completion date (if completed); and Commercial Operation date. Such status report shall be due sixty (60) days following the end of each six-month financial period, commencing with the first period in which funds are drawn down under the Shareholders' subscription agreements, and continuing until such time as the Shareholders agree to dispense with project status reporting.

"Working Capital Requirements", for purposes of determination of dividends on Class A Common Shares for a financial year of the Permitted Generation Business Unit, shall mean fifteen percent (15%) of the sum of: the Permitted Generation Business Unit's operations, maintenance, administrative and general expenses, capital expenditures, interest expense and repayment of debt, and cash taxes or payments in lieu of taxes for such year. For clarity, "operations, maintenance, administrative and general expenses" includes without limitation, leasing expense, development expense, management expense, operating expense, insurance and on-going legal expenses, but excludes depreciation expenses. For purposes of the dividend declaration that follows receipt of the unaudited financial statements for the Permitted Generation Business at year-end, the operations, maintenance, administrative and general expenses, interest expense and repayment of debt, and cash taxes or payments in lieu of taxes shall be the amounts reported in the most recent unaudited financial statements for the Permitted Generation Business. For purposes of the dividend declaration that follows receipt of the unaudited financial statements for the Permitted Generation Business at mid-year, such amounts shall be the greater of:

- the amounts reported in the most recent unaudited year-end financial statements for the Permitted Generation Business, or

- the sum of fifty percent (50%) of the amounts reported in the most recent unaudited year-end financial statements for the Permitted Generation Business plus 100% of the amounts reported in the most recent unaudited mid-year financial statements for the Permitted Generation Business (i.e. for a six-month period).

For each year, the capital expenditure component shall be the greatest of:

- the amount of actual capital expenditures reported in the most recent unaudited year-end financial statements for the Permitted Generation Business; or

- the amount of actual capital expenditures reported in the most recent unaudited mid-year financial statements for the Permitted Generation Business (i.e. for a six-month period), multiplied by two (2); or

- seventy-five percent (75%) of the capital cost, as estimated by the Corporation, of solar PV projects for which the Corporation has entered into a contract with the Ontario Power Authority under the Feed-In Tariff Program but for which the Commercial Operation Date has not yet been reached at the date of the dividend declaration.

"Net Free Cash Flow" means for purposes of computation of amount payable to the holders of the Class A Common Shares in the Post-Construction Period, "net free cash flow" in respect of Period "n" shall be 95% of the amount computed as follows:

Cash balance at beginning of Period n

Plus: Cash flow from operations in Period n

Less: Dividend(s) paid in Period n in respect of Period n-1 or any prior period

Less: Repayment of debt in Period n

Less: A portion of the balance of deferred taxes at the end of Period n, such that the debt ratio of the Permitted Generation Business Unit remains consistently between 59% and 61%.

The Corporation shall provide to the Shareholders on a semi-annual basis the associated calculations that were used to derive the amount payable to the holders of Class A Common Shares.

Until such time as no further Solar PV projects are under development or planned for development by the Corporation, the above balances will be related to the Permitted Generation Business, with amounts determined on the basis of projects in their Post-Construction Period. Thereafter, the balances used will be taken from the most recent unaudited financial statements for the Permitted Generation Business.

<u>Criteria for Determination of Dividends</u>

Dividends will be declared by the Corporation's Board of Directors after due consideration is given to the following:

- All financial covenants on any debt issued by the Corporation.
- Qualifications to meet external bond rating criteria and ensure no adverse impact on the current credit rating of the Corporation. The Corporation will advise the Shareholders of its credit rating from time to time (and at least on an annual basis).
- Cash flow requirements of the Permitted Generation Business Unit of the Corporation to meet working capital requirements and short-term (2 year) plans of capital expenditures.
- The maintenance of the planned 60/40 debt to equity ratio.

<u>Determination of Dividends</u>

Dividends on the Class A Common Shares amounts will be determined as follows:

- The Corporation will target an IRR of 10.5% on the Permitted Generation Business Unit.
- As each project is completed by the Permitted Generation Business Unit, the Corporation expects to make distributions calculated with reference to the Class A Common Shares equity injections made by the Shareholders from time to time, provided that the amount of each dividend will be at the discretion of the Board

and may be greater or lesser than the aforesaid having regard to the financial and operating results of the Corporation as a whole.

- In the Post-Construction Period or earlier as determined by the Board, the net free cash flow will be paid to the holders of the Class A Common Shares subject to the criteria listed herein.

Payment of Dividends

The Board of Directors will make the dividend declaration on the Class A Common Shares semi-annually after receipt of the unaudited financial statements at mid-year, and after receipt of the audited financial statements at year's end. Dividends will normally be paid within 60 days of declaration.

Review of Dividends Policy for Class A Shares

The dividend and distribution policy for Class A Common Shares is being established at the inception of the Permitted Generation Business. The dividend policy for Class A Common Shares will be reviewed on an annual basis by the Board of Directors and Shareholders.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

BOARD STAFF INTERROGATORY #64:

Reference(s): <u>Ref: 2013 Cost Allocation Model, v2.0, Sheets I5.1 and I6.1</u>

In row 26 of Sheet I5.1 of the Cost Allocation Model, PowerStream has provided values for the approved monthly service charge for each rate class. Similarly, in rows 34 and 35 of Sheet I6.1 of the Cost Allocation Model, PowerStream has provided values for the approved variable charges for each rate class. PowerStream currently has distinct fixed and variable charges for each rate class in each rate zone.

Please explain the methodology used to calculate the indicated charges provided in Sheets I5.1 and I6.1 and the rationale for using this methodology.

RESPONSE:

While PowerStream has distinct fixed and variable charges for two rate zones, the Cost Allocation model is not designed to include the data by the rate zones within the same utility. Therefore PowerStream had to develop the weighted average rates to be inputted in the Cost Allocation model as "existing" rates on sheets I5.1 and I6.1. The fixed rates were calculated as a weighted average of 2012 approved fixed rates, net of rate adders and rate riders, by each customer class, using 2013 Test Year customer count for two rate zones. The variable rates were calculated as a weighted average of 2012 approved volumetric rates, using the appropriate billing determinant (kW or kWh) for 2013 Test Year for two rate zones. This methodology is identical to the methodology used by PowerStream in its rate harmonization application, as approved by OEB in its decision in EB-2007-0074.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

BOARD STAFF INTERROGATORY #65:

Reference(s): <u>2013 Cost Allocation Model, v2.0 and 2013 Cost Allocation Model, v3.0, issued on June 28, 2012</u>

On June 28, 2012, the Board issued version 3.0 of the Cost Allocation Model. The "Instructions" worksheet of the model stated:

> "Version 3.0 is designed for use with 2013 rate applications. It is identical to Version 2 except for accommodating the deferred PP&E balance due to the transition to IFRS (account 1575)."

The "Instructions" worksheet indicated (in red) the inputs a distributor should make to account for the deferred PP&E balance.

Please provide an updated Cost Allocation Model, in version 2.0, that incorporates the changes indicated in the "Instructions" worksheet of version 3.0 of the Cost Allocation Model. When providing the Service Revenue Requirement on Sheet I3 (cell F13) of the model, please ensure that the adjustment to return on rate base associated with the deferred PP&E balance as a result of the transition to IFRS is accounted for.

RESPONSE:

PowerStream has reviewed the updated cost allocation model Version 3.0. As noted above: "It is identical to Version 2 except for accommodating the deferred PP&E balance due to the transition to IFRS (account 1575)."

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

In the cost allocation model Version 2.0 filed, PowerStream has used a rate base amount of $838,472,595 and a revenue requirement of $178,549,804. As can be seen in Table 1: Base Revenue Requirement Calculation found in Exhibit F, Tab 1, Schedule 4, the rate base amount has been reduced by $2,575,585, the account 1575 PP&E amount, and the revenue requirement has been reduced by $643,896 for amortization of the account 1575 PP&E amount over 4 years. The adjusted depreciation expense was entered in D430 as per the updated instructions.

PowerStream submits that there is no further adjustment to be made with respect to the account1575 PP&E amount.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

BOARD STAFF INTERROGATORY #66:

Reference(s): 2013 Cost Allocation Model, v2.0, Sheet I5.2 and *Report of the Board – Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219), p.26

On Sheet I5.2 of the Cost Allocation Model, PowerStream has provided the default weighting factors for billing and collections. On page 26 of the second reference, the Board states:

> "Default values and the basis on which they were derived will be included in the documentation; however, any distributor that proposes to use those default values will be required to demonstrate that they are appropriate given their specific circumstances."

Please provide evidence in support of the continued use of the default weighting factors for allocating costs related to billing and collections.

RESPONSE:

PowerStream did not adopt the default weighting factors but carried out a review of the various billing and collecting activities relative to the various rate classes. See Table Board Staff #66-1 below for explanations of how each weighting factor was determined:

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

Table Board Staff #66-1: Determination of Billing and Collections Weighting Factors

COST ALLOCATION MODEL SHEET I5.2 - (BILLING AND COLLECTIONS WEIGHTING FACTORS)		
RATE CLASS	**WTG FACTOR**	**EXPLANATION OF WEIGHTING FACTOR**
Residential	1.0	Default weighting factor per guidelines.
GS <50	2.0	Costs associated with the level of effort needed to issue, administer and collect on a General Service less than 50 is approximately 2x that of a residential service due to the nature of bill calculations and complexity of the bill.
GS> 50	7.0	The costs associated with the level of effort needed to issue, administer and collect on GS Greater than 50 is approximately 7x that of a residential service due to multiple units of measure and the resulting nature of the bill calculations and complexity of the bill and the costs associated with annual rate reclassifications, customer care and key account expenses.
Large User	15.0	The costs associated with the level of effort needed to issue administer and collect on Large User accounts is approximately 15 x that of a residential service due to the effort to obtain MV90 meter readings with multiple measures of units, the nature of the bill calculations, complexity of the bill s and the costs associated with customer care and key account expenses.
Streetlight	2.0	Monthly manual modifications to streetlight files, monthly provision of load for pricing files
Sentinel	0.1	The costs associated with the level of effort needed to issue, administer and collect on Sentinel lights is /10th that of a residential account. There are no meter readings required and once set up the administration of the account is minimal.
Unmetered Scattered load	1.0	Similar effort as residential

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

BOARD STAFF INTERROGATORY #67:

Reference(s): <u>2013 Cost Allocation Model, v2.0, Sheet I5.1</u>

PowerStream has provided a service weighting factor of 1 for the Residential class and zero for all other classes. Please provide the rationale for the use of these weighting factors.

RESPONSE:

Page 6 of the August 4, 2011 *Staff Report to the Board - Implementation of the Revisions to the Board's Electricity Distributor Cost Allocation Policy*, (EB-2010-0219), states that the services weighting is to be based on activity in account 1855.

A review of account 1855 confirms it contains only costs associated with the residential class. This is in accordance with PowerStream's policy that non-residential customers own and are responsible for the electrical service from the transformer to the customer's meter base /electrical room. This practice is unchanged from PowerStream's 2009 Cost of Service filing. Accordingly, the residential rate class is allocated 100% of the services costs. The weighting factor for all non-residential classes is 0.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

BOARD STAFF INTERROGATORY #68:

Reference(s): <u>2013 Cost Allocation Model, v2.0, Sheet O1 and EH/T1/S2/p.2</u>

In the second reference, PowerStream states that it 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."

The first reference, Sheet O1 of PowerStream's Cost Allocation Model shows that no costs have been allocated to the Standby class.

Please explain how PowerStream has accounted for the costs incurred to provide Standby Power to its affected customers in its cost allocation study.

RESPONSE:

The "Report of the Board: Review of Electricity Distribution Cost Allocation Policy" (EB-2010-0219) dated March 31, 2011, stated the following regarding Load Displacement Generation and Standby Charges:

> *Additional research and further consultation on this topic will be required before a standard methodology is established. The Board believes that these issues warrant attention in the short term, and will to that end initiate a separate consultation in the near future. In the meantime, the Board will entertain applications by distributors requesting, as part of their next cost of service application, to have their existing interim standby rates declared final.*

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

The PowerStream - Barrie Rate zone has an approved interim standby charge of $2.6854 per kW that has been in place for many years. There is no standby charge in the PowerStream South rate zone. There have been no standby customers in the Barrie rate zone to date nor are there any in the South rate zone.

PowerStream proposes to continue the approved interim standby charge for the entire harmonized rate zone until the Board provides further guidance on the setting of Standby Charges.

As there are no existing standby customers, nor any projected for the 2013 Test Year, no costs have been allocated to this class in the Cost Allocation Model.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

VECC INTERROGATORY #42:

Reference(s): Exhibit G, Tab 1, Schedule 2, page 1

a) The Board's EB-2010-0219 Report (page 26) directed distributors to establish distributor-specific weighting factors for Services costs as well as Billing and Collecting. Are the weighing factors used by PowerStream for these cost the default values or utility specific values?

b) If they are the Board's default values, please explain why they are appropriate as required by the OEB's EB-2010-0219 Report (page 26).

c) If they are PowerStream-specific values, please explain how they were established and provide any supporting reports/analyses prepared by PowerStream.

RESPONSE:

a) The weighting factors used by PowerStream for services and billing and collecting are utility specific factors.

b) Not applicable. See response to a) above.

c) Please refer to responses provided for Board Staff IRs #66 and #67 in this Exhibit.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

VECC INTERROGATORY #43:

Reference(s): Exhibit G, Tab 1, Schedule 2, page 2

Preamble: On page 2 (lines 17-20) reference is made to a correction to the average number of street lights per connection with respect to Barrie.

a) Please provide a schedule that sets out the previous and current assumptions used by PowerStream regarding the number streetlights per connection.
b) Please the study/analysis supporting the change.

RESPONSE:

a) Table VECC #43-1 shows the previous and current assumptions used regarding the number of streetlights per connection.

Table VECC #43-1: Streetlights per Connection

	Average Number of Streetlights per Connection
Barrie 2008 COS	1.25
PowerStream 2009 COS	4.85
PowerStream 2013 COS	4.85

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

b) Due to staff attrition, PowerStream was unable to locate the analysis underlying the average streetlights per connection for either Barrie or PowerStream. As noted in the application, PowerStream used the value from the 2006 Cost Allocation Study in both the 2009 and 2013 COS applications.

This information is not available in our GIS (Geographical Information System). As a result it is necessary to calculate an average number of streetlights per connection by referring to maps and drawings. Due to the manual process a sampling is done to estimate the average number of streetlights per connection.

As the original documentation could not be located, a new sampling was done. The results of this sample indicate an average of 2.88 streetlights per connection, with a range from 1 to 26 lights per connection. PowerStream proposes to update the Cost Allocation to reflect this sample.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

VECC INTERROGATORY #44:

Reference(s): Cost Allocation Model, Sheet I7.1

a) Please explain how PowerStream derived the unit meter costs used to allocate meter capital costs to customer classes.
b) Please provide a schedule that sets out the capital costs for smart meters by customer class and the resulting per customer smart meter capital costs by class consistent with previous smart meter applications.

RESPONSE:

a) Installed meter unit costs are based on four components: materials, labour, vehicle and overhead. Materials costs are derived from inventory issues. Labour costs for installation can be either contractors or internal staff. Vehicle charges may be included in contractor costs or where the work is performed by PowerStream staff standard vehicle rates are used. Overhead is applied on a similar basis as on other distribution assets.

PowerStream filed and received Board approval on smart meter costs in its 2009 COS application and two separate smart meter cost recovery rate applications (EB-2008-0244, EB -2010-0209 and EB-2011-0128). Costs assigned to a class are based on the installed costs for the types of meters used by the class.

b) Table VECC#44-1 summarizes the smart meter capital costs for each rate class per CA model sheet 7.1 and the average cost per meter.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

Table VECC #44-1: Smart Meter Costs by Rate Class

SM Type	Residential			General service < 50		
	Quantities	Total Costs	Costs per unit	Quantities	Total Costs	Costs per unit
Smart Meter - 200 amp	297,616	$ 30,654,448	$ 103	0	$ -	$ 103
Smart Meter - 200 amp (GS<50)	0	$ -	$ 210	5,792	$ 1,216,320	$ 210
Smart Meter - Network/2-phase	5,489	$ 1,525,942	$ 278	0	$ -	$ 278
Smart Meter - Transformer rated/400 amp	1,830	$ 488,610	$ 267	0	$ -	$ 267
Smart Meter - 3 phase 120 to 480 volt	0	$ -	$ 562	21,069	$ 11,840,778	$ 562
Total	**304,935**	**$ 32,669,000**	**$ 107**	**26,861**	**$ 13,057,098**	**$ 486**

The following table summarizes the approved installed cost of smart meters by rate class.

Table VECC #44-2: Approved Smart Meter Installed Cost

	Residential	GS<50kW
2009 COS EDR	$ 9,521,791	$ -
2010 SM EDR	$ 12,926,000	$ 1,642,000
2011 SM EDR	$ 7,980,791	$ 11,586,912
Total	**$ 30,428,582**	**$ 13,228,912**
# of meters	285,705	25,062
Average cost per meter	**106.50**	**527.85**

The recent installed cost for smart meters was used in completing Sheet I7.1. A comparison with Table VECC#44-2 shows that this accurately captured the actual cost of smart meters

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

for the Residential class. However it appears that the smart meter capital for the GS<50 kW class was understated by approximately $1,120,000. The estimated cost failed to take into account that the 3-phase meters installed in 2010 were much more expensive than the current pricing and did not identify that there are some 3-phase meters that are more expensive than the common 3-phase meter shown in sheet I7.1.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

VECC INTERROGATORY #45:

Reference(s): Cost Allocation Model, Sheets I7.1 and I6.2

a) With respect to Sheet I6.2, please explain why none of the GS, Street Lighting, Sentinel Lighting or USL customers are assumed to make use of Services.

b) Are all of the buildings with suite-metered Residential customers served at secondary voltages (i.e. none of the buildings provide their own transformer)? If not, how many suite-metered Residential customers are in buildings that provide their own transformer and are served at primary voltage?

RESPONSE:

a) Only the Residential class service lines are owned by PowerStream. The other rate classes own their service lines and are responsible for any maintenance, repair or replacement thereof.

b) Yes, all buildings with suite-metered residential customers are served at secondary voltages and there are no suite-metered residential buildings where the customers own the transformer.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

AMPCO INTERROGATORY #1:

Reference(s): Exhibit G, Tab 1, Schedule 2

Preamble: The evidence states the following:

> "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."

a) Please discuss the steps PowerStream has taken to notify its pre-existing Large Use customer of the change in the Large User class and the new costs allocated to this class and the resulting impact. Please include in the response any allowance made for this Large Use Customer to express its views.

b) Please provide a detailed breakdown of the assets and costs dedicated to this class for the years 2009 to 2013.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

c) Please provide a detailed breakdown of the new assets and costs allocated to the Large User class in 2013.

d) In AMPCO's view, the new Large Use customer is being subsidized by the pre-existing Large Use customer. Please comment.

RESPONSE:

a) As discussed in the response to Staff IR# 48, in its 2010 IRM application PowerStream attempted to update the Large Use (LU) rates at that time to reflect a broader mix of LU customers so that it could move existing customers averaging over 5,000 kWs demand into the LU class. At that time PowerStream met with the existing LU customer to describe the impact if the proposed rate change was approved.

At that time, this customer had recently experienced the significant decrease in 2009 as a result of the change in the Large Use rate. PowerStream explained how the addition of additional LU customers would change the costs allocated to the class resulting in a return to the level of rates prior to the decrease. The customer was not pleased that the rate would be increasing but did not object or challenge this.

When the Board decided that a change in the LU rate would have to wait for an updated cost allocation study, PowerStream notified the customer that this change would not occur until a later date. This cost of service filing with its cost allocation study is that later date.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

b) PowerStream does not track assets and costs by customer class. Most of PowerStream's assets are used by most or all customer classes. The assets and costs are allocated to customer classes using the Board's cost allocation methodology and model.

A cost allocation study was submitted as part of PowerStream's 2009 and 2013 Cost of Service applications. Table AMPCO#1-1 below compares the assets and costs assigned to the Large Use class in 2009, when there was a single Large Use customer, to 2013, when there are two Large Use customers. The change column shows the additional assets and costs assigned to the Large Use class in 2013.

Table AMPCO #1-1: Assets and Cost Allocated to the Large Use Class

	2009 Cost Allocation	2013 Cost allocation	Change
Costs Allocated:			
Distribution Costs (di)	$ 5,530	$ 68,959	$ 63,429
Customer Related Costs (cu)	$ 616	$ 2,891	$ 2,275
General and Administration (ad)	$ 5,860	$ 65,534	$ 59,675
Depreciation and Amortization (dep)	$ 11,148	$ 81,174	$ 70,026
PILs (INPUT)	$ 3,784	$ 6,350	$ 2,566
Interest	$ 9,376	$ 62,128	$ 52,753
Total Expenses	$ 36,312	$ 287,036	$ 250,724
Direct Allocation	$ 9,281	$ 10,240	$ 959
Total Costs for Large Use	**$ 45,593**	**$ 297,276**	**$ 251,683**
Assets Allocated:			
Distribution Plant - Gross	$ 351,374	$ 2,331,181	$ 1,979,807
General Plant - Gross	$ 43,290	$ 277,600	$ 234,310
Accumulated Depreciation	$ (104,066)	$ (198,961)	$ (94,896)
Capital Contribution	$ (52,511)	$ (565,419)	$ (512,908)

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

	2009 Cost Allocation	2013 Cost allocation	Change
Total Net Assets allocated	$ 238,088	$ 1,844,400	$ 1,606,312
Directly Allocated Net Fixed Assets	$ 100,089	$ 79,414	$ (20,675)
Total Net Assets for Large Use	**$ 338,177**	**$ 1,923,814**	**$ 1,585,637**

c) See the reply to part (b) above.

d) PowerStream would agree that some degree of cross-subsidization occurs in each customer class, in the sense that the cost to service individual customers will differ even within a class. PowerStream submits that it is generally neither desirable nor practical to have a separate customer for specific customers.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.2 Are the revenue to cost ratios in the cost allocation for Test Year 2013 appropriate?

BOARD STAFF INTERROGATORY #69:

Reference(s): <u>EG/T1/S2/p.2/Table 1, *Settlement Proposal, PowerStream 2009 Cost of Service Application* (EB-2008-0244) May 29, 2009, p.26 and *Decision and Order*, Barrie Hydro 2008 Cost of Service Application (EB-2007-0746) March 25, 2008, p.12</u>

The first reference shows a revenue-to-cost ("R/C") ratio of 43.7% for the Large Use class resulting from PowerStream's 2013 cost allocation study.

In the second reference, parties agreed to a R/C ratio of 115% for the Large Use class.

The third reference shows that Barrie Hydro did not have a Large Use class at the time of its last cost of service application (EB-2007-0746). The Board approved R/C ratio of the most comparable class at the time (i.e. GS > 50 kW) was 86.3%.

In the current application, PowerStream is proposing to harmonize rates between the Barrie and PowerStream South rate zones. For most other classes, the R/C ratio proposed in the Application has resulted in a value between what was approved for Barrie Hydro in 2008 and PowerStream in 2009.

Please provide an explanation for the significant reduction in the R/C ratio for the Large Use class resulting from the 2013 cost allocation study? Please explain why PowerStream believes this result to be reasonable.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.2 Are the revenue to cost ratios in the cost allocation for Test Year 2013 appropriate?

RESPONSE:

As discussed in the response to Board Staff IR#48 at Exhibit J1, Tab 5, Schedule 5.1, there have been significant changes in the Large Use (LU) class in the South rate zone. These changes are reflected in the 2006 Cost Allocation Study (CAS), the 2009 CAS and the 2013 CAS.

The 2008 revenue-to-cost ratio (R/C) for Barrie is not relevant. As noted above, Barrie did not and in fact never has had a LU customer nor are any forecast for 2013. All changes in the R/C for this class relate to changes in the LU class in the South.

Large Use class rates prior to 2009 were based on a Large Use class consisting of several customers. All but one of these customers used the various components of PowerStream's distribution system and the Large Use rates reflected this.

Prior to 2009 several of the Large Use manufacturing customers went out of business. The subsequent users of these facilities had much lower load requirements. In 2009 only one LU customer remained. This remaining customer used only a PowerStream-owned transformer station (Over 50kV assets) and short dedicated feeders (the costs of which are directly allocated in the CAS). Under these circumstances the 2009 CAS determined that the cost to service the LU class was much lower than the revenues at the approved 2008 rates. The R/C was lowered to the top of the Board approved range of 115.0%.

The situation in 2013 is different. In 2013 there is another LU customer that, similar to the post 2009 situation, uses more of PowerStream's distribution system. As a result the CAS allocates more costs to this class and the revenue at the rates set based on the 2009 CAS result in an R/C

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.2 Are the revenue to cost ratios in the cost allocation for Test Year 2013 appropriate?

ratio that reflects the costs to service this class being significantly greater than revenues at current approved rates.

PowerStream submits that the cost allocation results for the Large Use class are reasonable.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.2 Are the revenue to cost ratios in the cost allocation for Test Year 2013 appropriate?

ENERGY PROBE INTERROGATORY #47:

Reference(s): Exhibit G, Tab 1, Schedule 2

a) Please explain why PowerStream proposes to increase the Large Use revenue to cost ratio from 43.7% to 100.2 rather than to the bottom of the range of 85%.

b) Please show the required changes in other revenue to cost ratios if the Large Use ratio is increased to 85%. In answering this, please leave the Street Lighting ratio at 118.9% and increase the ratios currently below 100% in tandem.

RESPONSE:

a) PowerStream notes that an adjustment to the Large Use (LU) class revenue to cost (R/C) ratio to bring it to the closest boundary of the Board Approved range is one option. In this case, the adjustment of $220,000 was chosen as it brought most of the R/C ratios within a close range near 100%.

b) If the Large Use R/C ratio is adjusted to the 85% lower boundary, this reduces the increase in revenue requirement allocated to the LU from $220,000 to $163,000 with a corresponding change in the amount that can be deducted from the revenue requirement allocated to other classes.

In this IR, EP has requested that PowerStream not apply any of the revised adjustment of $163,000 to reduce the Street light class R/C ratio and bring it closer to 100% but rather use it to “increase the ratios currently below 100% in tandem”.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.2 Are the revenue to cost ratios in the cost allocation for Test Year 2013 appropriate?

PowerStream notes that applying this amount to ratios currently below 100%, rather than to ratios above 100%, will reduce those ratios rather than increase them, moving them further way from 100% as shown in the attached Appendix A. PowerStream is not proposing this adjustment and has prepared this attachment only in response to Energy Probe's request.

The attached "Revenue to Cost Ratios by Customer Class" sheet (Appendix A) shows the impact of moving the LU class ratio only to 85% and applying this difference pro rata to the other classes where the ratio is below 100%, rather than to the Street lighting class.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.2 Are the revenue to cost ratios in the cost allocation for Test Year 2013 appropriate?

VECC INTERROGATORY #46:

Reference(s): Exhibit G, Tab 1, Schedule 2, pages 2-3

a) Please explain why PowerStream is proposing to increase the revenue to cost ratio for Large Users above 80% - the lower end of the Board's target range for this class.

b) Please explain why Power Stream is proposing to increase the revenue to cost ratio for Large User from 43.7% to over 100%.

c) Please provide the revenue to cost ratio for Street Lighting assuming the ratio for Large Users is increased to 80% and the ratios for all other classes remain unchanged from the status quo values.

RESPONSE:

a) Please see response to Energy Probe IR#47, filed in this Exhibit.

b) Please see response to Energy Probe IR#47, filed in this Exhibit.

c) The attached "Revenue to Cost Ratios by Customer Class" sheet (Appendix B) shows the impact of moving the Large Use (LU) class ratio only to 80% and applying this difference to the Street lighting class.

RESPONSES TO INTERROGATORIES BY ISSUE

7. COST ALLOCATION (Exhibit G)

7.2 Are the revenue to cost ratios in the cost allocation for Test Year 2013 appropriate?

PowerStream notes that the Board- approved range for the LU class is 85% to 115%. PowerStream is not proposing this adjustment and has prepared this attachment only in response to VECC's request.

POWERSTREAM

2013 EDR Model

Example Only: As requested in EP # 47b

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%	**98.6%**
GS 50 to 4,999 kW	106.5%	98.1%	80%	120%	**97.9%**
GS 50 to 4,999 kW Legacy					
Large Use	115.0%	**41.7%**	85%	115%	**85.0%**
Unmetered Scattered Load	119.9%	100.6%	80%	120%	**100.6%**
Sentinel Lighting	**75.4%**	92.4%	80%	120%	**92.2%**
Street Lighting	74.5%	118.9%	70%	120%	**118.9%**

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	2009 EDR Final Approved 2009	2013 EDR CA model at "status quo" rates 2013	Proposed per Application 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	$27,352,374
GS 50 to 4,999 kW	$38,541,454	$51,360,723	$51,254,197
GS 50 to 4,999 kW Legacy	$0	$0	$0
Large Use	$62,735	$157,180	$320,180
Unmetered Scattered Load	$517,171	$512,345	$512,345
Sentinel Lighting	$20,148	$16,742	$16,706
Street Lighting	$1,259,116	$2,701,841	$2,701,841
	$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

Distribution Revenue Requirement	2009 EDR Final Approved 2009	2013 EDR CA model at "status quo" rates 2013	Distribution revenue re-allocation 2012	Proposed per Application 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	(56,437)	$25,954,654
GS 50 to 4,999 kW	$37,292,703	$48,967,911	(106,526)	$48,861,386
GS 50 to 4,999 kW Legacy				$0
Large Use	$61,830	$149,350	163,000	$312,350
Unmetered Scattered Load	$430,612	$474,251		$474,251
Sentinel Lighting	$19,603	$15,904	(37)	$15,867
Street Lighting	$1,243,810	$2,600,983		$2,600,983
Total	$114,562,987	$169,487,804	**(0.0)**	$169,487,804

POWERSTREAM

2013 EDR Model

Example only: requested in VECC IR#46

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%	**80.0%**
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%	**112.6%**

	2009 EDR Final Approved	2013 CAS	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	$301,180
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	$2,557,841
	$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	144,000	$293,350
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	(144,000)	$2,456,983
Total	$114,562,987	$169,487,804	-	$169,487,804

RESPONSES TO INTERROGATORIES BY ISSUE

8. MODIFIED INTERNATIONAL FINANCIAL REPORTING SYSTEM (Exhibits A and F)

8.1 Is the proposed service revenue requirement calculated using modified IFRS appropriate?

CCC INTERROGATORY #65:

Reference(s): (A3/T1/S5)

In the move from CGAAP to MIFRS what are the most significant changes impacting the 2013 revenue requirement relative to 2008. Please quantify those changes. Of the $7.5 million revenue deficiency, how much of that is attributable to the move from CGAAP to MIFRS?

RESPONSE:

The most significant changes impacting the 2013 Revenue Requirement related to the adoption of MIFRS are those affecting Property Plant and Equipment (PP&E). These amounts were identified for 2011 as this year is reported under both CGAAP and MIFRS (the latter for the 2012 comparative statements). These amounts have been estimated for 2012 based on the 2011 experience. Table CCC#65-1 summarizes the major impacts based on 2012 amounts used in calculating account 1575 IFRS Transitional PP&E amount.

Table CCC #65-1: Significant MIFRS Changes Impacting Revenue Requirement ($000)

	Increase (decrease)		
Description	**Rate Base**	**OM&A, Depreciation**	**Other Revenue**
Lower depreciation expense	$ 14,805	$ (14,805)	
Lower burden capitalized	$ (12,200)	$ 12,200	
Lower Interest capitalized	$ (250)	$ 250	
Derecognition	$ (1,400)	$ 1,400	
Damage claims	$ 700		$ 700
Total	$ 1,655	$ (955)	$ 700

RESPONSES TO INTERROGATORIES BY ISSUE

8. MODIFIED INTERNATIONAL FINANCIAL REPORTING SYSTEM (Exhibits A and F)

8.1 Is the proposed service revenue requirement calculated using modified IFRS appropriate?

PowerStream prepared its 2012 – 2013 budgets, which underpin this application, under MIFRS. PowerStream has not calculated CGAAP values for 2013 as this was not needed for the 2013 COS rebasing under MIFRS.

PowerStream has used the 2012 amounts from Table CCC #65-1 above to estimate the impact on the 2013 revenue requirement resulting from moving from CGAAP to MIFRS. The revenue requirement impact is estimated as a $3.1 million decrease in revenue requirement. In other words, the revenue deficiency would have been higher by approximately $7.3 million under CGAAP. The calculation is shown in Table CCC #65-2 below.

Table CCC #65-2: Revenue Requirement Impact of MIFRS ($000)

	Amount	
Rate Base Impacts		
Increase in rate base -2011	$	920
Increase in rate base -2012	$	1,655
Account 1575 adjustment	$	(2,575)
net impact on rate base	**$**	**-**
Revenue Requirement (RR) Impacts		
Rate base impact on RR	$	-
OM&A	$	13,150
Depreciation	$	(14,805)
Amortization of PP&E amount	$	(644)
subtotal	$	(2,299)
PILs grossed up (26.5%)	$	(4,973)
Total RR impact	**$**	**(7,272)**

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.1 Is the full Tariff of Rates and Charges as proposed appropriate?

CCC INTERROGATORY #66:

Reference(s): (A2/T1/S1/p. 9)

Please indicate whether Table 4 includes the impacts of all of the clearances of the deferral and variance accounts included in the application.

RESPONSE:

Table 4 includes the impacts of all rate changes proposed in this application, including the clearance of deferral and variance accounts.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.1 Is the full Tariff of Rates and Charges as proposed appropriate?

CCC INTERROGATORY #67:

Reference(s): (A2/T1/S2/p. 1)

Please indicate how the $7.443 million deficiency is being recovered from each rate class. How was that allocation determined?

RESPONSE:

PowerStream does not allocate the revenue deficiency by customer class. The Basic Revenue Requirement is calculated and then allocated to all customer classes. The resulting revenue allocated by customer class is used to calculate the proposed distribution rates. The summary of revenues by class is shown in the OEB Appendix 2-U “Revenue Reconciliation”, filed at Exhibit H, Tab 6, Schedule 6.

For details of the allocation methodology, please refer to response to Board Staff interrogatory # 70, filed at Exhibit J1, Tab 9, Schedule 9.5.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.1 Is the full Tariff of Rates and Charges as proposed appropriate?

CCC INTERROGATORY #68:

Reference(s): (A2/T1/S3/p. 1)

Please provide the impact on the revenue deficiency related to PowerStream's request for full depreciation in 2013.

RESPONSE:

Please refer to response to CCC #7, filed at J1, Tab 2, Schedule 2.1.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.1 Is the full Tariff of Rates and Charges as proposed appropriate?

CCC INTERROGATORY #69:

Reference(s): (A2/T1/S3/p. 1)

For each of the line items in Table 1 please explain how they were calculated.

RESPONSE:

Each line item in Table 1 was calculated by comparing the Base Revenue Requirement as calculated in this application to the combined Board Approved Revenue Requirement for PowerStream and Barrie Hydro in the previous Rate Applications, as the latter underpins the current distribution rates.

The table below shows the calculation.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.1 Is the full Tariff of Rates and Charges as proposed appropriate?

Table CCC #69: Calculation of Causes of Revenue Deficiency

	2013 Test Year, '$000	South 2009 EDR	Approved Barrie 2008 EDR	Total	Change from Total Approved
Rate Base	838.5	526.8	149.9	676.7	161.8
Cost of Capital	6.51%	6.56%	7.30%	6.72%	
Return on Rate Base	54.6	34.5	10.9	45.5	9.1
Distribution Expenses	85.7	43.2	10.0	53.3	32.4
Amortization	35.8	36.2	10.2	46.4	(10.5)
Payment in Lieu of taxes	2.4	7.1	2.9	10.0	(7.6)
Service Revenue Requirement	178.5	121.1	34.0	155.2	23.4
Less Revenue offsets	(9.1)	(6.6)	(2.6)	(9.1)	0.1
Base Revenue Requirement	***169.5***	***114.6***	***31.5***	***146.0***	***23.5***
Adjust for TA in Rates (Barrie Hydro only)			(0.5)	(0.5)	0.5
Base Revenue Requirement	**169.5**	**114.6**	**30.9**	**145.5**	**24.0**
Revenue at current rates	**162.0**	**114.6**	**30.9**	**145.5**	**16.6**
Revenue deficiency	**(7.4)**				**(7.4)**

The $16.6 million increase in revenue at current rates is comprised of:

- $8.8 million for Smart Meter Incremental Revenue Requirement revenues, calculated based on the approved SMIRR rate riders and the corresponding forecasted customer count by rate zone, class and rate year;
- $7.2 million due to load growth and IRM increases, calculated by comparing 2013 forecasted load and customer count to the base year load and customer count (2009 for PowerStream South and 2008 for Barrie Hydro). The total impact of IRM included in this amount is $2.4 million; this was calculated by applying the approved annual IRM rate increases for 2010-2012 to the base year load and customer count, multiplied by base year distribution rates.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.1 Is the full Tariff of Rates and Charges as proposed appropriate?

In Table 1, the $16.6 million increase is offset by the amount of transformer allowance included in Barrie Hydro 2008 Rates. In the current application, the transformer allowance is treated separately from the Base Revenue requirement.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.1 Is the full Tariff of Rates and Charges as proposed appropriate?

VECC INTERROGATORY #47:

Reference(s): Exhibit C2, Tab 1, Schedule 2, page 5 (lines 4-7)

a) PowerStream proposes to apply the proposed charge to the "incoming customer". However, as noted in the previous paragraph, the incoming customer can only be assessed this charge it he/she agrees to assume responsibility. What will happen in those situations where the incoming customer does <u>not</u> agree to assume responsibility?

RESPONSE:

a) Pursuant to Section 2.8.3 of the Distribution System Code, the "incoming customer" is responsible for charges at the property only when the "incoming customer" has agreed to assume responsibility for those charges. Consequently, in situations where no customer has assumed responsibility for the charges, PowerStream must disconnect or risk the possibility of consumption occurring for which charges cannot be recovered. In the situation where the service has been disconnected as outlined in the reference, PowerStream requires the "incoming customer" to assume responsibility for charges prior to the reconnection occurring and the fee being charged.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.2 Is the derivation of the proposed base distribution rates appropriate?

VECC INTERROGATORY #48:

Reference(s): Exhibit G, Tab 1, Schedule 1, page 2 (lines 15-23) / Exhibit G. Tab 1, Schedule 2, page 4 (lines 6-7)

a) Please provide a schedule that sets out the calculation of the current fixed-variable for each customer class as used by PowerStream in its rate design determinations.

b) With respect to the schedule provided in response to part (a), for those customer classes where some/all of the customers receive the transformer ownership allowance, were the variable revenues used to determine the fixed-variable split net of (i.e., reduced to account for) the transformer ownership allowance? If not, please re-do the response to part (a), where the variable revenues used to determine the fixed-variable split are net of the transformer ownership allowance.

RESPONSE:

a) The attached Appendix A represents the calculation of fixed and variable rates for each customer class. This calculation is done in three steps:
   1. Distribution revenue by class is split between customer classes based on the existing split for each rate zone/ customer class. Then the combined revenues for the two rate zones are calculated and the original fixed/variable split is obtained. This step is shown in the "Revenue Allocation" schedule.
   2. Fixed rates calculated in step one are compared to the ceiling determined by Cost Allocation and the existing fixed rates, to determine the final fixed rate. This step is shown on the "Fixed Rates" page.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.2 Is the derivation of the proposed base distribution rates appropriate?

3. The adjusted fixed rates determined in step 2 are multiplied by the 2013 forecasted number of customers in each class, to determine fixed revenue by class. The variable revenue is calculated as the difference between total revenue by class and fixed revenue. This step is shown on the “Rates Design” page.

The methodology described above is similar to that used by PowerStream in its 2009 EDR application. The only difference is that the 2013 rate application includes the data by two rate zones and the consequent harmonization of fixed and variable rates.

b) The variable revenues in part a) are net of transformer allowance.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.2 Is the derivation of the proposed base distribution rates appropriate?

VECC INTERROGATORY #49:

Reference(s): Exhibit G, Tab 1, Schedule 2, page 4, Table 3

a) For those classes where either the 2012 MSC in the Northern or Southern service area exceeds the 2013 CAS ceiling, why is the maximum charge used as the ceiling as oppose to the weighted average charge?
b) Please provide the weighted average 2012 MSC for GS>50 based on the 2012 MSC values and the 2013 number of GS>50 customers in the South and North service areas.
c) Please provide the weighted average 2012 MSC for USL based on the 2012 MSC values and the 2013 number of USL customers in the South and North service areas.
d) Please provide the weighted average 2012 MSC for LU based on the 2012 MSC values and the 2013 number of LU customers in the South and North service areas.
e) Please provide the weighted average 2012 MSC for Residential based on the 2012 MSC values and the 2013 number of Residential customers in the South and North service areas.
f) Are any of the Large Use customers located in PowerStream's Northern service area?

RESPONSE:

a) Since the weighted average rate would be a calculated rate and therefore, subjective to some extent, PowerStream decided to use the Board-approved rates for both rate zones to determine the effective MSC ceiling. Since for most classes the CAS ceiling is higher than a weighted average of existing rates, this becomes the "effective ceiling". The proposed fixed rates, calculated in the model as weighted average, in most cases are below the OEB proposed ceiling from the Cost Allocation model. Consequently, using the weighted average

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.2 Is the derivation of the proposed base distribution rates appropriate?

for MSC as a ceiling would have a minimal or no impact on the final rate. For example, the weighted average of existing rates for the Residential class is $12.73, and the CA ceiling from the 2013 CA model is $15.21. $15.21 becomes an "effective ceiling" for the fixed rate for the Residential class, while the proposed rate, as calculated in the model is $13.57; since it is lower than OEB CA ceiling, the final proposed fixed rate for the Residential class is $13.57.

b) – e) Please refer to the table below.

Table VECC #49b-e

	2012 Fixed Rates		2013 Customer count			weighted Average MSC
	South	North	South	North	Total	
Residential	11.99	15.34	240,496	67,813	308,309	**12.73**
GS 50 to 4,999 kW	84.45	395.68	3,844	817	4,662	**139.02**
Large Use	2,173.63	9,690.24	2	-	2	**2,173.63**
Unmetered Scattered Load	14.32	7.95	2,160	654	2,814	**12.84**

f) No, none of the Large Use customers are currently located in PowerStream North service territory. For the details on Large Use customers please refer to response to Board Staff IR # 48 filed at Exhibit J1, Tab5, Schedule 5.1 and Energy Probe IR #18 filed at Exhibit J1, Tab 3, Schedule 3.2.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.2 Is the derivation of the proposed base distribution rates appropriate?

f) **VECC INTERROGATORY #50:**

Reference(s): Exhibit G, Tab 1, Schedule 2, page 2

a) Given the significant difference in the assets required to service the two Large Use customers was any consideration given to making a distinction as between the rates charged these two customers (e.g., introduce a further discount for not using Primary Assets)?

RESPONSE:

a) PowerStream did not consider treating customers within the Large Use class differently.

PowerStream
- 2013 EDR Model

1. Revenue Allocation

Revenue to be Allocated	Calculated Revenue for Allocation on Customer classes			Allocation to customer classes, %	Allocation between Fixed and Variable Revenue			Revenue Requirement Allocation		
169,487,804	Volumetric($ /kwh or KW)	Monthly Fixed Charges ($)	Total ($)	Total for Class (%)	Variable %	Fixed %	Total %	Total ($)	Variable $	Fixed $
Residential	38,183,067	47,085,582	85,268,648	53.64%	44.8%	55.2%	100.0%	90,911,252	40,709,809	50,201,443
GS<50	13,405,746	9,799,713	23,205,459	14.6%	57.8%	42.2%	100.0%	24,741,066	14,292,863	10,448,203
GS>50	39,514,576	7,774,756	47,289,333	29.7%	83.6%	16.4%	100.0%	50,418,677	42,129,431	8,289,246
Time of use	-	-	-	0.0%	0.0%	0.0%	0.0%	-	-	-
Large Use	178,303	52,167	230,470	0.1%	77.4%	22.6%	100.0%	245,722	190,102	55,619
USL	135,131	433,566	568,697	0.4%	23.8%	76.2%	100.0%	606,330	144,073	462,257
Sentinel Lighting	10,952	2,880	13,832	0.0%	79.2%	20.8%	100.0%	14,747	11,676	3,071
Street Lighting	1,129,879	1,261,860	2,391,739	1.5%	47.2%	52.8%	100.0%	2,550,010	1,204,648	1,345,362
Total	92,557,654	66,410,523	158,968,177	100.0%	58.2%	41.8%	100.0%	169,487,804	98,682,603	70,805,201

PowerStream

- 2013 EDR Model

1. Revenue Allocation

	Number of Customers (Connections)	PowerStream South - KWh per customer						Calculated kwh per customer	Calculated kwh
	Customer count	PS South - Board Approved (information only)	Historic Actual			Bridge Year	Test Year	Average per Customer	2013 customer count x average kwh per cust.
	2013	2009	2009	2010	2011	2012	2013		
Residential	*240,496*	9,326	9,563	9,503	9,337	9,155	8,966	9,304.7	2,237,732,701
GS<50	*25,062*	33,887	34,374	34,298	34,206	33,975	33,523	34,075.1	853,990,324
GS>50	*3,844*	1,001,562	962,911	1,012,946	1,007,190	999,434	985,046	993,505.4	3,819,034,678
Time of use	-	-	-	-	-	-	-	-	-
Large Use	*2*	31,414,814	27,221,419	27,770,469	27,959,582	28,138,353	31,516,490	28,521,262.7	57,042,525
USL	*2,160*	3,864	4,448	4,465	4,546	4,520	4,491	4,493.8	9,706,626
Sentinel Lighting	*120*	4,809	3,335	3,534	3,805	3,938	3,948	3,712.2	445,460
Street Lighting	*67,258*	664	742	742	732	722	710	729.5	49,067,325
Total	*338,942*								

	Number of Customers (Connections)	PowerStream North - KWh per customer						Calculated kwh per customer	Calculated kwh
	Customer count	PS North - Board Approved (information only)	Historic Actual			Bridge Year	Test Year	Average per Customer	2013 customer count x average kwh per cust.
	2013	2008	2009	2010	2011	2012	2013		
Residential	*67,813*	8,940	8,971	8,555	8,402	8,556	8,429	8,582.7	582,020,101
GS<50	*6,137*	35,853	36,561	34,452	33,937	34,726	34,172	34,769.7	213,381,582
GS>50	*817*	957,339	890,002	921,976	914,081	936,556	938,027	920,128.3	751,744,834
Time of use	-	-	-	-	-	-	-	-	-
Large Use	-	14,600,000	-	-	-	-	-	-	-
USL	*654*	5,966	4,974	4,609	4,628	4,935	4,922	4,813.5	3,148,023
Sentinel Lighting	-	-	-	-	-	-	-	-	-
Street Lighting	*16,112*	759	822	782	773	788	777	788.4	12,703,505
Total	*91,533*								

PowerStream

- 2013 EDR Model

1. Revenue Allocation

	Powerstream South - KW per customer						Calculated kw per customer	Calculated kw
	PS South - Board Approved (information only)	Historic Actual			Bridge Year	Test Year	Average per Customer	2013 customer count x average kw per cust.
	2009	2009	2010	2011	2012	2013		
Residential	-	-	-	-	-	-	-	-
GS<50	-	-	-	-	-	-	-	-
GS>50	2,611	2,592	2,727	2,712	2,691	2,652	2,674.8	10,281,960
Time of use	-	-	-	-	-	-	-	-
Large Use	82,809	81,160	82,797	83,361	83,894	93,966	85,035.9	170,072
USL	-	-	-	-	-	-	-	-
Sentinel Lighting	12	9	9	10	10	10	9.7	1,166
Street Lighting	2	2	2	2	2	2	2.1	142,526
Total								10,595,724

	PowerStream North -KW per customer						Calculated kw per customer	Calculated kw
	PS North - Board Approved (information only)	Historic Actual			Bridge Year	Test Year	Average per Customer	2013 customer count x average kw per cust.
	2008	2009	2010	2011	2012	2013		
Residential	-	-	-	-	-	-	-	-
GS<50	-	-	-	-	-	-	-	-
GS>50	2,422	2,247	2,328	2,308	2,364	2,368	2,322.9	1,897,842
Time of use	-	-	-	-	-	-	-	-
Large Use	30,000	-	-	-	-	-	-	-
USL	-	-	-	-	-	-	-	-
Sentinel Lighting	-	-	-	-	-	-	-	-
Street Lighting	2	3	2	2	2	2	2.4	38,684
Total								1,936,526

PowerStream
- 2013 EDR Model

1. Revenue Allocation

	PS South - Calculated Revenue for Allocation on Customer classes			Allocation to customer classes, %	Allocation between Fixed and Variable Revenue		
	Volumetric($ /kwh or KW)	Monthly Fixed Charges ($)	Total ($)	Total for Class (%)	Variable %	Fixed %	Total %
Residential	30,209,391	34,602,564	64,811,956	40.77%	46.6%	53.4%	100.0%
GS<50	9,906,288	8,613,308	18,519,596	11.6%	53.5%	46.5%	100.0%
GS>50	36,023,875	3,895,510	39,919,385	25.1%	90.2%	9.8%	100.0%
Time of use	-	-	-	0.0%	0.0%	0.0%	0.0%
Large Use	178,303	52,167	230,470	0.1%	77.4%	22.6%	100.0%
USL	84,448	371,174	455,622	0.3%	18.5%	81.5%	100.0%
Sentinel Lighting	10,952	2,880	13,832	0.0%	79.2%	20.8%	100.0%
Street Lighting	692,905	677,961	1,370,866	0.9%	50.5%	49.5%	100.0%
Total	77,106,162	48,215,564	125,321,726	78.8%	61.5%	38.5%	100.0%

	PS North -Calculated Revenue for Allocation on Customer classes			Allocation to customer classes, %	Allocation between Fixed and Variable Revenue		
	Volumetric($ /kwh or KW)	Monthly Fixed Charges ($)	Total ($)	Total for Class (%)	Variable %	Fixed %	Total %
Residential	7,973,675	12,483,017	20,456,692	12.87%	39.0%	61.0%	100.0%
GS<50	3,499,458	1,186,405	4,685,863	2.9%	74.7%	25.3%	100.0%
GS>50	3,490,701	3,879,247	7,369,948	4.6%	47.4%	52.6%	100.0%
Time of use	-	-	-	0.0%	0.0%	0.0%	0.0%
Large Use	-	-	-	0.0%	0.0%	0.0%	0.0%
USL	50,683	62,392	113,075	0.1%	44.8%	55.2%	100.0%
Sentinel Lighting	-	-	-	0.0%	0.0%	0.0%	0.0%
Street Lighting	436,974	583,899	1,020,873	0.6%	42.8%	57.2%	100.0%
Total	15,451,492	18,194,959	33,646,451	21.2%	45.9%	54.1%	100.0%

PowerStream - 2013 EDR Model

1. Revenue Allocation - PowerStream Combined

PowerStream Combined

	2013			Base Revenue requirement allocated		Base Rates (Harmonized)			
	Customer count	kwh	kw	Variable	Fixed	*Rate type*	Rate per kwh $	Rate per kw	Fixed service charge $
Residential	308,309	2,727,901,711	-	$ 40,709,809	$ 50,201,443	*$/kWh*	$ 0.0149		$ 13.57
GS<50	31,199	1,049,877,268	-	$ 14,292,863	$ 10,448,203	*$/kWh*	$ 0.0136		$ 27.91
GS>50	4,662	4,553,483,283	12,130,724	$ 42,129,431	$ 8,289,246	*$/kW*		$ 3.4730	$ 148.18
Time of use	-	-	-	$ -	$ -	*$/kW*			
Large Use	2	63,032,980	187,932	$ 190,102	$ 55,619	*$/kW*		$ 1.0115	$ 2,317.47
USL	2,814	12,918,549	-	$ 144,073	$ 462,257	*$/kWh*	$ 0.0112		$ 13.69
Sentinel Lighting	120	473,795	1,240	$ 11,676	$ 3,071	*$/kW*		$ 9.4144	$ 2.13
Street Lighting	83,370	60,257,245	176,787	$ 1,204,648	$ 1,345,362	*$/kW*		$ 6.8141	$ 1.34
Total	**430,475**	**8,467,944,830**	**12,496,684**	**$ 98,682,603**	**$ 70,805,201**				
	(0)	-	-		**$ 169,487,804**				

PowerStream South

	2013		
	Customer count	kwh	kw
Residential	240,496	2,156,279,348	-
GS<50	25,062	840,157,445	-
GS>50	3,844	3,786,763,164	10,195,076
Time of use	-	-	-
Large Use	2	63,032,980	187,932
USL	2,160	9,699,018	-
Sentinel Lighting	120	473,795	1,240
Street Lighting	67,258	47,738,154	138,665
Total	**338,942**	**6,904,143,903**	**10,522,913**

PowerStream North

	2013		
	Customer count	kwh	kw
Residential	67,813	571,622,363	-
GS<50	6,137	209,719,823	-
GS>50	817	766,720,119	1,935,649
Time of use	-	-	-
Large Use	-	-	-
USL	654	3,219,531	-
Sentinel Lighting	-	-	-
Street Lighting	16,112	12,519,091	38,122
Total	**91,533.01**	**1,563,800,927**	**1,973,771**

PowerStream - 2013 EDR Model

2. Fixed Charges Calculation

	PowerStream South					PowerStream Combined										
	As per Cost Allocation Model (2009)			OEB proposed		2013 Cost Allocation			OEB proposed		Fixed Rates (before SM adder)			Fixed rates calculation		
	Avoided Cost	Direct	Min. System with PLCC Adjustment	floor	ceiling	Avoided Cost	Direct	Min. System with PLCC Adjustment	floor	ceiling	Current Rate - PS South	Current Rate - PS North	Cost Allocation ceiling	As calculated	Proposed	**Final Proposed**
	a	*b*	*c*	*d=a*	*e=c*	*A*	*B*	*C*	***D=A***	***E=C***	*F*	*G*	*H= **max** (F,E, G)*	*I*	*J*	
Residential	$4.12	$6.31	$16.56	**$4.12**	**$16.56**	$3.81	$6.49	$15.21	**$3.81**	**$15.21**	$11.99	$15.34	$15.34	$13.57	$13.57	**$13.57**
GS Less Than 50 kW	$6.93	$12.54	$18.94	**$6.93**	**$18.94**	$13.54	$13.54	$30.60	**$13.54**	**$30.60**	$28.64	$16.11	$30.60	$27.91	$27.91	**$27.91**
GS 50 to 4,999 kW	$23.76	$41.61	$84.73	**$23.76**	**$84.73**	$31.64	$31.64	$104.67	**$31.64**	**$104.67**	$84.45	$395.68	$395.68	$148.18	$148.18	**$148.18**
GS 50 to 4,999 kW Legacy				**$0.00**	**$0.00**						$0.00	$395.68	$395.68	$0.00	$0.00	**$0.00**
Large Use	$122.60	$179.07	$164.61	**$122.60**	**$164.61**	$267.67	$267.67	$499.49	**$267.67**	**$499.49**	$2,173.63	$9,690.24	$9,690.24	$2,317.47	$2,317.47	**$6,017.47**
Unmetered Scattered Load	$2.39	$5.24	$10.82	**$2.39**	**$10.82**	$3.14	$5.90	$12.35	**$3.14**	**$12.35**	$14.32	$7.95	$14.32	$13.69	$13.69	**$8.06**
Sentinel Lighting	$0.81	$1.60	$11.91	**$0.81**	**$11.91**	$0.93	$1.78	$7.26	**$0.93**	**$7.26**	$2.00	$0.00	$7.26	$2.13	$2.13	**$3.51**
Street Lighting	$0.73	$1.40	$7.50	**$0.73**	**$7.50**	$0.66	$1.28	$1.26	**$0.66**	**$1.26**	$0.84	$3.02	$3.02	$1.34	$1.34	**$1.34**

PowerStream - 2013 EDR Model

3. Rates Design - Final Rates calculation

	As per 2009 CA model	Test Year at Existing rates		Proposed per Rate Application	Distribution revenue split - final	
Distribution Revenue %	**2012**	**2013**			**Variable**	**Fixed**
Residential	50.8%	53.8%		53.8%	45.0%	55.0%
GS Less Than 50 kW	15.1%	15.3%		15.3%	59.8%	40.2%
GS 50 to 4,999 kW	32.6%	28.9%		28.9%	83.1%	16.9%
GS 50 to 4,999 kW Legacy	0.0%	0.0%		0.0%	0.0%	0.0%
Large Use	0.1%	0.1%		0.2%	60.9%	39.1%
Unmetered Scattered Load	0.4%	0.3%		0.3%	42.6%	57.4%
Sentinel Lighting	0.0%	0.0%		0.0%	68.2%	31.8%
Street Lighting	1.1%	1.5%		1.4%	43.7%	56.3%
	100.0%	100.0%		100.0%	58.3%	41.7%

Final Rates Calculation	2013 Test Year				Distribution Revenue		distribution charges					FINAL RATES	
	Distribution revenues	customers	kw	kwh	Variable	Fixed	Variable charge	Fixed charge	LV	Transformer Allowance	SM	Variable	Fixed
Residential	$91,268,313	308,309	-	2,727,901,711	$41,063,334	$50,204,979	$ 0.0151	13.57	$0.0003		$0.00	**$ 0.0154**	**$13.57**
GS Less Than 50 kW	26,011,092	31,199	-	1,049,877,268	$15,561,867	$10,449,225	$ 0.0148	27.91	$0.0003		$0.00	**$ 0.0151**	**$27.91**
GS 50 to 4,999 kW	48,967,911	4,662	12,130,724	4,553,483,283	$40,678,796	$8,289,115	$ 3.3534	148.18	$0.1191	$0.1915	$0.00	**$ 3.6640**	**$148.18**
GS 50 to 4,999 kW Legacy	-	-	-	-	$0	$0		-	$0.0000	$0.0000	$0.00	**$ -**	**$0.00**
Large Use	369,350	2	187,932	63,032,980	$224,931	$144,419	$ 1.1969	6,017.47	$0.1439	$0.6000	$0.00	**$ 1.9408**	**$6,017.47**
Unmetered Scattered Load	474,251	2,814	-	12,918,549	$202,087	$272,165	$ 0.0156	8.06	$0.0003		$0.00	**$ 0.0159**	**$8.06**
Sentinel Lighting	15,904	120	1,240	473,795	$10,849	$5,054	$ 8.7473	3.51	$0.1033		$0.00	**$ 8.8506**	**$3.51**
Street Lighting	2,380,983	83,370	176,787	60,257,245	$1,040,396	$1,340,588	$ 5.8850	1.34	$0.0918		$0.00	**$ 5.9768**	**$1.34**
Total	$169,487,804	430,475	12,496,684	8,467,944,830	**$98,782,259**	**$70,705,545**							
						$169,487,804							

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.4 Are the proposed Total Loss Factors appropriate?

ENERGY PROBE INTERROGATORY #48:

Reference(s): Exhibit H, Tab 7, Schedule 1

a) Please explain why PowerStream proposes to use 3 years of historical data rather than the 5 years that is preferred in the filing guidelines.

b) Please expand Appendix 2-P to reflect 2007 through 2011 data and the corresponding 5 year average.

RESPONSE:

a) PowerStream proposes to use 3 years of historical data due the fact that a 3 year data set is more representative of the current losses in PowerStream's service territory after the merger of the former Barrie Hydro Distribution Inc. ("Barrie Hydro") and the former PowerStream Inc. ("PowerStream"), service territories, on January 1, 2009.

b) Please refer to the attached Table EP #48a

Table EP #48a: Expanded Appendix 2-P Reflecting 2007 Through 2011 Data and the Corresponding 5-Year Average

	PS Harmonized	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
	Losses in Distributor's System										
A_1	"Wholesale" kWh delivered to distributor (higher value)	Not available	Not available	Not available	Not available	Not available	Not available	Not available	Not available	Not available	Not available
A_2	"Wholesale" kWh delivered to distributor (lower value)	7,725,712,302	7,858,446,400	8,098,236,716	8,562,998,306	8,502,489,126	8,666,887,254	8,568,153,323	8,238,568,148	8,611,402,381	8,658,416,020
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)	396,326,073	390,381,087	406,795,158	401,950,361	273,918,904	41,045,125	30,336,556	27,205,480	27,609,737	27,116,405
C	Net "Wholesale" kWh delivered to distributor (A_2)-(B)	7,329,386,229	7,468,065,313	7,691,441,559	8,161,047,945	8,228,570,221	8,625,842,129	8,537,816,767	8,211,362,668	8,583,792,644	8,631,299,615
D	"Retail" kWh delivered by distributor	7,476,698,822	7,585,814,984	7,850,063,206	8,317,532,471	8,220,576,557	8,340,776,228	8,357,586,382	8,039,883,040	8,334,777,460	8,394,821,657
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)	392,362,812	386,477,276	402,727,206	397,970,654	271,206,836	41,045,125	30,336,556	27,205,480	27,609,737	27,116,405
F	Net "Retail" kWh delivered by distributor (D)-(E)	7,084,336,010	7,199,337,708	7,447,336,000	7,919,561,817	7,949,369,721	8,299,731,103	8,327,249,826	8,012,677,559	8,307,167,723	8,367,705,252
G	Loss Factor in distributor's system [(C)/(F)]	1.0346	1.0373	1.0328	1.0305	1.0351	1.0393	1.0253	1.0248	1.0333	1.0315
	Losses Upstream of Distributor's System										
H	Supply Facility Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses										
I	Total Loss Factor [(G)x(H)]	1.0392	1.0420	1.0374	1.0351	1.0398	1.0440	1.0299	1.0294	1.0379	1.0361

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.5 Is PowerStream's proposed rate harmonization appropriate?

BOARD STAFF INTERROGATORY #70:

Reference(s): <u>EH / T2/ S1/p.1</u>

PowerStream states that it used a method similar to the one approved by the Board in its application to harmonize the rates for the four former rate zones of Richmond Hill, Aurora, Markham and Vaughan and that that it seeks to harmonize rates for its two rate zones into a single rate.

a) Please provide a more detailed summary of the approach used by PowerStream to harmonize rates across the four former rate zones.

b) Please provide the rationale for PowerStream's proposal to harmonize rates across its two rate zones. Please provide any analysis that PowerStream has performed to support its decision to harmonize rates across its two rate zones.

RESPONSE:

a) In 2007, the rate harmonization application (EB-2007-0074) was based on the 2006 cost of service applications for PowerStream Inc. and Aurora Hydro Distribution Corporation.

In that case the various components from the two 2006 rate applications were combined into a consolidated 2006 rate model to determine the consolidated base revenue requirement (BRR). The BRR was allocated to customers classes on the same basis as the original applications in aggregate, i.e., the approved 2006 revenue per class was totaled for all rate zones to get the aggregate class percent of total 2006 approved revenue. The resulting

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.5 Is PowerStream's proposed rate harmonization appropriate?

percentages were then used to allocate the BRR resulting from the consolidated 2006 rate model to the customer classes. This was done separately for both the fixed and variable revenue amounts. The billing determinants for each rate zone were combined and used to calculate the harmonized rates from the allocated consolidated BRR.

In the current application the consolidated BRR was determined through the test year cost of service methodology. The initial allocation of BRR to customer classes was based on the combined per class revenues at current approved rates as a percent of the total revenue at current rates. The fixed revenues by class were derived by multiplying 2013 test year customer numbers by current fixed rates. Volumetric revenues by class were derived by multiplying the billing determinants for each customer class (based on the average use per customer in 2009-2013) by current volumetric rates. This methodology is the same one that was used in 2006 EDR model. This calculation was performed for two rate zones separately. Then, the revenues by class were combined and used to derive the percentages to allocate the combined BRR to customer classes.

In this respect the harmonization methodology was similar in that the combined revenue requirement was allocated to customer classes based on the allocation inherent in approved rates. Rates were then derived by using the total billing determinants for each customer class.

The 2013 Rate Application included the additional step of adjusting revenue allocation between the customer classes, when required, based on the results of Cost Allocation, according to the Board's guidelines.

b) There are two reasons for PowerStream to harmonize rates across its two rate zones in this application.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.5 Is PowerStream's proposed rate harmonization appropriate?

At the time of the MAADs application, PowerStream made the commitment to the OEB and customers to harmonize rates within 3 to 5 years of the merger. The merger was effective January 1, 2009 so harmonization of rates as of January 1, 2013 would satisfy this commitment.

This cost of service application reflects the costs of the merged entity. Many of the costs in this application apply to both rate zones and it is not possible to separate these costs by rate zone. The logical course is to calculate harmonized rates. To continue to maintain separate rate zones would require some allocation methodology to allocate shared and common costs between rates zones.

PowerStream did not perform any other analysis to support this harmonization as it felt the reasons cited above were strong reasons to harmonize rates. The rate impacts from harmonization are relatively small so this did not warrant further study.

RESPONSES TO INTERROGATORIES BY ISSUE

9. RATE DESIGN (Exhibit H)

9.5 Is PowerStream's proposed rate harmonization appropriate?

CCC INTERROGATORY #70:

Reference(s): (H/T2/S1)

Please identify all alternatives PowerStream considered with respect to rate harmonization. If alternatives were considered why were they rejected?

RESPONSE:

Please see the response to Board Staff IR #70, above.