PowerStream Custom IR
Technical Conference – April 21, 2015
Undertaking Responses

1. A-CCC-11: Provide in one table the budget and historical actual storm damage costs for 2013 to 2015 and budget for 2016 to 2020.

RESPONSE:

The Budget and Actual OM&A storm damage costs are included in the table below:

OM&A Storm Damage Costs ($000's)

	2013	2014	2015	2016	2017	2018	2019	2020
Budget	321	347	369	377	385	391	397	403
Actual (Note 1)	2,136	265	127	-	-	-	-	-

Note 1: Actuals for 2015 are to end of March

2. G-SEC-19: Provide missing appendices which are the System Hardening reports.

RESPONSE:

Please see TCQ-2 G-SEC-19 Appendix A and B.

3. A-CCC-8: Provide estimated productivity savings built into forecast for existing and new initiatives split between capital and OM&A.

RESPONSE:

PowerStream's best estimate of productivity savings incorporated into the forecasts has been presented in Exhibit F, Table 1 as updated in F-SEC-6.

PowerStream has been focused on achieving productivity improvements through projects such as Work Force Management and the new Customer Information System, and overall in our "Journey to Excellence". We have made progress, but recognize that there is more to be done.

At the time of preparing the 2015- 2020 budgets which began in May 2014, PowerStream's budgeting process did not specifically require staff to identify the productive reductions built into their budgets. PowerStream is taking steps to incorporate this into the budgeting process going forward.

Since 2013, PowerStream has managed budget targets based on a 1% inflationary increase for non-labour expenses in order to find efficiencies and manage OM&A cost pressures. Productivity savings have therefore been incorporated in actual results or budgets as they have been realized in order to mitigate other cost increases that may have exceeded the inflationary target in any given year. Where initiatives are taken to improve service at a lower cost, these cost reductions tend to offset cost increases for external services or an increased need for service costs due to growth that may be higher than the 1% inflationary budget target.

PowerStream believes that the budgeting process which involved several rounds of cuts to the initial budgets will require PowerStream to both utilize the current productivity initiatives and find additional productivity savings in order to operate within the approved budgets.

In capital the major productivity savings are from underground cable injection and pole reinforcement which have been built into the capital budgets.

4. B-EP-3: Provide updated Revenue Requirement and associated schedules reflecting corrections noted in interrogatory responses.

RESPONSE:

In the responding to the interrogatories, PowerStream discovered a number of items that needed to be corrected or adjusted:

Affecting Revenue Requirement:

- The cost of the new CIS system going into service in 2015 was understated by $3,206,000 (B-CCC-15)
- The estimated accumulated depreciation on dispositions was overstated (G-EP-13)
- Taxes:
    - Update for changes affecting target net income
    - Correct CEC additions for 2017 to 2020 (J-EP-42)
    - CCA additions for additional CIS cost and correct adjustments re RCGRP (J-EP-43)
    - Correct additions to taxable income for depreciation to gross amount before re-allocation to OM&A (J-EP-42).

Affecting Cost Allocation:

- Remove suite metered customers from Residential Secondary customer base (L-VECC-37)
- Corrections to suite meter capital costs and meter reads (L-VECC-35).

Undertaking TCQ # 33, regarding cost allocation input sheets, I7.1 Meter Capital and I7.2 Meter Readings, questioning why the are suite meters reads for GS>50 kW customers on I7.2 but no Suite meters on I7.1. This was a misunderstanding on our part and these reads have been moved from suite meter reads to the normal manual reads.

Affecting Deferral and Variance Account Rate Riders:

- The only The ICM true-up amount was overstated (G-EP-15)
- Recalculate 2015 interest for Q2 to Q4 at the OEB prescribed rate for Q2 of 2015.

The impacts of the changes on Revenue Requirement, Bill Impacts, Rate Base, Cost Allocation and Deferral and Variance Account rate riders are discussed in the respective sections below.

Revenue Requirement:

The impact on revenue requirement resulting from these changes is summarized in Table 1 below along with explanations regarding the changes.

Table 1: Change in Revenue Requirement – April 24, 2015 Update (in thousands)

April 24/15 Revised	**2016**	**2017**	**2018**	**2019**	**2020**	
Return on Rate base	$64,833	$70,324	$75,613	$80,095	$84,435	
OM&A	$96,216	$98,112	$99,920	$102,195	$104,193	
Depreciation	$47,224	$51,161	$53,848	$56,706	$59,844	
Income Taxes	($3,760)	$4,183	$5,196	$6,312	$6,566	
Revenue Offsets	($12,591)	($12,718)	($12,817)	($12,939)	($13,069)	
Base Revenue Requirement	**$191,922**	**$211,062**	**$221,760**	**$232,369**	**$241,969**	
Feb 24/15 Proposal	**2016**	**2017**	**2018**	**2019**	**2020**	
Return on Rate base	$64,667	$70,181	$75,497	$80,005	$84,371	
OM&A	$96,216	$98,112	$99,920	$102,195	$104,193	
Depreciation	$46,903	$50,841	$53,527	$56,386	$59,524	
Income Taxes	($3,749)	$3,588	$4,560	$5,600	$5,850	
Revenue Offsets	($12,591)	($12,718)	($12,817)	($12,939)	($13,069)	
Base Revenue Requirement	**$191,447**	**$210,004**	**$220,687**	**$231,247**	**$240,868**	
Increase (Decrease)	**2016**	**2017**	**2018**	**2019**	**2020**	**Notes**
Return on Rate base	$166	$143	$117	$90	$64	1
OM&A	$0	$0	$0	$0	$0	2
Depreciation	$321	$321	$321	$321	$321	3
Income Taxes	($11)	$595	$636	$712	$716	4
Revenue Offsets	$0	$0	$0	$0	$0	5
Base Revenue Requirement	**$475**	**$1,059**	**$1,073**	**$1,122**	**$1,101**	

Notes:

1. The return on rate base is a function of the change in rate base which is discussed in the Rate Base section below.

2. No change in OM&A

3. Increase in depreciation represents the annual depreciation on the additional CIS cost of $3,206,000.

4. Increase in income taxes is due mainly to the correction regarding the amount of depreciation to be added back in arriving at taxable income. The correct amount to be added back is the gross depreciation including the allocation to OM&A, which ranges from $2.4 million in 2016 to $2.9 million in 2020. This increases taxable income by the amount of depreciation allocated to OM&A. The updated Tax model is provided electronically as TCQ-4 Appendix A.

5. No change in Revenue Offsets.

Bill Impacts:

The currently approved 2015 Tariff of Rates and Charges contains 2014 LRAM rate riders specific to the Barrie former rate zone. As a result, there are two sets of bill impacts, one for the former York Region rate zone and another for the former Barrie rate zone.

Appendix 2-W is provided electronically as TCQ-4 Appendix B. Summaries of the total and distribution impacts for each rate class, for each service region, are provided in Tables 2 through 5 below. They exclude HST and the Ontario Clean Energy benefit (OCEB).

Table 2: Summary of Monthly Bill Impacts for a Typical Customer – Total Bill (York Region)

Customer Class	Billing Determinant	Consumption per Customer (kWh)	Load per Customer (kW)	Total bill 2016	2017	2018	2019	2020
Residential	kWh	800		4.0%	2.4%	1.2%	0.6%	1.1%
GS<50 kW	kWh	2,000		3.8%	1.8%	1.1%	0.8%	0.9%
GS>50 kW	kW	80,000	250	3.5%	1.2%	(0.3%)	0.7%	0.6%
Large Use	kW	2,800,000	7,350	2.3%	1.0%	0.6%	0.6%	0.5%
Unmetered Scattered Load	kWh	150		5.8%	3.0%	1.2%	1.3%	1.0%
Sentinel Lights	kW	180		7.6%	4.2%	0.6%	1.7%	1.4%
Street Lighting	kW	280		5.4%	4.6%	3.3%	1.7%	1.6%
Average				**4.6%**	**2.6%**	**1.1%**	**1.0%**	**1.0%**

Table 3: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (York Region)

Customer Class	Billing Determinant	Consumption per Customer (kWh)	Load per Customer (kW)	Distribution Component 2016	2017	2018	2019	2020
Residential	kWh	800		17.4%	8.9%	3.9%	1.8%	3.4%
GS<50 kW	kWh	2,000		17.5%	7.2%	3.5%	2.6%	2.8%
GS>50 kW	kW	80,000	250	30.8%	7.6%	(3.1%)	3.6%	2.9%
Large Use	kW	2,800,000	7,350	29.6%	9.3%	4.1%	3.9%	3.0%
Unmetered Scattered Load	kWh	150		16.3%	7.9%	3.1%	3.2%	2.3%
Sentinel Lights	kW	180		21.7%	10.4%	1.1%	3.7%	3.1%
Street Lighting	kW	280		20.6%	13.5%	5.4%	5.4%	4.8%
Average				**22.0%**	**9.3%**	**2.6%**	**3.4%**	**3.2%**

Table 4: Summary of Monthly Bill Impacts for a Typical Customer – Total Bill (Barrie)

Customer Class	Billing Determinant	Consumption per Customer (kWh)	Load per Customer (kW)	Total bill				
				2016	2017	2018	2019	2020
Residential	kWh	800		3.9%	2.4%	1.2%	0.6%	1.1%
GS<50 kW	kWh	2,000		3.5%	1.8%	1.1%	0.8%	0.9%
GS>50 kW	kW	80,000	250	3.5%	1.2%	(0.3%)	0.7%	0.6%
Large Use	kW	2,800,000	7,350	2.3%	1.0%	0.6%	0.6%	0.5%
Unmetered Scattered Load	kWh	150		5.8%	3.0%	1.2%	1.3%	1.0%
Sentinel Lights	kW	180						
Street Lighting	kW	280		5.4%	4.6%	3.3%	1.7%	1.6%
Average				**4.1%**	**2.3%**	**1.2%**	**0.9%**	**0.9%**

Table 5: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (Barrie)

Customer Class	Billing Determinant	Consumption per Customer (kWh)	Load per Customer (kW)	Distribution Component 2016	2017	2018	2019	2020
Residential	kWh	800		16.7%	8.9%	3.9%	1.8%	3.4%
GS<50 kW	kWh	2,000		16.0%	7.2%	3.5%	2.6%	2.8%
GS>50 kW	kW	80,000	250	30.5%	7.6%	(3.1%)	3.6%	2.9%
Large Use	kW	2,800,000	7,350	29.6%	9.3%	4.1%	3.9%	3.0%
Unmetered Scattered Load	kWh	150		16.3%	7.9%	3.1%	3.2%	2.3%
Sentinel Lights	kW	180						
Street Lighting	kW	280		20.6%	13.5%	5.4%	5.4%	4.8%
Average				**21.6%**	**9.1%**	**2.8%**	**3.4%**	**3.2%**

PowerStream's updated proposed 2016 Tariffs of Rates and Charges is provided electronically as TCQ-4 Appendix C. Tables 6 to 9 below provide a summary of the Current and Proposed distribution rates and other rates for 2016-2020.

Table 6: Current and Proposed Distribution Rates

				Proposed Rates									
Customer Class	Billing Determinant	Current 2015 Rates		2016		2017		2018		2019		2020	
		Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable
Residential	kWh	$12.67	$0.0140	$14.62	$0.0170	$15.78	$0.0189	$16.27	$0.0201	$16.74	$0.0213	$17.11	$0.0224
GS<50 kW	kWh	$26.08	$0.0139	$30.09	$0.0167	$32.71	$0.0183	$33.48	$0.0194	$33.58	$0.0208	$33.73	$0.0219
GS>50 kW	kW	$138.48	$3.3278	$138.48	$4.0220	$138.48	$4.4497	$138.48	$4.6761	$138.48	$4.8998	$138.48	$5.0969
Large Use	kW	$5,966.29	$1.4159	$5,966.29	$2.1550	$5,966.29	$2.5095	$5,966.29	$2.7130	$5,966.29	$2.8987	$5,966.29	$3.0595
Unmetered Scattered	kWh	$7.01	$0.0159	$8.09	$0.0193	$8.70	$0.0214	$8.91	$0.0228	$9.08	$0.0243	$9.16	$0.0258
Sentinel Lights	kW	$3.41	$8.0172	$3.93	$9.7254	$4.36	$10.4768	$4.58	$10.8774	$4.80	$11.2562	$4.99	$11.5900
Street Lighting	kW	$1.26	$6.6546	$1.45	$8.1382	$1.57	$9.0858	$1.62	$9.8029	$1.67	$10.4188	$1.71	$11.0145

Table 7: Current and Proposed Low Voltage Rates

Customer Class	Billing Determinant	Current 2015	Proposed 2016	2017	2018	2019	2020
Residential	kWh	$0.0003	$0.0006	$0.0006	$0.0007	$0.0007	$0.0007
GS<50 kW	kWh	$0.0003	$0.0005	$0.0005	$0.0006	$0.0006	$0.0006
GS>50 kW	kW	$0.1189	$0.1989	$0.2092	$0.2192	$0.2299	$0.2299
Large Use	kW	$0.1437	$0.2040	$0.2146	$0.2249	$0.2358	$0.2358
Unmetered Scattered Load	kWh	$0.0003	$0.0006	$0.0006	$0.0006	$0.0007	$0.0007
Sentinel Lights	kW	$0.1031	$0.1464	$0.1539	$0.1613	$0.1692	$0.1692
Street Lighting	kW	$0.0917	$0.1612	$0.1695	$0.1777	$0.1863	$0.1864

Table 8: Proposed Rate Riders

Customer Class	Billing Determinant	DVA Dispostion	Global Adjustment Dispostion	LRAMVA (2013 Balance)	Stranded Meter Asets	Account 1575
		Recovery Period 2 YEARS	Recovery Period 2 YEARS	Recovery Period 1 YEAR	Recovery Period 1 YEAR	Recovery Period 1 YEAR
Residential	kWh	$0.0002	$0.0011	($0.0001)	$0.0001	($0.0005)
GS<50 kW	kWh	$0.0002	$0.0011	$0.0001	$0.0002	($0.0003)
GS>50 kW	kW	$0.0309	$0.4161	($0.0126)		($0.0564)
Large Use	kW	$0.0148		$0.0000		$0.0000
Unmetered Scattered	kWh	$0.0002	$0.0011	($0.0002)		($0.0005)
Sentinel Lights	kW	$0.0231	$0.4308	($0.1662)		($0.2470)
Street Lighting	kW	($0.2075)	$0.3973	($0.1296)		($0.2306)

Table 9: Current and Proposed RTS rates

				Proposed Rates									
	Billing	**Current 2015 Rates**		**2016**		**2017**		**2018**		**2019**		**2020**	
Customer Class	***Determinant***	**TN**	**TC**	**TN**	**TC**	**TN**	**TC**	**TN**	**TC**	**TN**	**TC**	**TN**	**TC**
Residential	*kWh*	$ 0.0080	$ 0.0035	$ 0.0080	$ 0.0037	$ 0.0081	$ 0.0038	$ 0.0083	$ 0.0038	$ 0.0084	$ 0.0039	$ 0.0086	$ 0.0040
General Service < 50 kW	*kWh*	$ 0.0072	$ 0.0030	$ 0.0072	$ 0.0032	$ 0.0073	$ 0.0032	$ 0.0075	$ 0.0033	$ 0.0076	$ 0.0034	$ 0.0077	$ 0.0035
General Service > 50 kW	*kW*	$ 2.9192	$ 1.1726	$ 2.8960	$ 1.2343	$ 2.9367	$ 1.2538	$ 2.9823	$ 1.2758	$ 3.0321	$ 1.2998	$ 3.0802	$ 1.3234
General Service > 50 kW Interval	*kW*	$ 3.0601	$ 1.2687	$ 3.0358	$ 1.3354	$ 3.0784	$ 1.3566	$ 3.1263	$ 1.3803	$ 3.1785	$ 1.4064	$ 3.2289	$ 1.4319
Large Use	*kW*	$ 3.4638	$ 1.2027	$ 3.4798	$ 1.2820	$ 3.5558	$ 1.3123	$ 3.6338	$ 1.3437	$ 3.7114	$ 1.3753	$ 3.7928	$ 1.4086
Unmetered Scattered Load	*kWh*	$ 0.0072	$ 0.0034	$ 0.0070	$ 0.0035	$ 0.0069	$ 0.0035	$ 0.0068	$ 0.0034	$ 0.0067	$ 0.0034	$ 0.0067	$ 0.0034
Sentinel Lighting	*kW*	$ 2.2561	$ 0.8629	$ 2.2538	$ 0.9146	$ 2.2870	$ 0.9297	$ 2.3200	$ 0.9450	$ 2.3520	$ 0.9600	$ 2.3857	$ 0.9760
Street Lighting	*kW*	$ 2.2203	$ 0.9503	$ 2.5104	$ 1.1400	$ 2.9365	$ 1.3359	$ 3.5555	$ 1.6206	$ 3.6409	$ 1.6631	$ 3.7471	$ 1.7154

Appendix 2-V Revenue Validation is provided electronically as TCQ-4 Appendix D.

Rate Base:

Table 10 below summarizes the change in rate base.

Table 10: Change in Rate Base – April 24, 2015 Update

April 24/15 Revised	**2016**	**2017**	**2018**	**2019**	**2020**
Average Net Fixed Assets	$920,437	$998,801	$1,076,767	$1,146,727	$1,215,176
Working Capital Allowance	$155,926	$157,219	$163,628	$167,216	$169,953
Rate Base	**$1,076,363**	**$1,156,020**	**$1,240,394**	**$1,313,943**	**$1,385,129**
Feb 24/15 Proposal	**2016**	**2017**	**2018**	**2019**	**2020**
Average Net Fixed Assets	$917,689	$996,456	$1,074,873	$1,145,246	$1,214,127
Working Capital Allowance	$155,926	$157,219	$163,628	$167,216	$169,953
Rate Base	**$1,073,615**	**$1,153,675**	**$1,238,501**	**$1,312,462**	**$1,384,080**
Increase (Decrease)	**2016**	**2017**	**2018**	**2019**	**2020**
Average Net Fixed Assets	$2,748	$2,345	$1,893	$1,481	$1,049
Working Capital Allowance	$0	$0	$0	$0	$0
Rate Base	**$2,748**	**$2,345**	**$1,893**	**$1,481**	**$1,049**

The increase in rate base is from the change in average net fixed assets (NFA). There was no change in working capital or working capital allowance. Updated Fixed Asset Continuity Schedules (Chapter 2 APP. 2-BA) are provided as TCQ-4 Appendix E.

The increase in NFA is mainly attributable to the increase of $3,206,000 in additions in 2015 regarding the new CIS. After a half year depreciation in 2015 of $160,300 and annual depreciation of $320,600 in 2016 , this adds $2,885,400 to average NFA in 2016 with the addition to subsequent years decreasing by $320,600 each year. This has been offset in part by the increase in the net book value of dispositions as discussed in the response to G-EP-13.

Cost Allocation (CA):

The Board 3.2 CA Models have been used to determine the proportion of PowerStream's total revenue requirement that is recoverable from each rate class in each year.

The 2016 – 2020 CA models are provided electronically as TCQ-4 Appendix F.

The Status Quo class revenue-to-cost ratios as determined in the cost allocation models are shown in Table 11 below.

Table 11: Revenue-to-Cost Ratios (Status Quo)

	"STATUS QUO"						
	2013 BA	2016	2017	2018	2019	2020	Policy Allowed Range
Residential	**102.1%**	102.6%	103.9%	104.9%	105.7%	106.4%	**85 - 115**
GS Less Than 50 kW	**98.0%**	99.6%	100.4%	100.6%	100.8%	100.8%	**80 - 120**
GS 50 to 4,999 kW	**98.0%**	96.5%	94.1%	92.5%	91.3%	90.3%	**80 - 120**
Large Use	**85.0%**	71.3%	68.5%	67.0%	66.0%	65.2%	**85 - 115**
Unmetered Scattered Load	**102.4%**	91.3%	94.9%	96.3%	97.2%	98.1%	**80 - 120**
Sentinel Lighting	**95.0%**	84.6%	83.6%	83.4%	83.2%	83.1%	**80 - 120**
Street Lighting	**89.7%**	88.1%	85.0%	82.3%	81.6%	80.9%	**70 - 120**

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 Policy Allowed Range. PowerStream proposes that the revenue-to-cost ratio be increased to the bottom of the Policy Allowed Range. The resulting additional revenue from the Large Use class in 2016-2020 is in a range of $63,000- $120,000. Since the Residential customer class has the highest revenue-to-cost ratio, the additional revenue has been credited to this customer to move its revenue-to-cost ratio closer to 1.00. Table 12 below provides the proposed Revenue-to-Cost ratios.

Table 12: Appendix 2P (D) – Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios					Policy Allowed Range
	2016	2017	2018	2019	2020	
Residential	102.5%	103.8%	104.8%	105.6%	106.3%	**85 - 115**
GS < 50 kW	99.6%	100.4%	100.6%	100.8%	100.8%	**80 - 120**
GS > 50 kW	96.5%	94.1%	92.5%	91.3%	90.3%	**80 - 120**
Large User	85.0%	85.0%	85.0%	85.0%	85.0%	**85 - 115**
Unmetered Scattered Load (USL)	91.3%	94.9%	96.3%	97.2%	98.1%	**80 - 120**
Sentinel Lighting	84.6%	83.6%	83.4%	83.2%	83.1%	**80 - 120**
Street Lighting	88.1%	85.0%	82.3%	81.6%	80.9%	**70 - 120**

Tables 13 through 17 provide details on the revenue allocation to rate classes for 2016 through 2020.

Table 13: Appendix 2P (B) – Allocated Class Revenues - 2016

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 88,037,077	$ 104,012,502	$ 103,949,352	$ 7,527,078
GS < 50 kW	$ 24,606,848	$ 29,072,068	$ 29,072,068	$ 1,867,749
GS > 50 kW	$ 46,721,959	$ 55,200,240	$ 55,200,240	$ 2,910,817
Large User	$ 266,234	$ 314,546	$ 377,696	$ 14,413
Street Lighting	$ 2,320,226	$ 2,741,259	$ 2,741,259	$ 209,717
Sentinel Lighting	$ 16,350	$ 19,316	$ 19,316	$ 1,592
Unmetered Scattered Load (USL)	$ 475,661	$ 561,975	$ 561,975	$ 59,237
Total	$ 162,444,354	$ 191,921,907	$ 191,921,907	$ 12,590,603

Table 14: Appendix 2P (B) – Allocated Class Revenues - 2017

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 88,807,634	$ 114,750,689	$ 114,664,499	$ 7,590,447
GS < 50 kW	$ 24,646,566	$ 31,846,479	$ 31,846,479	$ 1,865,737
GS > 50 kW	$ 46,908,541	$ 60,611,765	$ 60,611,765	$ 2,976,590
Large User	$ 265,314	$ 342,819	$ 429,009	$ 14,937
Street Lighting	$ 2,213,358	$ 2,859,938	$ 2,859,938	$ 209,866
Sentinel Lighting	$ 16,286	$ 21,043	$ 21,043	$ 1,590
Unmetered Scattered Load (USL)	$ 487,250	$ 629,589	$ 629,589	$ 59,146
Total	$ 163,344,950	$ 211,062,322	$ 211,062,322	$ 12,718,312

Table 15: Appendix 2P (B) – Allocated Class Revenues - 2018

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 89,692,812	$ 121,054,694	$ 120,954,444	$ 7,638,780
GS < 50 kW	$ 24,692,287	$ 33,326,163	$ 33,326,163	$ 1,871,678
GS > 50 kW	$ 47,043,329	$ 63,492,444	$ 63,492,444	$ 3,019,116
Large User	$ 264,402	$ 356,853	$ 457,103	$ 15,267
Street Lighting	$ 2,099,230	$ 2,833,244	$ 2,833,244	$ 210,116
Sentinel Lighting	$ 16,285	$ 21,979	$ 21,979	$ 1,594
Unmetered Scattered Load (USL)	$ 499,851	$ 674,628	$ 674,628	$ 60,131
Total	$ 164,308,195	$ 221,760,005	$ 221,760,005	$ 12,816,681

Table 16: Appendix 2P (B) – Allocated Class Revenues - 2019

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 90,524,165	$ 127,266,638	$ 127,154,938	$ 7,703,798
GS < 50 kW	$ 24,736,122	$ 34,776,163	$ 34,776,163	$ 1,879,928
GS > 50 kW	$ 47,112,553	$ 66,234,869	$ 66,234,869	$ 3,062,935
Large User	$ 263,499	$ 370,449	$ 482,149	$ 15,519
Street Lighting	$ 2,116,796	$ 2,975,973	$ 2,975,973	$ 213,785
Sentinel Lighting	$ 16,284	$ 22,894	$ 22,894	$ 1,594
Unmetered Scattered Load (USL)	$ 513,592	$ 722,052	$ 722,052	$ 61,393
Total	$ 165,283,011	$ 232,369,037	$ 232,369,037	$ 12,938,953

Table 17: Appendix 2P (B) – Allocated Class Revenues - 2020

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 91,320,209	$ 132,857,309	$ 132,736,209	$ 7,772,989
GS < 50 kW	$ 24,817,227	$ 36,105,371	$ 36,105,371	$ 1,891,564
GS > 50 kW	$ 47,242,131	$ 68,730,268	$ 68,730,268	$ 3,106,853
Large User	$ 262,603	$ 382,049	$ 503,149	$ 15,739
Street Lighting	$ 2,131,874	$ 3,101,559	$ 3,101,559	$ 217,463
Sentinel Lighting	$ 16,284	$ 23,691	$ 23,691	$ 1,595
Unmetered Scattered Load (USL)	$ 528,571	$ 768,992	$ 768,992	$ 62,882
Total	$ 166,318,900	$ 241,969,238	$ 241,969,238	$ 13,069,086

Deferral and Variance Account (DVA) Rate Riders:

The DVA continuity schedule has been updated as follows:

- Replace ICM true-up amount with updated amount as per the response to interrogatory G-EP-15.
- Forecast interest for 2015 has been revised using the OEB prescribed rate of 1.10% (Q2-2015) for the period April 1, 2015 to December 31, 2015.

The updated EDDVAR model is provided electronically as TCQ-4 Appendix G.

The result is a reduction in the DVA claim amount as summarized in Table 18 below.

Table 18: DVA Claim Summary- Updated and Change ($000)

Description	Apr 24/15	Feb 24/15	Change
Group 1 and 2 excluding certain accounts[1]	$ 2,236.2	$2,556.6	-$ 320.4
Account 1589 Global Adjustment	$ 10,386.0	$10,422.1	-$ 36.1
Account 1575 IFRS PP&E Amount	-$ 2,392.7	($2,392.7)	$ -
Account 1568 LRAMVA	-$ 504.3	($504.3)	$ -
Account 1555 Stranded Meters residual	$ 599.1	$599.1	$ -
Total for disposition	**$10,324.3**	**$10,680.8**	**($356.5)**
Notes:			
1. Excluding accounts, 1555, 1568, 1575 and 1589			

The updated rate riders for the amounts that have changed are shown in the tables below.

Table 19: Updated Group 1 and 2 Rate Riders (excluding Global Adjustment)

Group 1 and 2 excluding certain accounts[1]			years	2
Rate Class	**Units**	**Quantity**	**Allocated Amount**	**Rate Rider**
RESIDENTIAL	kWh	2,750,618,680	$1,148,872	$0.0002
GENERAL SERVICE LESS THAN 50 KW	kWh	1,040,222,607	$384,850	$0.0002
GENERAL SERVICE 50 TO	kW		$754,670	$0.0309

4,999 KW		12,212,781		
LARGE USER	kW	150,807	$4,461	$0.0148
UNMETERED SCATTERED LOAD	kWh	14,169,725	$4,817	$0.0002
SENTINEL LIGHTING	kW	975	$45	$0.0231
STREET LIGHTING	kW	148,205	($61,502)	($0.2075)
Total			$2,236,214	

Table 20: Global Adjustment Rate Riders

Account 1589 Global Adjustment			years	2
Rate Class	**Units**	**Quantity**	**Allocated Amount**	**Rate Rider**
RESIDENTIAL	kWh	159,139,043	$ 353,579	$0.0011
GENERAL SERVICE LESS THAN 50 KW	kWh	170,983,976	$ 379,897	$0.0011
GENERAL SERVICE 50 TO 4,999 KW	kW	11,434,409	$ 9,515,092	$0.4161
LARGE USER	kW	-	$ -	
UNMETERED SCATTERED LOAD	kWh	274,430	$ 610	$0.0011
SENTINEL LIGHTING	kW	119	$ 103	$0.4308
STREET LIGHTING	kW	172,101	$ 136,764	$0.3973
Total			**$ 10,386,044**	

5. G-VECC-18: (a) Provide further explanation of $19.9M capital spending on CIS for 2016 to 2020. (b) Provide details for the “smaller CIS project” amount of $321K. Clarify if this is part of the $19.9M.

RESPONSE:

The following table is taken from the Distribution System Plan section 5.4.1 page 8 of 11. These are the amounts that were included in additions for the period 2016 to 2020 for these categories.

Table 1: CIS Capital Spending 2016-2020 ($000)

	2016	2017	2018	2019	2020	Total
CIS modifications	$ 3,884.1	$ 6,708.9	$ 2,996.0	$ 2,996.0	$ 2,996.0	**$ 19,581.0**
Other CIS project	$ 107.0	$ 107.0			$ 107.0	**$ 321.0**
Total	$ 3,991.1	$ 6,815.9	$ 2,996.0	$ 2,996.0	$ 3,103.0	**$ 19,902.0**

This shows a total spending on CIS modifications for the 2016 to 2020 period of $19.6 million. This consists of $9.2 million for future regulatory requirement changes and enhancements, $5.0 million for a version upgrade and $5.4 million for post go-live additional business requirements.

The smaller project that totals $321,000 is involves linking our outage management system with the CIS system.

6. B-CCC-15: If possible, provide an estimate of reduction in billing lag as a result of the new CIS.

RESPONSE:

It is anticipated that the Oracle CIS that is being implemented in 2015 will allow PowerStream to reduce the time between meter reads and bill production. This has not been quantified terms of time or dollar value. The focus has been on system implementation and subsequent stabilization.

7. B-CCC-14: Provide more details regarding 2014 capital additions of $8.2M for emergency restoration.

RESPONSE:

Table TCQ-7-1 provides further breakdown of the 2014 capital additions for Emergency Restoration.

TABLE TCQ – 7-1: B-CCCC 14 - Emergency Restoration ($000)

General Project Description	Additional Information	Project Work Order	2014 Actual
Replacement of failed distribution equipment	Multiple locations [blanket work order]	305007	714
Storm Damage	Multiple locations	302321; 305008	1,160
Unplanned replacement of failed distribution equipment	Multiple locations	300772	4,158
Emergency replacement of switchgears	Multiple locations [blanket work order]	308134	1,310
South Non-recoverable accidents	Multiple locations [blanket work order]	305006	199
Unplanned Replacement of Switchgear	Multiple locations	various Work orders	139
Tree Contractor - O/H Primary	206 ROBERT ST - PENETANG	311819	16
Emergency LIS replacement	Multiple locations	various Work orders	125
Damage claims - Transformers hit	Multiple locations	various Work orders	112
Damage claims - Broken poles	Multiple locations	various Work orders	145
Truck hit and significantly damaged transformer	320 SAUNDERS RD – replace 1000kva transformer	311567	39
Other unplanned replacements	Multiple locations	various locations	84
TOTALS			8,200

8. B-CCC-14: Provide gross, contributed capital and net amounts for Road Authority Work for 2013 through 2020.

RESPONSE:

Refer to the updated Table below from IR Response G-SEC-23.

	Historical					Proposed				
Material Investments	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
System Access	**Actual**	**Actual**	**Actual**	**Actual**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
New Connections and Subdivisions	**($)**	**($)**	**($)**	**($)**	($)	($)	($)	($)	($)	($)
New Commercial Subdivision Development	- 6,859	316,257	1,365,649	1,249,667	1,600,010	1,601,908	1,603,808	1,605,707	1,607,607	1,609,506
New Residential Subdivision Development	473,519	10,593,928	3,799,355	3,956,902	7,895,964	8,633,109	9,392,346	9,759,944	10,135,066	10,517,394
New Subdivision Development - Secondary Service Lateral	1,383,741	1,716,273	2,428,920	2,348,217	1,989,034	2,173,796	2,364,815	2,458,773	2,554,113	2,650,954
O/H and U/G Residential Service Upgrades	900,744	730,652	762,179	925,892	928,921	984,657	1,043,737	1,106,360	1,172,741	1,243,109
Road Authority										
Road Authority Expenditures (net PowerStream)	7,536,780	2,812,835	2,513,594	13,896,134	6,258,891	9,701,973	8,678,858	8,356,668	5,718,617	6,221,949
Road Authority Expenditures (contributed)			1,754,455	5,085,059	3,082,737	4,778,585	4,274,662	4,115,970	2,816,633	3,064,542
Road Authority Expenditures (gross)			4,268,049	18,981,193	9,341,628	14,480,558	12,953,520	12,472,638	8,535,250	9,286,491
Metering										
GS>50 MIST Meter Program Implementation	-	-	-	-	1,592,952	1,196,859	1,303,795	1,308,610	1,195,725	574,761
Residential Meter "ICON F" Meter Replacement Program	-	-	-	-	411,051	494,361	494,746	872,435	2,280,384	4,517,454
Other Customer Initiated Work										
Unforeseen Projects Initiated by the Customer	1,990,470	- 845,891	273,294	1,075,163	329,005	786,802	929,401	1,080,390	1,255,781	1,414,541
Total Material Investments System Access	**12,278,396**	**15,324,054**	**11,142,991**	**23,451,976**	**21,005,828**	**25,573,466**	**25,811,508**	**26,548,888**	**25,920,034**	**28,749,669**

9. C-EP-9: Provide the PowerStream Board Budget presentation from December 2015 (partial provided at Dec 15, 2014 meeting with intervenors.)

RESPONSE:

The presentation of the OM&A and Capital budget made to the Board of directors in December 2014 for approval will be sent in confidence.

10. F-EP-9: Calculate the PEG total predicted cost using the Oshawa Hydro rate case parameters rather than the PowerStream parameters.

RESPONSE:

The calculation of predicted costs involves the use of a number of business conditions, including input prices for capital and OM&A, together with measures of LDC output. The OM&A Price Index is constructed as a weighted average of a labor and non-labor component, with the weights determined by the Board to reflect the historical share of labor and non-labor OM&A expenses in the Ontario electricity distribution industry. The methodology calls for 70% of the weight to be placed on the Average Weekly Earnings (AWE) – labour component, and the other 30% on the GDPIPI – non-labor component. The Capital Price Index includes terms for the rate of return, depreciation and construction cost. The Construction Cost is based on the Electric utility Construction Price Index.

PowerStream reviewed the OPUCN rate filing (EB-2014-0101), Exhibit 10, Tab A, Table 3, where the OPUCN presents the development of the Input Price Forecast. Table 1 below presents the comparison of the input price forecast as submitted by PowerStream in the rate proposal against the OPUCN values presented in Exhibit 10, Tab A, Table 3.

Table 1: Input Price Forecast Comparison

	5-Year Average Values	
Model Input	**OPUCN Exh. 10/Tab A/Table 3**	**PowerStream**
AWE	2.59%	1.58%
GDPIPI	1.99%	1.87%
EUCPI	2.58%	2.04%
Labour Input Weight	70%	70%
Non-Labour Input Weight	30%	30%
Rate of Return	5.96%	6.48%
Depreciation	4.59%	4.59%
Input Price OM&A	2.41%	1.78%
Input Price Capital	2.76%	2.04%

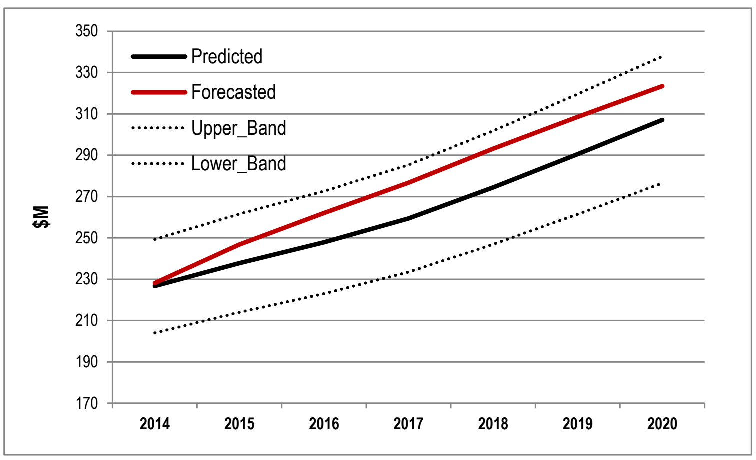
PowerStream revised the predicted and actual costs calculations to replace the original input price forecasts assumptions with the ones used by OPUCN as presented in the Table 1 above. Table 2 below presents the resulting predicted costs values as compared to the original values submitted in the rate proposal.

Table 2: Predicted vs. Actual (and Forecasted) Costs ($000)

Year	Predcited by the Model Total Costs	Actual (Forecasted) Total Costs	Actual (Forecasted) OM&A	Actual (Forecasted) Capital	Cost Performance
2014	226,659	228,125	65,541	162,584	0.6%
2015	237,718	246,731	69,674	177,057	3.7%
2016	247,810	262,049	70,309	191,740	5.6%
2017	259,356	276,704	72,465	204,240	6.5%
2018	274,371	293,162	75,437	217,725	6.6%
2019	290,505	308,491	77,734	230,756	6.0%
2020	307,108	323,421	79,734	243,686	5.2%
				Average (2016 - 2020)	**6.0%**

PowerStream's forecasted costs remain within ±10% of Predicted Costs. This coincides with the Board's criteria for Stretch factor Group 3, where PowerStream currently resides. This is illustrated in Figure 1 below.

Figure 1: Time Series of Predicted vs. Actual Forecasted Costs



11. F-EP-9: Reconcile OM&A per Table 1 to Rate Proposal forecast.

RESPONSE:

PEG's actual cost calculations are broken down in the calculations form OM&A and capital. The chosen definition of costs includes some adjustments (i.e. addition/removal of certain costs items). For OM&A, High Voltage Assets (HV) costs are removed to control for the different scope of work done by LDCs. Hydro One Low Voltage (HONI LV) charges are not captured by the OM&A accounts used for benchmarking exercise, so these charges are added.

PowerStream made further adjustment to the OM&A costs to account for an MIFRS impact. Under MIFRS accounting standards, total gross capital addition expenditures are defined as expenditures on capital additions, plus contributions and retirements. CGAAP total gross capital additions are defined as MIFRS total gross capital additions plus a CGAAP capital adjustment, equal to 19.2% of net capital additions, which is correspondently, deducted from OM&A expenses. This adjustment represents the increase in PowerStream's OM&A as a result of moving from CGAAP to IFRS. The purpose is to adjust the OM&A back to a CGAAP basis consist with the historical data used in the PEG model.

Table 1 below shows the reconciliation details for an OM&A between OM&A and Benchmarking exhibits.

Table 1: Actual OM&A Costs Reconciliation

		Rounded Value	Adjustments to OM&A			
	A	B	C	D	E	B - C - D + E
Year	OM&A	OM&A (rounded)	IFRS Impact	HV OM&A	HONI LV Charges	Actual OM&A Exh. F/ Tab 2 / Page 2
2014	**$85,453,828**	86,800,000	20,774,400	600,000	115,507	**65,541,107**
2015	**$92,557,500**	92,900,000	22,732,800	600,000	106,429	**69,673,629**
2016	**$96,216,191**	96,300,000	25,516,800	600,000	125,896	**70,309,096**
2017	**$98,112,314**	98,200,000	25,267,200	600,000	131,724	**72,464,524**
2018	**$99,919,944**	100,000,000	24,096,000	600,000	133,085	**75,437,085**
2019	**$102,194,621**	102,300,000	24,096,000	600,000	130,305	**77,734,305**
2020	**$104,193,445**	104,300,000	24,096,000	600,000	130,305	**79,734,305**

12. F-EP-9 and Ex. F, Tab 1, Table 4: reconcile 2013 Board approved and 2013 actual OM&A to Exhibit J, Tab 1.

RESPONSE:

Page 5, Exhibit F, Tab 4, Table 4 reconciled to J1, Tab1, Table 1 for 2013 Board Approved is below (in $000's):

2013 OM&A per Exhibit F (2013 Board Approved)	83,319
2013 OM&A per Exhibit J (2013 Board Approved)	82,941
Difference	378

The correct number is the 2013 Board approved OM&A per Exhibit J of $82,941K, the difference of $378K relates to non-distribution items that should have been excluded from the $83,319K.

Page 5, Exhibit F, Tab 4, Table 4 reconciled to J1, Tab 1, Table 1 for 2013 Actuals is below (in 000's):

2013 OM&A per Exhibit F (2013 Actuals)	81,192
2013 OM&A per Exhibit J (2013 Actuals)	80,849
Difference	343

The correct number is the 2013 actual OM&A per Exhibit J of $80,849K, the difference of $343K relates to non-distribution items that should have been excluded from the $81,192K.

13. F-EP-9: Show how the WACC (weighted average cost of capital) of 6.48% was calculated.

RESPONSE:

PowerStream used Board-Approved Cost of Capital Parameters for rates with effective dates in 2015 as presented in the Board Letter of November 20, 2014. Detailed calculations of the WACC are presented below in Table 1.

Table 1: Calculation of WACC for 2015

	A	B	A x B
Deemed ST Debt Rate	**4%**	**2.16%**	0.086%
Deemed LT Debt Rate	**56%**	**4.77%**	2.671%
ROE	**40%**	**9.30%**	3.720%
		WACC	**6.478%**

14. G-EP-14 and Table G-EP-54-1: Provide OM&A dollar amounts

RESPONSE:

Table TCQ#14-1: Fully Allocated Deprecation OMA Portion ($000)

Asset Category	notes	2016	2017	2018	2019	2020
Vehicles	1	507.8	532.0	560.6	614.1	617.0
Tools	2	313.7	319.4	328.9	341.5	348.4
Stores	3	2.0	2.0	2.0	2.0	2.0
Total		823.5	853.4	891.4	957.6	967.4

Notes:

1) Vehicle depreciation allocation to OMA is 26%
2) Tools depreciation allocation to OMA is 63%
3) Stores depreciation allocation to OMA is 3%

15. G-EP-15: Provide explanation as to why the ICM true up rate riders collected of over $900K per year are higher than the amount used to set the rate riders of $834K per year.

RESPONSE:

The difference is due to rounding and increased actual volumes in 2014. The ICM workform, as filed in 2014 IRM (EB-2012-0161) generated fixed and variable rates riders that were rounded to two and four decimal places for fixed and variable component respectively. Rate riders were calculated using 2013 EDR approved billing determinants. The rounding and growth has caused the variance in the collected revenues.

16. G-AMPCO-9: Update table based on useful life in addition to engineering end of life.

RESPONSE:

Please refer to the updated tables below. A live Excel file is provided as TCQ-16 Appendix A. Our experience is that switchgears do not last 45 years.

Asset	Population	Typical End of Life IFRS (Years)	Population Equal to or beyond TUL at December 31, 2014	% Population Equal to or beyond TUL at December 31, 2014
Transformer Station Power Transformers	24	40	0	0
Municipal Station Power Transformers	72	40	18	25
Transformer and Municipal Station Circuit	398	40	41	10.3
Transformer Station 230 kV Primary Switches	22	40	0	0
Municipal Station Primary Switches	58	No Data*	N/A	N/A
Transformer Station Capacitor Banks	9	30	0	0
Transformer Station Reactors	34	No Data*	N/A	N/A
TS Station Service Transformers	20	No Data*	N/A	N/A
TS 230 kV Primary Metering Units	18 combined 12 separate	No Data*	N/A	N/A
TS P&C Relays - Electromechanical	35	30	4	11.4
TS P&C Relays - Solid State	45	30	9	20
TS P&C Relays - Microprocessor	115	No Data*	N/A	N/A
Underground Cable	8,137.5 (km)	25	2,746	33.4
Distribution Transformers	44,192	30 - Underground TX 40 - Overhead TX	777	1.8
Switchgear	1,847	45	0	0
Mini-Rupter Switches	433	30	73	16.9
Automated Switches	360	40	8	2.2
Wood Poles	38,070	45	3301	8.7

Switchgear - There is no separate category for the Switchgear and hence they are lumped under the U/G conduit and Devices with 45 year life

Distribution Transformer -EOL (IFRS) Life is 30 years for Underground Transformer and 40 years for Overhead Transformer. The useful life is 40 year. However this asset is run to failure for the overhead and underground except as determined through Inspection.

Automated Switch Useful Life is 30 years vs EOL (IFRS) of 40 years. The asset age is only one factor for replacement. The replaceme is primararily driven by inspection, condition assessment and other issues (obsolesence) etc.

** - No EOL IFRS exist in the system.

Asset	Population	Typical Useful Life (Years) Kinectrics	Population Equal to or beyond End of Life at December 31, 2014	% Population Equal to or beyond End of Life at December 31, 2014
Transformer Station Power Transformers	24	40	0	0
Municipal Station Power Transformers	72	40	18	25
Transformer and Municipal Station Circuit	398	40	41	10.3
Transformer Station 230 kV Primary Switches	22	40	0	0
Municipal Station Primary Switches	58	50	4	0.7
Transformer Station Capacitor Banks	9	30	0	0
Transformer Station Reactors	34	70	0	0
TS Station Service Transformers	20	45	0	0
TS 230 kV Primary Metering Units	18 combined 12 separate	30	0	0
TS P&C Relays - Electromechanical	35	30	4	11.4
TS P&C Relays - Solid State	45	30	9	20
TS P&C Relays - Microprocessor	115	20	2	1.8
Underground Cable	8,137.5 (km)	25	2,746	33.4
Distribution Transformers	44,192	40	777	1.8
Switchgear	1,847	30	182	10
Mini-Rupter Switches	433	30	73	16.9
Automated Switches	360	30	52	16.1
Wood Poles	38,070	45	3301	8.7

17. G-AMPCO-9: Provide similar breakdown showing condition (e.g. good/fair/poor) and number of planned replacements for 2015 -2020. Provide live Excel file.

RESPONSE:

Please refer to the updated table below. A live Excel file is provided as TCQ-17 Appendix A.

Asset	Population	Condition				Number of Units Planned for Replacement						
		Good	Fair	Poor	N/A (1)	2015	2016	2017	2018	2019	2020	
Transformer Station Power Transformers	24	24	0	0	0	0	0	0	0	0	0	
Municipal Station Power Transformers	72	60	1	0	11	0	0	0	0	0	0	
Transformer and Municipal Station Circuit Breakers	398	337	3	53	5	7	12	12	10	8	4	
Transformer Station 230 kV Primary Switches	22	22	0	0	0	0	0	0	0	0	0	
Municipal Station Primary Switches	58	58	0	0	0	0	0	0	0	0	0	
Transformer Station Capacitor Banks	9	9	0	0	0	0	0	0	0	0	0	
Transformer Station Reactors	34	34	0	0	0	0	0	0	0	0	0	
TS Station Service Transformers	20	20	0	0	0	0	0	0	0	0	0	
230 kV Primary Metering Units - Combined	18	18	0	0	0	0	0	0	0	0	0	
230 kV Primary Metering Units - Separate	12	12	0	0	0	0	0	0	0	0	0	
TS P&C Relays (2) - Electromechanical	35	21	6	8	0	4	0	0	2	6	4	
TS P&C Relays (2) – Solid State	45	24	17	4	0	0	0	0	9	7	7	
TS P&C Relays (2) - Microprocessor	115	106	9	0	0	2	0	0	2	9	0	
Underground Cable	8,137.5 (km)	4568	1107	2371	0	105-115	105-115	105-115	105-115	105-115	105-115	Cable Injection
						25-30	25-30	25-30	25-30	25-30	25-30	Cable Replacement
Distribution Transformers	44192	22187	9026	6285	6694	68	64	60	60	60	60	
Switchgear	1847	1530	105	180	32	31	36	36	36	36	36	
Mini-Rupter Switches	433	270	123	38	2	15	15	15	15	15	15	
Automated Switches	360	327	19	14	0	5	5	5	5	5	5	
Wood Poles (3)	38070	29872	7064	1134	0	370	370	370	370	370	370	Pole Replacement
						30	30	30	30	30	30	Pole Reinforcement

18. G-AMPCO-11(g): Explain increase in insulator washing costs from 2014 to 2015.

RESPONSE:

The reason for the increase in insulator washing from 2014 to 2015 is described below:

OM&A COSTS	2014	2015	Increase	Explanation of increase
insulator washing	$99,615	$140,000	$40,385	The program was expanded to include washing of non-porcelain insulators in high-risk areas (eg, close to highways) after a high incidence of pole fires in 2014.

19. G-AMPCO-18 and G-AMPCO-26: Convert failure rates to number of units (show both).

RESPONSE:

Please refer to the updated tables below.

Submersible Transformer Failure Rate

Year	2011	2012	2013	2014
Submersible TX Failed Units*	0.47%	1.91%	1.48%	2.75%
No of Failure	1	4	2	3
Total Count	212	209	135	109

*- Includes other submersible transformer

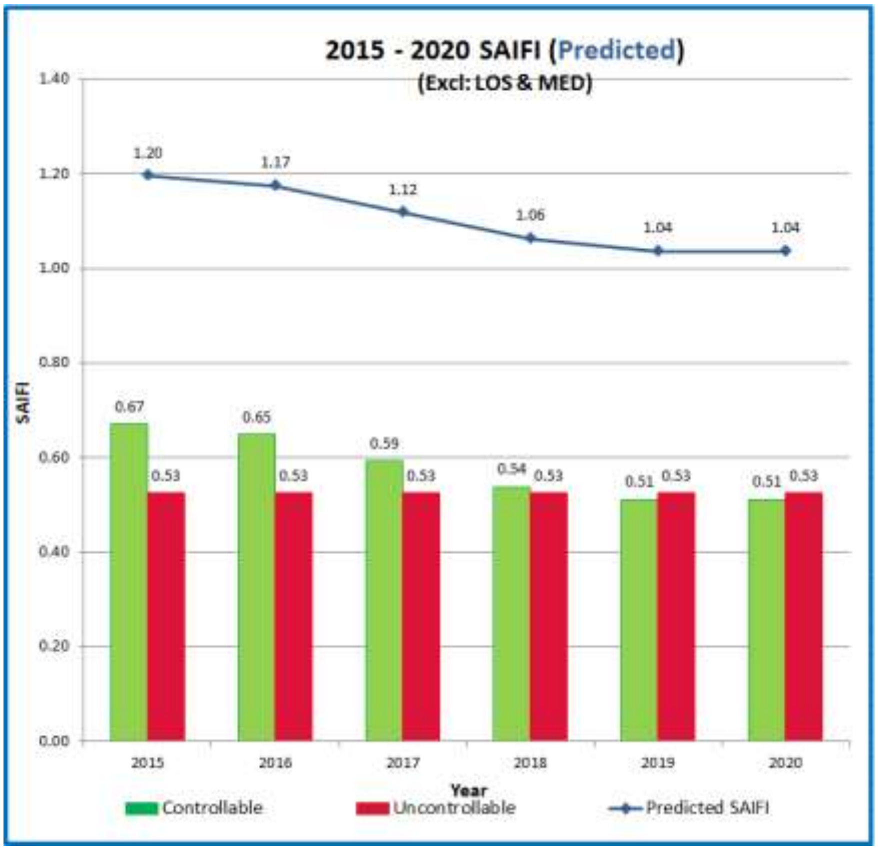
Annual failure rate for poles

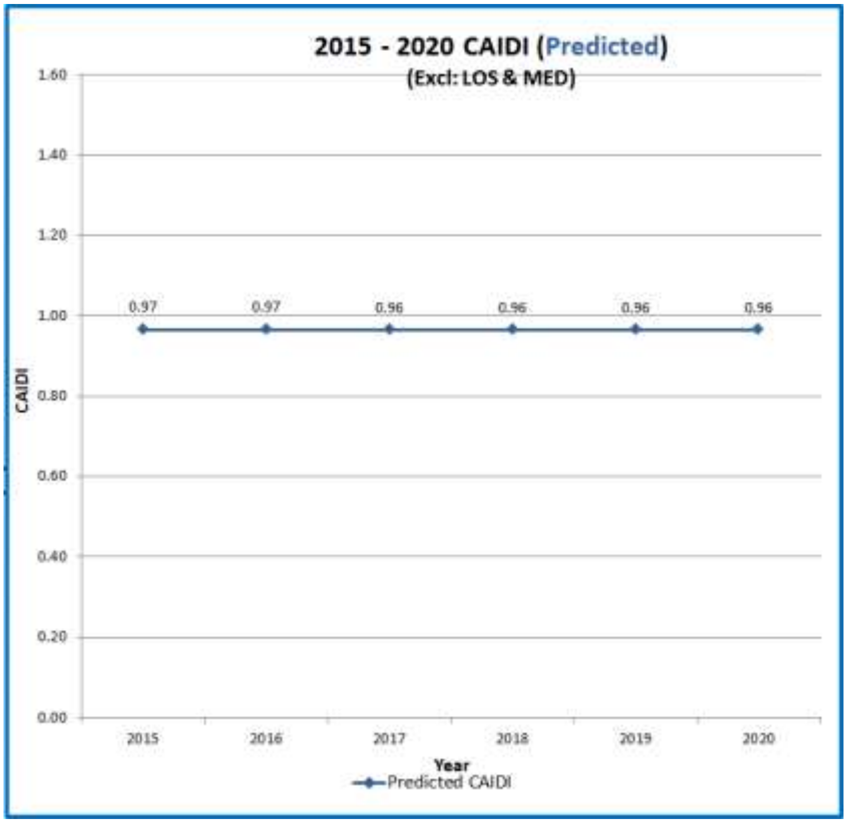
Year	2010	2011	2012	2013	2014
Annual failure rate for poles	0.005%	0.008%	0.008%	0.039%	0.063%
No of Failure	2	3	3	15	24
Total Count	38,070	38,070	38,070	38,070	38,070

20. G-SEC-20(c): Provide targets for SAIFI and CAIDI.

RESPONSE:

Please refer to the two new tables below.




2015 - 2020 CAIDI (Predicted)
(Excl: LOS & MED)
CAIDI
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0.97
0.97
0.96
0.96
0.96
0.96
2015
2016
2017
2018
2019
2020
Year
Predicted CAIDI

21. G-VECC-15: Add 2013 and 2014 data to table. Add any forecast values for 2015 to 2020 that are available.

RESPONSE:

Please refer to the table below.

	2009		2010		2011		2012		2013		2014	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Defective Equipment	26.45	0.39	14.28	0.32	30.63	0.47	30.48	0.51	35.68	0.59	29.07	0.46
Scheduled Outage	6.47	0.03	3.26	0.03	4.07	0.04	4.32	0.04	7.52	0.04	8.37	0.05
Tree Contact	3.37	0.05	2.64	0.03	1.82	0.03	3.05	0.05	6.61	0.07	2.96	0.07

SAIFI Predictions for 2015-2020 are system wide and are not specific to any cause codes. There are no predicted values for Defective Equipment, Scheduled Outages and Tree Contact available. The overall SAIFI predictions for 2015-2020 are shown below.

Overall SAIFI (Predicted)	2015	2016	2017	2018	2019	2020
	1.20	1.17	1.12	1.06	1.04	1.04

22. G-SEC-27: Provide PowerStream's Procurement Policy.

RESPONSE:

PowerStream's procurement policy has been added as TCQ-22 Appendix A

23. G-SEC-24: Provide number of units for Switchgear replacements for 2015 to 2020 (table incomplete)

RESPONSE:

Please refer to the updated table below.

	Actual				Planned					
Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Distribution Lines - Emergency/Reactive Replace										
Unscheduled Replacement of Failed Switchgear Program Cost	$0	$1,381,861	$1,663,004	$1,495,973	$1,420,148	$1,431,384	$1,420,148	$1,421,218	$1,400,444	$1,140,858
# of Switchgears Replaced	0	36	42	34	31	31	30	29	27	22

24. G-VECC-19: Provide costs for a typical line construction project, PowerStream staff vs external contractor.

RESPONSE:

Three recent projects were reviewed to compare costs between PowerStream lines crews and the external contractor.

The projects for comparison were selected such that:

- the hours estimated for PowerStream's crews and the actual hours completed using the external contractor's crews were very close; and
- the project costs were above $200,000 and consisted of a minimum of 20 poles to represent substantial work.

In these scenarios, the all in cost per hour (burdens and fleet) resulted in comparable rates. The external contractor dollar/hour was 97% of PowerStream's.

25. DSP 5.4.1: Provide historical data 2010 to 2014, for Unforeseen Customer Driven Capital.

RESPONSE:

These amounts are shown in Table 2: Material Investments - System Access in G-SEC-23 IR, and are also included in the updated Table in in the response to Undertaking #8 above.

26. Table G-CCC-44-2: Clarify is that there is no smart grid demonstration capital spending for 2017 -2020. Correct table as required.

RESPONSE:

This was a misinterpretation of the question. The response only included the actual capital spending in the deferral accounts up to December 31, 2015 and showed when this was added to rate base.

Table TCQ-26-1 below now includes the new smart grid capital spending added to rate base.

Table TCQ-26-1: Smart Grid Capital Additions ($000)

SMART GRID PROJECTS	2014	2015	2016	2017	2018	2019	2020	Total	Notes
Electric vehicles	$ 40							$ 40	1
Digital fault indicators	$ 157	$ 212						$ 369	2
Geomagnetic induced Current	$ 40							$ 40	3
EV charging stations and associated Technologies	$ 28	$ 535	$ 535	$ 535	$ 535	$ 535	$ 535	$ 1,098	4
SG strategy	$ 59							$ 59	5
Micro grid	$ 1,167	$ 177	$ 268	$ 268	$ 268	$ 268	$ 268	$ 1,611	6
Home Technologies, Green Button	$ 144		$ 1,239	$ 535	$ 535	$ 535	$ 535	$ 1,383	7
SG technology	$ 67	$ 12	$ 598	$ 268	$ 268	$ 268	$ 268	$ 676	8
Automatic feeder Restoration	$ 129	$ 205						$ 334	9
Storage Technologies	$ 1	$ 424	$ 696	$ 535	$ 535	$ 535	$ 535	$ 1,120	10
Analytics technologies	$ 2	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 537	11
TOTALS	$	$	$	$	$	$	$	$	

	1,834	1,831	3,602	2,408	2,408	2,408	2,408	7,266	

Notes
1) Electric vehicles and related pilot testing to utilize power from the distribution grid. In 2013 to 2014 PS was investigating the application of V2H [vehicle to home). Vehicles powering up homes.
2) PS successfully demonstrated the application of the Sensus Flexnet AMI system to deliver fault location, magnitude and other information to the control room. Additional application includes system performance relating to capacity and prioritization
3) PowerStream had successfully utilized GIC technology to detect solar induced currents which was tripping transformers and causing outages. Advance notice to operators would avoid premature outages. Effectiveness being monitored by system operators
4) PS is operating a Level III charger at our Cityview Head Office to identify the grid impact and customer usage patterns. Examples of learnings include the wide variation in actual amperage draw (independent of charger capacity) dependent on factors such as temperature and vehicle battery state-of-charge. In 2015, PowerStream will make any necessary upgrades and changes to this system as well as maintain operations.
5) PS has engaged various consultants to work with PS in developing an effective Smart grid strategy and plan including ongoing consultation with MOE to avoid duplicative work. Navigant has been one of the key partners in this work
6) PS is currently operating a demonstration micro grid including a control system to provide an automated system.
7) PowerStream is the LDC partner on the Rogers Ministry of Energy Smart Grid Fund Smart Home project. PS is supporting the introduction of energy management capabilities into the Rogers Smart Home offering. This will provide energy conservation and cost reduction to our customers. In addition, PS is a partner in the Energate Ministry of Energy Smart Grid Customer Opt-in dynamic pricing project. PS is currently introducing a voluntary residential dynamic pricing plan to residential customers whereby daily on-peak price varies in response to overall provincial demand. Shift consumption away from the more expensive on-peak price period to a lower price periods
8) PS is an observer LDC on the Opus One Ministry of Energy Smart Grid Fund Distributed Generation Integration with Distributed Energy Management and Storage Network project. The experiences and observations from this project will be used in developing an Advanced Distribution Management Systems and Energy Management Systems.
9) Part of SG technology. Special hardware and software that support more effective feeder restoration.
10) Partnering with other companies to develop and pilot battery storage systems and other electrical storage systems as part of the smart grid
11) PS in partnership with our Operational Data Store vendor has developed an advanced transformer loading tool that leverages our residential and commercial-industrial smart meter data. Access to detailed hour by hour transformer loading that can be used to optimize asset utilization and identify over and under loaded transformers. In 2015, PowerStream will update this tool to integrate into our new CIS system.

27. H-EP-5: Explain use of AR-1 variable vs. AR-12

RESPONSE:

The autoregressive adjustment (AR(1) term) has been used in the residential customer counts model to correct a serial correlation modeling issue. Serial correlation occurs when the error in the current period is partly a function of the error in the prior period. Figure 1 below demonstrates that there is a clear pattern in residential customer count residual values when an AR(1) term is not included. By including an AR(1) term the serial correlation is corrected in residential customer counts model (see Figure 2).

Figure 1: Residual graph without AR(1)

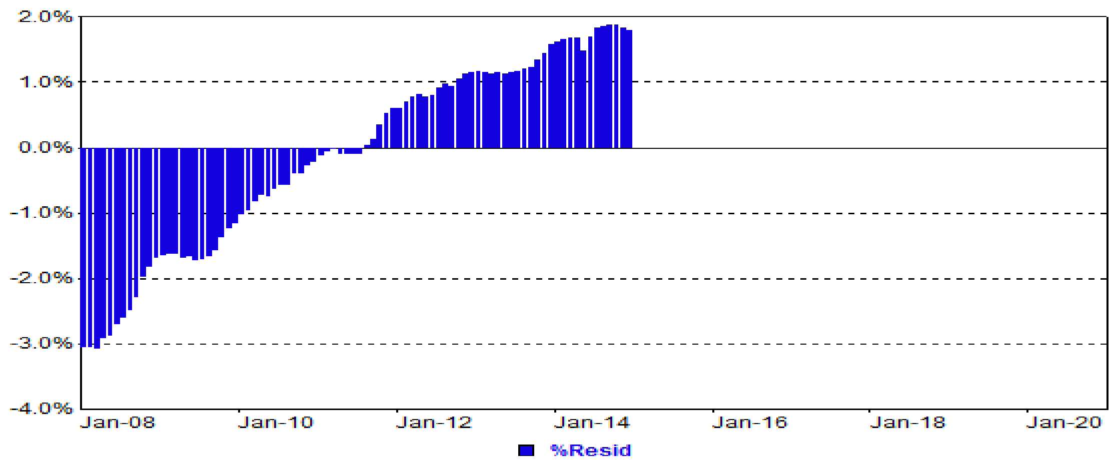
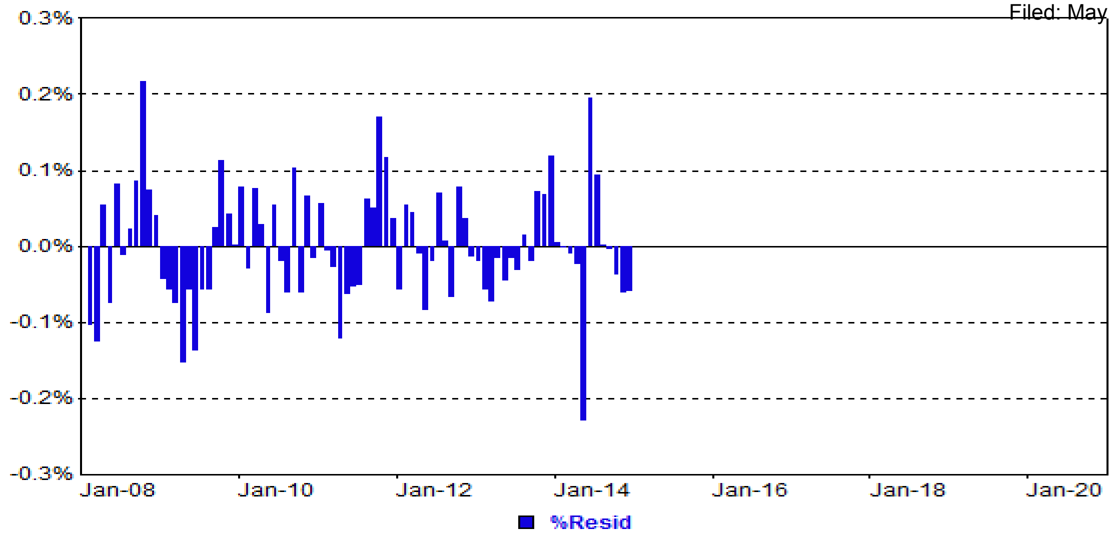
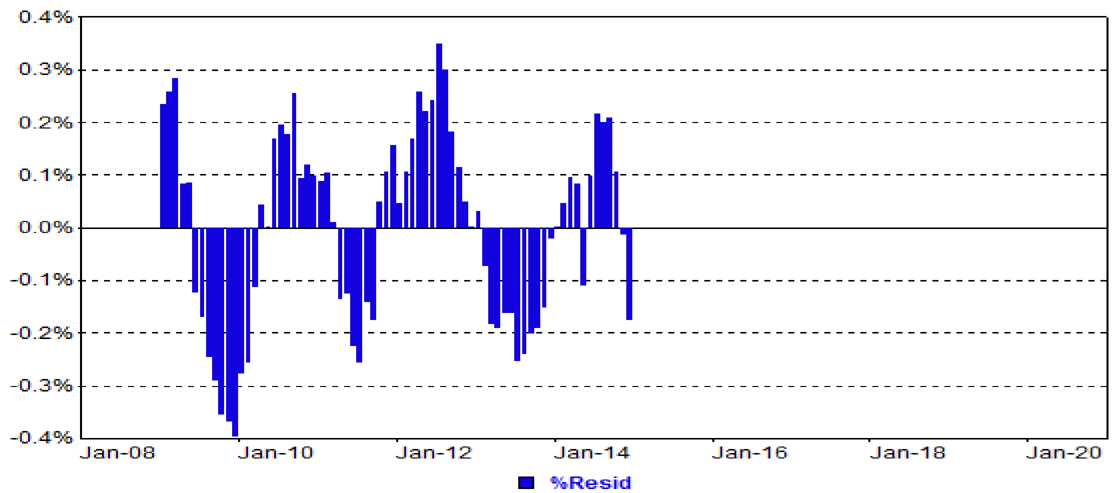


Figure 2: Residual graph with AR(1)



An AR(12) term can be used to correct serial correlation caused by seasonal patterns in the residual values. There is no clear seasonal pattern in residential customer counts. In residential customer count model, including an AR(12) term proved to be statistically significant but the Adjusted R-square declines from 1.0 to 0.998 and the MAPE increases from 0.06% to 0.16%. Additionally there is still a clear pattern in residential customer counts residual values when using an AR(12) term (see Figure 3).

Figure 3: Residual graph with AR(12)



28-1. H-EP-25: Explain why despite higher population growth in the forecast period than the historical data why the residential customer growth is lower in the forecast period than in the historic data.

RESPONSE:

For the historical years, customer growth rates have been declining (2.10 % in 2009 to 1.91% in 2014) while population growth rates have been increasing (1.57% in 2009 to 1.69% in 2014). The same pattern continues in the forecast years. The customer growth rates decline (2.05% in 2015 to 1.99% in 2020) when estimated population growth rates increase (1.73% in 2015 to 1.87% in 2020). Table 1 demonstrates Historical and Forecast Customer Counts and Population Change in Percentage.

Table 1: Historical and Forecast Customer Counts and Population Change in Percentage

Year	Customer Counts	% Change	Population	% Change
2008	277,828		5,505	
2009	283,665	2.10%	5,591	1.57%
2010	290,951	2.57%	5,682	1.62%
2011	297,962	2.41%	5,770	1.56%
2012	304,801	2.30%	5,870	1.73%
2013	310,830	1.98%	5,960	1.53%
2014	316,765	1.91%	6,060	1.69%
2015	323,261	2.05%	6,165	1.73%
2016	329,778	2.02%	6,273	1.75%
2017	336,480	2.03%	6,387	1.81%
2018	343,223	2.00%	6,504	1.82%
2019	350,040	1.99%	6,623	1.84%
2020	357,020	1.99%	6,747	1.87%

PowerStream has been experiencing reduced growth trends in residential customer counts. The forecast results derived from the regression model are reflecting the declining trend in residential customer growth.

28-2. H-VECC-25: Explain how PowerStream arrived at the kWh reduction from LED street lighting.

H-VECC-26: reconcile Appendix 2-I to OPA report.

RESPONSE:

The street light LED adjustment was derived by multiplying the estimated LED connections by the reduction on average use per connection.

Assumptions used to estimate LED street light connections:

- 65% of total street lights in PowerStream's service territories are owned by the City of Vaughan, Markham and Barrie;
- We assumed that the Street Lighting upgrades for those 3 municipalities will be completed in the 3-year window, at 1/3 annually, starting in 2016.

The average use per connection (kWh) for street lights was calculated based on 3 years historical average use (2012-2014); for the load forecast adjustment, we assumed that the converted LED street lights will reduce the energy use per connection by 50%.

Please refer to TCQ-28 Appendix A for detailed calculation.

28-3. I-VECC-28(a): Provide explanation for drop in late payment charges in 2013.

RESPONSE:

Late payment charges dropped from 1.973M in 2012 to 1.923M in 2013. The reason for this decrease is due an adjustment made on a large customers account as part of a payment plan.

29. I-EP-27: Provide details of when water billing contracts were signed and when these expire.

RESPONSE:

PowerStream has water billing included in joint service agreements with the City of Vaughan and the City of Markham. The details of these contracts are as follows:

1. City of Markham joint service agreement start and end dates :
   a. January 1, 2011 to December 31, 2013.
   b. January 1, 2014 to December 31, 2015.

2. City of Vaughan joint service agreement start and end dates:
   a. January 1, 2011 to December 31, 2015

It is anticipated that these contracts will be extended for three years to the end of 2018.

30. J-EP-37: Provide correct response to interrogatory in confidence (forecast wage increases).

RESPONSE:

This response will be provided in confidence.

31. J-CCC-62: Add 2013 Board approved and 2014 actual.

RESPONSE:

Below are the revised tables in J-CCC-62 that include Board Approved 2013 and 2014 actuals (in 000's):

Billing and Collecting:

Finance			Bridge Year	Test Years				
In $000	**2013 OEB Approved**	**2014 Actual**	**2015 Budget**	**2016 Budget**	**2017 Budget**	**2018 Budget**	**2019 Budget**	**2020 Budget**
Customer Service	**$14,124**	**$16,089**	**$16,711**	**$17,282**	**$16,745**	**$16,881**	**$17,176**	**$17,473**
$ Increase		$1,965	$622	$571	($537)	$137	$295	$297
% Increase		13.9%	3.9%	3.4%	-3.1%	0.8%	1.7%	1.7%

Community Relations:

Corporate Services			Bridge Year	Test Years				
In $000	**2013 OEB Approved**	**2014 Actual**	**2015 Budget**	**2016 Budget**	**2017 Budget**	**2018 Budget**	**2019 Budget**	**2020 Budget**
Corporate Communications	**$1,399**	**$1,740**	**$1,806**	**$2,124**	**$2,194**	**$2,221**	**$2,250**	**$2,276**
$ Increase		$342	$66	$318	$70	$27	$28	$26
% Increase		24.4%	3.8%	17.6%	3.3%	1.3%	1.3%	1.2%

<u>Administration and General</u>

Corporate Services:

Corporate Services			Bridge Year	Test Years				
In $000	**2013 OEB Approved**	**2014 Actual**	**2015 Budget**	**2016 Budget**	**2017 Budget**	**2018 Budget**	**2019 Budget**	**2020 Budget**
Supply Chain Services	**$5,812**	**$5,737**	**$5,979**	**$6,277**	**$6,351**	**$6,424**	**$6,493**	**$6,559**
$ Increase		($74)	$242	$298	$73	$73	$69	$65
% Increase		-1.3%	4.2%	5.0%	1.2%	1.2%	1.1%	1.0%
Information Services	**$6,904**	**$6,061**	**$9,132**	**$9,085**	**$9,260**	**$9,256**	**$9,454**	**$9,484**
$ Increase		($843)	$3,071	($48)	$175	($3)	$197	$30
% Increase		-12.2%	50.7%	-0.5%	1.9%	-0.04%	2.1%	0.3%
Legal	**$479**	**$351**	**$513**	**$639**	**$737**	**$761**	**$787**	**$808**
$ Increase		($128)	$162	$126	$99	$24	$26	$21
% Increase		-26.8%	46.3%	24.6%	15.4%	3.2%	3.4%	2.7%
HR & Organizational Effectiveness	**$4,870**	**$5,125**	**$5,458**	**$5,669**	**$5,736**	**$5,776**	**$5,883**	**$5,982**
$ Increase		$255	$333	$210	$67	$40	$106	$100
% Increase		5.2%	6.5%	3.9%	1.2%	0.7%	1.8%	1.7%

Corporate Finance and Reporting:

Finance			Bridge Year	Test Years				
In $000	2013 OEB Approved	2014 Actual	2015 Budget	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget
Corporate Finance & Reporting	**$5,386**	**$5,138**	**$5,701**	**$6,049**	**$6,183**	**$6,308**	**$6,534**	**$6,589**
$ Increase		($249)	$564	$347	$134	$125	$226	$55
% Increase		-4.6%	11.0%	6.1%	2.2%	2.0%	3.6%	0.8%

Rates and Regulatory:

Finance			Bridge Year	Test Years				
In $000	2013 OEB Approved	2014 Actual	2015 Budget	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget
Rates & Regulatory Affairs	**$2,778**	**$3,074**	**$3,259**	**$3,034**	**$3,061**	**$3,115**	**$3,080**	**$3,134**
$ Increase		$296	$185	($226)	$27	$54	($35)	$54
% Increase		10.7%	6.0%	-6.9%	0.9%	1.8%	-1.1%	1.8%

Corporate:

Corporate			Bridge Year	Test Years				
In $000	2013 OEB Approved	2014 Actual	2015 Budget	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget
Corporate	**$9,324**	**$8,759**	**$8,591**	**$8,660**	**$8,919**	**$9,025**	**$9,202**	**$9,380**
$ Increase		($565)	($168)	$69	$259	$106	$177	$178
% Increase		-6.1%	-1.9%	0.8%	3.0%	1.2%	2.0%	1.9%

32. J-CCC-56: Provide budget amounts for 2011 – 2014.

RESPONSE:

Below is table showing the budget amounts from 2011 to 2020 for overtime costs.

2011 Forecast	2012 Forecast	2013 Board Approved	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
$2,239,426	$2,542,844	$2,870,725	$2,620,264	$2,596,718	$2,704,847	$2,734,972	$2,785,969	$2,842,366	$2,896,170

33. L-EP-47 (c): Table 47-3 – Why no change to Residential? Increase number of decimal places to determine if rounding.

For cost allocation sheets I7.1 and I7.2, advise why showing suite metered reads.

RESPONSE:

Under the requested scenario, for each of the test years 2017 through 2020, PowerStream followed the following process:

- Step 1:

  Status Quo ratios, as per Cost Allocation Model, were brought to the Status Quo 2016 levels, except that the Large Use class was initially increased to 85%, in order to calculate the total revenue deficiency/sufficiency that needs to be re-allocated;

- Step 2:

  The ratio of the lowest rate class was increased to the second lowest ratio;

- Step 3:

  Both of these ratios were increased to the next lowest ratio, and so on, until sufficient revenue is generated to result in no deficiency or sufficiency;

- Step 4:

  If the last step resulted in the revenue sufficiency, the last ladder adjustment was re-scaled in order to "zero out" revenue sufficiency. Figure 1 below illustrates this process for 2017 Test year.

Figure 1: 2017 Revenue-to-Costs Ratios Adjustment

- Step 1:

This step resulted in the total revenue deficiency of $68,552 to be allocated.

	2017 CA Model at Status Quo	Adjustment to bring to 2016	2017 Revised Status Quo
Residential	$114,175,187	($1,507,874)	$112,667,313
GS Less Than 50 kW	$31,686,762	($278,443)	$31,408,318
GS 50 to 4,999 kW	$60,307,783	$1,551,197	$61,858,979
GS 50 to 4,999 kW Legacy	$0	$0	$0
Large Use	$341,100	$84,889	$425,989
Unmetered Scattered Load	$626,431	($25,363)	$601,068
Sentinel Lighting	$20,938	$287	$21,224
Street Lighting	$2,845,595	$106,757	$2,952,352
Total	**$210,003,796**	**($68,552)**	**$209,935,244**

	2017 CA Model Status Quo R/C	2017 Revised R/C
Residential	**103.7%**	**102.4%**
GS Less Than 50 kW	**100.7%**	**99.9%**
GS 50 to 4,999 kW	**94.3%**	**96.6%**
GS 50 to 4,999 kW Legacy		
Large Use	**68.6%**	**85.0%**
Unmetered Scattered Load	**94.8%**	**91.3%**
Sentinel Lighting	**83.6%**	**84.7%**
Street Lighting	**85.1%**	**88.1%**

- Step 2:

  The ratio of the lowest rate class (Sentinel – 84.7%) was increased to the second lowest ratio (LU – 85%), allocating $81 to Sentinel class.

- Step 3:

  Both of these ratios, LU and Sentinel, were increased to the next lowest ratio (Street Lighting – 88.1%), allocating $16,081 and $635 to these two classes respectively;

  Then, the next three lowest ratios, LU, Sentinel and Street Lighting, were increased to the next lowest ratio (USL – 91.3%), allocating $16,599, $862 and $114,856 to these three classes respectively;

- Step 4:

  The last step resulted in the revenue sufficiency of $80,762, consequently, the last ladder adjustment was re-scaled in order to “zero out” revenue sufficiency of $80,762. This re-scaling resulted in the three ratios to be adjusted to 89.3% vs. 91.3%.

  Table 1 below summarized all adjusted that took place in 2017.

Table 1: 2017 Revenue-to-Cost Ratios Adjustments

	Step 1	Step 2	Step 3 (A)	Step 3 (B)	Step 4	Total re-Allocation
Residential	($1,507,874)					
GS Less Than 50 kW	($278,443)					
GS 50 to 4,999 kW	$1,551,197					
Large Use	$84,889		**16,081**	16,599	**6,468**	**22,548**
Unmetered Scattered Loa	($25,363)					**-**
Sentinel Lighting	$287	**81**	**835**	862	**336**	**1,252**
Street Lighting	$106,757			114,856	**44,752**	**44,752**
Total	**($68,552)**	**$81**	**$16,916**	$132,317	**$51,555**	**$68,552**

Residential class was never adjusted, since it has the highest ratio.

The discrepancy between cost allocation input sheets, I7.1 Meter Capital and I7.2 Meter Readings, regarding suite meters reads for GS>50 kW customers was a misunderstanding. These reads have been moved from suite meters to the normal manual reads.

34. Explain how status quo fixed rates are determined. Is this based on 2013 approved split or 2015 revenue at approved rates?

RESPONSE:

The following description outlines the process for determining Fixed/Variable split for the purpose of rate design:

Step 1 - Determine revenue requirement allocation.

- Fixed component: 2016 projected number of customers 'times' 2015 Board-Approved Fixed Rates 'times' 12 (months);
- Variable component: 2016 projected kWh/kW per customer 'times' 2016 projected number of customers 'times' 2015 Board-Approved Volumetric Rates;

Step 2 – Split Base Revenue Requirement as based on percentage allocation identified in Step 1.

Step 3 – Determine Monthly Service Charge (MSC)

- Fixed Base Revenue Requirement divided by Test Year number of customers/connections further divided by 12 (month);
- For each year, where the current 2015 MSC is at or above the ceiling, the proposed MSC has been capped at the 2015 MSC. Otherwise, the proposed MSC has been determined as the lower of the calculated MSC (calculated at the current fixed-variable revenue split) and the ceiling;

Step 4 – Determine Volumetric Rate

- Once the MSC for each class is determined, the fixed distribution revenue from the MSC calculated and subtracted from the total class revenue allocation. The remainder is the variable distribution revenue for the class. This variable distribution revenue value is then used to determine the variable charge.

35. Reconcile LRAMVA quantities to OPA report.

RESPONSE:

Table 1 below provides the requested reconciliation. References to the source file are for the OPA 2013 Final Verified Results Report issued in September 2014.

Table 1: LRAMVA Base Amounts Reconciliation

				Source Reference		
	Table N-VECC-40-10	OPA Report	Variance	Page	Column	OPA Program Reference / Notes
CDM Initiative	kWh	kWh	kWh			
Fridge Pick Up	424,061	424,061	0	4	Net Incremental Energy Savings (kWh)/2013	Appliance Retirement & Exchange
HVAC Rebates	2,830,426	2,830,426	0	4	Net Incremental Energy Savings (kWh)/2013	HVAC Incentives
Coupons (and retailers events)	1,652,111	1,652,111	0	4	Net Incremental Energy Savings (kWh)/2013	Conservation Instant Coupon Booklet & Bi-Annual Retailer Event
Peaksaver	16,249	16,249	0	4	Net Incremental Energy Savings (kWh)/2013	Residential Demand Response
Retailer Co-Op/Sears	0	0	0			
Residential New Construction	0	0	0			
Home Assistance Program (HAP)	595,251	595,251	0	4	Net Incremental Energy Savings (kWh)/2013	Home Assistance Program
Residential Total	**5,518,098**	**5,518,098**	**0**			
CDM Initiative	kWh	kWh	kWh			
ERIP: Retrofit	1,338,621	1,338,621	0	4	Net Incremental Energy Savings (kWh)/2013	Retrofit / this porgram is split beween GS<50 & GS>50; split provided by CDM
Direct Installed Lighting	7,944,313	7,944,313	0	4	Net Incremental Energy Savings (kWh)/2013	Direct Install Lighting
ERIP: pre-20112	0	0	0			
Multi-Family efficiency rebates: pre-2011	0	0	0			
Business Refrigeration	42,465	0	-42,465			PowerStream's program: source CDM Department
GS<50 Total	**9,325,398**	**9,282,934**	**-42,465**			
CDM Initiative	kW	kW	kW			
ERIP: Retrofit	4,744	4,744	0	4	Net Incremental Peak Demand Savings (kW)/2013	Retrofit / this porgram is split beween GS<50 & GS>50; split provided by CDM
New Construction and Major Renovation	778	778	0	4	Net Incremental Peak Demand Savings (kW)/2013	New Construction
Energy Audit	79	79	0	4	Net Incremental Peak Demand Savings (kW)/2013	Energy Audit
Energy Manager	421	421	0	4	Net Incremental Peak Demand Savings (kW)/2013	Energy Manager
Program Enabled Savings	5	5	0	4	Net Incremental Peak Demand Savings (kW)/2013	Program Enabled Savings
Business Refrigeration	2		-2	4		PowerStream's program: source CDM Department
ERIP: pre-2011	0		0			
High Performance New Construction: pre-2011	14	14	0	4	Net Incremental Peak Demand Savings (kW)/2013	High Performance New Construction / related to 2013 is 14 kW out of 83 kW
DR3	8,327	8,327	0	4	Net Incremental Peak Demand Savings (kW)/2013	Demand Response 3
GS>50 Total	**14,370**	**14,368**	**-2**			

36. Provide EDA fees for 2012 to 2014 and forecast for 2015 – 2020.

RESPONSE:

The EDA fees are included in the table below ($000's):

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Budget	120	124	126	113	115	116	117	118	119
Actual	114	112	116	-	-	-	-	-	-

37. Distribute SEC table re distribution rate increases for GS>50 school with 100 kW monthly peak demand.

RESPONSE:

Please see the table below.

Sample School Distribution Rate Calculations 2014-2019

GS>50 to 999 KW	2015	2016	2017	2018	2019	2020
Monthly Fixed	$138.48	$138.48	$138.48	$138.48	$138.48	$138.48
ICM Rate Rider	$0.72					
Recovery of CGAAP/CWIP Differential Rider	$6.99	$6.99				
Net Monthly Fixed	$146.19	$145.47	$138.48	$138.48	$138.48	$138.48
Volumetric Rate	$3.3278	$4.0108	$4.4248	$4.6509	$4.8735	$5.0712
ICM Rate Rider	$0.0173					
Net Volumetric Rate	$3.3451	$4.0108	$4.4248	$4.6509	$4.8735	$5.0712
Result at 100 KW	$334.51	$401.08	$442.48	$465.09	$487.35	$507.12
Total Monthly Distribution Changes	$480.70	$546.55	$580.96	$603.57	$625.83	$645.60
Annual Bill	$5,768.40	$6,558.60	$6,971.52	$7,242.84	$7,509.96	$7,747.20
Increase over Prior Year		$790.20	$412.92	$271.32	$267.12	$237.24
Percentage		13.70%	6.30%	3.89%	3.69%	3.16%
Five Year Increase						$1,978.80
Percentage						34.30%
Revenue at Current Rates	$28,842.00					
Proposed Revenue	$36,030.12					
Increase Revenue from Sample School 2016-2020	$7,188.12					

changes from corrected volumetric rate for 2018

38. AMPCO: Identify which OEB Appendices have been provided.

RESPONSE:

Please see the attached index page to the Chapter 2 Appendices.

The appendices that have been included in the materials provided are marked with a checkmark.

There are a number of schedules which are not applicable and are marked “n/a”. This includes items such as transition to IFRS and disposition of stranded meters which were dealt with in PowerStream’s 2013 Cost of Service application.

There are a number of schedules that were not provided as part of this Custom IR rate proposal and these are marked “No”.

In some cases, information that would be in the Chapter 2 appendix has been presented in the materials provided.

39. AMPCO: Complete list of capital projects.

RESPONSE:

Please see attached TCQ-39 Appendix A, TCQ-39 Appendix B, TCQ-39 Appendix C and TCQ-39 Appendix D for a complete listing of capital projects.

40. Please provide 2014 audited financial statements.

RESPONSE:

PowerStream's audited financial statements are attached as TCQ-40 Appendix A.

41. Could you please provide us with historic and forecast water billing revenues?

RESPONSE:

In the table below is the water billing revenues from 2013 to 2020 (in $000's):

	2013	2014	2015	2016	2017	2018	2019	2020
Water billing	2,568	2,494	2,569	2,646	2,726	2,807	2,892	2,979

PowerStream

2013 ICE STORM REVIEW

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1.0 Independent Assessment Report

NAVIGANT

Todd Williams, Managing Director
Navigant Consulting Ltd.
333 Bay Street, Suite 1250
Toronto, ON M5H 2R2
Direct: (647) 288-5204
TWilliams@Navigant.com

April 15, 2014

Independent Assessment of PowerStream's Ice Storm Review

I am pleased to provide herein the results from the independent assessment of PowerStream's Ice Storm Review conducted by Navigant Consulting Ltd. ("Navigant").

PowerStream initiated the review to better understand which processes, procedures, systems and resources were effective during the event, and which operational aspects could be improved to enhance PowerStream's response to future emergency events of a similar magnitude. As part of the review, PowerStream also identified various action items to explore and implement the necessary changes in its operations.

Navigant's assessment included a review of 1) the internal lines of questioning and broad areas of feedback; 2) the external survey instruments and outreach letters; and 3) the Ice Storm Review report. This assessment was undertaken by a cross-functional team of Navigant professionals with many years of distribution utility experience.

Throughout our assessment, we found that PowerStream's review process was both comprehensive and rigourous. Similarly, we found that the report prepared by PowerStream provides a clear, comprehensive and critical assessment of both the successes that PowerStream achieved and the opportunities for improvement. Given this, we are confident that successful completion of the specific recommendations and action items identified in the review will enhance PowerStream's response to future emergency events for the benefit of the customers and communities it serves.

Sincerely,

Todd Williams
Managing Director

2.0 Executive Summary

On the weekend of December 21-22, 2013, a significant ice storm moved through Southern Ontario. Ice accumulation resulted in downed branches, trees and power lines, causing over 500,000 customers in Ontario to lose power. This included over 92,000 customers without power (at the peak of the event) in PowerStream's service territory, predominantly in Aurora, Markham, Richmond Hill and Vaughan.

The majority of customers were restored within 24 hours of the completion of the storm, with 85% of customers restored within 48 hours, and the full restoration of PowerStream's service territory being realized on December 30, 2013.

Most importantly, the restoration efforts were completed without a serious injury to PowerStream staff or the general public.

This ice storm was by far the most severe outage event in PowerStream's ten-year history, based on the number and duration of customer outages. For comparison:

- The tornado that passed through Vaughan in August 2009 impacted approximately 2,200 customers, and had an outage duration of up to 12 hours for some customers
- Superstorm Sandy in October 2012 affected approximately 43,000 customers, and some customers had an outage duration of up to 2 days
- The July 2013 rain storm and related flooding impacted approximately 38,000 customers, and had an outage duration of up to 8 hours for some customers

This review was initiated by the Executive Management Team to facilitate continuous improvement efforts, an important part of PowerStream's Journey to Excellence. The purpose for the review was to identify lessons learned (specifically, what were the successes, what strengths can be built upon and what are the best opportunities for improvement), and develop action plans to enhance performance for the next time a major incident occurs. Information was gathered from internal personnel, municipalities, and customer feedback, in order to get different perspectives on PowerStream's performance during this event.

While there were many successes throughout the restoration, including the speed at which the priority sites were re-energized and the overall performance of PowerStream management and staff, there were also many lessons learned that are outlined in this report that have been prioritized and will be acted upon.

The key findings and 35 action items in this report are intended to enhance PowerStream's emergency restoration and communication efforts, and focussed around external communications, customer care, emergency restoration and capital asset management.

The following are some of the key improvements that will be acted upon by PowerStream in response to the lessons learned from the ice storm:

- By June 30, 2014:
  - Increase capacity of the corporate website (completed)
  - Implement a new online Outage Map with increased capacity
  - Develop a process to determine and communicate the estimated time of restoration
  - Create a new position for an Emergency Preparedness Manager and provide refresher training on the Electrical Emergency Preparedness Plan to staff in supporting roles

- By December 31, 2014:
  - Introduce a “one number” solution that combines the corporate and outage phone systems, including enhancements to the Interactive Voice Recognition System
  - Implement a new process utilizing smart meter functionality to assist with identification of “nested outages”
  - Develop an electronic tool for the Electrical Emergency Preparedness Plan, which refines the roles & responsibilities for all departments under various outage events
  - Analyze and, based on consideration of any upfront capital cost, corresponding customer rate increases and expected customer benefits, provide recommendations for improvements to PowerStream’s distribution grid to make the system more resilient to these types of events

- By March 31, 2015:
  - Investigate an external call centre that could be utilized to increase the number of live agents during significant outage events (currently engaged with a third-party service provider to determine options and pricing)

By implementing these and other improvements contained in this report, and by leveraging the many successes demonstrated throughout the ice storm response, PowerStream will be better prepared for and better able to respond to similar events in the future, for the benefit of the customers and communities it serves.

3.0 Methodology

PowerStream's review of the ice storm restoration and communication efforts was completed in the first quarter of 2014 as part of a focus on continuous improvement. This report has taken an overall risk management approach, with consideration given to the cost-benefit of the action plans. For every incremental mitigation strategy put in place, there is a corresponding cost, which needs to be weighed against the potential benefits, such as increased system reliability, reduced outage durations or increased customer satisfaction. PowerStream intends to find an appropriate balance, as these costs have a direct impact on the distribution rates that are charged to customers.

A total of 35 interview sessions were held with approximately 50 PowerStream personnel, which covered a cross-section of all departments that were involved in the ice storm restoration and communication efforts, including Lines, System Control, Engineering, Customer Service and Corporate Communications.

In order to ensure that this review incorporated feedback from external stakeholders, a survey was distributed to municipal staff, Councillors and Mayors for the municipalities that PowerStream serves. Further, social media posts on Facebook and Twitter were examined to get feedback that was provided directly from customers during the ice storm and restoration period.

To validate the internal findings and action items, Navigant Consulting Ltd. ("Navigant") has provided an independent assessment of this internal review (Section 1.0). Navigant compiled a team of industry experts, who examined the findings contained in the report to ensure the comprehensiveness of the review and appropriateness of the actions.

PowerStream has setup an internal "Ice Storm Task Force", which is in charge of coordinating the improvement initiatives identified in this report, and ensuring that the action items are implemented in an effective and timely manner. Periodic updates will be provided to PowerStream's Board of Directors through to the complete implementation of all action items contained in this report.

4.0 Successes

PowerStream's staff and management team came together in very tough circumstances, with many giving up their vacation or holidays. Everyone worked to their full potential, and all actions were focussed on the customer. The teamwork and collaboration between departments was an area where PowerStream excelled, and the restoration would not have been completed by December 30th without the hard work and dedication of those involved.

Prior to the start of the ice storm, System Control began tracking the weather event through a subscribed advanced meteorological service. This advanced tracking allowed Corporate Communications to issue a news release days prior to the ice storm, giving customers advanced notice of the potential severity, and tips to prepare for an extended outage should it occur. This pre-emptive communication garnered attention from City TV's Breakfast Television, which shared PowerStream's message with viewers throughout their broadcast area.

On the morning of Sunday December 22nd, once the storm had settled and the extent of damage became apparent, key management and staff personnel were onsite and the President & CEO assumed leadership of the Crisis Management Group meetings in System Control, to get updates on the status, develop incident-specific action plans and delegate responsibilities. These meetings were essential in keeping the restoration and communication efforts on track, especially given the severity of damage and the number of customers that were without power.

System Control worked closely with the affected municipalities, through their Emergency Operations Centres, to prioritize key public safety areas, such as hospitals, fire stations and water plants. Most community priority safety locations were restored upon restoration of the main line feeders, and coordination continued with municipalities throughout the restoration effort to identify any emerging health and safety locations that needed further attention. Restoring main line feeders also restored power to the greatest number of customers in the shortest amount of time, as evidenced by the restoration performance, with 85% of the 92,000 customer outages at the peak being restored within the first 48 hours.

Chart indicating the number of PowerStream customer outages during the ice storm restoration

Another area that repeatedly came up during this review was the customer-focus throughout the event. Everyone's efforts were devoted to making a positive impact on the customer. Many staff gave up their holiday season in order to restore power to as many customers as possible so they were able to enjoy the time with their families. The selflessness of the people involved is something that has been commended and should not be forgotten.

There were many technical issues that arose during the restoration efforts, and PowerStream management and staff remained flexible in being able to adapt given the challenges at hand. When the corporate website was overwhelmed by the volume of hits, a "Storm Centre" landing page was developed while work was underway to increase the web server capacity. The same resilience was demonstrated with respect to several other unexpected challenges that impeded the restoration and communication efforts.

Most importantly, the restoration efforts were completed without a serious injury to PowerStream staff or the general public. Given the extent of damages, weather conditions and the fast changing environment, this was a significant accomplishment.

These successes, along with the Key Findings outlined in the next section, will allow PowerStream to better serve its customers during significant events in the future.

5.0 Key Findings

While there were many successes throughout the ice storm restoration period, there were also many improvement opportunities that were identified. These areas of improvement are intended to enable PowerStream to better prepare for and respond to similar events in the future.

5.1 External Communications

PowerStream received a significant amount of feedback surrounding the quality of communication during the ice storm. Specifically, there was a need for timely and accurate information to be provided to the affected municipalities, as well as providing customers with updates on outages and restoration timelines. Additional challenges included getting sufficient media attention given the media focus on Toronto, dealing with the volume of messaging on social media, and advising customers of the demarcation point for electrical asset ownership and their associated responsibilities.

5.1.1 Outage Notifications

During the ice storm, customers were required to view PowerStream's website or make a call to the outage phone system or Call Centre in order to get information for their specific location. Customer access to this information was hindered by technical issues associated with the phone system and website, which are discussed later in this report.

An initiative that was already underway when the ice storm hit is the implementation of the automated Outage Notification Service. The Outage Notification Service is an email-based system that will be made available to all customers who register, and will utilize the existing Outage Management System to proactively send messaging to customers when an outage occurs at their location. The information provided will include an update notification (if there is a significant change in the incident) and a final notification when the power is restored.

During an emergency situation, this automated messaging will help provide accurate and up-to-date information directly to customers, and will also help to alleviate the volume of calls and requests going through the automated phone system and Call Centre.

The Outage Notification Service is currently operating as a pilot project, to ensure the system is working as intended and to get feedback on the messaging from the pilot group. The notices are very technical and efforts are being made to make them more customer-friendly. Management is also investigating the ability to utilize text messages for these notifications in additional to email. It is anticipated that this service will be rolled-out to all customers before the end of 2014.

Action Items:
- *Roll-out of Outage Notification Service, including making notices more customer-friendly and investigating the ability to utilize text messages in addition to emails (September 30, 2014)*

5.1.2 Restoration Notification

Currently, the Interactive Voice Recognition System is designed to take calls to help customers determine if there is a known outage in their area, or to report a new outage. This information is then fed into the Outage Management System to provide System Control with an up-to-date view of all outages in the service territory. One limitation of this system is that it is not designed to provide a restoration notification to customers when the power is restored.

The Outage Notification Service (Section 5.1.1) will alleviate some of the issues associated with this lack of outage updates being pushed out to customers, but only for those that register for the service when it goes live. For other customers who do not register or do not have email access, PowerStream will be investigating the feasibility for customers to leave a call back number in the Interactive Voice Recognition System, which would trigger automated calls to advise the customer that their outage information was received and when the power is restored at their location.

Action Items:
- *Identify what systems and processes would need to be implemented, along with the associated costs, in order to take and respond to call-back numbers for customers who report outages on the Interactive Voice Recognition System (September 30, 2014)*

5.1.3 Communication Channels

Mass communication during an event is intended to provide an overall update on the extent of damage (including location and approximate number of outages), inform customers of the process for reporting an outage and to provide safety messaging to ensure protection of the general public.

During the ice storm, it was difficult getting attention from Toronto-based media to communicate to customers as many of those media outlets were focussed on the situation in Toronto. In order to ensure appropriate communication for similar events in the future, PowerStream will be developing a mainstream media strategy to facilitate communications through Toronto-based media especially when an event includes Toronto.

Given the inconsistent attention in the mainstream media during the ice storm, PowerStream heavily leveraged social media to connect with customers. This included a strong presence on both Facebook and Twitter. These social media sites were being managed and monitored by at least one PowerStream representative on a 24-hour basis, in order to provide general updates as well as to respond to specific customer inquiries. However, given the tremendous volume of messages that PowerStream received over the duration of the event, it was not possible to provide responses to all customers. Consequently, PowerStream will develop a social media strategy that will leverage best practices from this emerging communication technology to enable PowerStream to effectively deal with the volume of messages and provide the best information to customers in situations where wide-spread power outages occur.

In the event electronic communication infrastructures are compromised in any future emergency situation, and in order to reach a wider customer group (with a specific focus on vulnerable individuals such as senior citizens), PowerStream will also utilize more basic communication channels. This will include strategies such as door-to-door flyer distribution, signs on major roads and loudspeakers. PowerStream will also work more closely with outreach groups, community centres and municipalities. Specific to the municipalities, as part of this Ice Storm Review it became evident that Councillors have other channels for direct communication with their constituents, and that leveraging this resource for future events would be invaluable.

Action Items:

- *Develop emergency communication strategy for mainstream media, social media and basic communication channels during emergency situations (June 30, 2014)*

5.1.4 Coordination with Municipalities

The primary communication channel between PowerStream and the municipalities affected by the ice storm was the municipal Emergency Operations Centres. The municipal Emergency Operations Centres coordinate with the emergency services (fire, police and medical services) and are in direct contact with System Control to provide priority sites that require immediate attention for the restoration effort.

While the communication with municipal Emergency Operations Centres was effective, there needed to be more structured communication with other municipal stakeholders, such as municipal staff and Councils. One area that was identified for improvement would be to offer a PowerStream representative to act as a liaison with the municipal stakeholders and as a resource for answering questions relating to PowerStream’s distribution system or restoration process.

On an ongoing basis, there is the potential for enhanced education for municipal staff and Councils on PowerStream's distribution system, emergency protocols and other relevant information. Similar information packages have been provided in the past to members of PowerStream's Board of Directors. PowerStream will work with municipal staff to share this pertinent information, with a goal to enhance coordination and communication efforts for when the next significant event occurs.

Action Items:

- *Identify and train internal personnel qualified to act as a liaison between PowerStream and the municipal stakeholders during an emergency event (September 30, 2014)*
- *Increase knowledge of utility and emergency preparedness by developing an education package for municipal staff and Councillors (March 31, 2015)*

5.1.5 Education for Customers on the Demarcation Point

Demarcation is the point at which PowerStream's distribution system ends and connects with the customer's own electrical wiring. Typically, for residential customers the demarcation point is the top of the customer's service mast for overhead services or the line side of the customer's meter base for underground services.

During the ice storm, multiple customers with overhead services had damage caused to their service masts and were not aware that this piece of equipment is not the property of PowerStream. Legislated requirements are in place requiring that the customer make repairs to their equipment through an Electrical Safety Authority approved and licensed electrician, and provide the distribution company with proof of inspection from the Electrical Safety Authority prior to reconnection of the service by the utility.

PowerStream worked closely with the Electrical Safety Authority and customers with damage to their electrical equipment in order to provide information on these requirements, and to ensure that their property was re-energized once the proof of inspection was received.

Example of damaged service mast which would fall under the responsibility of the customer (Source: http://www.esasafe.com/consumers/safety-at-home/safety-tips-for-after-a-storm)

Going forward, PowerStream will develop a communication strategy to educate customers by providing information relating to the demarcation point (including customer-owned primary laterals) and customer responsibilities. The intent of this customer education is to ensure that these responsibilities are clear and understood, to avoid confusion or additional delays in restoration during events such as an ice storm.

Action Items:

- *Develop a communication strategy to educate customers on the demarcation point for asset ownership and associated responsibilities (November 30, 2014)*

5.2 Customer Care

Given the volume of customer outages during the ice storm, PowerStream's Customer Service department faced many challenges in providing information and assistance to customers. This section identifies the findings related to these systems and processes, relative to handling outage events.

5.2.1 Interactive Voice Recognition System

Customers experienced many frustrations with the Interactive Voice Recognition System, specifically with registering the outage location based on voice prompts from the customer and difficulty getting through to a live agent when the automated system was not able to respond to their concerns.

Currently, PowerStream has two separate phone systems – the corporate line, used predominantly for account and billing related queries, and the outage line, used for identifying if there is a known outage or reporting a new outage. There are two distinct numbers to access these phone systems, and a customer cannot transfer from the outage line to a live agent without having to re-dial through to the corporate line.

A proposed enhancement to the Interactive Voice Recognition System, which was in the planning stages prior to the ice storm event, is the introduction of a "one number" system. This solution has multiple customer-facing benefits, such as:

- Customers only need to know one phone number to get through to PowerStream for all inquiries;
- The option for PowerStream to re-direct outage calls to a live agent; and
- An enhanced ability to customize the messaging on the Interactive Voice Recognition System for events such as mass outages, to encourage customers to use the corporate website or social media sites for additional information.

Subsequent to the ice storm, PowerStream has completed a third-party review of the capacity of the corporate phone systems, and will be implementing an infrastructure upgrade and scalable trunking to increase the number of available lines dynamically as required during normal operations and for emergency events. Further, the functionality of the menus and voice recognition capability on the Interactive Voice Recognition System is currently being examined with a service provider experienced in this subject matter, in order to identify additional enhancements that will be implemented to better serve customers.

Action Items:

- *Roll-out of "one number" solution that combines the corporate and outage Interactive Voice Recognition System (July 31, 2014)*
- *Implementation of phone system infrastructure upgrade and scalable trunking to increase phone system capacity (September 30, 2014)*
- *Review of functionality of the menus and voice recognition on the Interactive Voice Recognition System (June 30, 2014)*

5.2.2 Resourcing of Call Centre

As mentioned above, customers were not satisfied with the challenges they faced when trying to speak to a live agent to discuss their concerns and get information during the ice storm. While automated systems are effective in dealing with a significant portion of customer concerns, there is an expectation that a live agent will be available during an emergency situation. PowerStream effectively dealt with this issue by extending Call Centre hours starting on December 23rd and switching to a 24-hour Call Centre on December 26th. However, feedback received from customers indicates that this should have been initiated earlier.

Customer Service should plan to have Call Centre staff available immediately following a significant outage event. For events that are of the scale of the ice storm, having 24-hour service is essential to provide assurance to customers that PowerStream understands their situation and is working around the clock to provide support and restore power.

During the ice storm restoration period, access to the Outage Management System and smart meter pinging tools was rolled out to Customer Service. This proved to be a valuable tool in recording outages or providing updates to customers, and also took some of the workload off of System Control. Going forward, it is recommended that access to these tools be granted to Customer Service staff, and that they be provided with periodic training to ensure the tools can be used effectively when there are significant outages.

To ensure an adequate number of live agents are available when needed, management has committed to examining the feasibility of utilizing an external call centre for dealing with emergency call volumes. The external call centre could be opened as soon as possible in the early stages of the emergency and scaled to accommodate more lines on demand. Should the external call centre not proceed, then management will coordinate additional staff support from other departments to supplement existing Customer Service staff in the Call Centre during an emergency situation. These staff, while not trained to deal with customer calls, would receive basic training and be utilized to represent PowerStream and provide information or record concerns.

Action Items:

- *Establish resourcing of the Call Centre to operate on extended hours (24-hours if needed) immediately following a significant event (September 30, 2014)*
- *Roll-out of Outage Management System and smart meter pinging tools to Customer Service, along with appropriate training (August 31, 2014)*
- *Investigate the option of utilizing an external call centre for emergency call volumes (March 31, 2015)*
- *Investigate the ability to utilize other internal staff (Accounting, Human Resources, Information Services, etc.) to supplement existing Call Centre resources during an emergency situation (December 31, 2014)*

5.3 Emergency Restoration

PowerStream's emergency restoration protocols are contained in the Electrical Emergency Preparedness Plan, which is a manual that assigns responsibilities and defines processes to be followed during events that are outside of normal operations. It also contains detailed contact lists for internal personnel, emergency services and municipalities. While PowerStream's restoration efforts during the ice storm were effective, this section outlines findings for continued improvement, including a process for better determining and communicating the estimated time of restoration.

5.3.1 Damage Assessment and Triage

At the completion of the ice storm on the morning of December 22nd, PowerStream Lines crews began the restoration work based on the prioritization schedule in the Electrical Emergency Preparedness Plan. This prioritization is based on securing the distribution assets first (such as transformer stations), then moving on to public safety sites (such as hospitals and water pumping stations), then to main feeders that once restored can get power back on for the most customers. This approach is a generally accepted industry best practice for emergency restoration.

An area where PowerStream received significant criticism was that customers were not able to get an estimated time of restoration, and as such many were left wondering if they should "wait it out" or leave their home.

A recommended change to the restoration management process that came out of this event is performing additional damage assessment and triage prior to carrying out full restoration activities. This damage assessment could be carried out by a combination of Lines and Engineering staff, in order to ensure that an appropriate amount of Lines crews could still be out in the field to start restoration on the top priority sites.

In this new process, after completion of the damage assessment, a team would then review the findings, tabulate total resources required (labour hours, materials, equipment) and prioritize/schedule the remaining outage areas to ensure efficient restoration efforts. Further, once all the damage areas are examined relative to the resources required, System Control should be able to provide a more accurate estimated time of restoration based on grid area. The estimated time of restoration can then be provided to customers, the media and the affected municipalities.

This damage assessment and triage process will be formalized and incorporated into the Electrical Emergency Preparedness Plan.

Action Items:

- *Develop damage assessment and triage process in the Electrical Emergency Preparedness Plan (June 30, 2014)*

5.3.2 System Control Centre Operations and Call Dispatch

Due to the extent of damage and number of customer outages across PowerStream's service territory after the ice storm, System Control and the Lines department were operating 24-hours per day until full restoration was achieved. The main point of contact between System Control and the Lines crews was the Lines Supervisors, who were responsible for overseeing and directing their crew(s) based on direction from System Control.

Given the fast paced work environment and changing conditions, at times there was a lack of coordinated prioritization between System Control and Lines. In some instances the Lines Supervisors had different priorities than the System Control desks, which resulted in Lines crews being re-directed by System Control. Overall, the coordination between System Control and Lines was effective at prioritizing and completing the restoration work, but open communication and a planned restoration action plan would have increased their efficiency.

Some areas of improvement are to ensure clear communication and alignment between System Control and Lines, with a shared understanding of the prioritization efforts and effective tracking of crew availability/location. Some of this will be accomplished through the damage assessment and triage process (Section 5.3.1), as there will be a clear action plan for the restoration efforts agreed to by System Control and the Lines department.

Additional enhancements will also be incorporated into the Electrical Emergency Preparedness Plan for the roles and responsibilities of the System Control management team to ensure appropriate distribution of the workload for emergency events. The types of responsibilities that will be divided include collecting restoration data, communicating with municipal Emergency Operations Centres and managing the Outage Management System.

Action Items:

- *Clarify roles & responsibilities for System Control management in the Electrical Emergency Preparedness Plan (June 30, 2014)*

5.3.3 Resourcing and Work Practices

The speed at which internal and external resources are able to respond once a significant event occurs is important to ensure an efficient restoration. The Lines department utilizes an automated call out system, which is a standard process used for normal outages requiring additional crews. During the ice storm, Lines management began calling the Lines staff directly as the automated call out process was not as effective in getting staff to respond given the urgency of the situation and that it was the holiday season. The personal calls were more effective at conveying the extent of the damage and importance of the crews coming in to assist. For future wide-scale events, personal calls to staff should commence sooner in order to ensure prompt response from a greater number of staff.

With regard to external assistance, there was a strong turnout during this event from regular contractors, as well as contractors and other utilities from across the province. In order to ensure that sufficient external resources can be called upon in future events, the pre-approved vendor list could be increased for emergency backups that can be utilized immediately. Specific vendors that could be added based on the experience during the ice storm include forestry crews and mobile refueling services. The call for support from other Ontario utilities was initiated at the onset of the event, but consideration should be given to requesting assistance from US-based utilities where PowerStream has provided assistance in the past (such as Consumers Energy in Michigan). Having immediate access to other utilities outside of PowerStream's geographic area is especially important for localized weather events.

During the ice storm, material availability was not a major concern as the tree damage primarily resulted in downed secondary wires and there was not significant damage to the primary distribution plant (such as poles and transformers). However, in order to be better prepared for future events, a review of the current contingency stock levels should be initiated. This would include the collaboration of a cross-functional team to examine future requirements based on different events, and to determine the appropriate quantity to have on-hand and for suppliers to have available through contractual commitments.

Action Items:

- *Increase pre-approved vendor list for emergency support during major outages (October 31, 2014)*
- *Enter into emergency assistance agreements with US-based utilities or compile contact list to use in advance of an emergency situation (September 30, 2014)*
- *Review current contingency stock levels and determine requirements for potential outage events (October 31, 2014)*

5.3.4 Electrical Emergency Preparedness Plan

PowerStream's Electrical Emergency Preparedness Plan outlines the protocols, roles and responsibilities for responding to an emergency situation, including the contact lists for internal staff, municipalities and other stakeholders. The document is filed with the Independent Electricity System Operator as part of the Ontario electricity market rules, and a condensed version is provided to the municipalities that PowerStream serves. The documentation contained within the Electrical Emergency Preparedness Plan is updated on a periodic basis when there are significant changes, and practice drills are performed at least annually within System Control.

Currently PowerStream is in the process of developing an electronic program that will contain the Electrical Emergency Preparedness Plan, and make it more user-friendly for accessing the roles and responsibilities for all departments under various types of events. A large part of this initiative will be the refinement of roles and responsibilities for each department, along with incorporation of the lessons learned that are outlined in this Ice Storm Review. The roles and responsibilities will need to be clearly defined relative to the progression of outage response escalation:

- Level 1 – normal operations with minor outage events (i.e. day-to-day)
- Level 2 – escalated PowerStream response for significant outage events
- Level 3 – emergency declaration with the full Electrical Emergency Preparedness Plan in effect

These roles and responsibilities should also clarify the personnel required to be in attendance at the Crisis Management Group meetings.

During emergency situations, staff not directly involved in the restoration or communication efforts are often willing and able to assist in ad hoc roles where needed. In order to better leverage this support, the planned improvements to internal communications (Section 5.3.5) would help advise staff of the situation and make a request for them to come in and provide assistance.

It is essential that training be provided to all key personnel on an annual basis, to ensure that they are aware of their roles and responsibilities in an event, as well as how to access the Electrical Emergency Preparedness Plan. This is especially important given staff turnover and retirements, as the person in a current position may not be the one who developed the documentation in the plan.

By improving the clarity of roles and responsibilities (documented in advance and available to all staff in case of emergency), PowerStream will be able to be more effective and efficient in restoration and communication efforts for future events.

Given the significant responsibilities associated with emergency preparedness, and to ensure PowerStream remains a best-in-class company in this area, a separate position should be created to work closely with the Vice President of Operations on planning, training, exercise development, municipal and regional liaison (both York Region and Simcoe County), maintenance and continual development of the Electrical Emergency Preparedness Plan during normal operations, and to assist with execution of the plan during an emergency situation.

Action Items:

- *Refine the roles & responsibilities for all departments as part of the electronic program for the Electrical Emergency Preparedness Plan (September 30, 2014)*
- *Provide periodic training (once per year) for all key personnel on the Electrical Emergency Preparedness Plan (June 30, 2014)*
- *Develop and implement a new position for Emergency Preparedness Manager (June 30, 2014)*

5.3.5 Internal Communications

Internal communications should be structured, consistent and timely during an emergency situation. The responsibility for corporate-wide communications and customer-facing updates should be more clearly defined in the Electrical Emergency Preparedness Plan.

For corporate-wide updates, there needs to be a clear owner of this task to ensure all management and staff are aware of the event, specifically:

- Advance notice of a significant weather event, communicated clearly and through a channel that will be reviewed prior to the commencement of the weather event;
- Communication to all staff of the nature of the event and the extent of damages/outages, advising all key personnel to report to their normal office location;
- Notification of the roles and responsibilities for the key personnel and departments, whether as part of the normal Electrical Emergency Preparedness Plan or on an as-needed basis resulting from situation specific requests; and
- Periodic updates to all staff throughout the emergency situation.

While there were some updates provided through PowerStream's email distribution lists, ongoing internal communications are essential to ensure that all staff are aware of the event and actively involved where needed.

For customer-facing updates, such as updated outage numbers and estimated time of restoration, there should be a central role in System Control to disseminate this information directly to Customer Service and Corporate Communications. One of the key challenges faced internally was balancing the need to communicate this updated information without causing disruption for System Control in managing the restoration efforts. This is the primary reason for a separate role that would push the information out on a consistent and timely basis, in order to allow all departments to focus on their respective areas of responsibility. Incorporation of time stamps on the outage number updates will also help to clarify when the updates originated, and to ensure that consistent information is available on the corporate website, social media channels, news releases and through the Call Centre.

Action Items:
- *Define role for corporate-wide internal communication of emergency events, and incorporate into the Electrical Emergency Preparedness Plan (September 30, 2014)*
- *Define role for coordination of customer-facing information between System Control, Customer Service & Corporate Communications, and incorporate into the Electrical Emergency Preparedness Plan (September 30, 2014)*

5.4 Capital Asset Management

The ice storm produced significant damage to the tree canopy in PowerStream's service territory. It was this damage to the tree canopy that caused significant damage to the overhead primary and secondary distribution system. The damaged trees came down on the power lines causing outages. There were limited pole or transformer failures, and those that occurred were generally the result of the weight of the collapsed tree canopy and not the ice itself.

In addition, the damages were widespread such that the backup feeders that PowerStream normally relies upon to provide quick restoration of power also experienced failures. A significant number of the failures also occurred in the single phase or secondary lines for which there is no backup and direct restoration was required to re-establish power to the customer. There are a number of ways that PowerStream can consider to effectively "harden" the distribution system against ice storms of this nature and storms in general. These may include changes to the vegetation management program, upgrading of old systems (i.e. rear yard services) to a more conventional design and changes to PowerStream's distribution design standards.

5.4.1 Vegetation Management

PowerStream currently maintains a three-year cycle of vegetation management ("tree-trimming") throughout its service territory. Essentially, this means that vegetation surrounding each section of overhead primary lines on the right-of-way is cut back once every three years. PowerStream's budget for tree-trimming was $1.4 million in 2013, and was increased by approximately 20% to $1.7 million for 2014 when management reviewed the expected workload and costing prior to the start of the current fiscal year. PowerStream will commit to maintaining this three-year cycle for the foreseeable future, to ensure that the tree-trimming program remains at an adequate level.

Currently, the Operations department's objective is to trim for tree contact and right-of-way clearance of the distribution equipment, but not to trim to prevent trees or tree limbs from falling on power lines during a significant weather event. These clearances are required to ensure safe operation of the distribution equipment, and to provide adequate room for maintenance activities. During the ice storm, large limbs and sometimes entire trees came down under the excessive weight of the ice accumulation. While the extent of the damage was mitigated by PowerStream's tree-trimming program, in order to prevent overhead damage in this type of weather event the clearance area would have to be significantly increased, up to and including the proactive removal of entire trees, the vast majority of which reside on private property. There are no current plans to pursue this option.

An area that could be improved is the identification of areas with significant mature tree coverage in order to focus the tree-trimming program. This could be incorporated into the Geographic Information System map to enable cross-referencing against areas with overhead services, thereby providing an overall picture of vulnerable areas throughout PowerStream's territory.

Another area for improvement is better upfront coordination with municipalities to avoid the planting of new trees in the municipal road allowance in the vicinity of power lines, and to encourage customers to acquire qualified foresters to prune trees on private property that could contribute to outages. This will help to mitigate the risk of future outages due to damaged trees in areas outside of PowerStream's direct control.

Action Items:

- *Identify the geographic areas with significant tree coverage to assess vulnerabilities and augment the tree-trimming program (December 31, 2014)*
- *Coordinate with municipalities to avoid tree planting near power lines (June 30, 2014)*
- *Encourage customers to proactively perform tree-trimming on their properties (September 30, 2014)*

5.4.2 Rear Yard Services

Rear yard services have the primary wires, poles and transformers located in customers' back yards, versus the typical front yard service that has the distribution equipment located adjacent to the street. Rear yard services are prevalent in multiple residential subdivisions in PowerStream's service territory, specifically in Markham (including the Thornhill area), Tottenham and some areas of Barrie, and result from historical distribution design standards.

Damage that occurred to the electrical distribution grid in these neighbourhoods was quite extensive, especially in the Thornhill area of Markham. Further, when Lines crews went to work in these areas, there were additional challenges such as gaining access through frozen gates and getting the necessary equipment and machinery in place to make repairs.

As a result, customers with rear yard service generally faced the longest restoration times, with some being out of power for up to a week.

Lines crew clearing tree limbs and debris from a rear yard service during the ice storm restoration

In 2013, PowerStream analyzed all neighbourhoods containing rear yard services, and is reviewing the potential change to front yard service on a case-by-case basis. As these services have generally provided reliable service for many years, this type of decision would be made when the existing plant is nearing the end of its useful life and would otherwise require replacement. There are considerable cost implications that must be factored into this decision, along with potentially complex customer conversion issues that must be examined as well. The current long-term program would remediate all rear yard services by 2030. Management will review this plan to re-assess the approach and timeline given the events that occurred during the December 2013 ice storm.

Action Items:

- *Prepare a report analyzing the current 15-year remediation plan for rear yard services and making recommendations on the appropriate approach and timing, with the results to inform the next rate application in Q2 2015 (December 31, 2014)*

5.4.3 Distribution Design Standards

One of the areas that received heavy criticism from the media, municipalities and the general public is the use of overhead distribution systems. Given the extensive tree damage caused by this event, the overhead distribution equipment was simply not able to remain energized once the limbs and trees came down on the lines. As such, there is a perception that constructing the distribution system fully underground will significantly reduce outages for all events.

Example of overhead distribution system (left), as well as residential padmount transformer associated with an underground distribution system (right)

An underground distribution system is significantly more expensive than an overhead system. A recent PowerStream project estimated the cost differential of underground service at approximately eight times that of an overhead system, with other industry studies within a similar range (depending on greenfield versus urban, amount of underground congestion, number of customer connections, etc.). Further, retrofitting an underground distribution system around existing transit ways, residential neighbourhoods and commercial properties would increase cost, complexity and the time to install. Moving distribution equipment underground would have reduced the extent of outages for the December 2013 ice storm. However, this does not mean that an underground distribution system is free of risks – overall it is more susceptible to flooding, and while the frequency of outages is reduced, the average duration of outages is longer compared with an overhead service.

PowerStream will perform a review of the upfront capital cost and corresponding customer rate increases of fully undergrounding the distribution system, in order to determine the merits of this design change. Further, PowerStream will continue to consider system hardening options for specific areas with significant risk due to the geographic layout or for customers with sensitive/priority loads. This could include considerations for overhead versus underground, design of the feeders, redundant circuits, design of the structures, design of the right-of-ways, or other hardening techniques appropriate for the specific area.

Action Items:

- *Prepare a report analyzing the cost estimates and customer rate impact for fully undergrounding PowerStream's overhead distribution system, with the results to inform the next rate application in Q2 2015 (December 31, 2014)*
- *Review and provide recommendations on opportunities for making the distribution system more resilient for vulnerable areas, with the results to inform the next rate application in Q2 2015 (December 31, 2014)*

5.5 Technical Issues

During the ice storm, PowerStream faced several technical issues associated with its systems. Most of these issues caused varying levels of dissatisfaction with customers, and, where possible, PowerStream staff developed and implemented mitigation strategies during the ice storm restoration period. The goal of this section is to ensure that these key systems are able to operate effectively in providing the intended assistance to customers and support to internal personnel during significant outage events.

5.5.1 Outage Management System

PowerStream's Outage Management System utilizes the Telvent Responder software to track incidents reported through the Interactive Voice Recognition System, the Supervisory Control and Data Acquisition system (communication mediums and protocols used to monitor and control all assets on the PowerStream distribution system) and smart meter network, in order to have a continuously up-to-date listing of outages throughout the service territory. This system also utilizes Geographical Information System information of PowerStream's physical distribution grid to provide the electrical connectivity model for the system and to reflect the status of switches and fuses.

At the onset of the ice storm, the Outage Management System was overrun with approximately 3,200 data calls per hour, which caused system performance issues (system lagging or the client application crashing) for System Control. Since the majority of outages occurred in the first several hours of the storm, the Outage Management System had to process all of these incidents in a short period of time, and the infrastructure was not able to effectively handle this load.

A planned system upgrade is scheduled for October 2014, which will increase the throughput of the back-end server and implement minor software functionality improvements. This upgrade will increase the Outage Management System's ability to handle incidents from 600 (current) to 4,000 data calls per hour, and is expected to increase the resiliency for future events of a similar scale to the ice storm.

Further enhancements to the Outage Management System are also in the planning stage to improve the detail of outage information provided on the Interactive Voice Recognition System. Currently for callers who have not gone through the verification process (for their service address or PowerStream account number), the outage information is provided by municipality, whereas the enhancements would provide better identification such as street names or intersections. Improving the clarity of the outage location will allow customers to more easily verify whether their address is affected by the outage.

Action Items:

- *Implement system upgrade for the Outage Management System software/hardware to increase capacity to handle 4,000 data calls per hour (October 15, 2014)*
- *Implement Outage Management System enhancements to provide more location-specific information for customers on the Interactive Voice Recognition System (December 31, 2014)*

5.5.2 Corporate Website

On Monday December 23rd, PowerStream's corporate website (http://www.powerstream.ca) received approximately 2.5 million hits, compared to the average website traffic of approximately 8,000 hits per day during normal operations. Given this tremendous increase in volume, the website server was not able to handle the information requests, resulting in visitors receiving denial of service messages or significant delays in loading webpages.

Given that the corporate website is one of the main avenues for providing customers with information, keeping it running is essential. To reduce the demands on the system, a Storm Centre landing page was created, which gave general information without requiring viewers to load multiple pages. Further, the Information Services department, along with support from key vendors, increased the thread counts from 40 to 200 and added 8 gigabytes of memory allocated for the web server. This prompt response ensured that the corporate website was able to be accessed for the remainder of the event.

On a go-forward basis, the increased capacity of the website server thread counts and memory allocation will be retained.

Action Items:

- *Increase capacity for website (200 thread counts and an additional 8 gigabytes of memory allocation for the web server) (COMPLETE)*

5.5.3 Outage Map

The Outage Map, which is hosted on PowerStream's corporate website (http://weboutage.powerstream.ca), experienced a significantly increased number of visitors and also had to process more than 1,000 incidents (representing up to 92,000 customer outages) for display on the interactive map. As a result, customers viewing the Outage Map often received error messages or significant delays in loading the webpage.

The Outage Map should be available throughout emergency situations, as it is an easy-to-use tool for providing automated updates to customers for outages in their area, without putting additional strain on the live agents in the Call Centre.

PowerStream will be implementing a cloud-based and scalable solution that works on both desktop and mobile devices. This project will ensure that the Outage Map will have adequate resilience to handle more incidents and higher volume of visitors.

Action Items:

- *Implement a cloud-based and scalable Outage Map that works on both desktop and mobile devices (June 30, 2014)*

5.5.4 Advanced Metering Infrastructure Functionality

Another issue encountered during the ice storm was the process for clearing outages upon the restoration of a main feeder. The current process for treating these incidents in the Outage Management System relies on the smart meter "last gasp" communications and automated switching in order to effectively track customer outages. This process works well under normal outage situations, due to the smart grid and remote switching functionality currently in place, in which power is generally restored within a short timeframe.

During the ice storm, damaged trees falling on power lines caused significant damage to primary and secondary service run-offs that connect individual or groups of customers. Given that the customers' smart meters had been out of power for an extended period of time, there was no communication being routed through the Advanced Metering Infrastructure as the smart meters were fully discharged. As a result, these customers remained without power even after the feeder was restored (this scenario is referred to as "nested outages"), while the Outage Management System reflected that power had been restored to all customers on that feeder. Several customers who called in to the Interactive Voice Recognition System or Call Centre were notified that power had been restored at their location, when in fact the information provided was incorrect as their property was part of a nested outage.

Prior to the ice storm, System Control had been investigating improvements to this process, and is committed to improving the utilization of Advanced Metering Infrastructure functionality within the Outage Management System in order to rectify this issue. Developing a process to send mass pings to the smart meters in the area will help the Outage Management System identify the location of nested outages, and update the outage information accordingly. This will ensure that outage information provided to customers is as accurate as possible.

Action Items:

- *Develop and implement a process for interrogating smart meters to identify and report on nested outages in the Outage Management System (December 31, 2014)*

5.5.5 Systems Development

PowerStream's systems utilized in emergency management have been discussed throughout this report. Within each system there are many complex interfaces to ensure that information is shared and utilized in an effective manner. When there are software changes it is imperative that all interfaces are tested to ensure compatibility and robustness of the overall system.

The current practice of assigning dedicated professional project managers from the Project Management Office to cross-functional projects should continue in order to ensure that these highly critical projects receive the attention and resources required. This dedication and focus will help the team fully understand the implications of their changes, and ensure coordination with the cross-functional stakeholders from the affected business units.

Further, for any systems that are required for emergency management the internal Business Requirements Document will now require performance metrics for dealing with volumes associated with events such as the ice storm. Performance testing of the systems should be executed to ensure that the system remains operational based on that pre-determined volume, and any significant deficiencies will need to be rectified before the system is put into production.

Information Services, working in conjunction with business units, and with the support of the Project Management Office, will implement performance testing criteria, where applicable, by simulating load and transaction volumes to agreed upon peak levels, and report performance metrics to business stakeholders, requiring approval prior to the system being accepted into production.

Action Items:

- *Incorporate business requirement for system development to undergo performance testing based on pre-determined volumes before being put into production (September 30, 2014)*

Appendix – PowerStream Action Items

The following table summarizes the action items for PowerStream to implement in response to the December 2013 Ice Storm:

#	Action Item	Section Reference	Timeline for Implementation
1	Roll-out of Outage Notification Service, including making notices more customer-friendly and investigating the ability to utilize text messages in addition to emails	5.1.1	September 30, 2014
2	Identify what systems and processes would need to be implemented, along with the associated costs, in order to take and respond to call-back numbers for customers who report outages on the Interactive Voice Recognition System	5.1.2	September 30, 2014
3	Develop emergency communication strategy for mainstream media, social media and basic communication channels during emergency situations	5.1.3	June 30, 2014
4	Identify and train internal personnel qualified to act as a liaison between PowerStream and the municipal stakeholders during an emergency event	5.1.4	September 30, 2014
5	Increase knowledge of utility and emergency preparedness by developing an education package for municipal staff and Councillors	5.1.4	March 31, 2015
6	Develop a communication strategy to educate customers on the demarcation point for asset ownership and associated responsibilities	5.1.5	November 30, 2014
7	Roll-out of “one number” solution that combines the corporate and outage Interactive Voice Recognition System	5.2.1	July 31, 2014
8	Implementation of phone system infrastructure upgrade and scalable trunking to increase phone system capacity	5.2.1	September 30, 2014
9	Review of functionality of the menus and voice recognition on the Interactive Voice Recognition System	5.2.1	June 30, 2014
10	Establish resourcing of the Call Centre to operate on extended hours (24-hours if needed) immediately following a significant event	5.2.2	September 30, 2014

11	Roll-out of Outage Management System and smart meter pinging tools to Customer Service, along with appropriate training	5.2.2	August 31, 2014
12	Investigate the option of utilizing an external call centre for emergency call volumes	5.2.2	March 31, 2015
13	Investigate the ability to utilize other internal staff (Accounting, Human Resources, Information Services, etc.) to supplement existing Call Centre resources during an emergency situation	5.2.2	December 31, 2014
14	Develop damage assessment and triage process in the Electrical Emergency Preparedness Plan	5.3.1	June 30, 2014
15	Clarify roles & responsibilities for System Control management in the Electrical Emergency Preparedness Plan	5.3.2	June 30, 2014
16	Increase pre-approved vendor list for emergency support during major outages	5.3.3	October 31, 2014
17	Enter into emergency assistance agreements with US-based utilities or compile contact list to communicate with in advance of an emergency situation	5.3.3	September 30, 2014
18	Review current contingency stock levels and determine requirements for potential outage events	5.3.3	October 31, 2014
19	Refine the roles & responsibilities for all departments as part of the electronic program for the Electrical Emergency Preparedness Plan	5.3.4	September 30, 2014
20	Provide periodic training (once per year) for all key personnel on the Electrical Emergency Preparedness Plan	5.3.4	June 30, 2014
21	Develop and implement a new position for Emergency Preparedness Manager	5.3.4	June 30, 2014
22	Define role for corporate-wide internal communication of emergency events, and incorporate into the Electrical Emergency Preparedness Plan	5.3.5	September 30, 2014
23	Define role for coordination of customer-facing information between System Control, Customer Service & Corporate Communications, and incorporate into the Electrical Emergency Preparedness Plan	5.3.5	September 30, 2014
24	Identify the geographic areas with significant tree coverage to assess vulnerabilities and augment the tree-trimming program	5.4.1	December 31, 2014

25	Coordinate with municipalities to avoid tree planting near power lines	5.4.1	June 30, 2014
26	Encourage customers to proactively perform tree-trimming on their properties	5.4.1	September 30, 2014
27	Prepare a report analyzing the current 15-year remediation plan for rear yard services and making recommendations on the appropriate approach and timing, with the results to inform the next rate application in Q2 2015	5.4.2	December 31, 2014
28	Prepare a report analyzing the cost estimates and customer rate impact for fully undergrounding PowerStream's overhead distribution system, with the results to inform the next rate application in Q2 2015	5.4.3	December 31, 2014
29	Review and provide recommendations on opportunities for making the distribution system more resilient for vulnerable areas, with the results to inform the next rate application in Q2 2015	5.4.3	December 31, 2014
30	Implement system upgrade for the Outage Management System software/hardware to increase capacity to handle 4,000 data calls per hour	5.5.1	October 15, 2014
31	Implement Outage Management System enhancements to provide more location-specific information for customers on the Interactive Voice Recognition System	5.5.1	December 31, 2014
32	Increase capacity for website (200 thread counts and an additional 8 gigabytes of memory allocation for the web server)	5.5.2	COMPLETE
33	Implement a cloud-based and scalable Outage Map that works on both desktop and mobile devices	5.5.3	June 30, 2014
34	Develop and implement a process for interrogating smart meters to identify and report on nested outages in the Outage Management System	5.5.4	December 31, 2014
35	Incorporate business requirement for system development to undergo performance testing based on pre-determined volumes before being put into production	5.5.5	September 30, 2014

PowerStream

Hardening the Distribution System against severe storms

Final Report

October 2014

T000320A

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PowerStream

HARDENING THE DISTRIBUTION SYSTEM AGAINST SEVERE STORMS
FINAL REPORT

Prepared by : Walter Lionel Franco, P. Tech.

Ted P. Wojcinski, P. Eng.

Verified by : Denis Chartrand, Eng.

T000320A
October 3rd, 2014

7880 Keele Street, Suite 201
Vaughan ON L4K 4G7
CANADA

Phone : 905-695-1005
Fax : 905-695-0525
www.cima.ca

Executive Summary

This report presents various options, for PowerStream's consideration, to effectively "harden" the distribution system against ice storms and severe weather in general. Options include enhancements to vegetation management practices, distribution design, standards, operations, third party interactions, a strategic undergrounding program, and the upgrade of existing systems to present day standards (i.e. rear yard services).

The report is structured in seven parts:

1. *A review of climate change impacts and the need to adapt to changing weather conditions in the PowerStream service territory*
2. *A review of the North American practices and papers to harden distribution systems against various forms of severe weather*
3. *A summary of the consultations with PowerStream staff on the impact of severe weather, their current experiences and their ideas to harden the distribution system*
4. *A review and analysis of PowerStream's current practices with respect to designing, constructing, maintaining and operating the distribution system in changing climate conditions. Practice enhancements for potential adoption are summarized*
5. *A summary of practice enhancements prioritized for adoption consideration with high level budgetary Capital and OM&A impacts where appropriate or available.*
6. *Appendices*
7. *Reference list of the various documents reviewed in the development of the report*

Going forward, PowerStream's distribution system is expected to be primarily impacted by severe changing weather conditions related to:

1. *Temperature*
2. *Heavy Rain/Flooding*
3. *High Wind velocity/Wind gusts*
4. *Tornadoes*
5. *Freezing Rain*

Climate change projections show primarily increased probabilities of occurrence (return times) in the categories listed above. Magnitude of events experienced may increase slightly. The distribution system can be adapted to the increased frequency of occurrence and variations in magnitude.

Many North American utilities have developed programs to “harden” their distribution systems against increasing effects of severe weather such as hurricanes, ice storms, etc. Most programs consist of enhanced vegetation management programs and construction standards. Resiliency measures are also developed, hand in hand with hardening, to bring the distribution system back on-line as soon as possible after a severe weather event.

PowerStream’s current practices are considered “good utility practices” as defined in the OEB Distribution System Code. Enhancements to practices are suggested and will demonstrate “best in class” performance.
Practice enhancements have been developed into specific recommendations where appropriate. Recommendations are grouped into 3 key categories:

1. *Vegetation Management*
2. *Strengthening the Distribution System*
3. *Securing Stations*

The recommendations are prioritized within each category and have been assessed for cost and impact to provide a high level perspective for program development options and tradeoffs. Some of the programs have suggested paces to provide for consistent spending while delivering results within a reasonable timeframe that demonstrates progressive hardening of the distribution system. Program selection to be determined by PowerStream through budgetary and rate recovery processes.

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APPENDIX

REFERENCES

1. CHANGING CLIMATE IMPACTS ON POWERSTREAM SERVICE TERRITORY

1.1 CURRENT WEATHER NORMS

The two areas PowerStream serves have distinct characteristics. PowerStream north (Barrie and satellite communities) is located for the most part in County of Simcoe, while PowerStream south (Vaughan, Richmond Hill, Markham and Aurora) is located in the southern part of York Region. The two service areas are not contiguous. The service areas are about 45 minutes' drive from each other along Highway 400.

The PowerStream South service area has a humid continental climate (Köppen climate classification Dfa[1]) with four distinct seasons featuring cold, somewhat snowy winters and hot, often humid summers. Precipitation is moderate and consistent in all seasons, although summers are a bit wetter than winter due to the moisture from the Gulf of Mexico and the Great Lakes.

The PowerStream North service area has warm and sometimes hot summers with cold, longer winters (Köppen climate classification Dfb[2]) with roughly equal annual precipitation as the PowerStream south service area. Along the eastern shores of Georgian Bay (Penetanguishene area), frequent heavy lake-effect snow squalls increase seasonal snowfall totals upwards of 3 m (120 in). Barrie is on the southern edge of this snowbelt region.

The Köppen climate classification is the most widely used climate classification system. See figure 1 for Canada map of the Köppen climate classification.

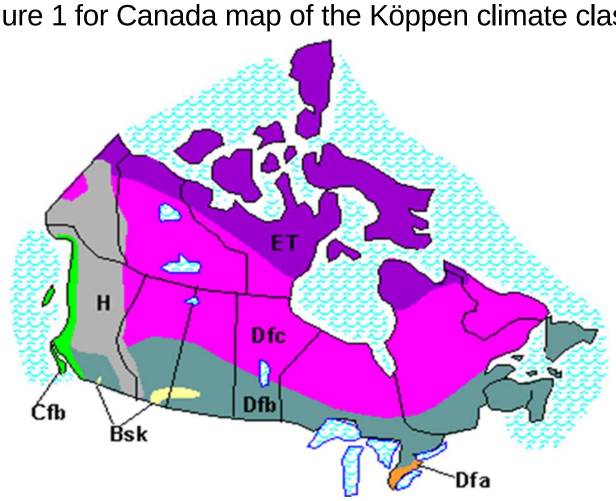

FIG 1. KÖPPEN CLIMATE CLASSIFICATION – CANADA[3]

1 http://en.wikipedia.org/wiki/Woodbridge,_Ontario
2 http://en.wikipedia.org/wiki/Barrie
3 http://www.rossway.net/Koppengeiger.htm

In both areas the proximity to the Great Lakes moderates winter temperatures but also results in significant snowfall in the general area. The Great Lakes moderation also results in higher autumn and winter precipitation. Autumn can also bring hurricane remnants and heavy precipitation.

Data from the Barrie Water Pollution Control Centre WPCC weather station (Environment Canada, 2010)[4] shows that the total annual precipitation (~925 mm) has decreased slightly (10 mm) over the 31 years of record (1978 – 2008). The total winter precipitation (~225 mm) has remained unchanged. The Total summer precipitation (~275 mm) has increased by 50 mm. Precipitation during the 2013-2014 winter was 9% below average nationally.

Severe weather in the summer manifests itself mostly in the form of thunderstorms that can damage overhead distribution plant. In the winter, severe weather may consist of snow squalls, high winds and the occasional episode of freezing rain. Major storms (high winds, ice storms) are 1 - 2 times per year. There have been 25 ice storms in southern Ontario since the mid-1800s. Ice storms last between 12 hours and 1-2 days. For example, Toronto experienced a total of 5 days (17 hours) of freezing rain in the period 1953 – 2001. Average freezing rain amount is 20-40 mm. It should also be noted that severe weather conditions can be the result of multiple contributors (i.e. high winds and freezing rain at the same time) which would compound the effects on the distribution system. For example, the 2013 ice storm could have been worse if high winds were also present.

Examples of severe events include Hurricane Hazel in 1954, the Barrie and Vaughan tornados in 1985 and 2009 respectively, the ice storm 1998, and the Toronto snowstorm of 1999.

With respect to summer temperatures, urban heat islands (i.e. central cores of Barrie, Markham, etc.) are generally 3°C higher than surrounding rural areas. In the summer, stagnant tropical air masses can result in heat waves and drought conditions. Average annual temperatures across Ontario have increased between 0°C and 1.40°C with the biggest increases in the spring. Winter temperature across Canada has increased by 3°C over the past 67 years while summer temperatures have increased 1.3°C over the same period.

CIMA

4 Barrie in a Changing Climate : a Focus on Adaptation – Final Report – Ontario Center for climats impacts and adaptation ressources (OCCIAR) - 2010

Data from the Barrie WPCC weather station (Environment Canada, 2010) shows that the average annual mean temperature (~7.8°C) at this location has increased 1.7°C over 31 years of record (1978 – 2008). The average winter mean temperature (~-5°C) has increased 2.2°C and the average summer mean temperature (~20.5°C) has increased 1.8°C.

Spring and summer are tornado season in south Ontario and these can reach both PowerStream service areas and cause significant damage as evidenced by the Barrie tornado of 1985 and the Vaughan tornado of 2009.

Rapid snowmelt and flooding can occur in the spring. Most flooding is January to May due to rain on snow conditions. Flooding due to heavy rain has a return period (repeat interval) of about 25 years, although there have been seven major events in the Toronto area, adjacent to PowerStream south, in past 20 years, the most recent being flooding in Burlington in August 2014.

Current weather norms can result in a number of climate events that the distribution system may experience in any year. The following events and threshold triggers are reproduced from the Toronto Hydro Electric System PIEVC Pilot Case Study (2012):

High Temperature	–	Average annual # days with T=> 30°C
Low Temperature	–	Average annual # days <-20°C
Heat Wave	–	3 or more days with Tmax =>30°C
Severe Heat Wave	–	3 or more days with Humidex =>40°C
Extreme Humidity	–	# Days with Humidex => 40°C
Cold Wave	–	3 or more days with Tmin <=-20°C
Temperature Variability	–	Daily T ranges => 25°C
Freeze-thaw cycle	–	annual probability of at least 70 freeze-thaw cycles (Tmax >0 and Tmin <0)
Fog	–	~15 hours/year (average) with visibility <= 0km
Frost	–	no threshold
High wind/downburst	–	gusts > 70km/h (~21 days/year at Airport)
High wind/downburst	–	gusts > 90km/h (~2 days/year at Airport)
Tornados	–	Tornado vortex extending from surface to cloud base (near infrastructure)
Heavy Rain	–	Daily rainfall > 50mm/day
Heavy 5 days total rainfall	–	Days of cumulative rain > 70 mm of rain
Ice Storm	–	Average annual probability of at least 25 mm of freezing rain per event

Freezing Rain	–	Average annual probability of freezing rain events lasting 6h or more (i.e. typically more than 10mm of freezing rain)
Blowing snow/Blizzard	–	Average # days/year with blowing snow (7.8/year)
Heavy snowfall	–	Snowfall > 10cm (2-3 days/yr)
Snow accumulation	–	Snow on the ground with depths => 30 cm and persisting for 5 or more days (0.17 events/year)
Hail	–	Average # of hail days (~1.1/year)
Severe thunderstorms	–	Average # of Thunderstorm Days (~2.8/year)
Lightning	–	Average # days/year with cloud-ground lightning strikes (~25)
Drought/Dry periods	–	At least one month at Ontario low water response level II (i.e. with mandatory water conservation)

The thresholds are limits beyond which the weather can have an adverse impact on distribution system infrastructure. Overhead infrastructure is more vulnerable to weather conditions than underground infrastructure.

Of the above events, mainly high winds/downbursts, tornados, ice storms, freezing rain and heavy rainfall are historically considered to have widespread impacts on the distribution system infrastructure when they occur.

1.2 CLIMATE CHANGE PROJECTIONS

The Intergovernmental Panel on Climate Change (IPCC) and other scientific bodies conclude that climate change affecting the entire world has started and will continue into the future driven in part by thermal inertia of the oceans. The impact of climate change varies by region. The southern Ontario region will be affected by climate change. A review of climate change literature was conducted focusing on papers/reports that provided some level of climate modelling forecasts for both the PowerStream north and south areas or adjacent areas (i.e. Toronto). Key papers consulted were:

- Barrie in a Changing Climate: a Focus on Adaptation – Final Report – 2010
- Canada's Sixth National Report on Climate Change (2014) – Government of Canada
- Changing Weather Patterns, Uncertainty and Infrastructure Risks: Emerging Adaptation Requirements - Environment Canada – 2007

- City of Barrie Emergency Management
- Climate Change Scenario over Ontario Based on the Canadian Regional Climate Model (CRCM4.2) – Ouranos - 2010
- Detection of Tornado Frequency Trend Over Ontario, Canada - Zuohao Cao, and Huaqing Cai – 2011
- Estimation of Severe Ice Storm Risks for South-Central Canada - Office of Critical Infrastructure Protection and Emergency Preparedness – 2003
- From Impacts to Adaptation: Canada in a Changing Climate 2007 – Natural Resources Canada
- Historical Climate Trends for Barrie, Ontario - Ontario Centre for Climate Impacts and Adaptation Resources (OCCIAR) – 2010
- Insurance Bureau of Canada - Telling the Weather Story - The Institute for Catastrophic Loss Reduction - 2012
- National Engineering Vulnerability Assessment of Public Infrastructure To Climate Change - Toronto and Region Conservation Authority – 2010
- Possible impacts of climate change on freezing rain in south-central Canada using downscaled future climate scenarios – C. S. Cheng, H. Auld, G. Li, J. Klaassen, and Q. Li - 2007
- Severe Ice Storm Risks in Ontario - Meteorological Service of Canada Environment Canada-Ontario Region – 2004
- The Tornadoes in Ontario Project (TOP) - Meteorological Service of Canada – 2003
- Toronto's Future Weather and Climate Driver Study - SENES Consultants Limited - 2011
- Toronto Hydro-Electric System Public Infrastructure Engineering Vulnerability Assessment Pilot Case Study

The following opinions are offered with respect to climate change in Southern Ontario and potential impacts to PowerStream's distribution system.

1.2.1 Temperature

Temperature is expected to increase. This will mean shorter, warmer winters with more rain and less snow, especially in the Barrie area. In the Toronto area, there will be a significant reduction in the number of days that the maximum temperature will be below zero and a significant increase in the number of days that the minimum temperature will be above the freezing point.

The TRCA[5] study (PowerStream South area equivalent) predicts that:

- Temperature days >30°C to more than double by 2050 – occurrences per year moving from “moderate/possible” to “often”
- Temperature days <-30°C to decrease - occurrences per year moving from “occasional” to “remote”
- Heat waves (3 or more days >32°C) historical pattern is once every 2 years. In the future there will be an increase in heat wave frequency and dry soil. (Dry soil affects thermal resistivity and the ability of underground cables to shed heat) – occurrences per year moving from “moderate/possible” to “often”
- Cold wave (3 or more days between -20°C and -10°C) is decreasing in the future – occurrences per year moving from “occasional” to “remote”

The IBC report[6] states that:

- Temperature extremes will move from about 12 hot days in the 1961–1990 period to about 37 in the period 2041–2069.
- The number of frost-free days is expected to double in winter 40 years from now.
- The number of days below –15°C and –20°C both showed decreasing trends from 1970–2006 and are expected to decrease greatly in next 40 years.

The Toronto Future Weather report[7] (PowerStream south area equivalent) stated that for the period 2040 - 2049:

- There will be less snow and more rain during the winter
- There will be 26 fewer snow days per year (9 less in December)
- Average annual temperatures increase of 4.4°C
- Average winter temperatures increase by 5.7°C
- Average summer temperatures increase by 3.8°C
- Extreme daily minimum temperature "becomes less cold " by 13°C
- Extreme daily maximum temperature "becomes warmer " by 7.6°C

5 National Engineering Vulnerability Assessment of Public Infrastructure to Climate Change – Toronto and Region Conservation Authority - 2010
6 Insurance Bureau of Canada – Telling the Weather Story – The Institute for Catastrophic Loss Reduction - 2012
7 Toronto’s Future Weather and Climate Driver Study – SENES Consultants Limited - 2011

The City of Barrie Emergency Management states[8]:

- The city is at risk from extreme heat and cold waves

The From Impacts to Adaptation: Canada in a Changing Climate 2007 report states[9]:

- Temperature days >30°C to more than double by 2050

The Climate Change over Ontario report states[10]:

- Annual mean minimum temperature is projected to increase all over Ontario. The warming is projected to be between 3 and 4 degrees at the 2050s horizon. For the 2070-2099 period, the warming is projected to be between 4 and 6 degrees.
- Mean daily maximum temperature is expected to increase over Ontario, with warming from 2 to 4 degrees and from 4 to 6 degrees at the 2050s and 2080s horizons, respectively.
- Mean annual temperature is projected to increase all over Ontario, between 2°C and 4°C, and between 4°C and 6°C for the 2050s and 2080s horizons, respectively.
- The number of occurrences of heat waves per year is projected to increase all over Ontario, but not uniformly. This change would range on average from 0 to 2.5 and from 1 to 5 occurrences per year at the 2050s and 2080s horizons, respectively. The greatest changes would occur in Southern Ontario

All reports support similar temperature projections.

Of interest to note, the electricity demand pivot point is 18°C. Every 10°C increase in summer temp has 4-5x impact on demand compared to 10°C decrease in winter temperature, hence the higher importance of heat wave changes versus cold wave changes. This primarily has an impact on demand and little effect on distributions system components unless they are already fully or overloaded to begin with.[11]

8 http://www.barrie.ca/Living/Emergency%20Services/Emergency-Planning/Pages/PlanningFacts.aspx
9 From Impacts to Adaptation: Canada in a Changing Climate 2007 – Natural Resources Canada
10 Climate Change Scenario over Ontario Based on the Canadian Regional Climate Model (CRCM4.2) – Ouranos - 2010
11 From Impacts to Adaptation: Canada in a Changing Climate 2007 – Natural Resources Canada

Overall assessment is that temperature changes by themselves will not present a problem to the distribution system that warrants "hardening" efforts.

1.2.2 Precipitation/Flooding

Future precipitation in southern Ontario is not expected to increase significantly on an annual basis. What is expected is that the frequency of future precipitation is expected to decrease while the intensity of individual events is expected to increase.

The TRCA study[12] (PowerStream South area equivalent) predicts that:

- Heavy Rain days (rainfall greater than or equal to 50 mm within a 24-hour period) will increase – occurrences per year moving from "moderate/possible" to "often"
- Heavy 5 day rain (a period of 5 days with a total rainfall exceeding 100 mm) will increase – moving from "remote" to "occasional".
- Winter Rain days (rainfall greater than or equal to 25 mm of rain – January - March) will stay roughly the same at "moderate/possible".

The IBC report[13] states that:

- In PowerStream south area, precipitation will increase by about 10% in winter. In the summer the precipitation changes will be much smaller, about 5% increase in PowerStream north and a little smaller change in PowerStream south.
- Heavy rains have shown the greatest seasonal increase over southern Ontario in the spring. Projecting forward for Ontario, the annual maximum 24-hour precipitation rate that at present occurs once every 20 years, will occur more often and become a once every 12–14 year event. This can present an increased risk of flash floods

The Toronto Future Weather report[14] (PowerStream south area equivalent) stated that for the period 2040 - 2049:

- There will be slightly more precipitation (snow and rainfall) overall

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12 National Engineering Vulnerability Assessment of Public Infrastructure to Climate Change – Toronto and Region Conservation Authority - 2010
13 Insurance Bureau of Canada – Telling the Weather Story – The Institute for Catastrophic Loss Reduction - 2012
14 Toronto's Future Weather and Climate Driver Study – SENES Consultants Limited – 2011

- Precipitation amounts will remain similar to present for about 8 months of the year
- Precipitation increases markedly in July and August (with 80% and 50% increases respectively over present values)
- The number of days of precipitation per month decrease (except in July and August)
- Extreme rainstorm events will be more intense. There will be fewer but more severe weather occurrences.
- Large increase in size of extreme (daily) rain events in July (almost threefold)

The City of Barrie Emergency Management[15] states:

- The City is at risk from severe winter storms: heavy snow, strong winds, freezing rain and from severe summer storms: heavy rain and flooding, strong winds, lightning, hail and tornadoes

The From Impacts to Adaptation: Canada in a Changing Climate 2007 report[16] states that:

- There will be a slight decrease(<2.5%) in precipitation for the entire province over the next 50 years
- Southern Ontario will see up to 10% in precipitation decrease during the summer and fall periods by 2050. Winter precipitation may increase by 10% during the same period

The Climate Change over Ontario report[17] states:

- Annual precipitation is projected to increase over all Ontario
- The wintertime precipitation is projected to increase all over Ontario.
- The summertime precipitation is projected to decrease in southern Ontario by as much as 25% (2050) and 40% (2080).
- Summertime soil moisture will decrease over most of Ontario

15 http://www.barrie.ca/Living/Emergency%20Services/Emergency-Planning/Pages/PlanningFacts.aspx
16 From Impacts to Adaptation: Canada in a Changing Climate 2007 – Natural Resources Canada
17 Climate Change Scenario over Ontario Based on the Canadian Regional Climate Model (CRCM4.2) – Ouranos - 2010

All reports indicate that precipitation projections have a high degree of variability with the majority projecting slight increases in annual precipitation. All tend to agree that extreme rainfall events will increase.

Increased heavy rainfall occurrences and intensity in the summer will lead to more flooding risk. The majority of floods recorded to date occurred during the January to May period and were the result of rain-on-snow conditions. Spring flooding events are expected to decrease due to increasing winter temperatures, earlier spring and more winter thaws. In general, streams in the Toronto area are characterized by steep slopes and little or no natural storage capacity. This leads to frequent inundation of the floodplains during intense storms and the spring snowmelt runoff.

In the PowerStream South area, three key watershed systems are the Humber, Don and Rouge river systems. For the Humber river system, the risk of flooding remains in portions of Woodbridge, and Oak Ridges (Richmond Hill)[18.] For the Don River system risk of flooding remains in areas of Vaughan (Steeles/Dufferin, Keele/Hwy7, Keele/Langstaff. North Rivermede Industrial area west of Hwy 407) and Richmond Hill (Yonge/Elgin mills)[19]. For the Rouge river system, risk of flooding remains in areas of Markham (Hwy7/ Kennedy to McCowan)[20]. Figures 2 and 3 indicate flood vulnerable parts of the Don and Rouge River watersheds.

In the PowerStream North area, the City of Barrie, three separate subwatersheds are the: Barrie Creeks, Lovers Creek and Hewitt's Creek. There is some risk of spring flooding along the three creek systems.

18 Humber River Watershed Report Card 2013
19 Don River Watershed Report Card 2013
20 Rouge River Watershed Report Card 2013

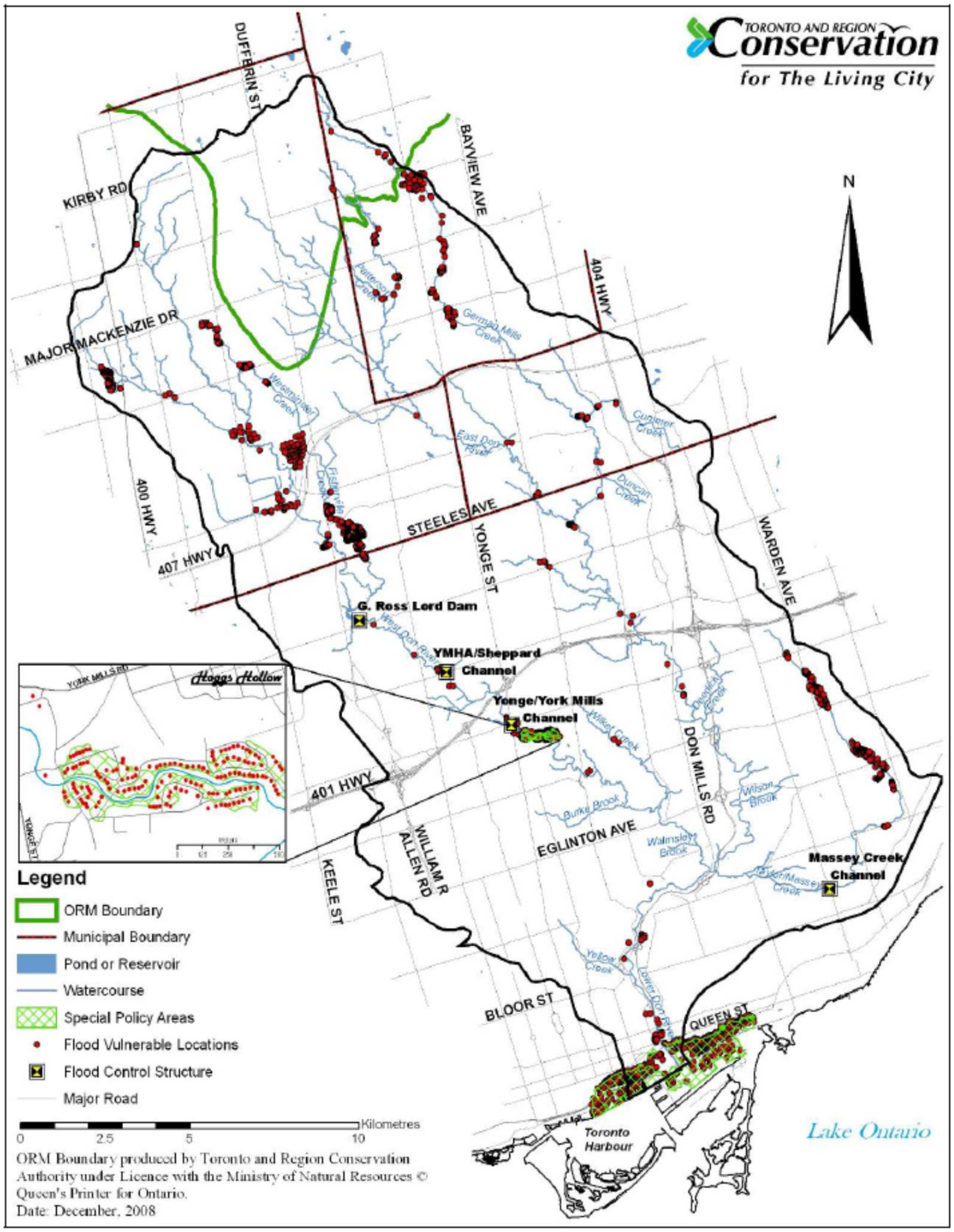

FIG 2. FLOOD VULNERABLE AREAS OF THE DON WATERSHED[21]

21 Rouge River Watershed Report Card 2013

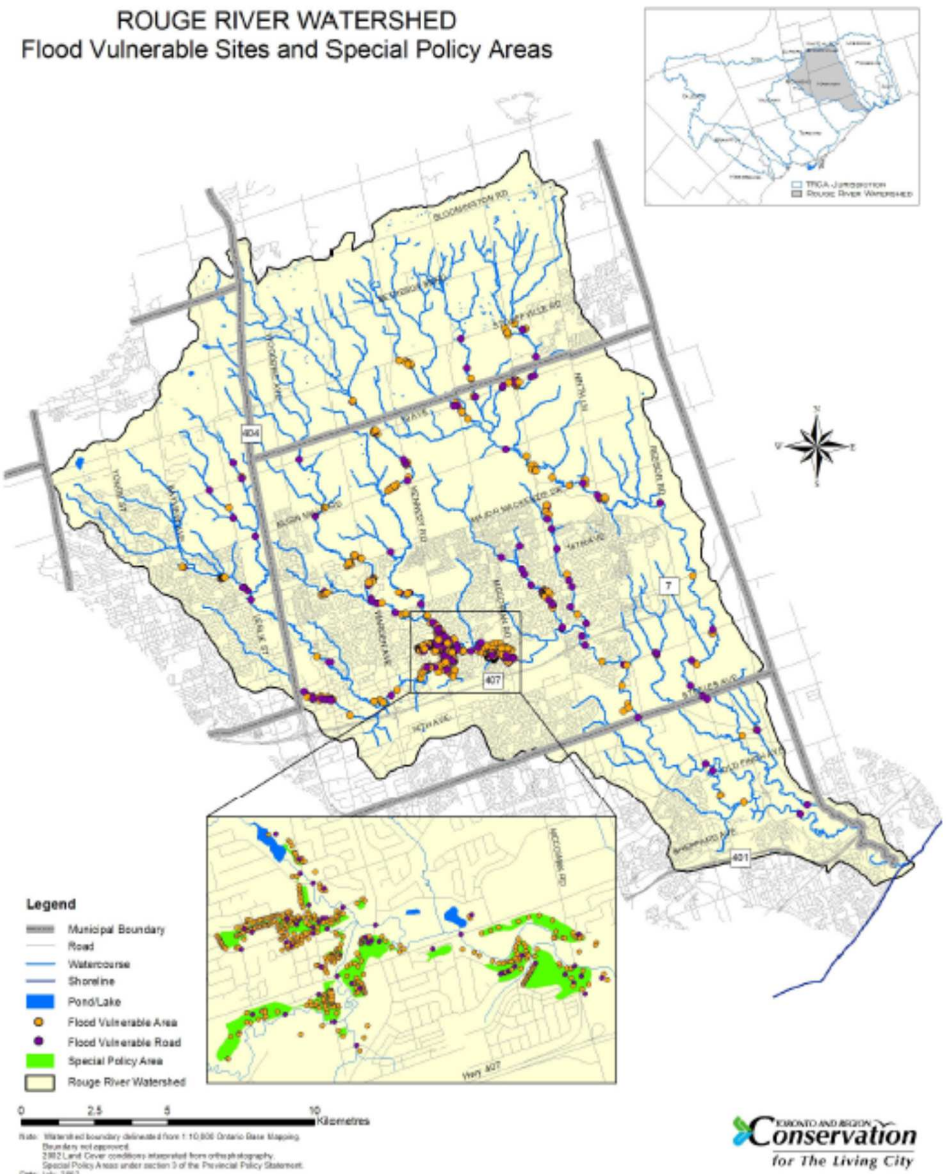

FIG 3. FLOOD VULNERABLE AREAS OF THE ROUGE WATERSHED[22]

In Toronto, there were 7 major heavy rainfall events in the last 20 years that resulted in flooding. Heavy rainfall is defined as rainfall that is greater or equal to 50 mm/hour or greater or equal to 75 mm in three hours. The return period (repeat interval) for these events was considered to be 25 years, so there has been a marked frequency increase in this type of event. In York Region there were 24 such events and in Simcoe area there were 13 to 43 such events. Regional return times are approaching annual events which are of importance to PowerStream as infrastructure is regionally located not just in one specific location.

22 Rouge River Watershed Report Card 2013

On the positive side, for the Humber, Rouge and Don River watersheds, Markham, Vaughan and Richmond Hill have comprehensive up to date storm water management systems in place that minimize the risk of future flooding compared to historical norms. Figure 4 provides a visual of heavy rainfall occurrences in the southern Ontario region.

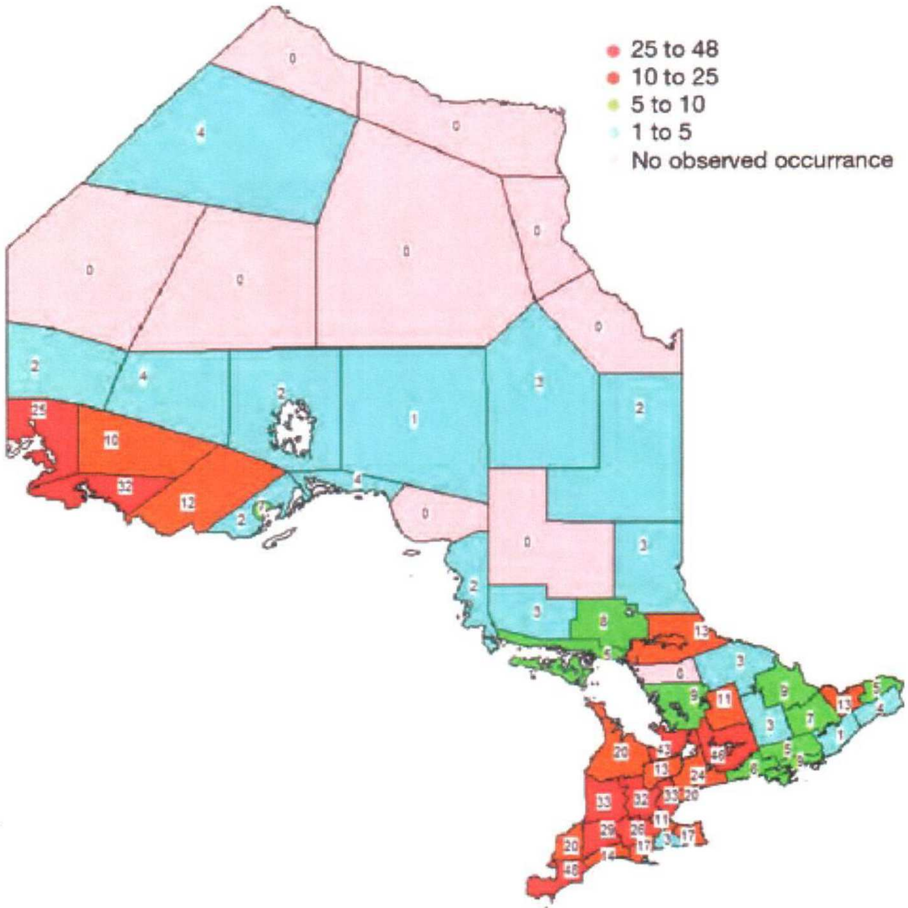

FIG 4. OCCURRENCES OF HEAVY RAINFALL 1979-2004[23]

Infrastructure that is located below grade (i.e. underground vaults, transformer station basements) is at risk of future flooding potential based on the changing return times experienced in the last 20 years. Events occurring every 1-2 years can be expected somewhere in PowerStream's service territory.

Station roof infrastructure can be subject to heavy rain events that can stress current roof condition.

23 From Impacts to Adaptation: Canada in a Changing Climate 2007 – Natural Resources Canada

Soil moisture decreases (and associated increases in thermal resistivity) require that cable ampacity values be reviewed for underground cables loaded to current maximum values. Station egress cables are of primary concern.

1.2.3 Severe weather/wind

Winds are expected to increase in frequency and velocity.

The TRCA study[24] (PowerStream South area equivalent) predicts that:

- the average number of days in a given year, with wind speeds recorded at greater than or equal to 63 km/hour will roughly remain the same at "moderate/possible"
- there will be a slight increase in hurricane/tropical storm sustained surface winds (speeds of 118km/hour or more) occurrences per year moving from "improbable/highly unlikely" to "remote"

The IBC report[25] states that:

- Severe weather frequency - an event that occurred on average once every 50 years will be likely to occur about once every 35 years by 2050. Weather events that used to happen once every 40 years are now happening once every six years in some regions in the country.
- Summer days with more than 50 km/hour winds have shown a significant increasing trend in Toronto, where the windy days increased on average by three times after 2000. This indicates an increased frequency of more severe damaging winds in the decades to come. The highest summer wind increases, also about 10%, will occur over the Great Lakes.
- There will be wintertime wind increases over northern Ontario and extending south over parts of the Great Lakes of nearly 10% by 2050.

The Toronto Future Weather report[26] (PowerStream South area equivalent) stated that for the period 2040 - 2049:

- There will be fewer but more severe weather occurrences including damaging winds.
- The average wind speed is expected to remain unchanged

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24 National Engineering Vulnerability Assessment of Public Infrastructure To Climate Change - Toronto and Region Conservation Authority – 2010

25 Insurance Bureau of Canada - Telling the Weather Story - The Institute for Catastrophic Loss Reduction - 2012

26 Toronto's Future Weather and Climate Driver Study - SENES Consultants Limited - 2011

- maximum hourly winds reduced
- maximum wind gusts reduced

The From Impacts to Adaptation[27]: Canada in a Changing Climate 2007 report states that:

- the frequency and magnitude of future wind storms is likely to increase

The THES PIEVC report[28] states that:

- Future winds above threshold to increase
- Trees impacted when wind reach/exceed 50-70km/h
- HV power lines impacted when wind reach/exceed 80-100km/h based on current standards

All reports indicate that wind speeds related to severe weather events are expected to increase in the future. Lack of data has precluded any definitive value of what specific severe wind speeds are expected to see in the future. Just more probability of events occurring that exceeds the current frequency and magnitude. A 10% increase in historical average annual peak wind gusts at Pearson Airport is shown at figure 5.

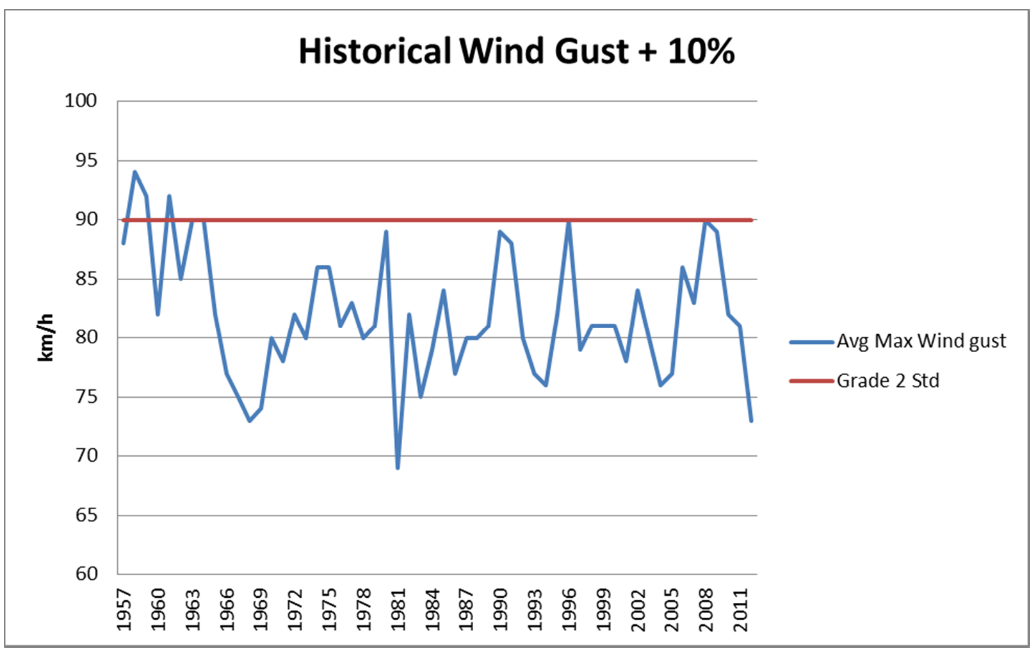

FIG 5. HISTORICAL + 10% WIND GUSTS AT PEARSON AIRPORT

27 Estimation of Severe Ice Storm Risks for South-Central Canada - Office of Critical Infrastructure Protection and Emergency Preparedness – Government of Canada – 2003
28 Toronto Hydro Electric System PIEVC Pilot Case Study (2012)

The graph shows that a 10% increase in yearly average wind gust is still within the expected performance of Grade 2 construction criteria (90 km/h withstand). A review of historical data shows that a 10% increase in peak gusts would result in ~4 gusts per year in excess of 90kmh versus the historical ~2 per year.

Of note with respect to wind speed increases, an Insurance Australia group report[29] stated that a 25% increase in peak gusts results in a 650% increase in building damage. Overhead infrastructure would be particularly vulnerable to significant increases in severe storms and wind speed.

While all poles would be at increased risk with wind speed increases, large 4 circuit poles with additional equipment (switches, transformers, etc.) would have the most load and equipment at risk. Station roof infrastructure can be subject to extreme wind events that can stress current roof condition.

1.2.4 Tornados

Tornados are rare but extremely destructive events. The historical frequency for Tornados in southern Ontario[30] has been in the order of 1 x 10^{-4}(< 1 in a 1000 probability) per 0.0001km^2yr^{-1}. For PowerStream this works out to roughly 1 tornado somewhere in PS territory every 12.4 years

The TRCA study[31] (PowerStream South area equivalent) predicts that:

- The future probability of occurrence will remain the same at "remote".

The IBC report[32] states that:

- There will be more frequent tornados in southwestern Ontario

The information gathered indicates that tornados will still be rare localized events that would be impossible to harden against for an overhead system. As figure 6 shows, even a robustly built municipal station is at the mercy of the power of a tornado.

29 Insurance Bureau of Canada - Telling the Weather Story - The Institute for Catastrophic Loss Reduction - 2012
30 Toronto Hydro Electric System PIEVC Pilot Case Study (2012)
31 National Engineering Vulnerability Assessment of Public Infrastructure To Climate Change - Toronto and Region Conservation Authority – 2010
32 Insurance Bureau of Canada - Telling the Weather Story - The Institute for Catastrophic Loss Reduction - 2012

FIG 6. SUBSTATION DESTROYED BY TORNADO33

1.2.5 Freezing Rain / Ice Storms

Freezing rain is a major hazard to infrastructure, especially overhead wires and poles. Freezing rain can cause tree branches and entire trees to bend and break and collapse on power distribution lines. Ice accumulation due to freezing rain can reach a point where even with no trees present, wires and poles can no longer sustain the weight and the structure collapses. The effect of freezing rain is cumulative. Small branches break at ~6-12 mm of ice accumulation. Large branches break at ~12-25 mm of ice accumulation. Add

33 http://www.wfec.com/media-center/photo-galleries/cana-substation

some wind and these thresholds are reduced. Literature studies on freezing rain and ice storms indicate that 30 mm of ice accumulation will likely result in major power outages lasting several days. 40 mm of ice accumulation will result in community disasters as a significant portion of the overhead distribution system will be destroyed. The 2013 storm event in southern Ontario was a moderate one with accumulations of ice significant enough to bring down branches and trees but not enough to bring down wires and poles themselves.

The TRCA study[34] (PowerStream South area equivalent) predicts that:

- The likelihood of freezing rain or drizzle, equal to or greater than 0.2 mm in diameter is expected to increase by 40% in the December to February period and decrease by 10% in November, March and April period - occurrences per year moving from “moderate/possible” to “probable”.
- Freezing rain amounts of less than 25mm is expected to increase - moving from “moderate/possible” (0.25 to 0.75 occurrences per year) to “probable” (1.25 to 2 occurrences per year).
- Ice Storms amounts of 25 mm or more is expected to increase – moving from “remote” (0.01 to 0.05 occurrences per year) to “occasional” (0.1 to 0.25 occurrences per year).

According to the Toronto Hydro Electric System PIEVC Pilot Case Study (2012)[35,] historical freezing rain frequency and severity in the Toronto area has been as follows:

- Freezing rain/drizzle – 8.8 days per year (0.1 mm – 0.3 mm/hr)
- Freezing rain at least 4 hours – 1.4 days per year (6 – 8 mm up to 15 mm)
- Freezing rain at least 6 hours – 0.65 days per year (once every 2 years) (9-12 mm up to 25 mm)
- Multi day ice storms => 25 mm – 0.06 days per year (once every 17 years) (>25 mm)

The THES PIECV[36] report also states that:

- Severe ice storms with 25 mm or more of freezing rain have occurred 3 times in the last 50 years. Two of the occurrences were only 8 years apart (1960 and 1968). See figure 7.

34 National Engineering Vulnerability Assessment of Public Infrastructure To Climate Change - Toronto and Region Conservation Authority – 2010
35 Toronto Hydro Electric System PIEVC Pilot Case Study (2012)
36 Toronto Hydro Electric System PIEVC Pilot Case Study (2012)

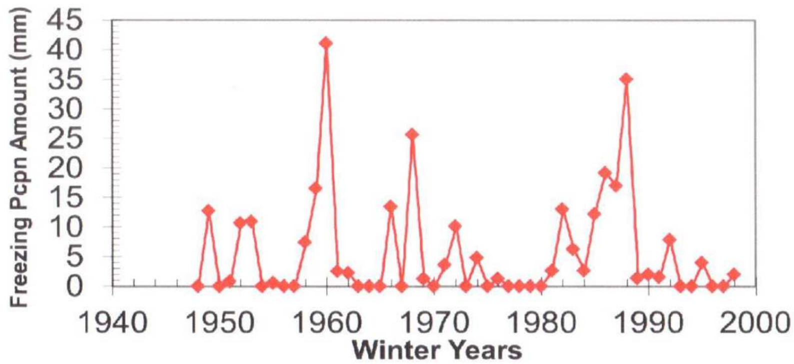

FIG 7. ESTIMATED 6 DAY DURATION ANNUAL MAXIMUM FREEZING PRECIPITATION FOR WOODBRIDGE WEATHER STATION

The IBC report[37] states that:

- The percentage increase for severe freezing rain events (lasting six hours per day or longer) is projected to be about 35% in southwestern Ontario and around the lower lakes.

The Estimation of Severe Ice Storm Risks for South-Central Canada[38] report states that:

- Frequency and intensity of ice storms to increase.
- There will be an increase in weather types for freezing rain >= 6 hours. The Great Lakes influence on freezing rain occurrence will show a decreased frequency on the west side shores of Lake Ontario, North shore of Lake Erie. In fall, early winter & early spring.
- In central Canada, the CSA/CEA freezing rain ice design criteria for high voltage power and transmission lines indicates a design limit for overhead structures of approximately 25 mm of radial ice accretion (not freezing rain totals) on a 1 inch conductor. Therefore, damage to the electrical transmission system normally occurs in the more severe ice storms. However, transmission lines may fail and towers may be damaged in less severe ice storms under the effects of "galloping," as the conductors and guy wires erratically oscillate and stretch under moderate but steady wind conditions.

37 Insurance Bureau of Canada - Telling the Weather Story - The Institute for Catastrophic Loss Reduction - 2012

38 Estimation of Severe Ice Storm Risks for South-Central Canada - Office of Critical Infrastructure Protection and Emergency Preparedness – Government of Canada – 2003

Changing Weather Patterns, Uncertainty and Infrastructure Risks: Emerging Adaptation Requirements report[39] states:

- Trees magnify the impact of ice storms. Tree management near distribution lines is an important adaptation action needed to reduce risks of power distribution system outages.
- Investigation included an assessment of the CSA/CEA freezing rain ice design criteria for high voltage power and transmission lines. The results indicated that the existing design ice loading specifications for overhead structures (not freezing rain totals) adequately cover existing ice storm return periods (repeat interval) for most regions, but would need to be upgraded if ice storm frequencies or amounts increase.
- the potential for long power outages and for community disasters becomes likely when freezing rain totals exceeded approximately 40 mm.

The Canadian Regional Climate Model (CRCM4.2) report[40] indicates an increase in longer duration freezing rain episodes as indicated in figure 8.

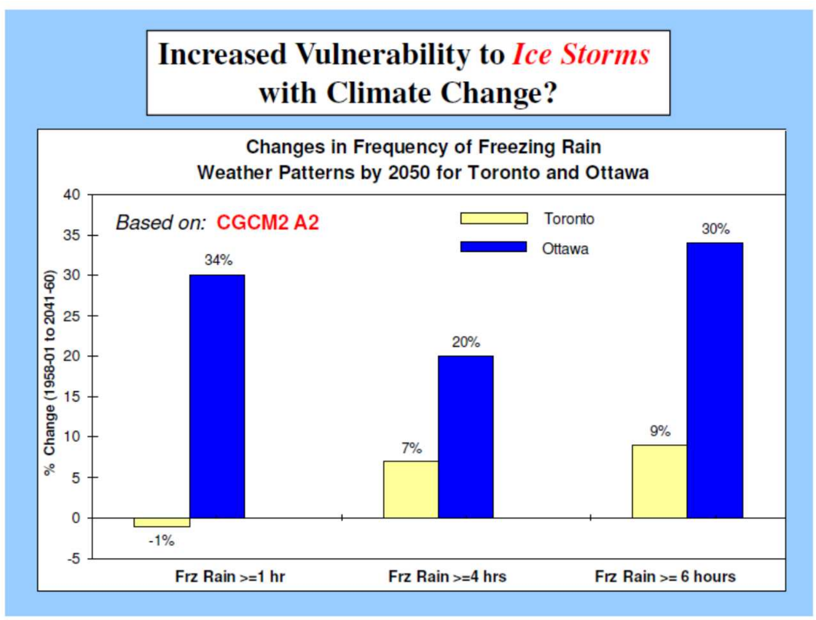

FIG 8. ICE STORMS AND CLIMATE CHANGE

39 Changing Weather Patterns, Uncertainty and Infrastructure Risks: Emerging Adaptation Requirements – Environment Canada – 2007

40 Climate Change Scenario over Ontario Based on the Canadian Regional Climate Model (CRCM4.2) – Ouranos - 2010

Most reports indicate that increases in freezing rain duration and intensity will be highest in northern and eastern Ontario. Moderate increases will be felt in southern Ontario with the Toronto area seeing a 10% increase in freezing rain frequency by 2050. A similar impact would be felt in the PowerStream service areas. For severe ice storms (>25 mm ice accumulation) this would change the historical probability from 0.06 per year (once every 17 years) to 0.07 per year (once every 14 years).

1.2.6 Impact Summary

The key findings of current and forecast climate norms and damage potential to PowerStream's distribution system are summarized in the table below:

Weather Event	Current norms	Climate Change Norms	Damage potential
Temperature	~12 days > 30^{0}C per year	Temp days >30^{0}C to double by 2050	Overload potential to equipment already heavily loaded
Heavy Rain/Flooding	Historical return of 25 years	Increased risk of flash floods	Station flooding
High Wind velocity/wind gusts	Severe high winds once every 50 years	Severe high winds once every 35 years	Aged overhead assets and multiple circuit poles at greatest risk
Tornados	Once every 12.4 years	Once every 12.4 years	Massive localized destruction of infrastructure
Freezing Rain >25mm	Once every 17 years	Once every 14 years	Major power outages

In summary, over the next 35 years, the number of days of 30 °C or more will double. The frequency and severity of heavy rain/flooding, high winds and freezing rain will increase.

It should be noted that climate change impacts can affect more than one type of infrastructure (i.e. transportation, communication, etc.). This needs to be taken into consideration in not just the initial design but in the response efforts to mitigate the effects of climate change. Hardening and resiliency efforts are warranted to ensure continued reliability of supply with the impacts of climate change.

2. DISTRIBUTION SYSTEM HARDENING - REVIEW OF NORTH AMERICAN UTILITY PRACTICES

There are two key concepts related to improving the performance of electrical distribution systems in severe storm situations: hardening and resiliency.

- Hardening - physical changes to make particular pieces of infrastructure less susceptible to storm-related damage
- Resiliency - increasing the ability to recover quickly from damage to facilities' components or to any of the external systems on which they depend

The following represents a summary of what some North American utilities are doing, or have done, to "harden" their distribution system.

2.1 HYDRO-QUEBEC[41]

The 1998 ice storm resulted in an accumulation of 40 to 90 mm of freezing rain between the 4th and the 11th of January in the southern regions of Quebec. As a result, Hydro-Quebec lost about 3,000 km of the network including 1,000 transmission pylons, 4,500 transformers and more than 16 000 wood distribution poles. At the peak of the crisis 1.5 million customers were left without electricity. The cost of the 1998 ice storm was evaluated to be $2 billion; the immediate cost to restore electrical service was $1 billion. After the crisis an additional $1 billion dollars was invested to reinforce the transmission and distribution networks. Major work began in 2000 to reinforcing the networks, it continued until 2006 for the distribution network and is ongoing for the transmission network and expected to be completed in 2015.

Hydro-Quebec transmission division (TransÉnergie) has developed and is implementing a program in order to secure electrical supply to the distribution network. A third of a billion dollars has been invested so far for the construction of four transmission electrical ties:

- Monteregie tie
- Montreal downtown tie
- Quebec City downtown tie
- Quebec-Mauricie tie.

An additional $400 million dollars is invested to reinforce the original transmission networks.

41 Renforcement du réseau de distribution d'Hydro-Québec - Rapport sur les orientations de fin de programme November 9th 2004

The Distribution network is composed of 100,000 km of lines which about 90% are overhead lines. One of the major elements of the hardening strategy is reinforcing these lines, Hydro-Quebec invested $200 million dollars to minimize the impacts and consequences of future storms by selecting concepts and technologies that exceed current standards and would be able to withstand major storms. The reinforcement program has two major objectives:

1. An increase in design criteria
2. Introduce the controlled failure concept to minimize damage

To achieve this, equipment has been modified and major changes have been made to distribution network construction criteria to be able to sustain up to 45 mm of ice. This value was chosen as Hydro-Quebec decided to manage the risk on a 50 year probability of occurrence. HQ revised its standards and created two sets of standards they call “regular” and “robust”. The regular standard applies to most of the grid and aims to withstand 1.41 inches of ice (36 millimeters). The robust standard has the objective of ensuring that critical portions of the system can withstand 1.77 inches (45 millimeters) of ice. Between 1999 and 2006, HQ hardened the critical portions of the system to the new Standard Criteria’s.

5,300 km of network was enhanced with the new controlled failure construction criteria. This makes Hydro-Quebec standards one the highest in the electrical distribution industry.

Poles and anchors have also been modified to better withstand the range of climates they are being exposed to. Hydro-Quebec has developed a polymer-based additive (PA) that is injected into poles treated with chromated copper arsenate (CCA) to make them as easy to climb as poles treated with pentachlorophenol (PCP) or other preservatives. This additive reduces the hardness usually found in other CCA treated poles without affecting the service life of the pole and allows the line teams to easily climb on them with their climbing equipment. This is very useful for inaccessible poles. With respect to anchors, Hydro-Quebec has stopped the installation of 10’’ screw anchors and replaced them with 14’’ anchors. Hydro-Quebec has also added the triple helix (10’’-12’’-14’’) screw anchor and the 900 sq.in. anchor plate to their inventory.

The new controlled failure system, which includes controlled sequential failures of crossarms and conductor ties, will ensure that if the lines are exposed to an extreme ice load they will fall without dragging the poles with them. Anti-cascade systems have been perfected to avoid the domino’s effect that created the damages experienced in the 1998 ice storm event. Every tenth distribution pole has anti-cascading to limit damage from pole collapse. Hydro-Quebec’s post storm analysis showed that 80% of the time spent in repairing the network was spent in replacing poles (see Figure 9); this time will be considerably reduced with the implementation of these concepts.

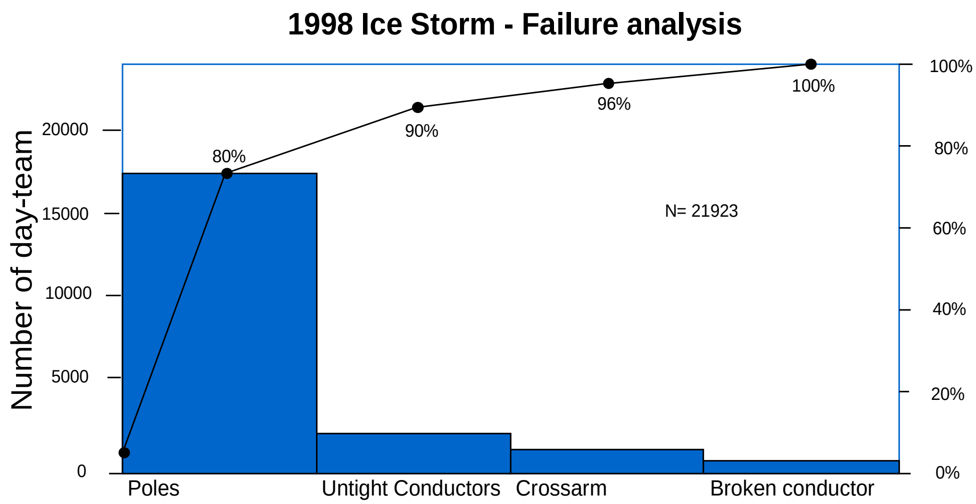

FIG 9. 1998 ICE STORM – FAILURE ANALYSIS [42]

Post-ice storm vegetation management was undertaken in order to increase the reliability of the distribution networks. Trees represent a major problem in most of Quebec's regions so a special pruning program was created and a substantial budget increase was enacted in order to eliminate overhangs and prune trees deemed dangerous to the lines in all areas at risk of receiving 25 mm or more of freezing rain. Work started with lines connecting priority customers such as hospitals, pumping stations, police and fire stations and shelters. The work was then completed on parts of the network that service dense populated cities. Of the 100,000 km of network, 37,500 km have undergone intense pruning at the cost of $20 million dollars (part of the overall $200M budget). Education of the public on the vegetation management program is very important in order to obtain the populations' support. Therefore, Hydro-Quebec has created different tools to facilitate this work.

The total vegetation management cycle varies from 3 - 6 years. For the priority distribution back bone, mainly 3 phase circuits, a 3 years cycle is normal. The remainder, mainly single phase conductors, is on a 6 year cycle. Planning is done every year and identifying dangerous trees is a priority. Worst performing feeders are identified and worst performing feeders at year N are treated at year N+1. Hydro Quebec does not trim services lines but forestry planners do advise the customer about what needs to be done.

42 Renforcement du réseau de distribution d'Hydro-Québec - Rapport sur les orientations de fin de programme November 9th 2004

In collaboration with the transmission division, Hydro-Quebec distribution has created reinforced links between satellite transmission substations. This allows bigger flexibility in case a satellite substation is damaged then the reinforced distribution link from another satellite substation will assure the supply in backup energy to priority customers. In case of a major event, Hydro-Quebec will repair these links first and then resume work on other parts of the network.

Finally, the typical number of circuits per pole is 1 (15MVA circuit). The exception is 2 and needs special approval. There are never more than 2 circuits per pole. Undergrounding from the substation to pockets of load is standard in urban and semi-urban areas. In rural areas, normally all the circuits can be aerial. Undergrounding in rural would be an exception.

2.2 MANITOBA HYDRO[43]

The Manitoba-Hydro distribution systems consist of 4 kV to 25 kV lines and the sub-transmission has voltages of 33 and 66 kV. It owns about 150 stations in the western part of Manitoba with 78,000 km of lines and over 500 feeders that can be up to 20 miles long in rural locations. See figure 10.

43 Manitoba Hydro Mitigates Ice Issue on Power Lines - Nov 1, 2012 Robert Lapka, Manitoba Hydro | T&D World Magazine

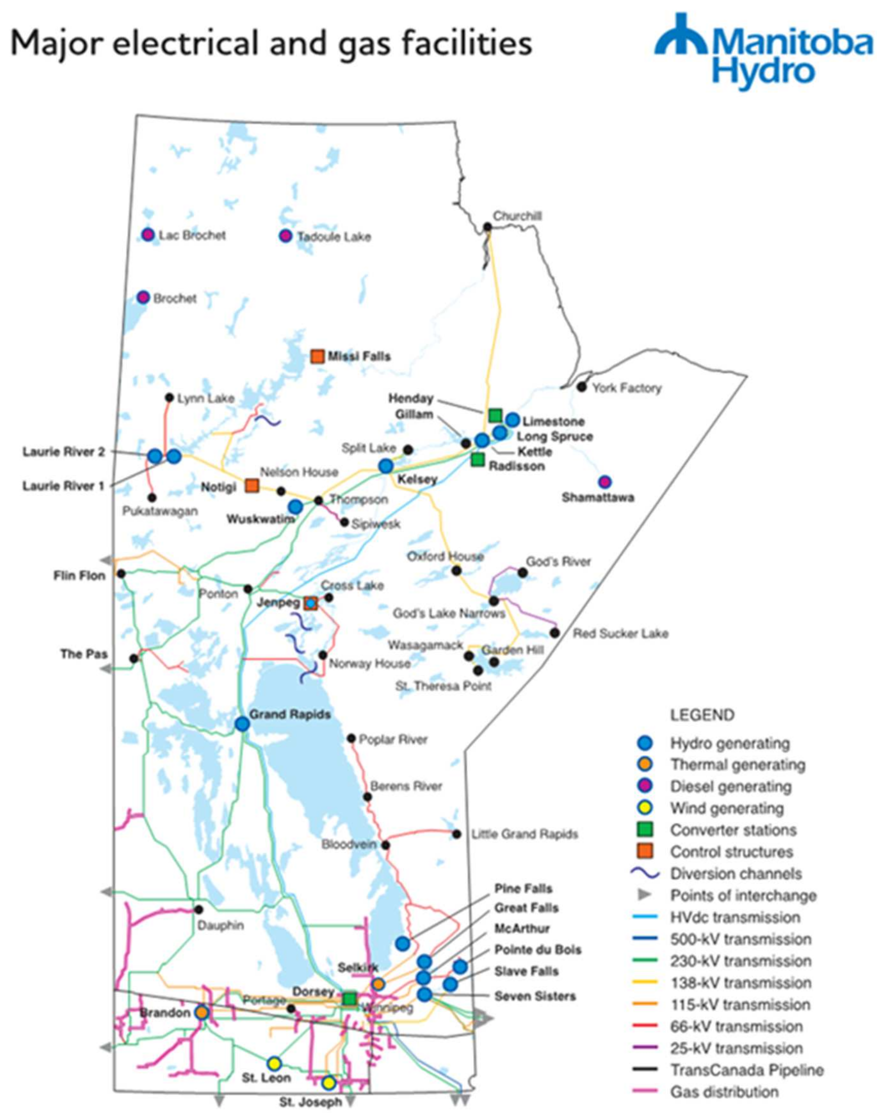

FIG 10. MANITOBA HYDRO FACILITIES[44]

About 96 per cent of the electricity Manitoba Hydro produces each year, 30 billion kilowatt-hours on average, is generated at 15 hydroelectric generating stations on the Nelson, Winnipeg., Saskatchewan, Burntwood and Laurie Rivers.

44 Manitoba Hydro Mitigates Ice Issue on Power Lines - Nov 1, 2012 Robert Lapka, Manitoba Hydro | T&D World Magazine

The province's remaining electricity needs are fulfilled by:

- 2 thermal generating stations;
- 4 remote diesel generating stations;
- Wind power purchases from independent wind farms in Manitoba.

Manitoba Hydro has an extensive infrastructure to support the production and delivery of power in the province. In 2011–12 they've invested $479 million toward maintaining a secure and dependable delivery system.

Weather conditions in the region are very extreme and fluctuating. High humidity, below-freezing temperatures and ice storms are favorable to ice forming on power lines. In windy conditions icy lines can whip violently and gallop causing tie wires to break, poles to snap and steel towers to snap. Quick removal of that ice helps prevent equipment breakage and loss of power.

Two methods have been approved by the Manitoba Hydro to remove ice from its lines[45]:

1. Ice melting
2. Ice rolling

Ice Melting

A short-circuit is placed at one end of a sub-transmission line, this creates a current flow and a gradual temperature increase in the line and melts the ice. Ice melting can be used only between -15°C and 0°C and it takes about 10 minutes to melt ice off the line. Ice melting is used on sub-transmission and distribution lines. Through the use of spare transformer banks, line configuration and portable substations mounted on a semi-trailers, the utility is able to perform this work while maintaining power to customers.

Ice Rolling

Field crew use an upside-down pulley attached to a wooden stick with a fiberglass insert and rope to remove ice on conductors. Line crew pull the rope/stick assembly and the ice roller applies pressure to crack the ice off the line (see figure 11). The line can be rolled in an energized state depending on the weather. In windy or wet weather, the line is rolled de-energized. This method is effective but depends on the amount of ice on the line and cannot be used if temperatures are hovering around 0°C as the ice becomes soft and flexible. A 10-person crew can de-ice roughly 1.6 kilometres of line per hour.

45 Manitoba Hydro Mitigates Ice Issue on Power Lines - Nov 1, 2012 Robert Lapka, Manitoba Hydro | T&D World Magazine

FIG 11. ICE ROLLING[46]

Manitoba Hydro has developed a new vision ice system, which incorporates live camera images. Connected to a communication system, the cameras give a real- time view of ice accumulation. The cameras are protected in a weatherproof housing and pointed directly to the power lines. Even with all this technology, field crew observations and reports are still a big part of the prevention plan.

CIMA

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2.3 CON ED - POST SANDY ENHANCEMENT PLAN[47]

Consolidated Edison services New York City. In the wake of Superstorm Sandy, ConEd embarked on a long-term storm plan (Post Sandy Enhancement Plan - PSEP) to make sure that their system is less susceptible to similar storms and more responsive to customer needs. The PSEP focuses on three key efforts:

- Fortifying the electric, gas, and steam systems against future storms;
- Improving estimated times of restoration, and enhancing storm planning and restoration processes;
- Improving the flow of information to customers and other stakeholders.

$1 billion will be invested over a 4 year period to achieve this. Some of the key hardening projects being undertaken are:

- Reconfiguring the most vulnerable underground networks to form separate flood areas – segmentation strategy.
- Flood-proofing energy equipment including requiring commercial customers, in those areas prone to flooding, to install submersible or elevated equipment in their facilities.
- Installing additional distribution automation such as sectionalizing switches to allow system operators to identify and isolate problem areas and rapidly bring power back to the surrounding areas.
- Upgrading of overhead distribution equipment, with the aim of making the system more resilient against damage from high winds and downed trees and limbs.
    - Separating feeders into sections and installing remotely operated sectionalizing switches to isolate problems, so that damage does not cause outages for all customers on the feeder.
    - Redesigning feeders so that they can be supplied power from both ends, or potentially from customer generation sources (e.g., combined heat and power/distributed generation) giving operators more options for restoring service.
    - Installing stronger poles able to withstand wind gusts of up to 110 miles per hour in strategic locations.
    - Redesigning wires to provide better protection from falling tree limbs, and to detach more easily when force on the wire is more extreme to reduce the likelihood of damage to poles and other pole-top equipment.

47 Post Sandy Enhancement Plan – Consolidated Edison - 2013

- Expanding use of overhead cables for greater resistance to damage from high winds and tree branches.
- Creating greater tree clearances around distribution facilities near substations and critical infrastructure.

+ Selectively undergrounding portions of the overhead system based on analysis of outage data and field surveys of tree density – focusing on areas where tree trimming alone may not be sufficient, and where the added costs can provide significant added value in terms of reducing future restoration costs.
+ Evaluating ways to shore up information systems to withstand flooding - focusing on expanding the use of water-resistant fiber-optic communications and control systems, rather than copper wires.
+ Developing plans to create strategically placed sub-networks that can be isolated from the rest of the grid and incorporating customer-side distributed generation resources into restoration plans.

ConEd's key focus on hardening was to reduce the impact of flooding and minimizing loss of their underground network system, as a whole, due to localized flooding. Summary of hardening efforts are in Table 1.

ELEMENT	HARDENING STRATEGY	COMMENTS
Substations	Each station that flooded during Sandy will be hardened to a new flood-level design – determine new minimum elevation for critical equipment	Install new expansive RTV foam seals at any trench and conduit penetrations into the critical areas of the station to minimize the infiltration of water.
UG Distribution	Move to submersible standard; install sectionalizing equipment to isolate flood areas (sub-network design)	Avoids taking an entire network out of service
	Watertight shrink-wrap cover that will enclose and protect RTU boxes in submersible locations.	
OH Distribution	Lower the number of customers served by each segment of primary supply to fewer than 500 using reclosers and SCADA switches	Will reduce OH outages by 15 – 20%
	Stronger equipment poles(+15% strength) – capable of withstanding wind gusts of 110 miles per hour – to be used on main runs and/or heavy tree cover areas, as well as for feeders supplying critical customers	
	Add isolation devices on runoffs that are more than two spans in length	Fusing laterals – trip saving

ELEMENT	HARDENING STRATEGY	COMMENTS
	Sectionalize overhead loops into smaller loops; add supply feeders; DG supply;	
	Use Hendrix Aerial Cable vs open wire design	More robust
	Implement so-called "sacrificial components," such as breakaway hardware and detachable service cable and equipment, to prevent pole and customer equipment damage during storms	
Proactive design/mtce	Incorporating hardening solutions for future storms into the repair process, or deferring permanent repairs until a stronger solution is available	
Customer infrastructure	Customers in flood-prone areas either install submersible electrical equipment, or raise critical equipment above the ground floor	Reduce the probability that the system would be impacted by a fault current on the customers' side of the meter
Selective undergrounding	Replace portions of the overhead system with underground equipment – focus on (1) feeders supplying areas that have experienced the highest storm-damage impact and (2) feeders supplying facilities that are vital to maintain community support following severe storms, such as hospitals, police and fire stations, schools, and stores that sell basic necessities, such as food, medicine, gasoline, and building supplies. Also select existing overhead double circuit distribution lines that have shown a history of higher exposure to incidents, and replace them with underground distribution mainline systems	$6.2 million per mile (2007)
Vegetation Management	"Hazard Tree" program – identify trees that are tall enough to contact the overhead distribution system and are also dead, declining, diseased, or otherwise structurally unsound.	Work with landowners to find agreeable solutions. All tree removals require written landowner authorization
	New clearance standard for Orange & Rockland territory of 15 feet to the side, 15 feet below and 20 feet above certain conductors	All 34.5 kV distribution wires, and the portions of 13.2 kV circuits that run between the transformer and the first protective device, such as a recloser.
	Branch Reduction program - view limbs as levers that can be pulled down by snow, ice, or wind stresses. By proactively shortening the length, can reduce the likelihood that a branch will break under weather stresses.	Training required for contractors and employees

ELEMENT	HARDENING STRATEGY	COMMENTS
Communication	New Con Ed owned fiber loops to reduce reliance on external telecomm carriers	Higher reliability level than carrier circuits; offers highest level of cyber and physical security; improve recovery time in the event of communications failures
	Reinforce antenna systems and implement backup generators at several critical fibre network and radio sites.	

TABLE 1 – CON ED HARDENING EFFORTS

2.4 LIPA STORM HARDENING PLAN (PSEG)[48]

LIPA was the Long Island Power Authority that serves Long Island, New York (excluding New York City). Since 2014 LIPA has become PSEG Long Island, but LIPA will be used in terms of reviewing their storm hardening plans. See Figure 12 for their territory

Serves approximately 1,110,853 customers
1,230 square miles of service territory
8,950 miles of overhead wire
4,661 miles of underground cable
535,050 utility poles

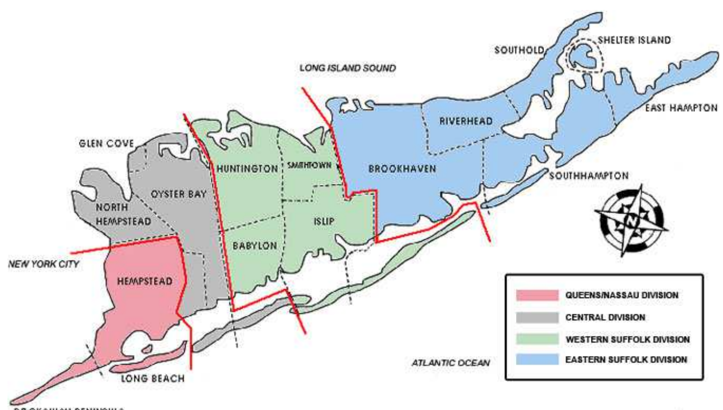

FIG 12. PSEG (LIPA) SERVICE TERRITORY

LIPA adopted a $500M-20 year proactive storm hardening plan in 2006. See Table 2 for the annual expenditure hardening plan. The purpose of the plan was to improve the capability of the electric system on Long Island to withstand the impacts of hurricanes and other severe storms, and to shorten the time required to restore service to customers when outages occur due to storms.

48 LIPA Storm Hardening Talking Points - 2012

The plan had 3 areas of focus:

- Durability - "minimize damage caused by severe storms"
- Resilience - "minimize impact of storm damage"
- Restoration - "minimize outage times"

PLAN KEY COMPONENTS	ANNUAL EXPENDITURE
Storm Hardening + Reinforced foundations to support critical equipment and structures + Higher strength steel infrastructure + Higher strength poles + Equipment repositioning to mitigate flooding issues + Selective undergrounding	$20M
Vegetation Management + Removal of dangerous trees adjacent to lines + Accelerated tree trim cycles in areas + Increase annual tree trimming mileage targets + Expand transmission right of ways to provide additional clearance	$5M

TABLE 2 – LIPA STORM HARDENING PLAN

Durability and Resilience initiatives

- Installation of new underground circuits
- Replace deteriorated poles
- Protect substations from flooding and storm surges
- Reinforce substation foundations and structures to withstand higher wind speeds
- Increase strength of selected pole lines to withstand higher wind speeds and storm related flooding along rail corridors and at major road crossings. LIPA moved from a Class 2 pole to a Class H1 pole, ensured no more than two attachments per pole, and does not allow junction boxes on these poles
- Prioritize Transmission Lines for hardening

- Increase strength of selected distribution pole lines to withstand higher wind speeds at distribution circuit supply points (e.g.. riser poles exiting substations, highway crossings), key automated circuit sectionalizing points and major equipment poles
- Increase tree trimming clearance and removal of hazardous trees/limbs outside clearance zones
- Fusing review

Restoration Initiatives

- Continue to expand distribution automation across the system
- Improve Damage Assessment process - field damage reports to be analyzed and entered into the OMS; job level information and estimated restoration times to be been to given to customers much sooner following a major storm
- Upgrade the Outage Management System (OMS)
- Implement a comprehensive resource control system to manage field personnel during restoration (Resources on Demand)
- Expand mobile substation capabilities - purchase of new emergency replacement equipment; mobility for use across the system
- Expand mobile generator capabilities - in-house capability up to 300 kVA; contracts in place for unique circumstances

LIPA made efforts to harden its transmission and stations to withstand a Category III Hurricane. The impact of their storm hardening efforts were noticeable in the impacts of Hurricane Irene (2011) compared to Hurricane Gloria (2005). See Table 3.

	Hurricane Gloria(2005) – Category 4	Hurricane Irene(2011) – Category 3
Landfall	Category 1-2	Category 1
Substation outages	30%	12%
Feeder lockouts	74%	19%
Damaged poles	n/a	½ of Gloria

TABLE 3 – POST HARDENING HURRICANE IMPACTS

Hurricane Sandy landfall by comparison was a Category 1 level.

2.5 PSEG – NEW JERSEY[49]

PSEG serves the New Jersey area.

PSEG's Energy Strong program calls for $3.9 billion in investments over 10 years to harden utility infrastructure and guard against increasingly extreme weather. The utility proposes spending $2.6 billion in the first five years, with a potential investment of another $1.3 billion in the following five years. In May of 2014, PSEG reached an agreement with its Regulator that resulted in a $1.22 billion settlement in its Energy Strong proposal to proactively protect and strengthen its electric and gas systems against severe weather conditions.

Key elements of the approved plan, to be enacted over 3 years, are:

- $620 million to raise, relocate or protect 29 switching and substations that were damaged by water in recent storms.
- $350 million to replace and modernize 250 miles of low-pressure cast iron gas mains in or near flood areas.
- $100 million to create redundancy in the system (distribution automation), reducing outages when damage occurs.
- $100 million to deploy smart grid technologies to better monitor system operations to increase the ability to more swiftly deploy repair teams.
- $50 million to protect five natural gas metering stations and a liquefied natural gas station affected by Sandy or located in flood zones.

Most elements of the hardening plan deal with issue related to flooding. The final settlement was considerably pared down from the original proposal that included additional items such as relocation of rear lot supplies, etc.

2.6 CONNECTICUT LIGHT AND POWER[50]

The Connecticut Light and Power (CL&P) electric distribution system serves approximately 1.2 million customers and covers approximately 4,400 square miles. CL&P's distribution system consists of approximately 16,976 circuit miles of overhead primary construction, and 6,352 circuit miles of underground primary construction, including both direct-buried and underground duct and manhole primary construction.

49 PSEG Settlement Fact Sheet 2014
50 Connecticut Light and Power Company System Resiliency Plan – CLP - 2012

The service territory includes heavily-treed areas, shoreline areas, and hilly terrain. Weather conditions are often severe and include ice and snow storms, heavy winds, thunderstorms, and occasional hurricanes and tornadoes. In the absence of trees, the distribution system infrastructure itself is generally able to withstand wind up to approximately 70 miles per hour and ¾" of radial ice before extensive damage begins to occur.

In 2012, (CL&P) produced a $300M 5-year System Resiliency Plan. CL&P expects that upon completion of the System Resiliency Plan fewer customers will be without service during both normal, day-to-day activities and especially in the wake of major and catastrophic storms and those customers that are without service will be restored more quickly.

CL&P's key goals in the development of the System Resiliency Plan include the following:

i. Achieve significant, sustainable improvement in infrastructure performance during weather events.
ii. Focus the System Resiliency Plan initially on the most impactful activities, with special emphasis on the CL&P's worst-performing circuits.
iii. Provide preference in the System Resiliency Plan to initiatives that also provide important improvement in day-to-day operations and system reliability.
iv. Utilize infrastructure retrofit initiatives (those targeted at achieving an immediate impact by directly seeking out and changing out a portion of the distribution system infrastructure) to achieve both near term and lasting impact.
v. Utilize infrastructure evolution initiatives (those targeted at achieving impact over a much longer period of time, such as modifying the criteria for selection of pole size/class) to continuously improve infrastructure resiliency gradually over the next 40 to 50 years mainly through revisions to construction standards and material selection/usage.
vi. Ensure expected improvement results occur and are sustained.

The CL&P's System Resiliency Plan includes three areas; vegetation management, structural hardening, and electrical hardening.

Vegetation management - enhanced tree trimming ("ETT") (clearing a wider envelope around primary wires, removal of overhanging limbs as well as weak, diseased or leaning risk trees in proximity to wires) and trimming on a shorter cycle. See Figure 13.

FIG 13. OVERHANG BRANCH FAILURE

Structural Hardening - strengthen structures incrementally over a long period of time through design standard and material changes, as well as which field structures may need to be retrofit in the near term to meet new design expectations.

Electrical Hardening - making electrical distribution conductors more resilient to failure during weather events and also utilizes protective device upgrades on overhead circuits to minimize the number of customers impacted when interruptions do occur. CL&P is evaluating the costs, benefits and prioritization of upgrading its older “bare wire” primary conductors with stronger, more tree-resistant covered “tree wire”. Circuit segment sectionalizing will be examined to determine if opportunities exist to minimize customers impacted by adding intermediate protective devices.

The electric supply to critical facilities can be “selectively hardened” to provide much higher levels of power supply security so that they can meet important societal needs. CL&P has identified the following general methods of “selectively hardening” electricity supplies to critical regional/town facilities:

1. Undergrounding distribution lines from the nearest bulk substation to critical facilities.
2. Supplying such facilities with reliable back-up generation that can provide alternative supply for extended periods of time.
3. Developing an electrical micro-grid (to these facilities) with local generation that can “island” and continue to supply the facilities during catastrophic weather events.

CL&P is evaluating the resiliency of its substation facilities relative to extreme weather. This evaluation predominately involves:

1. Identifying substations that may be in areas prone to flooding from either ocean or river initiated events.
2. Determining the extent of flooding that might be expected to occur and its potential impact on substation equipment.
3. Evaluating options for mitigating the impact of flooding on substation equipment.

Tree trimming in the Plan consists largely of two general initiatives, (i) working towards achieving a four-year cycle trim rate(8' (side), 10' (under) and 15' (top) clearance) and, (ii) working towards clearing the most critical circuitry to enhanced trimming specifications in order to reduce exposure of these lines to tree-related interruptions during major storms. Enhanced clearances involve removal of overhanging branches as well as removal of trees, from backbone circuitry and laterals that supply a larger number of customers that because of their condition and/or orientation to distribution lines pose an elevated risk, particularly during major weather events. CL&P expects a reduction of tree-related outages of at least 35% during major storms, and 50% at other times, as a result of fewer interruptions on circuitry that is trimmed to enhanced specifications.

Structural and electrical upgrades are planned for (i) certain critical line crossings (major, limited-access highways and major railroads) and (ii) on circuits with a history of poor reliability performance. These critical line crossings will be structurally upgraded to withstand category 3 hurricane force winds.

CL&P has incorporated both a structural design strength assessment and an inspection-based conditional assessment on backbone and major lateral structures to identify legacy plant that is vulnerable to wind and ice loading.

Electrical hardening upgrades will have three focus areas:

1. Segments of line on the worst performing circuits that are heavily treed and perform substantially poorer than average segments in terms of failures per mile will be considered for electrical rehabilitation or reconductoring (if bare) with either spacer cable or 175 mil tree-resistant, covered wire to reduce the amount of tree-related failures.

2. Segments of line where the bare conductor consists of aged very small gauge copper, will be considered for reconductoring with spacer cable or 175 mil tree resistant, covered wire. Very small gauge copper wire is mechanically frail and has a high propensity to break with relatively small limb contact or on longer span lengths for ice accretion of ¾" or greater.
3. Circuitry will be evaluated for other upgrades including the addition of intermediate protective devices to limit impact of line failure in terms of numbers of customers impacted.

Modifying/increasing the strength of the standard pole class used for distribution construction, composite (as opposed to wooden) cross arms, and modification of pole top configuration are options that are being considered as potential changes to standards.

Implement cost-effective system automation techniques to improve system resiliency through deployment of substation breaker automation, deployment of remotely-indicating right-of-way Smart Grid Sensors, deployment of additional recloser batteries to ensure longer life during major storms.

2.7 FLORIDA POWER & LIGHT[51]

FPL's storm hardening initiative has three key elements:

1. **Application of extreme wind loading ("EWL") criteria to critical infrastructure facilities** - FPL implemented EWL into three wind regions corresponding to expected extreme winds speeds of 105, 130 and 145 miles per hour. FPL began applying EWL to the top critical infrastructure feeders and any associated laterals serving critical customers. Critical feeders include those that serve facilities such as hospitals, 911 Centers, Emergency Operation Centers ("EOCs"), water treatment plants, police and fire stations. EWL is also being applied to poles included in FPL's targeted critical pole program. This program focuses on poles that can impact restoration efforts and includes poles on key highway crossings.
2. **Incremental hardening to certain feeders supplying critical community needs** - The objective of the incremental hardening program has been to increase the overall wind profile of a feeder to a higher wind rating, up to and including EWL. Some of the options that FPL has been using include pole guying, relocation, adding intermediate poles, upgrading of poles. FPL has targeted poles that are critical to restoration efforts and have additional electric equipment such

51 Hurricane Wilma and FPL - 2006

as automated feeder switches/reclosers capacitor banks and multiple circuits.

3. **Construction design guidelines that require EWL for the design and construction of all new overhead facilities, major planned work, relocation projects and daily work activities** - The guidelines are primarily associated with changes in pole class, pole type and desired span lengths to be utilized. For example, prior to this initiative, FPL used class 3 wood poles in critical pole locations however their new design standards call for Class III-H concrete poles in these cases.

After the storms, all Florida utilities implemented ten storm hardening initiatives including:

1. Three-year vegetation management cycle for distribution circuits
2. An audit of joint-use attachment agreements
3. A six-year transmission structure inspection program
4. Hardening of existing transmission structures
5. A transmission and distribution geographic information system
6. Post-storm data collection and forensic analysis
7. Collection of detailed outage data
8. Increased utility coordination with local governments
9. Collaborative research on effects of hurricane winds and storm surge
10. A natural disaster preparedness and recovery program

2.8 CITY OF OCALA UTILITY SERVICES[52]

The City of Ocala Utility Services is a small utility in Florida with 48,456 customers.

The key effort at storm hardening involved the City passing an ordinance in 2007 requiring all electrical facilities for new developments to be designed and installed using underground construction methods. This would lessen exposure to wind damage and speed restoration efforts after future storm events.

The utility standards, policies, guidelines, practices and procedures comply with the extreme wind loading standards of the NESC for:

1. New Construction
2. Expansion, rebuild or relocation of existing facilities

52 Ocala Electric Utility Storm 2013 Hardening Report

The utility has a Remove and Replace tree voucher program that addresses problem and hazard trees on property adjacent to utility easements by providing removal services and rewarding customers who cooperate with replacement vouchers and educational materials as an incentive.

2.9 OKLAHOMA GAS AND ELECTRIC (OGE)[53]

In 2009, OGE instituted a 3 year system hardening program that included:

1) Aggressive vegetation management. OGE concluded that managing vegetation around power lines is one of the most effective strategies for hardening a distribution system. OGE's program consists of several elements:
    a. Removal of risk trees
    b. Using herbicide more aggressively in rural areas
    c. Removing all voluntary trees with diameters of eight inches or less within easements
    d. Establishing four additional feet of clearance over standard 8 feet or 12 feet
    e. Removal of overhangs
    f. Implementation of the "right tree, right place" program

2) Circuit hardening. OGE's program has focused on upgrading circuits to current design standards, strengthening support structures, replacing certain wire conductors, upgrading the grade of construction for certain distribution facilities and targeting undergrounding of certain lateral sections of distribution lines.

2.10 ENTERGY[54]

ETI is located in southeast Texas and serves approximately 413,000 retail customers in 27 counties. ETI's transmission and distribution systems serves customers spread out over approximately 15,000 square miles ranging from the coastline of the Gulf of Mexico (between Port Bolivar and the Texas-Louisiana state line) to the northern boundaries located between 100 to 180 miles inland. ETI's entire service territory is susceptible to damage during severe weather. The most extensive damage has occurred during ice storms and hurricanes.

53 Oklahoma System Hardening Plan – 2009 Commission Order
54 Entergy Texas Inc. Infrastructure Improvement and Maintenance Report - 2011

To harden infrastructure for ice storms, ETI's standards follow the NESC combined ice and wind loading requirements. To harden distribution infrastructure for hurricanes, the following strategies were employed:

- Install minimum class 3 poles on trunk feeders for new construction or replacement in coastal areas
- Expand installation of storm guys, and
- Convert existing wood pole interstate crossings with steel poles.

ETI's distribution vegetation management program uses a multi-tiered approach to total ROW management. These subprograms include:

- Proactive (planned) Maintenance Program - ETI assigns a tailored cycle time (time between trims) to each feeder based on such factors as growth rates, type and density of side and floor vegetation, vegetation-related outage information, time from last maintenance trim, and other reliability metrics.
- Reactive (unplanned) Maintenance Program – this addresses customer requests for trimming, emergency situations, and other maintenance needs outside the annual trim plan.
- Hazard Tree ID & Removal Program - In 2002 Entergy developed the system-standard Danger Tree Patrol Process. This process identifies the timeline for hazard tree patrols and the physical attributes OC's will look for while conducting patrols. Hazard tree criteria includes, but is not limited to:
    - Dead trees with overhang
    - Dead trees straight up or leaning toward the line
    - Trees with a lean toward the line
    - Trees uprooting toward the line
    - Trees in decline, diseased or decaying (e.g.: lighting, base rotting, or weakened)
    - Broken limbs overhanging the line
    - Bad crotch/codominent stems that have branches overhanging the line or angle towards the line
    - Dead branches on a live tree that overhang the line
    - Vines 3/4 or more up the pole
    - Trees that are imminent (e.g.: within 1 or 2 days of falling) danger to the conductor, use the reactive process

- "Skyline" Overhang Removal Program - the removal of any limb capable of falling or hinging down upon energized conductors. ETI employs skylining on a limited basis, primarily on the main trunk of feeders, to decrease the potential for outages on these high customer count areas of line.
- Herbicide Application Program – targets vine problems for herbicide treatment in fast-growth areas and to destroy all tall growing woody tree species from under the line, promoting grasses and other non-woody plant species, and creating more easily accessible ROW's.
- Tree Growth Regulator (TGR) Program - the application of tree growth regulators that will allow for the increase in cycle time clearing

2.11 SUMMARY OF LARGE UTILITY HARDENING EXPENDITURES

The Table 4 summarizes the program cost and duration for a number of the larger utilities identified in this report. It must be understood that the programs reflect different investment focuses (i.e. some are gas and electric vs just electric) and locational needs whereby investments are geared to specific customer segments and not the overall customer base (i.e. urban focus vs rural focus). Hardening programs are costly and depending on scope, can take many years to implement.

Utility	Customers	Hardening program cost	Hardening program duration
Hydro-Québec	4.1 million	$200 million	6 years
Consolidated Edison	3.3 million	$1,000 million	4 years
LIPA	1.1 million	$500 million	20 years
PSEG New Jersey	2.5 million	$1,200 million	3 years
CL&P	1.2 million	$300 million	5 years

TABLE 4 – HARDENING PROGRAMS EXPENDITURE SUMMARY

2.12 DISTRIBUTION SYSTEM HARDENING - PAPER REVIEW

2.12.1 Best Practices in Storm Response (DistribuTech 2010)[55]

A paper on Best Practices in Storm Response was presented at DistribuTech 2010. The paper covers all utility activities to prepare for, combat and recover from a storm event. A brief mention was made of storm-hardening activities typically undertaken by utilities during normal operation is described below.

55 Best Practices for Storm Response on U.S. Distribution Systems – Lavelle A. Freeman, Gregory J. Stano, Martin E. Gordon DistribuTech

- Florida PSC issued Order No. PSC-06-0351-PAA-E1, requiring the investor-owned electric utilities to file plans and estimated implementation costs for ten ongoing storm preparedness initiatives including a three-year vegetation management cycle for distribution circuits; an audit of joint-use attachment agreements; a six-year transmission structure inspection program; and hardening of existing transmission structures. Some of the more common storm hardening activities include: tree trimming/vegetation management, system design changes, and maintenance activities such as pole inspection/replacement programs

2.12.2 Best Practices in Vegetation Management (Texas)[56]

A paper on Best Practices in Vegetation Management in Texas focused on vegetation management practices for distribution systems at all common distribution voltages. Vegetation caused outages is due to two mechanisms:

1. Mechanical tear-down of electric lines and/or apparatus, causing outages.
2. Electrical short circuits or arcs causing overcurrent faults, most often resulting in operation of system protection devices to clear the fault, thereby causing an outage.

The majority of tear-down conditions are due to trees outside the utility ROW and trim zone. Wind, ice and snow accumulations are the contributing factors to mechanical tear-down situations. Key learning points with respect to vegetation management are:

1. Trees and other vegetation represent less than 20% of all fault causation for non-storm conditions.
2. Mechanical tear-down is the primary (e.g. 80%) cause of vegetation outages. This is exacerbated during storms and/or high winds which cause trees to fall.
3. Electrical contact between a single conductor and live branches is rarely the root cause of a vegetation-caused outage.
4. Single-phase vegetation faults for 15 kV class or lower distribution voltages are rare due to the relatively low voltage gradient from line to ground.
5. Arcing vegetation faults on 15 kV class single-phase feeders are rare absent mechanical forces causing direct phase to neutral (metal to metal) contact.

56 Best Practices in Vegetation Management For Enhancing Electric Service in Texas - Texas Engineering Experiment Station – 2011

6. Higher voltage distribution feeders (e.g. 25 kV, 35 kV) have an increased probability of electrical faults due to vegetation because of the higher voltage gradient.
7. Phase-to-phase vegetation faults occur on 15 kV feeders if two conditions are met.
   (a) The vegetation (e.g. branch) must bridge phases in a mechanically stable way over a sufficient time period to create an arc path by charring and burning the branch (generally requires solid contact on the order of minutes).
   (b) The vegetation must not burn or fall free before a permanent outage occurs (e.g. arcing fault initiating protective device operation).
8. Downed energized electrical conductors represent a fire hazard and an electrical hazard to the public.

The report recommends a move from simple cycle based re-growth clearing to a program that focuses on elimination of overhanging branches and hazard trees in the vicinity of lines, especially heavily loaded three phase circuits. They also recommend using condition based scheduling of vegetation management to optimize the value of funds expended (Reliability Centered Vegetation Management). This would include documented inspection criteria for vegetation specialists.

Mandating a continual minimum clearance distance of vegetation from conductors will not achieve reliability objectives. Vegetation intrusion within a few feet of conductors has little effect on overall reliability (due to high impact of tear-down events).

Finally, ensuring that tree planting on municipal streets under powerlines is coordinated with the local utility will ensure that inappropriate trees are not being planted.
The best practice with respect to vegetation management budgets must include long term, sustainable, and consistent funding that is not subject to wild swings or instability.

2.12.3 Ice Resistant Tree Populations - (Trees and Ice Storms – Second Edition)[57]

The University of Wisconsin has issued a publication "Trees and Ice Storms" that classifieds tree species by their susceptibility to ice storms as shown in the Table 5.

57 Trees and Ice Storms – University of Illinois - 2006

Susceptible	Intermediate	Resistant
American basswood	American beech	Armur maple
American elm	Boxelder	Baldcypress
Bigtooth aspen	Chestnut oak	Balsam fir
Black ash	Choke cherry	Bitternut hickory
Black cherry	Douglas-fir	Black walnut
Black locust	Eastern white pine	Blackgum
Black oak	Gray birch	Blue beech
Bradford pear	Green ash	Bur oak
Butternut	Japanese larch	Catalpa
Common hackberry	Loblolly pine	Colorado blue spruce
Eastern cottonwood	Northern red oak	Crabapple
Honey locust	Paper birch	Eastern hemlock
Jack pine	Pin oak	Eastern redcedar
Pin cherry	Red maple	European larch
Pitch pine	Red pine	Ginkgo
Quaking aspen	Scarlet oak	Hophornbeam
Red elm	Scotch pine	Horsechestnut
River birch	Slash pine	Kentucky coffeetree
Siberian elm	Sourwood	Littleleaf Linden
Silver maple	Sugar maple	Mountain ash
Virginia pine	Sycamore	Northern white cedar
Willow	Tamarack	Norway maple
	Tulip poplar	Norway spruce
	White ash	Ohio buckeye
	Yellow birch	Pignut hickory
		Shagbark hickory
		Swamp white oak
		Sweetgum
		White oak
		White spruce
		Witch-hazel
		Yellow Buckeye

Adapted from Hauer et al. (1993) and published reports from 42 primary publications. Species ratings are consistent with the first edition of this publication except for green ash, pin oak (both previously rated as susceptible) and bur oak (previously rated as intermediate).

TABLE 5 – ICE STORM SUSCEPTIBILITY OF TREE POPULATIONS[58]

58 Trees and Ice Storms – University of Illinois - 2006

Tree species that have “included” bark (bark that is sandwiched in the narrow junction between two dominant tree stems) are particularly susceptible to ice storm damage and breakage. The publication notes that storm damage can be placed into five categories:

1. broken branches,
2. trunk bending,
3. splitting of main or co-dominant stems,
4. complete trunk failure,
5. tipping or up-rooting.

A proactive program that examines and assesses trees for any of the above potential hazards is important to mitigate future effects of severe weather.

2.12.4 MEA Report – Design and Component Failure Analysis from the 1998 Ice Storm (2000)[59]

This report is in the PowerStream library. The report is a survey of distribution utility responses (13) to the damage caused by the ice storm.

The key cause of outages was broken or downed lines caused by tree branches falling on lines. Secondary cause was broken or downed lines caused by ice loading alone. Damaged poles and insulators were the least frequent causes of outages.

The respondents indicated that armless construction (no cross arms), short spans, aggressive tree trimming, use of polymer insulators and adequate guying would go a long way to mitigate future outages. A number of services were lost by the service entrance rack being pulled away from the home. It was recommended that bolts, rather than screws, be used to secure the service entrance rack to the building.

The report identified seven different approaches to improving the reliability of the distribution system:

1. Re-building the system to a higher factor of safety (2.0 instead of 1.6)
2. Reducing span length
3. Installing periodic ground anchors in the direction of the line in long straight sections to act as dead-end structures
4. Avoid using high aspect ratio ground anchors

59 MEA Report – Design and Component Failure Analysis from the 1998 Ice Storm (2000)

5. Increasing the mechanical strength of components covered in CSA Standards
6. More aggressive vegetation control
7. Separation of communication and distribution systems from service poles

The top two approaches were judged to be vegetation control and reducing span length. Also higher loads on lines stressed guy wires and anchors beyond the mechanical limits of high aspect ratio guying systems causing guying failures and pole displacements.

2.12.5 MEA Report – Effectiveness of Maintenance Practices and Retrofit Designs in Improving Distribution System Reliability[60]

This report is in the PowerStream library. The report is a survey of distribution utility responses (19) to identify initiatives to decrease outages on the Distribution System.

Overhead plant improvement recommendations included replacing open wire with "tree proof" cable in highly treed areas; reducing pole fires through mitigation measures; and implementing cyclic vegetation management.

2.12.6 TD World storm hardening article (Quanta Technologies)[61]

This article compiled a list of the 12 best practices for distribution system hardening including:

1. Pole test and treat- ensure no pole has lost more than one-third of its original strength and no pole is likely to have lost more than one-third of its original strength before its next scheduled inspection.
2. Feeder inspections - have a formal feeder inspection program that periodically examines feeders for problems that will likely lead to an outage during normal and/or storm conditions.
3. Attachment audits - Third-party attachment audits should occur, at a minimum, every five years for all three-phase main feeder trunks
4. Foreign owned poles - ensure foreign-owned poles are in as good of shape as their own poles in terms of remaining strength and loading.
5. Setting depths - develop standards and processes to ensure the foundation of distribution poles will not fail before the pole(s).

60 MEA Report – Effectiveness of Maintenance Practices and Retrofit Designs in Improving Distribution System Reliability

61 Storm Hardening the Distribution System – TDWorld Magazine - Richard E. Brown – 2010

6. Loading calculations - have systems and processes in place to ensure poles do not become overloaded after they are initially installed.
7. Grade B construction - have an explicit process to review new construction and rebuilds to decide whether the system should be built to Grade B (NESC standard), or equivalent, rather than a weaker standard.
8. Non-wood poles - have standards for at least one type of non-wood distribution pole as a viable alternative should this be necessary for hardening
9. Post-storm data collection - have a plan that has trained staff collect data on distribution damage sites immediately after a storm subsides.
10. Hardening tool kit - develop a hardening tool kit that consists of a set of approved approaches to hardening and an application guide for their use.
11. Like-for-unlike replacement - enact systems and processes that allow the system to be gradually hardened through normal work processes.
12. Strengthen critical poles - identify critical poles that are highly undesirable to fail during a major storm. Take targeted actions to strengthen these poles.

2.12.7 Edison Electric Institute – Before and after the storm (2014)[62]

This report by the Edison Electric Institute is a compilation of recent studies, programs, and policies related to storm hardening and resiliency.

System hardening - physical changes to the utility's infrastructure to make it less susceptible to storm damage, such as high winds, flooding, or flying debris.

Resiliency - the ability of utilities to recover quickly from damage to any of its facilities' components or to any of the external systems on which they depend.

Hardening measures include:

- Undergrounding – eliminate poles and bury distribution lines to avoid the impact of severe weather. Has aesthetic benefits but tends to be cost prohibitive. Selective undergrounding is a compromise solution.

62 Before And After The Storm – EEI – 2014

- Vegetation Management – maintaining clearances is not sufficient. Targeted vegetation management of hazard branches and trees is more effective. Need to coordinate with municipalities to control tree planting beneath power lines.
- Higher Design Construction Standards – a targeted approach is recommended. Focus on the local conditions of the distribution facilities. Identify critical, poor performing, weak elements and replace them with improved system designs (e.g.. composite poles, guying, stronger pole classes, etc.). Have a robust inspection and maintenance plans to identify and mitigate potential structural problems.
- Smart Grid – utilize a looping system with distribution automation to detect outages and reroute power. This may not be effective in large tear-down situations – nowhere for the power to go.
- Microgrids – like the Smart Grid, it is vulnerable to large tear-down events.
- Advanced Technologies – hydrophobic nano-particle coatings on distribution lines may inhibit the formation of ice.

2.12.8 Hardening and Resiliency- U.S. Energy Industry Response to Recent Hurricane Seasons (2010)[63]

This report considered storm hardening measures in the energy sector. Electricity hardening measures noted were:

- Wind Protection
  - Upgrading damaged poles and structures
  - Strengthening poles with guy wires
  - Burying power lines underground
- Flood Protection
  - Elevating substations/control rooms
  - Relocating/constructing new lines and facilities
- Modernization
  - Installing asset tools and databases
  - Deploying sensors and control technology

Wind impacts on trees and powerlines are noted in the Table 6.

63 Hardening and Resiliency U.S. Energy Industry Response to Recent Hurricane Seasons – DOE – 2010

Category	Winds	Impact to Trees	Impacts to Power Lines
1	74-95 mph	Large branches of trees will snap and shallow rooted trees can be toppled.	Extensive damage to power lines and poles will likely result in power outages that could last a few to several days.
2	96-110 mph	Many shallowly rooted trees will be snapped or uprooted and block numerous roads.	Near-total power loss is expected with outages that could last from several days to weeks
3	111-130 mph	Many trees will be snapped or uprooted, blocking numerous roads.	Electricity will be unavailable for several days to a few weeks after the storm passes.
4	131-155 mph	Most trees will be snapped or uprooted and power poles downed.	Power outages will last for weeks to possibly months.
5	> 155 mph	Nearly all trees will be snapped or uprooted and power poles downed.	Power outages will last for weeks to possibly months.

TABLE 6 – SAFFIR-SIMPSON HURRICANE WINDS AND SELECTED IMPACTS[64]

Hardening for wind, for distribution systems, usually involves upgrading wooden poles to concrete, steel, or a composite material, and installing guys and other structural supports. Proper placement of guy wires can increase the ability of a pole to withstand higher winds. A pole truss system may also achieve similar results by increasing the pole bending capacity by one or more classes.

Elevating substations is effective hardening against flooding.

Distribution automation and sensors can lead to self-healing grids as part of a modernization hardening strategy.

3. FORECAST WEATHER DISTRIBUTION INFRASTRUCTURE IMPACTS SUMMARY

A review of climate change projections and distribution system hardening practices by the utilities examined in the previous section provides a number of potential key climate change impacts and responses. Some of these can be considered by PowerStream to address forecasted climatic change related impacts to the distribution system.

64 NOAA, National Weather Service, National Hurricane Center, http://www.nbcnoaa.gov/pdf/sshws_table.pdf accessed May 22, 2010

3.1 TEMPERATURE IMPACTS

Overall assessment is that temperature changes by themselves will not present a problem to the distribution system that warrants "hardening" efforts. Equipment loading will have to be monitored to ensure that sufficient capacity exists to handle the increasing frequency of heat waves. Drought conditions would warrant the review of soil thermal resistivity at station cable egress to ensure cable ampacity is not compromised – avoid thermal runaway effects.

3.2 HEAVY RAIN/FLOODING IMPACTS

The impact of heavy rains and localized flooding is of concern to ground level and below grade infrastructure vulnerable to water damage. For PowerStream this vulnerability may exist in certain transformer and municipal stations that have below grade equipment or ground level equipment and is in a flood prone area. Equipment examples include batteries and charging units in transformer station basements, relay cabinets, etc.

Hardening options would be to consider moving vulnerable equipment out of station basements to ground level locations and to ensure that vulnerable ground level equipment is above any known localized historical flood levels.

3.3 HIGH WIND VELOCITY/WIND GUSTS IMPACTS

Increasing average wind velocity and peak wind gusts will impact pole structures. Moving to higher grade construction or loading safety margin at critical poles or locations can mitigate against this. Selective undergrounding of portions of the distribution system will also work but is a much more expensive alternative.

3.4 TORNADO IMPACTS

Tornados are infrequent events and almost impossible to protect against with an overhead system as funnel wind speeds will exceed even the most robust construction standard.

3.5 FREEZING RAIN IMPACTS

As with the high winds scenario, higher construction standards and selective undergrounding can mitigate against ice storm impacts. In addition, the installation of breakaway connectors, enhanced tree clearances and third party interactions will reduce the overall damage impact.

4. POWERSTREAM STAFF CONSULTATIONS

A number of key PowerStream staff were consulted on their experiences and thoughts on the key issues of the 2013 ice storm and what hardening ideas/actions could be investigated for adaptation to mitigate the effect of future storms.

Some key observations were:

- Most of the 2013 ice storm problems were due to limbs on lines even in recently cleared areas; ice did not bring down infrastructure
- Most trees and limbs causing the problems were outside normal trim zones; hazard trees/limbs outside the trim zone need to be addressed
- Overhead secondaries are not part of the tree trimming program; this is where a number of the problems were
- Backyard construction was the most problematical to deal with from access and restoration perspective; left for last because most labour intensive and time consuming to restore
- Few failures on arterial streets; ice accumulation flashovers resulted in a few pole fires
- Most failures were in heavily treed side streets and rural areas
- Some pole locations are relatively inaccessible once installed (i.e. 407 ramps)
- A number of customer standpipes were damaged as a result of tree/tree limbs taking down the overhead service cable. In a few cases customers had to wait days, even after power was available, to get their services repaired by electricians
- Current overhead and underground standards are good but legacy construction is less robust (pole class and guying)

Some of the key ideas were:

- Remove, at a minimum, the primary from rear lots; this will make it easier for restoration purposes; mitigates weather and animal issues with respect to primary conductors
- In short term, focus on addressing rear lot tree trimming
- Consider expanded uses of insulated tree cable in heavily treed areas
- Coordinate with municipalities to ensure future tree planting along boulevards is compatible with existing overhead powerlines
- Incorporate secondary tree trimming into the vegetation management program

- Investigate more robust alternatives to wood poles (i.e. composite); may be more resistant to pole fires in high contamination areas
- Investigate the use of breakaway clamps for conductors
- Use electronic type reclosers for radial and backlot feeds instead of fuses
- Eliminate radial feeds; ensure loop configuration is in place so all have alternative supply points; diversify supply routes to large commercial customers
- If possible, put highway crossings underground – coordinate with bridge construction to get ducts installed in bridge structure
- Focus on hardening deadend and crossing poles; more storm guying in general
- Increase sectionalizing of feeder segments and distribution automation, especially in high treed area
- Underground major intersections and other strategic sections of line; diversify feeder routing
- Enforce underground supply as policy in undeveloped areas
- Review lifecycle cost of overhead versus underground with the cost of outages to customers included

These consultations were taken into consideration and incorporated into the practice review and hardening recommendations as deemed appropriate.

5. POWERSTREAM PRACTICES AND PHILOSOPHIES - HARDENING REVIEW

5.1 VEGETATION MANAGEMENT

5.1.1 Background

PowerStream's vegetation management practice is documented in its internal procedure ENG-P-018 Vegetation Management Procedure.

A three year tree trimming cycle has been adopted for the entire service area. It consists of annual cycle clearing (1/3 of PowerStream's service territory) and an annual program to address vegetation impacting worst performing feeders. To date the actual cycle clearing time for the whole service area is in the 4-5 year range however this is expected to improve in the near term as resources are allocated to achieve the 3 year cycle target.

Clearing is based on tree species and results in line clearances, between cycles, of 0.1 m – 3.5 m.

The program is limited to PowerStream plant on road rights of way and easements (including dedicated resources to address rear lot easements). It addresses PowerStream owned secondary service conductors crossing private property on an exception basis. If a customer calls with concerns about vegetation around the service conductor, PowerStream will respond and trim the vegetation. Otherwise the secondary lines are not dealt with. There are typically 15-20 calls a week related to service line trimming, quite a number of them related to back lot feeds. Since the ice storm, calls have increased to 20-30 a week. The program also does not address customer owned conductors, typically long span rural primary runoffs. The customer is considered responsible for vegetation clearing around lines that they own.

The line clearing activities are performed as per procedures outlined by PowerStream, the Occupational Health and Safety Act and its Regulations, the IHSA Rule Book and the IHSA Safe Practice Guide - Safety in Line Clearing Operations.

Line clearing performed in a given cycle is recorded on a Vegetation layer in the GIS.

On the strategic side, PowerStream has instituted tree planting coordination meetings with municipalities and the Region to ensure that incompatible tree species are not planted under or adjacent to powerlines.

5.1.2 Analysis

PowerStream's vegetation management program is typical of most utilities and as such can be said to follow good utility practice. The fixed cycle approach tends to result in all areas of the distribution system receiving equal attention which by itself can lead to over/under attention to vegetation growth in different areas. Discussions with staff have indicated that the fixed cycle approach is somewhat augmented by identification of vegetation "hot spots" (specific calls received from customers). This results in "out-of-cycle" pruning for select high vegetation growth areas. In addition to annual line clearing, vegetation congestion around worst performing feeders is targeted (worst peforming feeders identified by reliability deterioration from all causes). By incorporating a focus on "hot spots" and worst performing feeders, PowerStream has adopted aspects of reliability centered maintenance for vegetation which is considered a best practice in vegetation management. It will help ensure that funds are focused on where they will achieve the greatest impact on improving tree contact related reliability. This will have little impact on mechanical teardown (trees/limbs breaking wires and other distribution components) related reliability.

As seen in the 2013 ice storm, a number of outages were due to mechanical line teardown or contact due to branches and falling trees outside the trim zone (generally trees located on private property). Some damage was done to customer service standpipes and secondary lines as a result of teardowns. Severe storm teardowns and contacts from trees outside the trim are not mitigated through standard line clearances for trees. Severe winds and ice storms can result in limbs and trees outside the trim zone coming into contact with lines causing outages and at times, bringing them down. Mechanical teardown and severe storm contact can be mitigated through vegetation management programs that combines enhanced clearances and a proactive hazard tree program to remove potential teardown/contact sources.

PowerStream website information on vegetation management provides information to customers regarding planting and maintaining vegetation near powerlines and electrical equipment. As noted above, branches and trees outside the trim zone account for most mechanical teardowns. PowerStream website information does not address the need for proactive assessment of hazard trees on customer property outside the trim zone.

Tall 4-circuit poles present trim issues for vegetation at or over the top of the pole structure. Forestry vehicles currently have an 80 feet working height on road allowance and less to deal with field side issues. Overhang issues on 4-circuit polelines are difficult to deal with due to limited reach of forestry equipment.

A gap that exists at present is the treatment of overhead secondary services. Service line issues are dealt with on a reactive, not proactive basis. Secondary services, either front lot or rear lot, are addressed by exception in the existing line clearing program.

5.1.3 Summary of good utility practice in vegetation management

- PowerStream has adopted a 3 years tree trimming cycle to standard trim clearances including rear lot easements;
- PowerStream has adopted an annual vegetation management focus on worst performing feeders;
- Out of cycle "hot spot" issues addressed;
- Line clearing records are maintained in the GIS;
- PowerStream liaises with municipalities to coordinate tree planting below/adjacent to distribution lines

5.1.4 Potential practice adaptations

In reviewing best practices for vegetation management, there are a number of initiatives that PowerStream should consider adopting to improve its vegetation maintenance program:

1. Consider enhancing the trim zone - increase tree trimming clearances. Minimum clearance at 27.6 kV is currently 1.0 m with a maximum clearance of 1.5 m – 3.5 m depending on tree species. Approaches by other utilities have resulted in enhanced clearance with some adopting a "blue sky" approach to overhanging limbs. Complete overhead clearance is preferred to eliminate limb collapse on the circuits below. In absence of complete above wire clearance, consider the use of "tree cable" (i.e. Hendrix) to minimize contact issues. This would be especially beneficial in rear lot overhead where the single phase primary supply would be retained. View limbs as levers that can be pulled down by snow, ice, or wind stresses. By proactively shortening the limb length, the likelihood that a branch will break under weather stresses can be reduced. A target of 25 mm radial ice carry will cover most ice storms encountered. Limb pruning radius will be species and condition dependent. It should be noted that in all papers and practices reviewed, line clearing by itself is deemed insufficient to address vegetation related outages as a result of severe storm situations.

2. Consider incorporating aspects of reliability centered maintenance in the fixed pruning cycle program. A reliability centered program relies on rate-of-change tree-related outages, increase in hot spot frequency and expert assessment to determine where tree trimming is required. This will enhance the fixed cycle program in allocating resources. Fixed cycles tend to spend too much attention on areas that have good reliability history but perform better when augmented by "out-of-cycle" pruning. The vegetation management program could be documented in detail (scope, responsibilities, contractor requirements, planning, strategy, records, etc.).

3. Consider instituting a "Hazard Tree" program that identifies trees outside the trim zone that are tall enough (adopt ESA criteria) to contact the overhead distribution system and are also dead, declining, diseased, or otherwise structurally unsound. This can be incorporated as part of the 3 years trim cycle. Work with municipalities and home owners to expedite removal of hazardous trees/limbs outside clearance zone. A tree voucher program, that

addresses problem and hazard trees on property adjacent to utility easements, has been put in place by other utilities. It works by providing removal services and rewarding customers who cooperate with replacement tree vouchers and educational materials as an incentive.

4. Consider including proactive service line (when owned by PowerStream) clearing on private property as part of the 3 years trim cycle. These lines are owned by PowerStream and in general the responsibility for maintaining plant is a function of ownership. This means that line clearing responsibility, and ensuring plant is in a safe condition, extends beyond the plant on road allowance and also encompasses PowerStream plant private property. PowerStream, like other Ontario LDCs, has the authority under the Electricty Act to "enter and maintain any land for the purpose of cutting down or removing trees, branches or obstructions". This should be explicitly mentioned in the Conditions of Service.

   Most utilities in Ontario do not trim secondary lines on private property or do so on an exception basis. There are a few (i.e. Sault Ste. Marie. PUC) that do and explicitly state so:

   "It is the responsibility of PUC Distribution to maintain safe minimum clearances between trees and power lines as well as service lines that feed homes and businesses. PUC will only remove trees outside this safe limit when the tree poses a direct danger of falling into the line causing a hazard…..PUC Distribution is responsible to trim trees both within the municipal roadway and on private lands to the prescribed safe clearances from power lines."

   These set the bar for a forward looking standard of duty of care for the residential service class as a whole.

5. Consider continuing to educate and inform the municipalities, property developers and clients on vegetation near powerlines and how they can help to keep the network safe (i.e. add to PowerStream website – "Homeowners Guide to Maintaining Your Trees after Ice Storms and Preventing Further Damage"). Proactive education will mitigate future vegetation related issues in severe storm situations.

6. Consider training design staff and construction in basic vegetation management to help identify potential problems. A ½ day or 1 day course by a trained arborist can identify vegetation conditions that should be brought to the attention of the Line Clearing coordinator.

5.2 BACKYARD CONSTRUCTION

5.2.1 Background

PowerStream's position on residential backyard construction is documented in the Rear Lot Remediation Plan (December 2013). The report recommends a long-term remediation program which starts in 2015, and continues for 15 years to 2029, until all residential rear lot locations have been addressed. A total of 4,058 residential customers (1.1% of PS total) are currently fed from rear lot services. Some rear lot remediation work is currently underway and so for an expected 2015 program start there will be 3589 customers fed from rear lots to be scheduled for remediation. The average age of the rear lot fed areas is 45 years. PowerStream four remediation options:

- **Option 1** – Replace existing rear lot with new rear lot overhead
- **Option 2** – Replace existing rear lot with new front lot overhead
- **Option 3** – Hybrid – Install primary cable & transformer at front lot underground; replace/keep pole & secondary at rear lot
- **Option 4** – Replace existing rear lot with new front lot underground

Option 1 is the least expensive capital option and has been chosen as recently as 2005 when the Kleinburg rear lot supply was rebuilt and converted from 8 kV to 16 kV primary supply. It maintains the status quo of both the primary and secondary supply in the rear lots along easements.

Option 2 while feasible, is not considered achievable due to expected public and political backlash against new overhead plant in an "underground" area. An Option 1 program would cost approximately $27M (~$7.5k/customer).

Option 3 eliminates primary supply vulnerability but maintains secondary supply vulnerability to extreme weather conditions. The total cost of the program, based on Option 3, is approximately $59.5M (~$16.6k/customer).

Option 4 eliminates both the primary and secondary vulnerability to extreme weather conditions and potential political repercussions due to misplaced future reliability expectations. The total cost of the program based on Option 4 is approximately $87.4M, (~24.3k/customer).

Stakeholders interviewed were in general agreement that the rear lot supplies are problematical in both normal and severe weather conditions. There is anecdotal consensus that overall reliability will improve with the removal of rear lot primary in that primary related outages due to vegetation contact would be eliminated leading to less trouble calls and reduced trimming needs. It would be also somewhat safer with the primary removed for both workers and the homeowners. The retention of rear secondaries will continue to pose operational and customer service challenges. The key issue is the high cost and limited value to completely convert these areas to a more robust form of supply that can withstand severe weather impacts.

5.2.2 Analysis

PowerStream has developed a comprehensive strategy to remediate existing residential rear lot construction by 2029. The 15 year plan does not eliminate rear lot construction. In a number of cases, primary supply will be moved to the front yard and undergrounded. This will effectively mitigate the effects of extreme weather on the primary supply in the local area. In most, if not all cases, the secondary supply will remain in the rear and remain vulnerable to extreme weather conditions. Upstream overhead primary will also remain vulnerable to the extremes of severe weather.

The 2013 ice storm demonstrated the vulnerability of front and rear lot overhead secondary services to extreme weather events. Most of the problems were with the secondary services being pulled down due to vegetation issues. The rear lot primary and secondary bus was not as impacted in this particular set of circumstances, other than fuses operating on the overhead rear primary supply. This may not be the case under future scenarios if extreme weather events exceed the conditions experienced in 2013.

Environment Canada indicated that between 20 and 30mm of freezing rain fell in the area between Niagara and Trenton as a result of the 2013 ice storm[65]. Toronto Pearson Airport experienced 43 hours of freezing rain. The City of Markham reported that they had 20 – 25mm of ice accumulation[66], the City of Vaughan had 25mm and the City of Barrie had 20mm[67].

According to the Toronto Hydro Electric System PIEVC Pilot Case Study (2012) freezing rain storms lasting at least 6 hours have a probability of occurring every other year (0.65 annual probability) and can bring ice accumulation levels of up to 25mm. Multiday ice-storms with $\geq$ 25 mm of ice accumulation occur less frequently (0.06 annual probability). **With between 20**

65 Environment Canada – Canada's Top Ten Weather Stories for 2013
66 Ice Storm – December 2013 / Presentation to General Committee January 8, 2014
67 Ontariostorms.com

and 25mm of ice accumulation being reported in the PowerStream service territory, the 2013 ice storm can be considered a moderate one in line with the criteria for the 0.65 annual probability category. Very little if any PowerStream plant was brought down by ice accumulation that one would expect from an ice storm with > 25mm ice accumulation that would fall in the 0.06 annual probability category. This is also supported by the TRCA study that indicated that daily freezing rain amounts of less than 25 mm are expected to occur 1.25 to 2 times per year.

Climate change forecasts indicate that ice storms such as that experienced in 2013 are increasing in frequency (moving from once every two years to more of an annual occurrence). More severe ice storms with greater accumulation (>25 mm) that can take down wires and poles by weight alone, are expected once every 14 years according to the Toronto Hydro Electric System PIEVC Pilot Case Study (2012). The TRCA study was even more conservative with a range of 4 to 10 years repeat time for such storms.

This Option 3 remediation proposal will leave the rear lot secondaries exposed to extreme weather (mitigated by the vegetation management program) and it is likely that the customers will be impacted by service teardowns in future ice storms similar to what they experienced in 2013. It is expected that the underground primary supply will not be as impacted as in the past so outages may be limited to more individual homes versus all rear lot homes unless the secondary bus is torn down. Some secondary mitigation measures, such as breakaway connectors, may limit future damage to the customer service entrance equipment, but operational difficulties in accessing rear lots will lengthen repair and restoration times as in 2013. There would be less need for electricians to rebuild customer service stacks and get ESA permits for restoration.

The overall reliability of rear lot secondary overhead is similar to front lot overhead secondary. Both are impacted by weather and vegetation events. It is only in extreme weather conditions, as in the 2013 ice storm, that the differences in accessibility and restoration times between back and front are magnified. This needs to be taken into account in determining the “value” gained from the rear lot remediation options.

If Option 3 is chosen, it needs to be considered together with a program (material & labour) to install secondary breakaway connectors. This effectively raises the cost of Option 3 to $60.6M.

The 2013 ice storm also demonstrated the need to accelerate the mitigation program. The current program pace results in poles and hardware being replaced at points well past the Typical Useful Life standard (45 years) that have been reported to the OEB. With expected increases in return times in December through to February, it is quite feasible to have multiple freezing rain events, of varying ice accumulation and wind strength, over a 15 year period. Customer outcomes, expressed through direct feedback and municipal representative feedback to PowerStream staff, expect that appropriate actions will be taken to prevent reoccurrence of backlot problems that occurred as a result of the 2013 ice storm.

Of related interest is Toronto Hydro's rear lot conversion program. Since 2007, Toronto Hydro has embarked on a 20+ year program to convert rear lot overhead supply to front lot underground supply. The program is a full conversion program where the primary and secondary lines are removed from the rear lots and placed underground in the front lots. The poles have been left in the rear lot for the telecommunication provider needs (pole ownership transferred over). The cost to do this has been around $30k per customer with the biggest cost being the work to trench/bore secondary cables to the meter bases in the back of each customer's house. Annual program expenditures have been around $15 - $20M and represent a positive NPV expenditure for rate case financial analysis. Future annual expenditures are in the $10M range. All conversion costs have been borne by Toronto Hydro and are rate base funded. Customer communication is key in the successful implementation of the conversion program (i.e. equipment location, property disruption, etc.).

5.2.3 Summary of good utility practice in Backyard Construction

- PowerStream has a documented asset management program for rear lot residential plant. The long term plan is to move most of overhead rear lot primary supply to front yard underground supply. The Program has been smoothed ($3.2M/year + 3% inflation) to mitigate rate impacts. Prioritization is based on area end-of-life status.

5.2.4 Potential Practice Adaptations

In reviewing PowerStream's practices for backyard construction, there are a number of initiatives that PowerStream should consider adopting:

1. Consider accelerating the mitigation program to expeditiously deal with plant installed in the 1950s through to the 1970s that are already past the Typical Use for Lies (TUL) pole point (45 years). Consider a 6 year-$41M program to expedite replacement of pre-1980 vintage plant. This will partially address expected customer outcomes and mitigate risk of backyard plant subject to a future freezing rain event similar to the 2013 ice storm. Post 1980 plant ($18.6M program) can be scheduled for the 2024 – 2030 period.

2. For Option 3, consider installing breakaway connectors on overhead secondary services. Expedite installation, as a separate program, if current 15 year backyard remediation program is to be maintained. A three year install program is recommended. This will mitigate the problem of customer standpipe damage due to teardowns.
3. Consider Option 4 to completely eliminate residential rear lot supply. This will address expected customer outcomes and mitigate risk of backyard plant subject to a future freezing rain event similar to the 2013 ice storm. A 10 year - $60M program could expedite replacement of pre-1980 vintage plant. Post 1980 plant ($27.4M program) can be scheduled for the 2025 – 2030 period.

5.3 UNDERGROUNDING PRACTICES

5.3.1 Background

PowerStream's undergrounding practice/philosophy is documented in its Conditions of Service and Underground relocation policy. Overhead construction has been PowerStream's standard method of distribution on arterial streets as it is a lower cost of installation, it provides a high degree of flexibility in dealing with changing infrastructure requirements due to new commercial customers coming on stream, is not impacted by the space issues for required switching units that an underground system would need and has less technical barriers. For example, in the PowerStream north service area, the 44 kV distribution system is overhead as there are technical barriers related to very limited product availability for undergrounding 44 kV, particularly in regards to compact switching units. 44 kV undergrounding is not technically practical except for limited straight runs. In summary, the general practice is to consider undergrounding where overhead supply facilities are not possible for various reasons (i.e. limited building clearances). Note that this is not applicable to residential and commercial subdivisions where municipal by-laws and subdivision agreements require the developer to install underground plant for aesthetic reasons.

Section 3 of the Conditions of Service indicates that residential and general service customers are eligible to obtain overhead or underground service connections. This would be determined by the nature of the infrastructure in the area for single site plan applications. For example, an applicant in overhead area would likely get an overhead service connecting (depending on service size and voltage). Residential and commercial/industrial subdivisions are generally supplied via an underground distribution system as a result of municipal planning requirements that require undergrounding of power lines and other infrastructure (phone, cable, etc.).

On arterial streets, PowerStreams standard practice to install overhead facilities has resulted in 2 and 4 circuit pole lines to accommodate growth. This has been a flexible installation practice with a lower impact on rates compared to an underground equivalent installation. There is a high cost premium to install an underground system along arterial streets.

Recent efforts by municipal and transit authorities to build transit corridors along key arterial streets have reinforced the principle that the premium for constructing underground versus overhead should be paid by the requesting party and not the ratepayer.

5.3.2 Analysis

PowerStream's underground policy on arterial streets is typical for a number of major urban utilities. Where overhead construction can be used, it is and when space/clearances for overhead construction are not available, then underground construction is used. This has resulted in increasing density of circuitry on poles (moving from 2 to 4 circuits) as the municipalities have grown. 4 circuit construction on poles places a considerable amount of load (~ 60 MVA @ 27.6kV) at risk of disruption due to extreme weather events or other causes. Most non-weather disruptive events (i.e. foreign interference) affect a single pole location and are dealt with in a timely manner. Weather disruptive events can impact multiple poles/areas and require considerable time to restore to normal conditions (i.e. June 17, 2014 wind burst that resulted in loss of a 12 pole section along Warden Avenue in Markham and 46 hour outage to directly affected customers).

Most residential and commercial/industrial subdivisions are at low local weather related risk since they are designed as underground supply areas. They are impacted by damage to upstream plant that is vulnerable to severe weather events. Some subdivisions are supplied by overhead distribution lines.

Due to cost concerns, industry undergrounding hardening measures have ranged from a "going forward" approach to undergrounding new construction and only undergrounding existing construction when plant is to be replaced or relocated to selectively undergrounding portions of the overhead system (strategic undergrounding). Others have taken positions on the maximum number of circuits that will be allowed on overhead facilities (e.g. 2 circuits) and as such adopted a fixed "line-in-the-sand" beyond which underground facilities are utilized. Positions such as requiring all new service connections to be underground, would mitigate the impacts (i.e. downed service conductors, standpipes ripped off buildings, etc.) that were seen during the 2013 ice storm.

Fixing a limit to the amount of overhead circuits on a poleline has merit from a risk perspective, aesthetic perspective and restoration perspective. An underground 2 circuit system has the potential to backup a parallel 2 circuit overhead supplied area in the event of catastrophic damage to the overhead system. Appropriate interconnections with the supply area would be required. There are approximately 1200 poles of 27.6 kV 4-circuit in the system which equates to approximately 49 km of 27.6 kV 4-circuit poleline. Converting the top 2 circuits to a parallel underground supply would be in the order of $157M. A side benefit of this would be that the remaining two overhead circuits would likely be retroactively “hardened” as a result of the original design. This should be considered as adding “value” to offset the undergrounding cost. For example, an analysis of the 4-circuit pole line on Warden that collapsed in the wind burst indicated that it had been designed to withstand a 104kmh wind. By removing the top two circuits and leaving everything else in place, the 2-circuit poleline could have withstood a 152km/h wind (a 46% improvement in relative strength). The rebuild cost for the Warden poleline was approximately $520,000 – approximately $43.3k per pole.

Undergrounding the entire distribution system is an option but it is very expensive. A previous high-level analysis by PowerStream estimated a cost of $4.5 billion to underground the entire system.

Strategic undergrounding (converting existing high value overhead lines to underground) is generally targeted to improve the security of supply of critical facilities (i.e. hospitals, water pumping station, etc.). Generally these facilities tend to be prioritized for restoration in most utility emergency response plans. It also can be directed to specific sections of overhead line that are vulnerable to severe weather situations (i.e. north/south lines in open areas). Strategic undergrounding can also take advantages of opportunistic synergies, such as road widenings, bridge building/rebuilding, etc. to incorporate new underground facilities in a cost effective manner.

5.3.3 PowerStream area assessment

PowerStream North in Barrie - The 44 kV distribution system egresses from HONI owned Barrie TS and Midhurst TS. The normal limit is 2 x 44kV circuits on a pole line. The exception is in the vicinity of Midhurst TS where egress congestion has resulted in 3 x 44kV circuits on poles for some distance (Anne St. North). At times this circuitry congestion can be even more pronounced with additional underbuild circuits as well (i.e. 13.8 kV underbuild with 44 kV circuits above). Double circuit 44 kV polelines can be found on around a dozen other roads mostly in short sections. The 44 kV system supplies the 13.8 kV MSs and approximately 80 customer substations.

PowerStream North in Barrie - The 13.8kV distribution system is a mix of overhead and underground. In most cases the overhead 13.8 kV is limited to single circuits, sometimes as underbuild to overhead 44 kV circuits, with 2 circuit exceptions on portions of Essa Rd., Big Bay Point Rd., Bayview Avenue, Yonge St. and Mapleview Ave.

PowerStream North in Barrie - The 4 kV distribution system is a mostly overhead system, with some underground, primarily serving Barrie's inner core, including the downtown area. The number of customers and load served by 4kV infrastructure is relatively low compared to 13.8 kV and 44 kV facilities.

PowerStream South in Aurora – The 44 kV and 13.8 kV overhead system share most main arterial polelines with mainly a single 44 kV feeder with one or two 13.8 kV feeders as underbuild. Bathurst St., Bayview Avenue and Leslie St., all north-south roads, have the highest circuit density on the poles.

PowerStream South – The 27.6 kV system services in Vaughan, Richmond Hill and Markham. There are some minor residual MS 8 kV facilities in Vaughan and Markham but these lines service less than 5% of total load so are somewhat inconsequential with respect to the benefits of strategic undergrounding. Most of the 27.6 kV overhead system interconnects at various points except for some radial spurs in the rural areas of the three municipalities. There is approximately 49 km of 27.6 kV four circuit poleline present along major arterial streets and near station feeder egress points. Most newer residential and commercial subdivisions are underground. In general, underground lines have a better reliability record with respect to weather events, vegetation and animal contact and vehicular related damage. Underground faults tend to be permanent, unlike most overhead momentary faults, and can take more time to repair after identification of the fault location. Underground assets also present a significant cost liability when end of life is reached such as the cost to replace an entire underground subdivision. If equipment is located underground (i.e. transformers in vaults) then flooding becomes a new hazard that needs to be considered in planning, design and operations.

There are a number of approaches to "strategically" underground portions of the distribution system. One utility plans to underground areas prone to vegetation outages, another will focus on undergrounding from the station to "critical" facilities (as it defines them) while another will underground multi-circuit poles with high weather exposure.

For PowerStream, the best approach is seen to “strategically” underground portions of overhead lines to reduce 4 circuit poleline exposure to severe weather. Reducing 4 circuit pole lines to 2 circuit polelines would reduce the load and infrastructure at risk of severe weather. The undergrounded circuits would be able, in most cases, to backup the remaining overhead circuits in the event of severe weather problems. This has implications for past and future plant as going forward, approximately 52 km of new 4 circuit poleline is planned to be added over the next 10 year period.

5.3.4 Summary of good utility practice in Undergrounding

- Undergrounding is chosen where overhead supply options are not possible, or where funded by a third party, demonstrating good financial consideration of undergrounding impacts on ratepayers.
- Where implemented, direct buried cable in duct, emphasizing low relative installation cost and high values of reliability, has been the method of choice.

5.3.5 Potential Practice Adaptations

In reviewing PowerStream’s practices for undergrounding, there are a number of initiatives that PowerStream should consider adopting:

1. Consider adopting a proactive strategy for new or upgraded service connections that require them to be underground.
2. Consider adopting a limit of 2 circuits (13.8 kV / 27.6 kV / 44 kV) per pole line. Utilize parallel underground construction for excess circuitry with appropriate interconnection nodes that back up overhead supplied areas.
3. Consider undergrounding the entire distribution system.
4. Consider undergrounding station egress cables to distribution points that result in connections to 2 circuit overhead lines (as opposed to 3 or 4 circuit lines immediately outside stations).
5. Consider taking advantage of opportunities to underground critical points/areas on the distribution system in conjunction with road relocation work and new/rebuilt bridge crossings over major highways.

5.4 STANDARDS

5.4.1 Background

PowerStream has developed its own underground and overhead construction standards. Overhead construction standards cover framing and associated material for infrastructure on poles at all voltage levels. Underground construction standards cover installations of underground and grade level plant. Standards provide for common material and construction assemblies according to the design of the pole line.

5.4.2 Analysis

PowerStream overhead standards have undergone recent review and consolidation as a result of the Barrie merger. All internal staff interviewed consider the overhead standards to be in excellent condition. The standards have been set up to accommodate pole construction utilizing anywhere from Class 2 to Class H3 western red cedar wood poles. There is no standard for composite or concrete poles. PowerStream's Standards Committee is currently looking into pros/cons for the use of composite, concrete, ductile iron, steel and wood poles.

Use of alternatives to wood poles constitutes a "one-time" custom designed installation and material specified for a particular job.

Composite poles have been piloted in the past (Bayview Avenue) with satisfactory results. Compared to wood poles, composite poles are lighter, stronger and have lower conductive properties and are more fire resistant. They are not as vulnerable to rot and insect damage as wood poles are. They also do not lose strength as they age, so require minimal maintenance and inspection needs. This could be an operating savings worth exploring. Composite poles are designed to withstand heavy winds loads and impacts. Guying needs are reduced or eliminated through design and pole selection. Being hollow, composite poles also have a strategic advantage of being able to house the pole ground wire (theft mitigation) and large diameter poles may even be able to house communication related infrastructure. Modular nature of some composite pole products allows for a range of pole lengths and strengths to be made from discrete individual pole sections. The key drawback to use of composite poles at the distribution level has been the initial upfront cost which can be up to double the cost of a traditional wood pole. Overall lifecycle cost (no testing, longer life) mitigates this impact.

PowerStream utilizes 15 kV insulators for 13.8 kV circuits and 46 kV insulators for 27.6 kV circuits and 44 kV circuits. Overinsulation is considered a key mitigation strategy to reducing pole fires. PowerStream has adopted this strategy at the 27.6 kV level. The 13.8 kV and 44 kV construction does not mitigate pole fires in this area, however the incidences of pole fires at these voltage levels has been historically low so mitigation pressures are low as well.

Other strategies to mitigate pole fires include the elimination of wood crossarms and installation of high-resistance ground wire. PowerStream has not eliminated the use of crossarms but has standardized on fiberglass crossarms. Fiberglass crossarms are superior to wood crossarms in life, mechanical strength, insulation resistance and resistance to contamination. They are considered to provide superior protection against pole fires versus wooden crossarms.

PowerStream overhead standards are based on CSA Overhead Standard "heavy" weather loading on conductors which equates to a 12.5mm radial thickness of ice. Severe ice accumulation beyond the loading limit can cause significant loss to conductors and poles. Pole loss is more problematical and time-consuming to replace. In the 1998 Ice Storm, 80% of Hydro Quebec's time to repair the distribution system was spent on pole replacement. Strategies to mitigate the loss of poles due to ice accumulation include controlled failure strategies where under certain conditions, crossarms, holding brackets and conductor detaches from the pole minimizing pole failure. The application of this strategy has to be reviewed to determine if it will work with multiple circuit pole structures and with public safety considerations in mind.

Overhead secondary service standards cover the basic material and connection arrangement from the utility pole to the customer's overhead service stack. Standards incorporating breakaway connectors would serve to harden this part of the distribution system and mitigate vegetation damage to customer's equipment.

Underground standards are focused on infrastructure associated with grade level installations (padmount and vault infrastructure). Trenching and conduit is well detailed. There is little detail on subsurface infrastructure for below grade equipment limited to cable chamber racking. Precast cable chambers have been used on a customized basis. With increasing interest in moving to subsurface installations (aesthetic reasons, space, weather, etc.) detailed standards and material for constructing cable chambers and underground vaults is warranted. Standards should incorporate operational and drainage requirements (clearances to operate/work, connections to sewers, backwater valves, sumps, etc.).

5.4.3 Summary of good utility practice in Standards

- PowerStream has a complete and comprehensive set of overhead construction standards that adhere to CSA and ESA Regulation 22/04 requirements.

- PowerStream's underground construction standards meet their current needs and adhere to CSA and ESA Regulation 22/04 requirements.
- PowerStream is actively studying alternatives to wood poles that will meet design, assembly and operational needs.

5.4.4 Potential Practice Adaptations

In reviewing PowerStream's practices for Standards, there are a number of initiatives that PowerStream should consider adopting:

1. Consider developing standards for the use of composite poles as an alternative to wood poles.
2. Consider using breakaway overhead connectors at the utility pole to mitigate limb damage to customer overhead service entrance equipment.
3. Consider using controlled failure mechanisms, similar to those developed by Hydro-Quebec, for new and existing infrastructure. The controlled failure mechanisms on the Hydro-Quebec overhead distribution network prevent cascade failure of overhead pole lines in case of excessive ice loads. For crossarm pole strucutres, the sequence of controlled failure begins with the rupture of the crossarms on designated dead-end structures, followed by the controlled failure of all tie wires holding the conductors on the inline crossarm structures, and finally by the failure of the crossarms themselves on the inline poles, with the objective of preventing cascading failure of poles and anchors. To implement the same controlled failure mechanism on the PowerStream network, PowerStream would need to review their current standards, material and design practices. For designated dead-end crossarms to fail, PowerStream would have to determine the crossarm stress limits that would result in breakage under a certain ice load. For the inline poles structures, PowerStream's current arrangement of armless stand-off brackets with clamp line post insulators would need to be reviewed. For the controlled failure mechanisms to work here, PowerStream would have to research and review current design practices and material mechanical failure limits to ensure creating weak points of failure so that the conductor could detach itself from the insulators or that the insulator could break or detach itself from the standoff bracket should the ice loads exceed design criteria. With the new controlled failure system, the conductor will fall to ground without bringing down associated poles and anchors.
4. Consider the creation of standards covering cable chamber and vault construction to deal with drainage and operational needs.

5.5 DESIGN

5.5.1 Background

PowerStream's design practices have been developed in consideration of maintaining "good utility practice" as described in the OEB's Distribution System Code (DSC). The DSC defines "good utility practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, as applied to electricity distribution facilities of similar design, size and capacity to the facilities of PowerStream or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America.

Design practices are documented in PowerStream's comprehensive Distribution Design Manual. The Distribution Design Manual is issued to assist Distribution Design Technicians and Service Layout Technicians in the technical matters of design, construction and maintenance. There manual covers four principle design areas:

1. Capital Design
2. Residential and Industrial & Commercial Subdivision Design
3. Industrial & Commercial Service Design
4. Service Layout Design

OH construction conforms to the standards detailed in C.S.A. – C22.3 OH Systems (2010).

UG construction conforms to the standards detailed in C.S.A. – C22.3 No. 7-10 (2010).

Station design conforms to relevant CSA, IEEE and ANSI standards.

Other documents that guide the design practices in terms of construction, system configuration and operation are:

- PowerStream Overhead and Underground Standards
- PowerStream Planning Philosophy
- PowerStream Distribution Automation Strategy

- PowerStream Asset Condition Assessment information
- PowerStream Policies and Procedures
- Engineering Planning 5 Year Capital Plan

5.5.2 Analysis

PowerStream relies on overhead construction design for most of its distribution system that is located on arterial roads. This has resulted in overhead pole assemblies consisting of up to 4 circuits in certain areas. New residential and commercial/industrial subdivisions tend to be supplied via underground facilities as a result of the design requirements put upon the developer by the local municipality. Single unit site plan installations can be supplied underground or overhead depending on the local infrastructure that is in place at the time. There are approximately 3500 legacy residential rear-lot fed services and 32,300 front lot fed overhead services.

From a weather sensitivity perspective, the underground supplied subdivisions are “weather hardened” but as they are fed from the overhead supply system on arterial roads, their “reliability of supply” is linked to the performance of overhead plant that can be subject to adverse weather conditions.

PowerStream relies almost exclusively on the use of Western Red Cedar poles for typical overhead pole line design. Other pole types have been used in the past by predecessor utilities (i.e. concrete in Richmond Hill) or through pilot projects (i.e. composite poles on Bayview Avenue). Composite poles offer advantages over wood poles in terms of consistency of production (known strength), non-biodegradable, and resistance to pole fires. Installations of non-wood poles is done on a case by case basis and requires close coordination with the Standards group.

In general, PowerStream’s overhead poleline designs meet the CSA Grade 2 construction requirements except where Grade 1 construction is required per CSA Standard (i.e. rail crossing). In designing the poleline the minimum class of pole required to achieve minimum pole height is used as a starting point. In some cases this can vary from a Class 2 to class H3 pole (e.g. 75’ pole). Pole loading calculations are performed and can be satisfied through pole size modification and/or guying. Storm guying is focused on north-south lines in “unsheltered” areas. There are no storm guying consideration for east-west lines. Poles with expensive equipment (i.e. LIS) are also storm guyed. Storm guying helps strengthen the pole against wind related failure but once failure occurs, it will not protect against cascading failure (i.e. Warden Avenue pole line failure). Periodic in-line guying (i.e. periodic dead-end guying) is not normally considered in pole line design. Grade 1 construction utilizes higher loading factors in calculating assumed loads thereby providing a higher safety factor taking into account uncertainties in loading conditions and strength of materials. Under non-linear analysis, minimum load factors are based on the coefficient of variation (COV), for the given pole material as verified by the manufacturer.

Weather loading of structures is based on the CSA – C22.3 "Heavy" designation. This is deemed appropriate for PowerStream's service area. The key defining criteria for "Heavy" weather are:

- Radial thickness of ice, mm = 12.5 mm (25mm overall)
- Horizontal wind loading, N/m2 = 400
- Temperature = –20°C

It should be noted that the only difference between "Heavy" and "Severe", the highest CSA weather loading category is a radial ice thickness of 19 mm (38 mm overall). Climate change projections for the PowerStream area while indicating slightly higher probabilities of freezing rain in certain months, increased storm intensity in summer months, potential 10% increase in wind intensity, do not direct a move to the "severe" weather loading criteria. Figure 14 from CSA Standard Overhead Systems C22.3 No. 1-10, maps the current weather loading classifications for the various regions of Canada. Southern Ontario is considered a "Heavy" loading area based on past historical records.

FIG 14. WEATHER LOADING MAP

PowerStream is in the process of reinforcing all pole crossings of restricted access highways. Existing wood pole structures, that age and lose strength over time, will be replaced by concrete or steel or composite poles to ensure Grade 1 construction standards continue to be met. Going to large and stronger pole classes will also increase the "footprint "of the installed pole which may have some aesthetic impact.

PowerStream is moving from linear design methods for wood pole structures to geometric non-linear design. It is expected that geometric non-linear design will become the sole method for design of wood pole structures in the next release of the CSA – C22.3 OH Systems standard that is expected sometime in 2015. PowerStream is piloting use of the Schneider Overhead Design Analysis (OHDA) software for pole structure design. This product allows for the importation of data from ESRI Designer GIS thereby acting as an extension of the Designer tool with access to the additional functionality present in the Designer tool. Discussions with PowerStream staff have indicated that the OHDA's finite element calculations are currently linear which means that changes would be required to continue to use this product for non-linear analysis. PowerStream staff is working with the vendor to adapt the product for non-linear analysis.

Existing pole structures are managed through PowerStream's Asset Management practices. Poles are periodically inspected and any that test for < 60% of initial design strength (per C22.3 No. 1-10 section 8.3.1.3) are scheduled for replacement to bring the pole structure back up to original design strength.

Network configuration, capacity utilization, switching/sectionalizing and distribution automation criteria are specified in the various planning documents.

PowerStream station design tends to be customizable based on location, lot shape/composition and feeder egress capability. Stations are designed to relevant CSA, IEEE and ANSI standards/specifications.

Past transformer station designs have allowed for some electronic components (i.e. battery chargers) to be placed in locations (basements) that could be at risk due to localized severe weather flooding. (Greenwood TS#1 and #2 are just east of a flood risk area) There is an opportunity to harden the existing transformer station facilities to flooding by relocating sub-grade components to a higher level. Future designs will take this risk into consideration and insure that sub-grade station components are not "water" sensitive. Barrie municipal station facilities are generally above grade so operational risk due to flooding is low.

5.5.3 Summary of good utility practice in Design

- PowerStream constructs overhead facilities by default to Grade 2 Construction requirements and to Grade 1 requirements where specified by CSA – C22.3.
- PowerStream calculates weather loading as per the “heavy” criteria in CSA – C22.3.
- PowerStream is adopting non-linear analysis techniques for analysis of its pole structures.
- PowerStream has created a comprehensive Design Manual to guide technicians in the technical matters of design, construction and maintenance of the distribution system.
- Poles are periodically inspected and replaced when strength reduces to 60% initial design
- Station designs to ensure flood impactive equipment is above grade.

5.5.4 Potential Practice Adaptations

In reviewing PowerStream’s practices for Design, there are a number of initiatives that PowerStream should consider adopting:

1. Consider installing periodic ground anchors in the direction of the line in long straight sections to act as dead-end structures (i.e. HQ uses every 10 poles)
2. Consider adapting designs to be able to withstand wind gusts of up to 120 km/h in strategic locations (rail and highway crossings, station egress riser poles, 4 circuit poles at corners of major intersections, corner poles, dead end poles, 407 ramp poles, other locations deemed critical by PowerStream) and that require a minimum of guying.
3. Consider having poles containing 2 or more primary circuits to be designed to Grade 1 construction standards (Safety factor = 2.0). This is the standard practice in major utilities such as Hydro Quebec, BC Hydro and ATCO.
4. Consider using non-wood poles for 3 or more primary circuits based on the advantages previously mentioned and the increased load at risk
5. Consider a 70% strength replacement target for Grade 1 construction.
6. Consider moving existing flood sensitive equipment above grade in existing stations.

5.6 SYSTEM CONFIGURATION AND PROTECTION PRACTICES

5.6.1 Background

PowerStream currently owns and operates eleven DESN Transformer Stations in the south service area. These Stations are supplied from 230 kV Hydro One transmission circuits. They step the voltage down to the 28kV distribution level. Each station typically consists of 8 to 12 feeders, supplying a combination of three phase and single-phase loads. In the Aurora and Barrie areas, power is supplied from Hydro One transformer stations that step the voltage down to the 44 kV distribution level. The 44 kV feeders in turn supply PowerStream owned Municipal Stations that step the voltage down to 27.6 kV, 13.8 kV, 8.32 kV and 4.16 kV voltage levels that comprises most of the distribution system infrastructure.

5.6.2 Analysis

(i) Configuration

PowerStream's network configuration and planning criteria have a major impact on reliability of supply to customer load. PowerStream's distribution grid is configured in an open grid arrangement. This method of supply has multiple primary feeders (13.8 kV, 27.6 kV, 44 kV) traversing the distribution area with multiple interconnections between the feeders at various points. In the event of a fault on a feeder or loss of supply to a particular feeder, adjacent feeders could pick up supply to customers, except for those customers in the faulted area. The ability of adjacent feeders to pick up load is limited by the preloaded state, the quantity of feeder ties and spare capacity available. In a sense, on the primary side of the distribution system, most customers are implicitly connected to a "loop" type supply where they can be fed from an alternate feeder source if the primary feeder source is affected. Some customers have only one point of primary feeder supply and as such they are considered to have a "radial" supply. If elements of this supply are affected there is no contingency backup and they have to wait for repairs to be made to have power restored. Closing the "loop" in these situations would mitigate this.

There is also increasing amounts of Distributed Generation being connected to the distribution system. This could represent future potential alternate supplies subject to standards related to DG islanding.

The standard overhead conductors installed at PowerStream are 556 kcmil Aluminum. The ampacity of this overhead conductor at 30˚C is about 777 Amps or approximately 37 MVA (27.6 kV) / 60 MVA (44 kV). Normal maximum load for this size of conductor is 600 Amps and Normal planning loading is 400 Amps or 20MVA (27.6 kV) / 30 MVA (44kV) to allow for contingency switching.

Four circuit pole lines are common throughout PowerStream's South service area (27.6 kV). Loss of a pole (weather, vehicle hit etc.) would result in the loss of four circuits and possibly 60 to 80 MW of load. Depending on the site specific location of the affected pole(s), certain customers could expect an outage of 8 to 12 hours while the repairs are taking place. The recent June 17, 2014 pole line collapse on Warden Avenue, due to a microburst, resulted in a 46 hour interruption to the customers in the affected area.

In the Barrie area, the normal limit is 2 x 44 kV circuits on a pole line. The exception is in the vicinity of Midhurst TS where egress congestion has resulted in 3 x 44 kV circuits on poles for some distance (Anne St. North). At times this circuitry congestion can be even more pronounced with additional underbuild circuits as well (i.e. 13.8 kV underbuild with 44 kV circuits above).

Underground residential subdivisions are fed via a “loop” supply with a normally open point at one of the transformers in the middle of the underground feeder. Commercial/Industrial underground subdivisions are also fed via a “loop” supply.

The current feeder configuration will be improved by increased feeder segmentation and load transferability between feeders based on guidelines in PowerStream's recently published Distribution Automation strategy. Feeders will be divided into 3 segments (2.5 switching points per feeder, including a tie switch between feeders) that, together with installation of reclosers and motorized switches, will improve flexibility for operators and line crews to deal with contingency situations. PowerStream has piloted Automated Feeder Restoration (AFR) and Fault Detection Isolation and Recovery (FDIR) schemes for enhanced outage management capabilities.

(ii) Protection

PowerStream's Protection standards are ably described the Feeder Protection Standard - PS-STD-PF-01. The information below is based on a review of this document.

Most of the protection settings at the stations and along the distribution feeders have been set up for an overhead supply system. The general overhead protection philosophy basics are:

1. Treat all faults initially as temporary.

2. Circuit breaker/recloser lockouts should only occur when it has been determined that a fault is permanent. All PowerStream feeders are permitted to perform a single shot reclose attempt. Feeders that are predominately underground (80% or more) will not attempt a reclose.
3. The smallest possible portion of line should be removed from service in the case of a fault.
4. The fault should be cleared as quickly as possible to minimize hazard to the public, damage to equipment and to minimize the impact on power quality

PowerStream has implemented two feeder protection philosophies: “trip saving” and “fuse saving” depending on location.

A “trip saving” protection scheme allows the feeder breaker to clear transient and permanent faults on the feeder. Faults on the load side of lateral fuses are cleared by the associated lateral fuse. Trip saving is typically applied on Urban feeders in PowerStream South where:

- Service response times are much shorter for replacing fuses.
- The majority of the distribution conductors on the load side of the lateral fuses are underground.
- Faults on underground conductors tend to be permanent, not transient.
- Typically protections of underground feeders do not incorporate a reclosing scheme because underground faults are nearly always permanent. It is recommended that feeders which are 80% or more underground not be permitted to reclose.
- It is preferable to clear the lateral fuses in order to avoid momentary interruptions to all the customers on the feeder.

A “fuse saving” protection scheme allows the feeder breaker to clear non-permanent faults on the entire feeder without blowing sectionalizing fuses. Fuse saving is typically applied on rural feeders in PowerStream North where the majority of service lines are overhead and the service response times are much greater for replacing fuses.

Both schemes are designed to maximize the efficient coordination of protective devices to minimize overall outage time and reliability impacts to customers. Fuses need to be coordinated downstream from the first protective device (i.e. station circuit breaker or recloser) to ensure proper operation and alignment with the protection scheme for the specific feeder. In this sense each feeder needs to be analysed from beginning to end to ensure all protective devices coordinate properly.

Typical source of faults on the distribution system are:

- Tree contact (vegetation growth or falling limbs)
- Animal contacts (squirrels, racoons, etc.)
- Failed equipment (transformers, switchgear, etc.)
- Foreign interference (cars hitting poles or padmounted equipment)
- Weather and environmental sources (storms, ice, salt contamination, etc.)

From a storm hardening perspective, the protection standards are adequate and sufficient as long as the actual field installations of fuses and settings follow the protection philosophy. Misapplication of protective devices can result in nuisance operations and increased outage and restoration times (i.e. two 65k fuses in series will not coordinate).

In a storm situation there would be a heightened concern for multiple downed conductors and public safety, especially due to teardown effects of tree/tree limbs on poles and circuits. High-impedence faults due to downed conductors can be in the very low range (i.e. 10 – 100 amps) and may not be seen by low-set overcurrent protection. PowerStream's SEL 451 feeder protection relays have high-impedence fault protection built in. Enabling the SEL 451 relay High-Impedence fault protection mitigates the problems caused by downed conductors. This feature has been enabled in stations equipped with the SEL 451 relay.

This feature should also be enabled in the SEL 651R field relays paired with reclosers as part of the AFR scheme where deemed appropriate.

This feature is not present in the SEL 351 relays used with MS protection mostly in the Barrie service area. Protection is limited to Low Set overcurrent settings on the SEL 351 relays. Low set protection operates if there is sufficient current and is designed for equipment protection versus high impedence protection designed for safety and fire issues.

5.6.3 Summary of good utility practice in System Configuration and Protection

- Feeder grid arrangement provides for alternate methods to route supply in event of a contingency
- Fault sensing, sectionalizing switches and distribution automation allows for rapid isolation of impacted area and rapid restoration of customers outside of affected area

- Stations equipped with SEL 451 relays have had high impedence fault protection enabled. PowerStream has a program to replace existing TS feeder protection relays with new SEL 451 relays with high impedence fault protection enabled.

5.6.4 Potential Practice Adaptations

In reviewing PowerStream's practices for System Configuration and Protection, there are a number of initiatives that PowerStream should consider adopting:

1. Consider identifying and implementing opportunities for closing the "loop" on "radials" based on loading criteria in the Urban Design Issues report.
2. Consider reviewing all PowerStream feeders for protection coordination. Redundant, inexistent or misapplied protective devices should be identified and dealt with to suit the protection scheme applicable for the respective feeder.
3. Consider enabling high impedence fault detection in existing devices (i.e. SEL 651 relays) where appropriate
4. Consider incorporating high impedence fault detection at the MS level when and where appropriate.

5.7 THIRD PARTY AND CUSTOMER PRACTICES

5.7.1 Background

PowerStream interacts with a number of third parties in its day to day operations. A listing of third partys and perceived areas of interaction and interest with respect to weather related plant issues are shown in Table 7.

Third Party	Third Party Interactions	Third Party Interests	Third Party Perception of Weather related risks
PowerStream non-operations staff	Provide operations support as required	Assist with restoration activities	Limited ability to assist; loss of normal functionality
Residential Customer	Vegetation on private property; access issues	Reliable supply; aesthetics; get power on as soon as possible	Supply/reliability shortfalls; multiday outages
Small Commercial	Vegetation on private property; access issues	Reliable supply; get power on as soon as possible	Supply/reliability shortfalls; multiday outages
Large Commercial/Industrial	Vegetation on private property; access issues	Reliable supply; get power on as soon as possible	Supply/reliability shortfalls; multiday outages

Third Party	Third Party Interactions	Third Party Interests	Third Party Perception of Weather related risks
MEARIE	Provide PS with claim insurance	Reliable supply and diligent design of system	Excessive claims or class actions due to perceptions of inadequate design, configuration and maintenance
Cable/Telephone companies	Share facilities on PS poles: PS facilities on some Bell poles	Infrastructure able to withstand severe weather events	PS Infrastructure collapse results in service loss and damage to their plant
External support groups (i.e. forestry, other utilities, etc.)	Assist PS in restoration activities	PS coordination of activities and logistical support	working conditions need to be safe
Suppliers (material, food, lodging)	Provide PS with required logistical needs	PS logistical coordination and timely communication	Loss of logistical capability due to weather
Environment Canada	Provide forecast and real time appraisal of weather conditions; damage predictions	Accurate and timely information to stakeholders	Inaccurate information
Media	Disseminate information on restoration activities to public	Timely and accurate information updates	Inaccurate and/or non-timely information
HONI	Transmission affected by severe weather; distribution feeders and facilities that feed PS affected by severe weather; some PS plant on HONI poles and vice versa	Restoration of infrastructure as soon as possible	Crew/material availability; PS Infrastructure collapse results in service loss and damage to their plant
Municipalities(non-shareholders)	Municipal approvals for lines on road allowance; vegetation planting in vicinity of lines; vegetation control;	General visual aesthetics; healthy and growing tree canopy; reliable supply to customers	Supply/reliability shortfalls affecting their constituents
Municipal services (police, fire, parks, etc.)	Help to maintain public safety; assist with making area safe for PS crews to perform work	Make roads and sidewalks safe as soon as possible; provide emergency facilities for displaced public	Long term damage to infrastructure and public accessibility
Generators	Disconnection from grid upon loss of grid supply	Stable market and ability to connect to distribution system; islanding capability	Long term disruption to generation capability
OEB	Regulatory approval of storm costs to be passed on through rates; approval of storm mitigation plans	Efficient, low cost and reliable market; regulatory compliance	Increasing storm costs to be passed on through rates; political impact

Third Party	Third Party Interactions	Third Party Interests	Third Party Perception of Weather related risks
Provincial Government	Can provide emergency assistance in a major catastrophe; policy with respect to climate change and infrastructure standards	Efficient, low cost and reliable market to stimulate growth and political goodwill	Localized negative political impact
CSA	Overhead and underground utility infrastructure standards	Ensure that standards allow for appropriate grade of construction for local climate conditions	Standards do not ensure that extreme weather events can be withstood
ESA	Permits for customer equipment damaged by weather related event	Public safety is maintained through a weather related situation	Some customer facilities may be energized and in an unsafe condition
OPA	Transmission and regional reliability of supply	Regional planning incorporates climate change planning	System reliability decrease due to changing climate conditions
IESO	**Transmission affected by severe weather;**	**Grid adheres to IESO reliability guidelines; restoration of infrastructure as soon as possible**	Loss of major portions of grid; grid collapse

TABLE 7 – THIRD PARTY INTERACTIONS

Third party activities impact the storm performance of the distribution system before and during storm events. It is important to ensure that third party activities impact positively on the storm performance of the distribution system.

5.7.2 Analysis

Analysis of third party interactions is limited those that deal with hardening the distribution system as opposed to resiliency and other impacts.

Residential, commercial and industrial customers are serviced from PowerStream plant. In some cases, vegetation on customer property can interfere with PowerStream or customer owned plant as a result of a severe weather situation. Access to PowerStream plant on customer property can also be a problem in a severe weather situation. Implementing a "Hazard" tree program as mentioned in the Vegetation section may be able to mitigate some of the issues related to trees on private property. PowerStream like all other Ontario LDCS has the right under the Electricity Act to enter private property to maintain their plant and this would also apply to PowerStream owned service conductor and any related line clearing. Eliminating the need to access

PowerStream plant on private property (i.e. rear-lot feeds) can also mitigate customer impacts on storm response.

Cable and telephone companies often share space on PowerStream poles to run their communication lines. Communication infrastructure is installed in accordance to CSA standards and ESA regulation 22/04. The location and quantity of foreign plant on PowerStream poles is coordinated and controlled by PowerStream. In a severe weather situation, there will be occurrences where lines and poles are brought down due to wind, ice loading or vegetation related mechanical teardown. In this case PowerStream and telecommunication plant is down and in the same vicinity. In general the telecommunication companies wait for PowerStream to rebuild the pole before they come in and re-attach their plant. PowerStream builds and maintains its overhead infrastructure to the “Heavy” grade of construction. It is important for PowerStream to ensure by contract and by inspection that third party poles, on which it has its infrastructure, are also built and maintained to this standard.

Impacts to HONI transmission plant would adversely impact the ability of PowerStream to provide power to its customers. It is important that the transmission infrastructure meets the IESO reliability guidelines for supplying stations that supply PowerStream customers and expected weather conditions in South-Central Ontario. Recent planning studies with HONI, the OPA and IESO have identified actions to be taken by HONI to meet the IESO reliability guidelines. Weather withstand capability should be discussed as part of the planning exercise. Like other third parties, it is important for PowerStream to ensure that HONI plant supplying embedded PowerStream customers is built and maintained to the same standard as PowerStream plant. Redundancy of supply paths to embedded customers should also be pursued.

Municipalities coordinate the placement and type of plant of road allowance (i.e. sewer, water, poles, sidewalks, etc.). They approve PowerStream’s plans for plant on road allowance. It is important that other works in the vicinity of PowerStream overhead plant do not negatively impact on the distribution system. A key municipal controlled activity that affects PowerStream overhead plant is the planting of trees on directly under or adjacent to the distribution lines on road allowance. Planting the wrong species of tree can result in future vegetation encroachment problems with the distribution lines. Municipalities are often restrictive in permitting the pruning of the tree canopy. This can also result in future problems due to the teardown impact of limbs in a severe weather situation. PowerStream has started consultations with municipalities with respect to tree planting coordination. This discussion should also extend to tree canopy pruning and “hazard” tree removal on private property that can be assisted through judicious use of municipal by-laws.

The OEB is aware of severe weather impacts on the distribution system. Proactive regulatory engagement with the OEB will help promote the case for spending on storm hardening programs in the future.

The Provincial government sets energy policy. Policy directives could be put in place to provide direction to the OEB and utilities in determining cost recovery for undergrounding existing overhead systems to mitigate climate change impacts.

PowerStream presence on CSA Standards committees and ESA Regulation 22/04 committees will ensure that PowerStream is kept up to date on evolving standards and regulations and that PowerStream strategic interests and represented.

5.7.3 Summary of good utility practice in Third Party interactions

- Vegetation control issues are communicated to PowerStream's customers through its website and other publications.
- PowerStream controls and coordinates third party access to its pole structures.
- Planning studies initiated by PowerStream have identified actions required by HONI to strengthen the transmission system to current IESO reliability guidelines.
- PowerStream has begun discussions with municipalities to coordinate tree planting under or near overhead lines.
- PowerStream maintains strong ties and relationships with OEB staff.

5.7.4 Potential Practice Adaptations

In reviewing PowerStream's practices for Third Party interactions, there are a number of initiatives that PowerStream should consider adopting:

1. Consider ensuring that the conditions of Service are clear on PS ability to enter property to trim overhead secondary lines - see Vegetation Management section.
2. Consider developing a Hazard tree identification and mitigation program for trees on private property – see Vegetation Management section.
3. Consider ensuring joint use agreements with third parties incorporate expected grade of construction and maintenance assurances to withstand severe weather conditions.

6. DISTRIBUTION SYSTEM HARDENING – RECOMMENDATIONS SUMMARY

PowerStream's post-storm review identified 38 areas for review to improve the performance of the system during severe weather events. This report is one of the 38 areas of review.

There are two key concepts related to improving the performance of electrical distribution systems in severe storm situations: hardening and resiliency.

Hardening - physical changes to make particular pieces of infrastructure less susceptible to storm-related damage

Resiliency - increasing the ability to recover quickly from damage to facilities' components or to any of the external systems on which they depend

In order to maintain acceptable levels of safety and reliability of its distribution system, a strategy composed of short, medium and long-term hardening related actions should be implemented as shown in Figure 15.

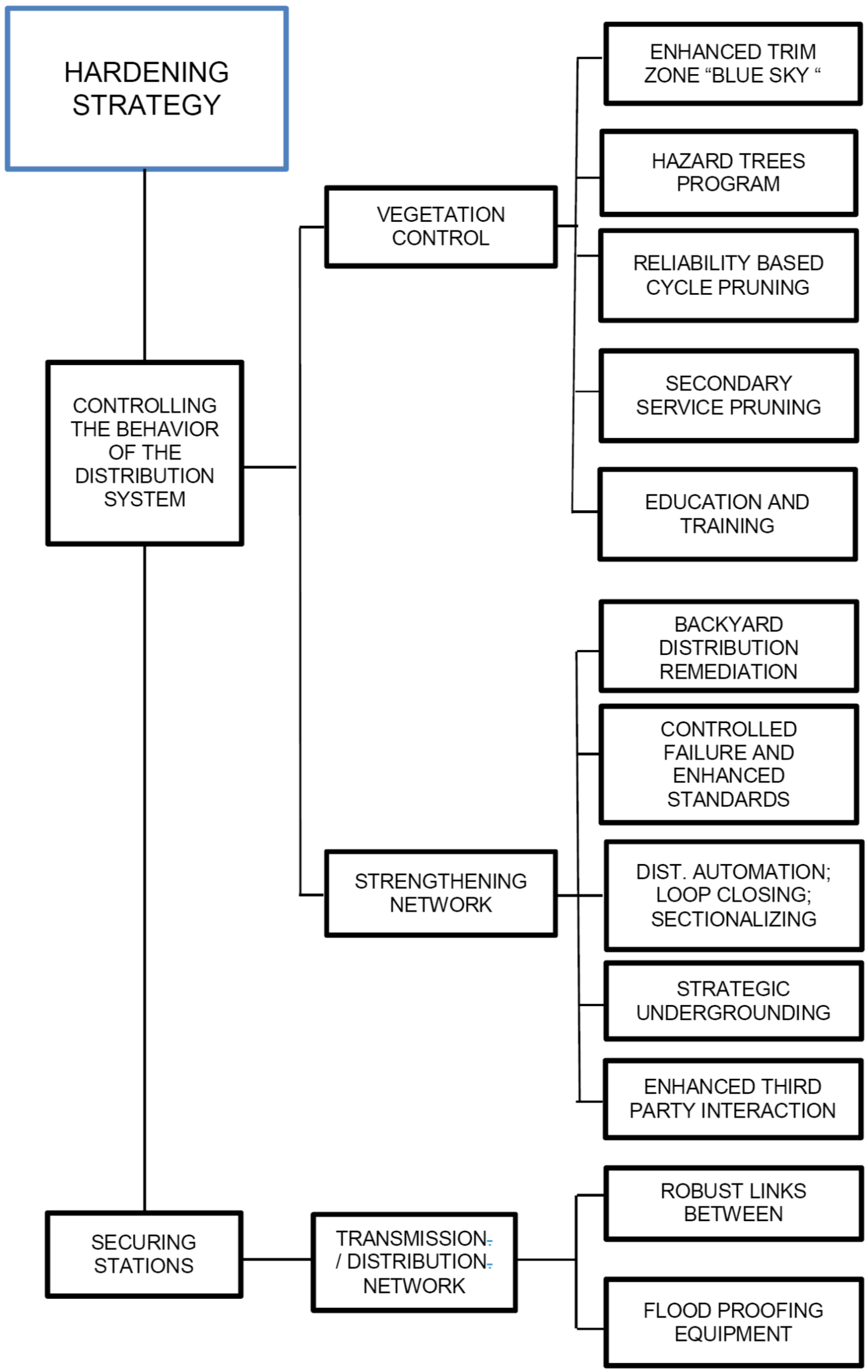

FIG 15. HARDENING STRATEGY

6.1 RECOMMENDATIONS

The report recommendations, for the most part, focus on hardening related matters as defined in Figure 15. These hardening options are discussed in the Controlling the Behaviour of the Distribution System, and Securing Stations sections.

It is understood that a number of the other 37 areas for review focus on resiliency and communication related matters such as emergency plans, mutual aid agreements, emergency generators, customer communications, etc. and as such resiliency related matters are not noted here.

The following recommendations have been derived based on previous information presented in this report related to climate change, best practices in physical hardening and PowerStream's existing practices in the design, configuration and operation of its distribution system. They augment PowerStream's existing good utility practices in distribution design, construction and operation.

Recommendations have been prioritized for implementation, in each of the three hardening categories, based on importance, cost and effectiveness in advancing hardening of the distribution system. Some recommendations involve expenditures that will be capital and others operating. Relative cost and hardening impact assessments (high, medium or low) are also provided. In some cases, a number of recommendations can be acted on concurrently. Some recommendations are presented in multiple options generally dealing with a "going forward" approach or a "legacy remediation" approach.

Where available, unit costs were based on PowerStream information, CIMA+ information, utility equipment supplier information and finally general estimates on perceived effort.

6.1.1 Vegetation control

There are 6 Vegetation control recommendations presented in Table 8. They are listed in order of priority with respect to a combination of cost and impact towards distribution system hardening. They are Operating in nature and would be funded as such.

Item	Option	Hardening Recommendation Description	Units	Program	Cost	Cost level	Impact level
V1		Create enhanced trim zone	total clearance to be 3.5m side;3.5m below; all above	Operating	$5.1M	Medium	High
V2		Incorporate aspects of reliability centered maintenance into the line clearing cycle	N/A	Operating	<$20k	Low	Medium
V3		Hazard tree program	Trees off road allowance	Operating	$100k	Medium	High
V4		Overhead service line clearing	32 300	Operating	$300k	Medium	Medium
V5		Educate stakeholders	N/A	Operating	<$20k	Low	Low
V6		Train design and construction staff	N/A	Operating	<$20k	Low	Low

TABLE 8 – VEGETATION CONTROL RECOMMENDATIONS

6.1.2 Strengthening the Distribution System

There are 18 Strengthening the Distribution System recommendations presented in Table 9. They are listed in order of priority with respect to a combination of cost and impact towards distribution system hardening. A number of recommendations address a common specific hardening action but have alternatives (a or b) that can be selected. In some cases the alternatives are strictly choose “a or b” but not both (i.e. backyard conversion). Other alternatives represent a split in program effort to address past infrastructure, future infrastructure or even both if so desired. This represents an understanding that funding for hardening programs is not unlimited and careful selection of programs and scope is required.

Item	Option	Hardening Recommendation Description	Units	Program	Cost	Cost level	Impact level
S1	a	Hybrid conversion - 5-6 years for pre 1980; address post-1980 in 2024 thru 2029	3589	Capital	$59.5M	High	Medium
		Breakaway connectors	3589	Capital	$1.1M	Medium	Medium
	b	Full conversion - 8 years for pre 1980; address post-1980 in 2024 thru 2029	3589	Capital	$87.4M	High	High
S2		All new or upgraded services underground	+ 400 annually	Capital	<$20k	Low	High
S3		Joint use standards	N/A	Capital	<$20k	Low	Medium
S4		Critical poles designed to handle 120kmh winds	459	Capital	$1.84M	Medium	High
S5		Breakaway connectors	36 100	Capital	$5.4M	Medium	Medium
S6		Periodic in-line anchoring (ie. storm dead end)	every 6 - 10 poles	Capital	$8M	Medium	Medium
S7		Poles with 2 or more primary circuits to Grade 1 construction -consider non-wood material	1200+	Capital	$24M	High	High
S8		70% strength replacement target for Grade 1 construction	As identified per pole testing	Capital	<$50k annually	Low	Medium
S9		Develop composite pole standards	stds book	Capital	<$50k	Low	Medium
S10	a	Controlled failure mechanism	See cost	Capital	+6%	Medium	Medium
	b	Controlled failure mechanism	See cost	Capital	$45k/km	Medium	Medium
S11		Opportunities for closing the “loop” on “radials” should be identified and implemented.	potential locations	Capital	TBD	Medium	Medium
S12	a	Underground station egress cables to 2 circuit riser points - going forward only	800m	Capital	$4M	Medium	Medium
	b	Underground station egress cables to 2 circuit riser points - existing infrastructure	TBD	Capital	$5000/m	Medium	Medium
S13	a	Strategic undergrounding - Limit overhead circuits to maximum of 2 for the key supply voltage in the area	51.7 km future	Capital	$155M	High	Medium
	b	Strategic undergrounding - convert existing 4 circuit poles to 2 circuit poles and 2 circuit underground	49km exist	Capital	$157M	High	High
S14		Strategic Undergrounding - Incorporate ducts in new/refurbished bridge structures or similar critical points	404/400 crossings	Capital	$300/m	Low	High
S15	a	Underground the distribution system – going forward only	120km	Capital	$360M	High	Medium
	b	Underground the distribution system – existing infrastructure	All	Capital	$4,500M	Very High	High
S16		Review and update feeder protection coordination	TS and MS feeders	Capital	$150k	Low	Low
S17		Install and enable High Impedence fault detection where appropriate	5 TS	Capital	$1.5M+	Medium	Low
S18		Cable chamber and vault drainage standards	as required	Capital	$10k/unit	Low	Low

TABLE 9 – STRENGTHENING THE DISTRIBUTION SYSTEM RECOMMENDATIONS

6.1.3 Securing stations – Transmission / Distribution Network

This area covers practices that tend to deal with securing transformer stations with respect to severe storm events. There are 3 Securing stations recommendations presented in Table 10. They are listed in order of priority with respect to a combination of cost and impact towards distribution system hardening. The After-storm management plan requires station inspection after service has been restored to ensure that all station assets are in good operating condition and standards have not been compromised.

Item	Option	Hardening Recommendation Description	Units	Program	Cost	Cost level	Impact level
SS1		Move existing flood sensitive equipment above grade in existing stations.	As per list	Capital	$1.1M	Medium	Medium
SS2		Updates on transmission system capability to withstand severe weather events.	annually	Operating	<$20k	Low	Medium
SS3		After storm management plan	as required	Operating	<$20k	Low	Low

TABLE 10 – SECURING STATIONS RECOMMENDATIONS

A summary graphic of respective option cost and impact assessment is shown in Table 11.

OPTION COST / IMPACT ASSESSMENT				
IMPACT	HIGH	S2; S14	V1; V3 S4;	S1b; ; S7; S13b; S15b*
	MEDIUM	V2; S3; S8; S9; S10 SS2	V4 S5; S6; S10a; S10b; S11; S12a; S12b SS1	S1a; S13a; S15a
	LOW	V5; V6 S16; S18 SS3	S17	
		LOW	MEDIUM	HIGH
		COST		

TABLE 11 – OPTION COST / IMPACT ASSESSMENT

** Very High cost*

In general, programs have been prioritized in the three recommendation sections by their impact on weather hardening the distribution system and relative cost to implement along with information from interviews with PowerStream Executive and staff. Interviews provided useful information on customer feedback received related to severe weather and service reliability expectations; existing asset management programs; and practical experiences in designing, constructing, operating and maintaining distribution infrastructure in PowerStream's service territory.

PowerStream's future pace in hardening the distribution system will be determined by the amount of capital and operating funds available to be allocated to the various programs that PowerStream chooses to pursue. A sample mix of capital program options based on varying levels of fixed annual funding and Table 9 priority position is illustrated in Tables 12 and 13.

Annual Capital funds	Program	Program Cost	Notes
$5M	S1b - full backyard conversion	$87.4M	12 year program ($5M/year) for pre- 1980 plant
	S2 – all new services UG	<$20k	Forward looking policy change to mitigate severe weather impacts on new service connections
	S3 – Joint use standards	<$20k	Ensure third party plant build to common grade of construction (i.e. "Heavy")
$10M	S1b - full backyard conversion	$87.4M	6 year program($10M/year) for pre- 1980 plant
	S2 – all new services UG	<$20k	Forward looking policy change to mitigate severe weather impacts on new service connections
	S3 – Joint use standards	<$20k	Ensure third party plant build to common grade of construction (i.e. "Heavy")
$15M	S1b - full backyard conversion	$87.4M	6 year program($10M/year) for pre- 1980 plant
	S2 – all new services UG	<$20k	Forward looking policy change to mitigate severe weather impacts on new service connections
	S3 – Joint use standards	<$20k	Ensure third party plant build to common grade of construction (i.e. "Heavy")
	S4 – Critical poles to handle 120kmh winds	$1.84M	5 year program($400k/year) for critical poles
	S5 – Breakaway connectors	$5.4M	5 year program - $1.1M/year to install breakaway connectors on overhead service conductors
	S6 – inline storm guying	$8M	5 year program($1.6M/year) focused on N-S critical lines (1000 poles)
	S7 – poles with 2+ circuits to Grade 1	$24M	12 year program ($2M/year)

TABLE 12 – CAPITAL FUNDING AND HARDENING PROGRAM VARIANTS

$5M Program	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
S1	$5M	$5M	$5M	$5M	$5M	$5M	$5M	$5M	$5M	$5M	$5M	$5M
S2	<$20k	c	c	c	c	c	c	c	c	c	c	c
S3	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k
S4	-	-	-	-	-	-	-	-	-	-	-	-
S5	-	-	-	-	-	-	-	-	-	-	-	-
S6	-	-	-	-	-	-	-	-	-	-	-	-
S7	-	-	-	-	-	-	-	-	-	-	-	-
S8	-	-	-	-	-	-	-	-	-	-	-	-
S9	-	-	-	-	-	-	-	-	-	-	-	-
S10	-	-	-	-	-	-	-	-	-	-	-	-
S11	-	-	-	-	-	-	-	-	-	-	-	-
S12	-	-	-	-	-	-	-	-	-	-	-	-
S13	-	-	-	-	-	-	-	-	-	-	-	-
S14	-	-	-	-	-	-	-	-	-	-	-	-
S15	-	-	-	-	-	-	-	-	-	-	-	-
S16	-	-	-	-	-	-	-	-	-	-	-	-
S17	-	-	-	-	-	-	-	-	-	-	-	-
S18	-	-	-	-	-	-	-	-	-	-	-	-

$10M Program	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
S1	$10M	$10M	$10M	$10M	$10M	$10M	c	c	c	c	c	c
S2	<$20k	c	c	c	c	c	c	c	c	c	c	c
S3	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k
S4	-	-	-	-	-	-	$400k	$400k	$400k	$400k	$400k	c
S5	-	-	-	-	-	-	$1.1M	$1.1M	$1.1M	$1.1M	$1.1M	c
S6	-	-	-	-	-	-	$1.6M	$1.6M	$1.6M	$1.6M	$1.6M	c
S7	-	-	-	-	-	-	$2M	$2M	$2M	$2M	$2M	$2M
S8	-	-	-	-	-	-	-	-	-	-	-	-
S9	-	-	-	-	-	-	-	-	-	-	-	-
S10	-	-	-	-	-	-	-	-	-	-	-	-
S11	-	-	-	-	-	-	-	-	-	-	-	-
S12	-	-	-	-	-	-	-	-	-	-	-	-
S13	-	-	-	-	-	-	-	-	-	-	-	-
S14	-	-	-	-	-	-	-	-	-	-	-	-
S15	-	-	-	-	-	-	-	-	-	-	-	-
S16	-	-	-	-	-	-	-	-	-	-	-	-
S17	-	-	-	-	-	-	-	-	-	-	-	-
S18	-	-	-	-	-	-	-	-	-	-	-	-

$15M Program	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
S1	$10M	$10M	$10M	$10M	$10M	$10M	c	c	c	c	c	c
S2	<$20k	c	c	c	c	c	c	c	c	c	c	c
S3	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k
S4	$400k	$400k	$400k	$400k	$400k	c	c	c	c	c	c	c
S5	$1.1M	$1.1M	$1.1M	$1.1M	$1.1M	c	c	c	c	c	c	c
S6	$1.6M	$1.6M	$1.6M	$1.6M	$1.6M	c	c	c	c	c	c	c
S7	$2M	$2M	$2M	$2M	$2M	$2M	$2M	$2M	$2M	$2M	$2M	$2M
S8	-	-	-	-	-	-	-	-	-	-	-	-
S9	-	-	-	-	-	-	-	-	-	-	-	-
S10	-	-	-	-	-	-	-	-	-	-	-	-
S11	-	-	-	-	-	-	-	-	-	-	-	-
S12	-	-	-	-	-	-	-	-	-	-	-	-
S13	-	-	-	-	-	-	-	-	-	-	-	-
S14	-	-	-	-	-	-	-	-	-	-	-	-
S15	-	-	-	-	-	-	-	-	-	-	-	-
S16	-	-	-	-	-	-	-	-	-	-	-	-
S17	-	-	-	-	-	-	-	-	-	-	-	-
S18	-	-	-	-	-	-	-	-	-	-	-	-

Notes: "-" = no funding
"c" = program complete

TABLE 13 – CAPITAL FUNDING AND HARDENING PROGRAM YEARLY PROGRESS

Conclusions

In this report, a number of potential distribution system hardening options have been presented for PowerStream's consideration. It is understood that creating a hardening program requires careful consideration of costs to balance rate impact and hardening program progress. By adopting a balanced rate fundable program of a number of these options, PowerStream will position itself as a company that has understood the impact of climate change on distribution infrastructure and has diligently moved forward to adapting its infrastructure to continue to deliver safe and reliable power.

CIMA+ have confidence that the information provided will enable PowerStream to develop a multi-year portfolio of distribution hardening measures that is rate base fundable and provides value to the customer.

APPENDIX A

Questions

Power Stream staff interview questions

1. What does "distribution system hardening" mean to you?
2. What was the role of your area (i.e. design, lines, system control, etc.) in the ice storm preplan and restoration efforts?
3. What were the specific infrastructure impacts caused by the ice storm that stand out to you?
4. Which were the most problematical?
5. Do you feel you had the resources and tools to respond effectively?
6. Do you have any thoughts on current tree trimming practices and what changes would minimize damage and outage response times in a future severe storm situation?
7. Do you have any thoughts on existing backyard construction and what changes would minimize damage and outage response times in a future severe storm situation?
8. Do you have any thoughts on current underground distribution practices and what changes would minimize damage and outage response times in a future severe storm situation?
9. Do you have any thoughts on the current design practices and what changes would minimize damage and outage response times in a future severe storm situation?
10. Do you have any thoughts on the current set of standards and what changes would minimize damage and outage response times in a future severe storm situation?
11. Do you have any thoughts on system configuration, protection and related operating practices and what changes would minimize damage and outage response times in a future severe storm situation?
12. Are there any other suggestions that you think could minimize damage and outage response times in a future severe storm situation?
13. Do you have any thoughts on how external agencies (i.e. ESA) could have aided assisted in the restoration efforts?
14. Do you have any thoughts on how third parties (i.e. cable) helped/hindered restoration efforts?
15. Are there any specific areas of the distribution system that stand out to you as in need of storm hardening efforts?

A P P E N D I X B

Future 4 circuit pole lines – Next 10 years

Future 4 circuit pole lines - next 10 years:

Vaughan	**km**
4 Ccts on Kirby Sdrd from Kipling to Jane St	6
4 Ccts on Weston Rd from Kirby to Rutherford	6
4 Ccts on Teston Rd Ave from Kipling to Jane St	6
4 Ccts on Kipling Ave from Kirby to Teston Rd	2
4 Ccts on Jane St from Teston Rd to KVTL	4
4 Ccts on Jane St from Steeles to Hwy 7	2
4 Ccts on Jane St from Rutherford to Langstaff Rd	2
4 Ccts on Steeles from Jane to Keele St	2
4 Ccts on Hwy 7 from Weston Rd to Jane St	2
4 Ccts on Major Mack from Pine Valley to Weston Rd	2
	34

Markham	
4 ccts on Warden from Hwy 7 to Major Mack Dr	4
4 Ccts on 14th Ave from Hwy 48 to 9th Line	2
	6

Richmond Hill (due to road widening work)	
4 Ccts on Carrville Rd from Bathurst St to Yonge St	2
4 Ccts on Yonge St from 16th Ave to Major Mack	2
	4

Barrie		
4 ccts on Sunnidale from Anne to Ferndale	1.6	
4 ccts on Ferndale from Edgehill to Tiffin	1.5	
4 ccts on Essa from Ferndale to Mapleview	2.2	
4 ccts on Mapleview Drive from Essa to Veterans	1.3	
4 ccts on Big Bay Point Road from Fairview to Bayview	0.5	
4 ccts on Big Bay Point Road from Huronia to Leggott Ave	0.6	
	7.7	
		51.7

APPENDIX C

Strategic Undergrounding

Strategic Undergrounding

4 Circuit pole to 2 circuit pole/2 circuit UG conversion schedule

Cost to convert: $3.2M/km

Priority	Municipality	Street	From/To	Line Orientation	Circuits	Avg. Pole Strength	KM	Project Cost($M)	Notes
1	Vaughan	Centre St.	Bathurst to Dufferin St.	East-West	4 x 27.6kV	83%	2.1	$6.72	Commercial/Residential - aesthetics - high rise
2	Vaughan	ROW	Greenwood TS to Centre St	North-South	8 x 27.6kV (2)	N/A	0.5	$1.60	VTS1/1EStation egress - no public exposure
3	Vaughan	Weston Rd.	Hwy #7 to Langstaff Rd	North-South	4 x 27.6kV	94%	3.2	$10.24	High density commercial
4	Richmond Hill	Hwy#7	Silver Linden to 404	East-West	4 x 27.6kV	82%	2.5	$8.00	High density commercial - VIVA
5	Vaughan	Major Mackenzie Drive	Weston Rd to Jane St	East-West	4 x 27.6kV	N/A	2.1	$6.72	400 crossing/Wonderland - hospital(?)
6	Vaughan	Hwy#7	Jane St. To Keele St	East-West	4 x 27.6kV	N/A	2	$6.40	Vaughan City Centre area
7	Vaughan	Dufferin St.	Greenwood TS to Langstaff Rd.	North-South	4 x 27.6kV	96%	1.75	$5.60	407/7 Highway crossing
8	Vaughan	Islington Avenue	Langstaff Rd to Rutherford Rd.	North-South	4 x 27.6kV	N/A	2	$6.40	Residential - aesthetics
9	Vaughan	Bathurst St.	Rutherford Rd. to Hwy#7	North-South	4 x 27.6kV	80%	2.2	$7.04	Residential - aesthetics
10	Markham	Riviera	Roddick to Woodbine	East-West	4 x 27.6kV	N/A	0.7	$2.24	Industrial area
11	Vaughan	Langstaff	Dufferin to Keele	East-West	4 x 27.6kV	N/A	2.2	$7.04	Industrial area
12	Vaughan	Keele	Langstaff Rd to Rutherford Rd.	North-South	4 x 27.6kV	N/A	2.2	$7.04	Commercial/Industrial
13	Vaughan	Jane St.	Hwy #7 to Courtland	North-South	4 x 27.6kV	N/A	2.4	$7.68	Commercial/Industrial
14	Vaughan	Hwy#7	Keele St. to Centre St.	East-West	4 x 27.6kV	N/A	1.8	$5.76	Commercial area
15	Vaughan	Huntington Rd.	Langstaff Rd to Rutherford Rd.	North-South	4 x 27.6kV	88%	2.1	$6.72	Low density residential - exposed
16	Vaughan	Hwy#7	Centre St to Langstaff Rd	East-West	4 x 27.6kv	N/A	1.8	$5.76	Highway parallel
17	Vaughan	Rutherford Rd	Weston Rd to Jane St	East-West	4 x 27.6kV	N/A	2	$6.40	400 crossing/Commercial
18	Vaughan	Rutherford Rd	Huntington Rd to Hwy 27	East-West	4 x 27.6kV	N/A	2	$6.40	Low density residential - VTS3 egress
19	Vaughan	Rutherford Rd	Hwy 27 to Islington Ave.	East-West	4 x 27.6kV	N/A	2.5	$8.00	Winding road/hill - residential
20	Vaughan	Rutherford Rd	Islington Ave. to Weston Rd	East-West	4 x 27.6kV	N/A	3.5	$11.20	low density residential
21	Markham	Woodbine Ave.	16th to Major Mackenzie Dr	North-South	4 x 27.6kV	90%	2.2	$7.04	Residential - aesthetics
22	Markham	Roddick Rd.	14th to Riviera	North-South	4 x 27.6kV	N/A	0.2	$0.64	MTS1 egress - H1/H2
23	Markham	Warden Ave	14th to HONI ROW	North-South	4 x 27.6kV	N/A	0.4	$1.28	Rail crossing/commercial
24	Markham	Warden Ave	14th to N. of Gibson Dr	North-South	4 x 27.6kV	N/A	1.4	$4.48	Commercial area (2013 rebuilt)
25	Markham	Kennedy Rd.	Helen to Hwy 407	North-South	4 x 27.6kV	N/A	0.3	$0.96	MTS3/3E egress - highway
26	Markham	Hwy #7	Cochrane to 404	East-West	4 x 27.6kV	83%	1.8	$5.76	Commercial area - VIVA - H2/H3
27	Markham	Hwy #7	Frontenac to town Centre	East-West	4 x 27.6kV	83%	1.3	$4.16	Commercial area - VIVA - H2/H3
							49.2	$157.28	
			Other						
	Vaughan	Hwy #27	MMD to Langstaff	North-South	2 x 27.6kV; 2 x 8kV	84%	4	$12.80	low density residential
	Vaughan	Keele	Hwy #7 to Administration Rd	North-South	2 x 27.6kV; 2 x 8.32kV	86%	0.3	$0.96	Commercial
	Markham	Woodbine Ave.	Riviera to Denison	North-South	2 x 27.6kV; 2 x 13.8kV	72%	1.8	$5.76	Commercial
	Markham	Bayview Avenue	John to Romfield	North-South	2 x 27.6kV; 1 x 13.8kV; 1 x 8.32kV	78%	2.2	$7.04	Commercial/residential
	Aurora	Leslie St	Wellington to Vandorf	North-South	2 x 44kV; 2 x 13.8kV	N/A	3	$9.60	low density commercial
	Aurora	Bayview Avenue	Ballymore to Stone Rd	North-South	2 x 44kV; 2 x 13.8kV	97%	4.3	$13.76	Commercial/residential
	Aurora	Vandorf	Leslie St. to Engelhard	East-West	2 x 44kV; 2 x 13.8kV	N/A	2.8	$8.96	Residential
	Aurora	St. John Sideroad	Bathurst St. to Bayview Avenue	East-West	2 x 44kV; 2 x 13.8kV	N/A	4.3	$13.76	Commercial/residential
	Barrie	Bayview Avenue	Mapleview Dr. to Big Bay Point Road	North-South	2 x 44kV; 2 x 1	N/A	1.5	$4.80	Commercial/residential - H1
	Barrie	Anne St.	Neelands to Cundles	North-South	3 x 44kV + 1 x	88%	1.2	$3.84	low density rural
	Vaughan	Albion-Vaughan	KVTL to Kirby	North-South	2 x 44kV; 1 x 27.6kV, 1 Unk	N/A	2.5	$8.00	concrete - low density rural
	Vaughan	Kirby	Albion-Vaughan to CPR	East-West	2 x 44kV; 1 x 27.6kV, 1 Unk	N/A	1	$3.20	concrete - low density rural
							78.1	$249.76	
								$252.96	

APPENDIX D

Rear Lot Priority List (2015-2029)

Rear Lot Priority List 2015-2029

Year	Location Reference #	Municipality	Year	2014 Age	Project	# of Customers	Project Cost	Option 3 Annual Cost	Option 4 Annual cost
2015	1	Barrie	1958	56	Shirley/ Vine	20	$1,065,718	$6,461,116	$9,492,672
	2	Barrie	1955	59	Blake/ Kempenfelt	21			
	4	Barrie	1968	46	North Park/ Park Dale	40			
	18	Penetanguishene	1975	39	Shannon Rd. at Main St.	11	$178,710		
	15	Penetanguishene	1975	39	Burke/ Country Club	10	$162,464		
	16	Penetanguishene	1968	46	Maria/ Edward	12	$194,957		
	42	Aurora	1968	46	Yonge & Wellington (NW) - Phase 1	69	$2,728,207		
	49	Markham	1962	52	Bayview & Steeles (NE) - Phase 1	191	$2,131,060		
2016	22	Tottenham	1965	49	Queen to Eastern and top of Eastern and Wilson - Phase 1	68	$883,687	$7,259,730	$10,665,996
	3	Barrie	1956	58	Wellington/ Oak	68	$1,392,391		
	42	Aurora	1968	46	Yonge & Wellington (NW) - Phase 2	185	$2,800,809		
	49	Markham	1962	52	Bayview & Steeles (NE) - Phase 2	191	$2,182,843		
2017	22	Tottenham	1965	49	Queen to Eastern and top of Eastern and Wilson - Phase 2	67	$1,117,968	$7,079,690	$10,401,481
	21	Tottenham	1960	54	Frazer Ave. 3 Phase line & Perdue Pl/ Alphonsus Crt.	22			
	27	Tottenham	1968	46	West side of Queen from #146 to Lionel Stone	58	$847,605		
	42	Aurora	1968	46	Younge & Wellington (NW) - Phase 3	185	$2,878,574		
	49	Markham	1962	52	Bayview & Steeles (NE) - Phase 3	191	$2,235,543		
2018	24	Tottenham	1980	34	Queen St. to Adeline Ave. and Rogers to Brown St. North Side - Phase 1	85	$1,144,795	$6,792,096	$9,978,947
	23	Tottenham	1965	49	Queen St. to Keogh St. and Wilson to Dilane St. E - Phase 2	30	$438,416		
	12	Alliston	1955	59	Victoria W. of Downey	8	$1,595,091		
	25	Tottenham	1971	43	North side of Adeline from Rogers to Brown St.	33			
	30	Tottenham	1974	40	Eastern Ave. backing onto railway from Wilson to Park	n/a			
	8	Barrie	1955	59	Marian/ Pratt/ Shannon - Phase 1	93	$1,324,602		
	45	Markham	1964	50	Main St. Unionville & Carlton(SW) - {NW side of Hwy 7/Kennedy} - Phase 1	156	$2,289,192		
2019	24	Tottenham	1980	34	Queen St. to Adeline Ave. and Rogers to Brown St. North Side - Phase 2	46	$1,212,199	$6,647,977	$9,767,207
	29	Tottenham	1968	46	East of Queen from George to Ryan Ln.	27			
	8	Barrie	1955	59	Marian/ Pratt/ Shannon - Phase 2	29	$1,364,340		
	5	Barrie	1957	57	Johnathan/ Bathwell	73			
	9	Barrie	1960	54	Alexander/ Oliver	40	$1,439,536		
	11	Alliston	1950	64	Queen/ Victoria E.	21			
	20	Penetanguishene	1973	41	Tessier at west of Main St.	18			
	19	Penetanguishene	1968	46	Robert St. at Main north side	16			
	28	Tottenham	1973	41	North of Mill St. and South of George and West of Queen	16	$207,926		
	45	Markham	1964	50	Main St. Unionville & Carlton(SW) - {NW side of Hwy 7/Kennedy} - Phase 2	155	$2,423,976		
2020	23	Tottenham	1965	49	Queen St. to Keogh St. and Wilson to Dilane St. E - Phase 1	89	$1,248,565	$6,663,221	$9,789,604
	7	Barrie	1955	59	Gunn/ Oakley Park Sq./ St. Vincent	92	$1,517,313		
	6	Barrie	1968	46	Ottoway Ave.	91	$1,400,647		
	45	Markham	1964	50	Main St. Unionville & Carlton(SW) - {NW side of Hwy 7/Kennedy} - Phase 3	155	$2,496,696		
2021								$0	$0
2022								$0	$0
2023									
2024	47	Markham	1982	32	Hwy 7 & McCowan (SE) - Phase 1	148	$2,956,339	$2,956,339	$4,343,454
2025	47	Markham	1982	32	Hwy 7 & McCowan (SE) - Phase 2	147	$3,034,104	$3,391,525	$4,982,829
	17	Penetanguishene	1988	26	Maria St. near robert St. E	9	$146,218		
	14	Beeton	1989	25	Main W./ Centre N.	13	$211,203		
2026	48	Markham	1994	20	Steeles & Henerson (NE & NW) - {NW Side of Steeles/Bayview} - Phase 1	190	$2,571,596	$2,571,596	$3,778,189
2027	48	Markham	1994	20	Steeles & Henerson (NE & NW) - {NW Side of Steeles/Bayview} - Phase 2	115	$2,648,744	$2,648,744	$3,891,535
2028	13	Alliston	2006	8	Sir Frederick Banting/ Victoria E.	8	$163,810	$3,275,679	$4,812,628
	44	Markham	2006	8	Major Mackenzie & Warden (SW)	63	$3,111,869		
	43	Vaughan	2005	9	Islington & Seville (NE & SE) - {NE Side of Major Mackenzie/ Islington}-Phase 1	114			
2029	26	Tottenham	2010	4	Brown St. from Railway to Queen St.	36	$584,871	$3,774,505	$5,545,503
	43	Vaughan	2005	9	Islington & Seville (NE & SE) - {NE Side of Major Mackenzie/ Islington}-Phase 2	64	$3,189,634		
Program Total:						3589		$59,522,219	$87,450,044

= North Locations
= South Locations

1.4692 Option 4 multiplier

A P P E N D I X E

Summary of the recommendations

Item	Option	Hardening Recommendation Description	Notes
V1		Create enhanced trim zone	PS existing is 1.0-3.5m side/bottom/top - Con Ed std 5.0m side; 5.0m below; 6.6m above; CLP 2.2 m side; 3.1m below; 5m above. UIC 3.0m side, "blue sky" above. Arborist expertise required. 3x current cost ($1.2M south; $0.5M north)
V2		Incorporate aspects of reliability centered maintenance into the line clearing cycle	SAIFI considerations, expert assessment, etc.
V3		Hazard tree program	Arborist expertise requried; baseline assessment of $100k; periodic review of hazard trees incorporatede as part of 3 year cycle; Remove and replace voucher system
V4		Overhead service line clearing	Limb pruning with customer consultation; 3rd man on truck required; can be done as part of regular 3 year cycle
V5		Educate stakeholders	Hazard tree/storm impact focus
V6		Train design and construction staff	1 or 1/2 day VM training
Item	Option	Hardening Recommendation Description	Notes
S1	a	Hybrid conversion - 5-6 years for pre 1980; address post-1980 in 2024 thru 2029	**See Appendix D**
		Breakaway connectors	install within 3 years; mat = $50/service, labour = $250/service
	b	Full conversion - 8 years for pre 1980; address post-1980 in 2024 thru 2029	**See Appendix D**
S2		All new or upgraded services underground	amend Conditions of Service; increased cost to the customer; regulatory approval
S3		Joint use standards	common grade of construction and maintenance assurances to withstand severe weather conditions
S4		Critical poles designed to handle 120kmh winds	41 highway,239 railway crossings and 179 major intersection (4 circuit poles) - assume 20% to be replaced at $20k/pole
S5		Breakaway connectors	Front and rear overhead; mat = $50/service, labour=$250/service; assume 50% have vegetation issues
S6		Periodic in-line anchoring (ie. storm dead end)	Install periodic ground anchors in the direction of the line in long straight sections to act as storm dead-end structures; assume 1000 poles to retrofit at $8k/pole
S7		Poles with 2 or more primary circuits to Grade 1 construction -consider non-wood material	4 circuit pole count - $20k/pole
S8		70% strength replacement target for Grade 1 construction	Accelerates replacement rate through pole replacement program
S9		Develop composite pole standards	develop composite pole stds from wood pole stds.
S10	a	Controlled failure mechanism	new infrastructure - +6% increase in project cost
	b	Controlled failure mechanism	existing infrastructure - $45k/km to retrofit
S11		Opportunities for closing the "loop" on "radials" should be identified and implemented.	1. Weston - Kirby to KVTL 2. Leslie - N. of Elgin to Stouffville 3. MMD 9th line to Reesor Rd 4. Elgin Rd - Markham locations
S12	a	Underground station egress cables to 2 circuit riser points - going forward only	Vaughan TS4 opportunity; assume $5000/m based on MTS4 figures
	b	Underground station egress cables to 2 circuit riser points - existing infrastructure	Existing TS; assume $5000/m based on MT4 figures
S13	a	Strategic undergrounding - Limit overhead circuits to maximum of 2 for the key supply voltage in the area	10 year forecast - UG 2 circuits @ $3.0M/km (no removal considerations); **See Appendix B**
	b	Strategic undergrounding - convert existing 4 circuit poles to 2 circuit poles and 2 circuit underground	1200 existing 4 circuit poles; 49km of 4 circuit poleline - UG 2 circuits @ $3.2M/km; **See Appendix C**
S14		Strategic Undergrounding - Incorporate ducts in new/refurbished bridge structures or similar critical points	4W2H(8 ducts) - $300/m
S15	a	Underground the distribution system – going forward only	10 year forecast - approx. 40km in the north; approx. 80km in the south.(52km = 4 circuit poleline) - assume $3.0M/km
	b	Underground the distribution system – existing infrastructure	Entire existing distribution system
S16		Review and update feeder protection coordination	3 year program - $50k annually
S17		Install and enable High Impedence fault detection where appropriate	5 TS feeder relays; at MS level where appropriate
S18		Cable chamber and vault drainage standards	permit, storm sewer connection, backwater valve
Item	Option	Hardening Recommendation Description	Notes
SS1		Move existing flood sensitive equipment above grade in existing stations.	battery chargers, battery banks, etc.
SS2		Updates on transmission system capability to withstand severe weather events.	HONI, OPA and IESO consultation
SS3		After storm management plan	Ensure TS and MS facilities are secure

Note: The "a" and "b" designations in the Options column represent alternatives within a specific hardening recommendation(ie. convert just backyard primary to front underground or convert all backyard primary and secondary to front undergound).

Note: Low costs generally assessed as <$1M; Medium cost generally assessed as >$1M and < $10M; High costs generally assessed as > $10M; Very high reserved for complete UG conversion

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Breaking the ice: de-icing power transmission lines with high-frequency, high-voltage excitation - Sullivan, C. R. Petrenko, V. F. McCurdy, J. D. V. Kozliouk – 2003
Hardening and Resiliency U.S. Energy Industry Response to Recent Hurricane Seasons – DOE – 2010
Before And After The Storm – EEI – 2014
The Ice Storm: Extreme Weather and Urban Energy - Centre for Urban Energy Roundtable VI – 2014
Storm Hardening the Distribution System – TDWorld Magazine - Richard E. Brown – 2010
The Hardening of Utility Lines —Implications for Utility Pole Design and Use - North American Wood Pole Council- 2007
Electrical Transmission and Distribution Mitigation: Loss Avoidance Study – FEMA – 2008
Storm Safe Product brochure – 2007
Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs – Quanta – 2009
MEA Report – Design and Component Failure Analysis from the 1998 Ice Storm (2000)
MEA Report – Effectiveness of Maintenance Practices and Retrofit Designs in Improving Distribution System Reliability

PowerStream Practice Review Section

Rear Lot Supply Remediation Plan - DRAFT 1 December 6, 2013
Distribution Automation Strategy – May 12, 2014
Distribution Design Manual
Overhead and Underground Standards
Urban Design Issues - October, 2013
Overhead to Underground Relocation Policy Framework
York Region Power Plant Relocation Impact Study
Town of Markham Report – Financial Risk for Overhead to Underground Relocations
ADM-56 - Inspection and Maintenance Policy
ENG-P-P001 - Distribution System Planning Process
ENG-P-P002 - Load Forecast
ENG-P-P003 - Engineering Planning Five Year Capital Plan Report
ENG-P-P004 - Feeder Load Connection-Feeder Reconfiguration Review

ENG-P-P005 - Distribution Switchgear Inspection and Maintenance
ENG-P-P007 - Planning for Station Capacity - Deterministic Technique
ENG-P-P008 - Overhead Plant Inspection and Maintenance
ENG-P-P009 - Tan Delta Cable Test
ENG-P-P010 - Feeder Planning Capacity
ENG-P-P011 - Under Ground Transformer Inspection and Maintenance Procedure
ENG-P-P012 - Issuance of Instructions to Proceed (ITP) for System Planning
ENG-P-P013 - Short Circuit Levels Calculations
ENG-P-P014 - Installation of Load Interrupter Switches at Major Intersections
ENG-P-P015 - Process for Designation of Annual Worst Performing Feeders
ENG-P-P016 - Reliability Committee Terms of Reference
ENG-P-P017 - Equipment Failure, Analysis, Reporting and Corrective Action System
ENG-P-P018 - Vegetation Management
ENG-P-P019 - Pole Inspection and Testing
ENG-P-P020 - Vault Inspection and Maintenance
Feeder Protection Standard

Other related

ESA Guideline for Third Party Attachments
ESA Planting Under or Around Powerlines & Electrical Equipment
ESA Trimming Trees Around Powerlines
ESA Tree Trimming Obligations
C22.3 No. 1-10 Overhead systems
C22.3 No. 7-10 Underground systems
SEL High-Impedance Fault Detection
GE Multilin - Distribution Feeder Principles
GE High Impedance Fault Detection Technology
PSEG Long Island Electric Utility Emergency Plan
Installing electrical conduit in bridges & structures - WSDOT HQ Traffic Office – 2004
Cost Benefits for Overhead/Underground Utilities: - EDWARDS AND KELCEY, INC/EXETER ASSOCIATES, INC – 2003
Mayor's Power Line Undergrounding Task Force Findings & Recommendations – District of Columbia 2013
Consolidated Distribution System Plan – Algoma Power Inc. – 2013
Tree Liability – MEARIE – 2001

7880 Keele Street
Suite 201
Vaughan ON L4K 4G7

T. 905 695-1005
F. 905 696-0525

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Income Tax/PILs Workform for 2016 Custom IR

PILs Tax Provision - Test Year 1 (2016)

						Wires Only	
Regulatory Taxable Income						-$ 6,196,533	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	4.50%	**B**	$ -	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**				
	Rate reduction	-7.00%	**E**	$ -	**F = D * E**		
Ontario Income tax						$ -	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.50%	**K = J / A**		
	Federal tax rate			15.00%	**L**		
	Combined tax rate					26.50%	**M = K + L**
Total Income Taxes						**-$ 1,642,081**	**N = A * M**
Investment Tax Credits						$ 605,593	**O**
Miscellaneous Tax Credits						$ 516,000	**P**
Total Tax Credits						**$ 1,121,593**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**-$ 2,763,674**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				73.50%	**S = 1 - M**	**-$ 996,427**	**T = R / S - R**
Income Tax (grossed-up)						**-$ 3,760,101**	**U = R + T**

PILs Tax Provision - Test Year 2 (2017)

						Wires Only	
Regulatory Taxable Income						$ 15,873,912	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 1,825,500	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction	-7.00%	**E**		**F = D * E**		
Ontario Income tax						$ 1,825,500	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.50%	**K = J / A**		
	Federal tax rate			15.00%	**L**		
	Combined tax rate					26.50%	**M = K + L**
Total Income Taxes						**$ 4,206,587**	**N = A * M**
Investment Tax Credits						$ 605,593	**O**
Miscellaneous Tax Credits						$ 526,400	**P**
Total Tax Credits						**$ 1,131,993**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**$ 3,074,594**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				73.50%	**S = 1 - M**	**$ 1,108,527**	**T = R / S - R**
Income Tax (grossed-up)						**$ 4,183,121**	**U = R + T**

PILs Tax Provision - Test Year 3 (2018)

Wires Only

Regulatory Taxable Income						$ 18,722,762	A
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	B	$ 2,153,118	C = A * B		
Small business credit	Ontario Small Business Threshold	$ 500,000	D				
	Rate reduction	-7.00%	E		F = D * E		
Ontario Income tax						$ 2,153,118	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.50%	K = J / A		
	Federal tax rate			15.00%	L		
	Combined tax rate					26.50%	M = K + L
Total Income Taxes						**$ 4,961,532**	N = A * M
Investment Tax Credits						$ 605,593	O
Miscellaneous Tax Credits						$ 536,900	P
Total Tax Credits						**$ 1,142,493**	Q = O + P
Corporate PILs/Income Tax Provision for Test Year						**$ 3,819,039**	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]				73.50%	S = 1 - M	**$ 1,376,932**	T = R / S - R
Income Tax (grossed-up)						**$ 5,195,971**	U = R + T

PILs Tax Provision - Test Year 4 (2019)

						Wires Only	
Regulatory Taxable Income						$ 21,857,988	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 2,513,669	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction	-7.00%	**E**		**F = D * E**		
Ontario Income tax						$ 2,513,669	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.50%	**K = J / A**		
	Federal tax rate			15.00%	**L**		
	Combined tax rate					26.50%	**M = K + L**
Total Income Taxes						**$ 5,792,367**	**N = A * M**
Investment Tax Credits						$ 605,593	**O**
Miscellaneous Tax Credits						$ 547,600	**P**
Total Tax Credits						**$ 1,153,193**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**$ 4,639,174**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				73.50%	**S = 1 - M**	**$ 1,672,627**	**T = R / S - R**
Income Tax (grossed-up)						**$ 6,311,801**	**U = R + T**

PILs Tax Provision - Test Year 5 (2020)

						Wires Only	
Regulatory Taxable Income						$ 22,604,248	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 2,599,489	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction	-7.00%	**E**		**F = D * E**		
Ontario Income tax						$ 2,599,489	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.50%	**K = J / A**		
	Federal tax rate			15.00%	**L**		
	Combined tax rate					26.50%	**M = K + L**
Total Income Taxes						**$ 5,990,126**	**N = A * M**
Investment Tax Credits						$ 605,593	**O**
Miscellaneous Tax Credits						$ 558,600	**P**
Total Tax Credits						**$ 1,164,193**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**$ 4,825,933**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				73.50%	**S = 1 - M**	**$ 1,739,962**	**T = R / S - R**
Income Tax (grossed-up)						**$ 6,565,895**	**U = R + T**

Summary of Bill Impacts

A Distribution Charge

				TEST YEAR 1 - 2016		TEST YEAR 2 - 2017		TEST YEAR 3 - 2018		TEST YEAR 4 - 2019		TEST YEAR 5 - 2020	
Customer Class	***Billing Determinant***	**Consumption per customer**	**Load per customer**	**Monthly Distribution Charge Impact**		**Monthly Distribution Charge Impact**		**Monthly Distribution Charge Impact**		**Monthly Distribution Charge Impact**		**Monthly Distribution Charge Impact**	
		kwh	**kW**	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Residential	*kWh*	800		$ 4.78	17.4%	$ 2.88	8.9%	$ 1.37	3.9%	$ 0.64	1.8%	$ 1.25	3.4%
GS<50 kW	*kWh*	2,000		$ 10.93	17.5%	$ 5.27	7.2%	$ 2.77	3.5%	$ 2.10	2.6%	$ 2.36	2.8%
GS>50 kW	*kW*	80,000	250	$ 371.07	30.8%	$ 119.76	7.6%	$ (52.65)	(3.1%)	$ 58.60	3.6%	$ 49.27	2.9%
Large Use	*kW*	2,800,000	7,350	$ 7,500.30	29.6%	$ 3,066.94	9.3%	$ 1,462.65	4.1%	$ 1,445.01	3.9%	$ 1,181.88	3.0%
Unmetered Scattered Load	*kWh*	150		$ 1.63	16.3%	$ 0.92	7.9%	$ 0.39	3.1%	$ 0.41	3.2%	$ 0.31	2.3%
Sentinel Lights	*kW*	180	1	$ 2.59	21.7%	$ 1.51	10.4%	$ 0.17	1.1%	$ 0.61	3.7%	$ 0.52	3.1%
Street Lighting	*kW*	280	1	$ 1.80	20.6%	$ 1.42	13.5%	$ 0.65	5.4%	$ 0.67	5.4%	$ 0.64	4.8%

B Delivery Charge

Customer Class	***Billing Determinant***	**Consumption per customer**	**Load per customer**	**Monthly Delivery Charge Impact**		**Monthly Delivery Charge Impact**		**Monthly Delivery Charge Impact**		**Monthly Delivery Charge Impact**		**Monthly Delivery Charge Impact**	
		kwh	**kW**	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Residential	*kWh*	*800*	-	$ 4.97	13.4%	$ 3.05	7.3%	$ 1.54	3.4%	$ 0.81	1.7%	$ 1.50	3.2%
GS<50 kW	*kWh*	*2,000*	-	$ 11.39	13.7%	$ 5.48	5.8%	$ 3.39	3.4%	$ 2.52	2.4%	$ 2.77	2.6%
GS>50 kW	*kW*	*80,000*	*250*	$ 380.70	17.1%	$ 134.81	5.2%	$ (35.75)	(1.3%)	$ 77.05	2.8%	$ 67.20	2.4%
Large Use	*kW*	*2,800,000*	*7,350*	$ 8,200.75	13.7%	$ 3,848.24	5.7%	$ 2,266.74	3.2%	$ 2,247.63	3.0%	$ 2,024.93	2.7%
Unmetered Scattered Load	*kWh*	*150*	-	$ 1.62	13.9%	$ 0.90	6.8%	$ 0.36	2.5%	$ 0.39	2.7%	$ 0.31	2.0%
Sentinel Lights	*kW*	*180*	*1*	$ 2.64	17.5%	$ 1.56	8.8%	$ 0.22	1.2%	$ 0.65	3.3%	$ 0.57	2.8%
Street Lighting	*kW*	*280*	*1*	$ 2.28	17.5%	$ 2.04	14.4%	$ 1.55	9.6%	$ 0.80	4.5%	$ 0.79	4.3%

C Total Bill

Customer Class	***Billing Determinant***	**Consumption per customer**	**Load per customer**	**Total Monthly Bill Impact**		**Total Monthly Bill Impact**		**Total Monthly Bill Impact**		**Total Monthly Bill Impact**		**Total Monthly Bill Impact**	
		kwh	**kW**	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Residential	*kWh*	*800*	-	$ 5.63	4.0%	$ 3.44	2.4%	$ 1.74	1.2%	$ 0.91	0.6%	$ 1.69	1.1%
GS<50 kW	*kWh*	*2,000*	-	$ 12.90	3.8%	$ 6.19	1.8%	$ 3.84	1.1%	$ 2.85	0.8%	$ 3.13	0.9%
GS>50 kW	*kW*	*80,000*	*250*	$ 431.42	3.5%	$ 152.34	1.2%	$ (40.40)	(0.3%)	$ 87.07	0.7%	$ 75.94	0.6%
Large Use	*kW*	*2,800,000*	*7,350*	$ 9,310.14	2.3%	$ 4,348.51	1.0%	$ 2,561.42	0.6%	$ 2,539.82	0.6%	$ 2,288.17	0.5%
Unmetered Scattered Load	*kWh*	*150*	-	$ 1.83	5.8%	$ 1.02	3.0%	$ 0.41	1.2%	$ 0.45	1.3%	$ 0.34	1.0%
Sentinel Lights	*kW*	*180*	*1*	$ 2.99	7.6%	$ 1.76	4.2%	$ 0.25	0.6%	$ 0.74	1.7%	$ 0.65	1.4%
Street Lighting	*kW*	*280*	*1*	$ 2.58	5.4%	$ 2.30	4.6%	$ 1.75	3.3%	$ 0.91	1.7%	$ 0.90	1.6%

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Appendix 2-W
Bill Impacts - Residential

Customer Class: RESIDENTIAL

TOU / non-TOU: TOU

Consumption 800

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change
Monthly Service Charge	Monthly	1	$ 12.67	$ 12.67		$ 14.62	$ 14.62	$ 1.95	15.4%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 0.20	$ 0.20		$ 0.20	$ 0.20	$ -	0.0%
ICM Rate Rider (2014)	Monthly	1	$ 0.07	$ 0.07		$ -	$ -	$ (0.07)	-100.0%
		1	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kWh	800	$ 0.0140	$ 11.20		$ 0.0170	$ 13.60	$ 2.40	21.4%
Smart Meter Disposition Rider	per kWh	800	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	800	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kWh	800	$ 0.0001	$ 0.08		$ -	$ -	$ (0.08)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	per kWh	800	$ 0.0001	$ 0.08		$ -	$ -	$ (0.08)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kWh	800	$ -	$ -		-$ 0.0001	$ (0.08)	$ (0.08)	
Recovery of Stranded Meter Assets (2016)	per kWh	800	$ -	$ -		$ 0.0001	$ 0.08	$ 0.08	
Account 1575	per kWh	800	$ -	$ -		-$ 0.0005	$ (0.40)	$ (0.40)	
		800	$ -	$ -		$ -	$ -	$ -	
		800	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 24.30			$ 28.02	$ 3.72	15.3%
Deferral/Variance Account Disposition Rate Rider (2014)	per kWh	800	-$ 0.0006	$ (0.48)		$ -	$ -	$ 0.48	-100.0%
Disposition of Deferral/Variance Accounts (2016)	per kWh	800	$ -	$ -		$ 0.0002	$ 0.16	$ 0.16	
		800	$ -	$ -		$ -	$ -	$ -	
		800	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	per kWh	800	$ 0.0003	$ 0.24		$ 0.0006	$ 0.48	$ 0.24	100.0%
Line Losses on Cost of Power		27.60	$ 0.0950	$ 2.62	29.52	$ 0.0950	$ 2.80	$ 0.18	7.0%
Smart Meter Entity Charge	Monthly	1	$ 0.7900	$ 0.79		$ 0.7900	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 27.47**			**$ 32.25**	$ 4.78	**17.4%**
RTSR - Network	per kWh	828	$ 0.0080	$ 6.62	830	$ 0.0080	$ 6.64	$ 0.02	0.2%
RTSR - Line and Transformation Connection	per kWh	828	$ 0.0035	$ 2.90	830	$ 0.0037	$ 3.07	$ 0.17	6.0%
Sub-Total C - Delivery (including Sub-Total B)				**$ 36.99**			**$ 41.96**	$ 4.97	**13.4%**
Wholesale Market Service Charge (WMSC)	per kWh	828	$ 0.0044	$ 3.64	830	$ 0.0044	$ 3.65	$ 0.01	0.2%
Rural and Remote Rate Protection (RRRP)	per kWh	828	$ 0.0013	$ 1.08	830	$ 0.0013	$ 1.08	$ 0.00	0.2%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	800	$ 0.0070	$ 5.60		$ 0.0070	$ 5.60	$ -	0.0%
TOU - Off Peak	per kWh	512	$ 0.0770	$ 39.42		$ 0.0770	$ 39.42	$ -	0.0%
TOU - Mid Peak	per kWh	144	$ 0.1140	$ 16.42		$ 0.1140	$ 16.42	$ -	0.0%
TOU - On Peak	per kWh	144	$ 0.1400	$ 20.16		$ 0.1400	$ 20.16	$ -	0.0%
Energy - RPP - Tier 1	per kWh	800	$ 0.0880	$ 70.40		$ 0.0880	$ 70.40	$ -	0.0%
Energy - RPP - Tier 2	per kWh	0	$ 0.1030	$ -		$ 0.1030	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 123.56**			**$ 128.54**	$ 4.98	**4.0%**
HST			13%	$ 16.06		13%	$ 16.71	$ 0.65	4.0%
Total Bill (including HST)				$ 139.62			$ 145.25	$ 5.63	4.0%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 139.62**			**$ 145.25**	$ 5.63	**4.0%**
Total Bill on RPP (before Taxes)				**$ 117.96**			**$ 122.94**	$ 4.98	**4.2%**
HST			13%	$ 15.33		13%	$ 15.98	$ 0.65	4.2%
Total Bill (including HST)				$ 133.29			$ 138.92	$ 5.63	4.2%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 133.29**			**$ 138.92**	$ 5.63	**4.2%**
Loss Factor (%)			3.45%			3.69%			

	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change
Monthly Service Charge	$ 15.78	$ 15.78	$ 1.16	7.9%	$ 16.27	$ 16.27	$ 0.49	3.1%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ (0.20)	-100.0%	$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0189	$ 15.12	$ 1.52	11.2%	$ 0.0201	$ 16.08	$ 0.96	6.3%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ 0.08	-100.0%	$ -	$ -	$ -	
Recovery of Stranded Meter Assets (2016)	$ -	$ -	$ (0.08)	-100.0%	$ -	$ -	$ -	
Account 1575	$ -	$ -	$ 0.40	-100.0%	$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 30.90	$ 2.88	10.3%		$ 32.35	$ 1.45	4.7%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ 0.0002	$ 0.16	$ -	0.0%	$ -	$ -	$ (0.16)	-100.0%
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$ 0.0006	$ 0.48	$ -	0.0%	$ 0.0007	$ 0.56	$ 0.08	16.7%
Line Losses on Cost of Power	$ 0.0950	$ 2.80	$ -	0.0%	$ 0.0950	$ 2.80	$ -	0.0%
Smart Meter Entity Charge	$ 0.7900	$ 0.79	$ -	0.0%	$ 0.7900	$ 0.79	$ -	0.0%
Sub-Total B - Distribution (includes Sub-Total A)		**$ 35.13**	$ 2.88	**8.9%**		**$ 36.50**	$ 1.37	**3.9%**
RTSR - Network	$ 0.0081	$ 6.72	$ 0.08	1.2%	$ 0.0083	$ 6.89	$ 0.17	2.5%
RTSR - Line and Transformation Connection	$ 0.0038	$ 3.15	$ 0.08	2.7%	$ 0.0038	$ 3.15	$ -	0.0%
Sub-Total C - Delivery (including Sub-Total B)		**$ 45.01**	$ 3.05	**7.3%**		**$ 46.54**	$ 1.54	**3.4%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 3.65	$ -	0.0%	$ 0.0044	$ 3.65	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 1.08	$ -	0.0%	$ 0.0013	$ 1.08	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 5.60	$ -	0.0%	$ 0.0070	$ 5.60	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 39.42	$ -	0.0%	$ 0.0770	$ 39.42	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 16.42	$ -	0.0%	$ 0.1140	$ 16.42	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 20.16	$ -	0.0%	$ 0.1400	$ 20.16	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 70.40	$ -	0.0%	$ 0.0880	$ 70.40	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
							$ -	
Total Bill on TOU (before Taxes)		**$ 131.58**	$ 3.05	**2.4%**		**$ 133.12**	$ 1.54	**1.2%**
HST	13%	$ 17.11	$ 0.40	2.4%	13%	$ 17.31	$ 0.20	1.2%
Total Bill (including HST)		$ 148.69	$ 3.44	2.4%		$ 150.43	$ 1.74	1.2%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 148.69**	$ 3.44	**2.4%**		**$ 150.43**	$ 1.74	**1.2%**
							$ -	
Total Bill on RPP (before Taxes)		**$ 125.98**	$ 3.05	**2.5%**		**$ 127.52**	$ 1.54	**1.2%**
HST	13%	$ 16.38	$ 0.40	2.5%	13%	$ 16.58	$ 0.20	1.2%
Total Bill (including HST)		$ 142.36	$ 3.44	2.5%		$ 144.10	$ 1.74	1.2%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 142.36**	$ 3.44	**2.5%**		**$ 144.10**	$ 1.74	**1.2%**
Loss Factor (%)	3.69%				3.69%			

	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 16.74	$ 16.74	$ 0.47	2.9%	$ 17.11	$ 17.11	$ 0.37	2.2%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0213	$ 17.04	$ 0.96	6.0%	$ 0.0224	$ 17.92	$ 0.88	5.2%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Stranded Meter Assets (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 33.78	$ 1.43	4.4%		$ 35.03	$ 1.25	3.7%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$ 0.0007	$ 0.56	$ -	0.0%	$ 0.0007	$ 0.56	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 2.80	$ -	0.0%	$ 0.0950	$ 2.80	$ -	0.0%
Smart Meter Entity Charge		$ -	$ (0.79)	-100.0%		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 37.14**	$ 0.64	**1.8%**		**$ 38.39**	$ 1.25	**3.4%**
RTSR - Network	$ 0.0084	$ 6.97	$ 0.08	1.2%	$ 0.0086	$ 7.13	$ 0.17	2.4%
RTSR - Line and Transformation Connection	$ 0.0039	$ 3.24	$ 0.08	2.6%	$ 0.0040	$ 3.32	$ 0.08	2.6%
Sub-Total C - Delivery (including Sub-Total B)		**$ 47.35**	$ 0.81	**1.7%**		**$ 48.85**	$ 1.50	**3.2%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 3.65	$ -	0.0%	$ 0.0044	$ 3.65	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 1.08	$ -	0.0%	$ 0.0013	$ 1.08	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 5.60	$ -	0.0%	$ 0.0070	$ 5.60	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 39.42	$ -	0.0%	$ 0.0770	$ 39.42	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 16.42	$ -	0.0%	$ 0.1140	$ 16.42	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 20.16	$ -	0.0%	$ 0.1400	$ 20.16	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 70.40	$ -	0.0%	$ 0.0880	$ 70.40	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 133.93**	$ 0.81	**0.6%**		**$ 135.42**	$ 1.50	**1.1%**
HST	13%	$ 17.41	$ 0.10	0.6%	13%	$ 17.61	$ 0.19	1.1%
Total Bill (including HST)		$ 151.34	$ 0.91	0.6%		$ 153.03	$ 1.69	1.1%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 151.34**	$ 0.91	**0.6%**		**$ 153.03**	$ 1.69	**1.1%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 128.33**	$ 0.81	**0.6%**		**$ 129.82**	$ 1.50	**1.2%**
HST	13%	$ 16.68	$ 0.10	0.6%	13%	$ 16.88	$ 0.19	1.2%
Total Bill (including HST)		$ 145.01	$ 0.91	0.6%		$ 146.70	$ 1.69	1.2%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 145.01**	$ 0.91	**0.6%**		**$ 146.70**	$ 1.69	**1.2%**
Loss Factor (%)	3.69%				3.69%			

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Appendix 2-W
Bill Impacts - GS<50

Customer Class: GS<50

TOU / non-TOU: TOU

Consumption 2,000

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change
Monthly Service Charge	Monthly	1	$ 26.08	$ 26.08		$ 30.09	$ 30.09	$ 4.01	15.4%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 0.55	$ 0.55		$ 0.55	$ 0.55	$ -	0.0%
ICM Rate Rider (2014)	Monthly	1	$ 0.14	$ 0.14		$ -	$ -	$ (0.14)	-100.0%
		1	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kWh	2,000	$ 0.0139	$ 27.80		$ 0.0167	$ 33.40	$ 5.60	20.1%
Smart Meter Disposition Rider	per kWh	2,000	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	2,000	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kWh	2,000	$ 0.0001	$ 0.20		$ -	$ -	$ (0.20)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	per kWh	2,000	$ 0.0004	$ 0.80		$ -	$ -	$ (0.80)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kWh	2,000	$ -	$ -		$ 0.0001	$ 0.20	$ 0.20	
Account 1575	per kWh	2,000	$ -	$ -		-$ 0.0003	$ (0.60)	$ (0.60)	
Recovery of Stranded Meter Assets (2016)	per kWh	2,000	$ -	$ -		$ 0.0002	$ 0.40	$ 0.40	
		2,000	$ -	$ -		$ -	$ -	$ -	
		2,000	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 55.57			$ 64.04	$ 8.47	15.2%
Deferral/Variance Account Disposition Rate Rider (2014)	per kWh	2,000	-$ 0.0006	$ (1.20)		$ -	$ -	$ 1.20	-100.0%
Disposition of Deferral/Variance Accounts (2016)	per kWh	2,000	$ -	$ -		$ 0.0002	$ 0.40	$ 0.40	
		2,000	$ -	$ -		$ -	$ -	$ -	
		2,000	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	per kWh	2,000	$ 0.0003	$ 0.60		$ 0.0005	$ 1.00	$ 0.40	66.7%
Line Losses on Cost of Power		69.00	$ 0.0950	$ 6.56	73.80	$ 0.0950	$ 7.01	$ 0.46	7.0%
Smart Meter Entity Charge	Monthly	1	$ 0.7900	$ 0.79		$ 0.7900	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 62.32**			**$ 73.24**	$ 10.93	**17.5%**
RTSR - Network	per kWh	2,069	$ 0.0072	$ 14.90	2074	$ 0.0072	$ 14.93	$ 0.03	0.2%
RTSR - Line and Transformation Connection	per kWh	2,069	$ 0.0030	$ 6.21	2074	$ 0.0032	$ 6.64	$ 0.43	6.9%
Sub-Total C - Delivery (including Sub-Total B)				**$ 83.42**			**$ 94.81**	$ 11.39	**13.7%**
Wholesale Market Service Charge (WMSC)	per kWh	2,069	$ 0.0044	$ 9.10	2074	$ 0.0044	$ 9.12	$ 0.02	0.2%
Rural and Remote Rate Protection (RRRP)	per kWh	2,069	$ 0.0013	$ 2.69	2074	$ 0.0013	$ 2.70	$ 0.01	0.2%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	2,000	$ 0.0070	$ 14.00		$ 0.0070	$ 14.00	$ -	0.0%
TOU - Off Peak	per kWh	1,280	$ 0.0770	$ 98.56		$ 0.0770	$ 98.56	$ -	0.0%
TOU - Mid Peak	per kWh	360	$ 0.1140	$ 41.04		$ 0.1140	$ 41.04	$ -	0.0%
TOU - On Peak	per kWh	360	$ 0.1400	$ 50.40		$ 0.1400	$ 50.40	$ -	0.0%
Energy - RPP - Tier 1	per kWh	1,000	$ 0.0880	$ 88.00		$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	per kWh	1,000	$ 0.1030	$ 103.00		$ 0.1030	$ 103.00	$ -	0.0%
Total Bill on TOU (before Taxes)				**$ 299.46**			**$ 310.88**	$ 11.42	**3.8%**
HST			13%	$ 38.93		13%	$ 40.41	$ 1.48	3.8%
Total Bill (including HST)				$ 338.39			$ 351.29	$ 12.90	3.8%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 338.39**			**$ 351.29**	$ 12.90	**3.8%**
Total Bill on RPP (before Taxes)				**$ 300.46**			**$ 311.88**	$ 11.42	**3.8%**
HST			13%	$ 39.06		13%	$ 40.54	$ 1.48	3.8%
Total Bill (including HST)				$ 339.52			$ 352.42	$ 12.90	3.8%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 339.52**			**$ 352.42**	$ 12.90	**3.8%**
Loss Factor (%)			3.45%			3.69%			

	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change
Monthly Service Charge	$ 32.71	$ 32.71	$ 2.62	8.7%	$ 33.48	$ 33.48	$ 0.77	2.4%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ (0.55)	-100.0%	$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0183	$ 36.60	$ 3.20	9.6%	$ 0.0194	$ 38.80	$ 2.20	6.0%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ (0.20)	-100.0%	$ -	$ -	$ -	
Account 1575	$ -	$ -	$ 0.60	-100.0%	$ -	$ -	$ -	
Recovery of Stranded Meter Assets (2016)	$ -	$ -	$ (0.40)	-100.0%	$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 69.31	$ 5.27	8.2%		$ 72.28	$ 2.97	4.3%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ 0.0002	$ 0.40	$ -	0.0%	$ -	$ -	$ (0.40)	-100.0%
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$ 0.0005	$ 1.00	$ -	0.0%	$ 0.0006	$ 1.20	$ 0.20	20.0%
Line Losses on Cost of Power	$ 0.0950	$ 7.01	$ -	0.0%	$ 0.0950	$ 7.01	$ -	0.0%
Smart Meter Entity Charge	$ 0.7900	$ 0.79	$ -	0.0%	$ 0.7900	$ 0.79	$ -	0.0%
Sub-Total B - Distribution (includes Sub-Total A)		**$ 78.51**	$ 5.27	**7.2%**		**$ 81.28**	$ 2.77	**3.5%**
RTSR - Network	$ 0.0073	$ 15.14	$ 0.21	1.4%	$ 0.0075	$ 15.55	$ 0.41	2.7%
RTSR - Line and Transformation Connection	$ 0.0032	$ 6.64	$ -	0.0%	$ 0.0033	$ 6.84	$ 0.21	3.1%
Sub-Total C - Delivery (including Sub-Total B)		**$ 100.29**	$ 5.48	**5.8%**		**$ 103.68**	$ 3.39	**3.4%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 9.12	$ -	0.0%	$ 0.0044	$ 9.12	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 2.70	$ -	0.0%	$ 0.0013	$ 2.70	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 14.00	$ -	0.0%	$ 0.0070	$ 14.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 98.56	$ -	0.0%	$ 0.0770	$ 98.56	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 41.04	$ -	0.0%	$ 0.1140	$ 41.04	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 50.40	$ -	0.0%	$ 0.1400	$ 50.40	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 103.00	$ -	0.0%	$ 0.1030	$ 103.00	$ -	0.0%
							$ -	
Total Bill on TOU (before Taxes)		**$ 316.36**	$ 5.48	**1.8%**		**$ 319.75**	$ 3.39	**1.1%**
HST	13%	$ 41.13	$ 0.71	1.8%	13%	$ 41.57	$ 0.44	1.1%
Total Bill (including HST)		$ 357.48	$ 6.19	1.8%		$ 361.32	$ 3.84	1.1%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 357.48**	$ 6.19	**1.8%**		**$ 361.32**	$ 3.84	**1.1%**
							$ -	
Total Bill on RPP (before Taxes)		**$ 317.36**	$ 5.48	**1.8%**		**$ 320.75**	$ 3.39	**1.1%**
HST	13%	$ 41.26	$ 0.71	1.8%	13%	$ 41.70	$ 0.44	1.1%
Total Bill (including HST)		$ 358.61	$ 6.19	1.8%		$ 362.45	$ 3.84	1.1%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 358.61**	$ 6.19	**1.8%**		**$ 362.45**	$ 3.84	**1.1%**
Loss Factor (%)	3.69%				3.69%			

	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 33.58	$ 33.58	$ 0.09	0.3%	$ 33.73	$ 33.73	$ 0.16	0.5%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0208	$ 41.60	$ 2.80	7.2%	$ 0.0219	$ 43.80	$ 2.20	5.3%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Stranded Meter Assets (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 75.18	$ 2.89	4.0%		$ 77.53	$ 2.36	3.1%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$ 0.0006	$ 1.20	$ -	0.0%	$ 0.0006	$ 1.20	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 7.01	$ -	0.0%	$ 0.0950	$ 7.01	$ -	0.0%
Smart Meter Entity Charge		$ -	$ (0.79)	-100.0%		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 83.39**	$ 2.10	**2.6%**		**$ 85.74**	$ 2.36	**2.8%**
RTSR - Network	$ 0.0076	$ 15.76	$ 0.21	1.3%	$ 0.0077	$ 15.97	$ 0.21	1.3%
RTSR - Line and Transformation Connection	$ 0.0034	$ 7.05	$ 0.21	3.0%	$ 0.0035	$ 7.26	$ 0.21	2.9%
Sub-Total C - Delivery (including Sub-Total B)		**$ 106.20**	$ 2.52	**2.4%**		**$ 108.97**	$ 2.77	**2.6%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 9.12	$ -	0.0%	$ 0.0044	$ 9.12	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 2.70	$ -	0.0%	$ 0.0013	$ 2.70	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 14.00	$ -	0.0%	$ 0.0070	$ 14.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 98.56	$ -	0.0%	$ 0.0770	$ 98.56	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 41.04	$ -	0.0%	$ 0.1140	$ 41.04	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 50.40	$ -	0.0%	$ 0.1400	$ 50.40	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 103.00	$ -	0.0%	$ 0.1030	$ 103.00	$ -	0.0%
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 322.27**	$ 2.52	**0.8%**		**$ 325.04**	$ 2.77	**0.9%**
HST	13%	$ 41.90	$ 0.33	0.8%	13%	$ 42.26	$ 0.36	0.9%
Total Bill (including HST)		$ 364.16	$ 2.85	0.8%		$ 367.30	$ 3.13	0.9%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 364.16**	$ 2.85	**0.8%**		**$ 367.30**	$ 3.13	**0.9%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 323.27**	$ 2.52	**0.8%**		**$ 326.04**	$ 2.77	**0.9%**
HST	13%	$ 42.03	$ 0.33	0.8%	13%	$ 42.39	$ 0.36	0.9%
Total Bill (including HST)		$ 365.29	$ 2.85	0.8%		$ 368.43	$ 3.13	0.9%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 365.29**	$ 2.85	**0.8%**		**$ 368.43**	$ 3.13	**0.9%**
Loss Factor (%)	3.69%				3.69%			

Appendix 2-W
Bill Impacts - GS > 50

Customer Class: GS > 50

TOU / non-TOU: TOU

Consumption	80,000
Load	250

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change
Monthly Service Charge	Monthly	1	$ 138.48	$ 138.48		$ 138.48	$ 138.48	$ -	0.0%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 6.99	$ 6.99		$ 6.99	$ 6.99	$ -	0.0%
ICM Rate Rider (2014)	Monthly	1	$ 0.72	$ 0.72		$ -	$ -	$ (0.72)	-100.0%
		1	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kW	250	$ 3.3278	$ 831.95		$ 4.0220	$ 1,005.50	$ 173.55	20.9%
Smart Meter Disposition Rider	per kW	250	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kW	250	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kW	250	$ 0.0173	$ 4.33		$ -	$ -	$ (4.33)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	per kW	250	$ 0.0134	$ 3.35		$ -	$ -	$ (3.35)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kW	250	$ -	$ -		-$ 0.0126	$ (3.15)	$ (3.15)	
Account 1575	per kW	250	$ -	$ -		-$ 0.0564	$ (14.10)	$ (14.10)	
		250	$ -	$ -		$ -	$ -	$ -	
		250	$ -	$ -		$ -	$ -	$ -	
		250	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 985.82			$ 1,133.72	$ 147.91	15.0%
Deferral/Variance Account Disposition Rate Rider (2014)	per kW	250	-$ 0.2207	$ (55.18)		$ -	$ -	$ 55.18	-100.0%
Disposition of Deferral/Variance Accounts (2016)	per kW	250	$ -	$ -		$ 0.0309	$ 7.73	$ 7.73	
Disposition of Global Adjustment Sub-Account (2014)	per kW	250	-$ 0.0720	$ (18.00)		$ -	$ -	$ 18.00	-100.0%
Disposition of Global Adjustment Sub-Account (2016)	per kW	250	$ -	$ -		$ 0.4161	$ 104.03	$ 104.03	
		250	$ -			$ -			
			$ -			$ -			
			$ -			$ -			
Low Voltage Service Charge	per kW	250	$ 0.1189	$ 29.73		$ 0.1989	$ 49.73	$ 20.00	67.3%
Line Losses on Cost of Power		2,760.00	$ 0.0950	$ 262.20	2,952.00	$ 0.0950	$ 280.44	$ 18.24	7.0%
Smart Meter Entity Charge				$ -				$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,204.57**			**$ 1,575.64**	$ 371.07	**30.8%**
RTSR - Network	per kW	250	$ 2.9192	$ 729.80	250	$ 2.8960	$ 724.00	$ (5.80)	-0.8%
RTSR - Line and Transformation Connection	per kW	250	$ 1.1726	$ 293.15	250	$ 1.2343	$ 308.58	$ 15.43	5.3%
Sub-Total C - Delivery (including Sub-Total B)				**$ 2,227.52**			**$ 2,608.21**	$ 380.70	**17.1%**
Wholesale Market Service Charge (WMSC)	per kWh	82,760	$ 0.0044	$ 364.14	82952	$ 0.0044	$ 364.99	$ 0.84	0.2%
Rural and Remote Rate Protection (RRRP)	per kWh	82,760	$ 0.0013	$ 107.59	82952	$ 0.0013	$ 107.84	$ 0.25	0.2%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	80,000	$ 0.0070	$ 560.00		$ 0.0070	$ 560.00	$ -	0.0%
TOU - Off Peak	per kWh	51,200	$ 0.0770	$ 3,942.40		$ 0.0770	$ 3,942.40	$ -	0.0%
TOU - Mid Peak	per kWh	14,400	$ 0.1140	$ 1,641.60		$ 0.1140	$ 1,641.60	$ -	0.0%
TOU - On Peak	per kWh	14,400	$ 0.1400	$ 2,016.00		$ 0.1400	$ 2,016.00	$ -	0.0%
Energy - RPP - Tier 1	per kWh	1,000	$ 0.0880	$ 88.00		$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	per kWh	79,000	$ 0.1030	$ 8,137.00		$ 0.1030	$ 8,137.00	$ -	0.0%
Total Bill on TOU (before Taxes)				**$ 10,859.50**			**$ 11,241.29**	$ 381.79	**3.5%**
HST			13%	$ 1,411.73		13%	$ 1,461.37	$ 49.63	3.5%
Total Bill (including HST)				$ 12,271.23			$ 12,702.65	$ 431.42	3.5%
***Ontario Clean Energy Benefit* [1]**								$ -	
Total Bill on TOU (including OCEB)				**$ 12,271.23**			**$ 12,702.65**	$ 431.42	**3.5%**
Total Bill on RPP (before Taxes)				**$ 11,484.50**			**$ 11,866.29**	$ 381.79	**3.3%**
HST			13%	$ 1,492.98		13%	$ 1,542.62	$ 49.63	3.3%
Total Bill (including HST)				$ 12,977.48			$ 13,408.90	$ 431.42	3.3%
***Ontario Clean Energy Benefit* [1]**								$ -	
Total Bill on RPP (including OCEB)				**$ 12,977.48**			**$ 13,408.90**	$ 431.42	**3.3%**
Loss Factor (%)			3.45%			3.69%			

	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change
Monthly Service Charge	$ 138.48	$ 138.48	$ -	0.0%	$ 138.48	$ 138.48	$ -	0.0%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ (6.99)	-100.0%	$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 4.4497	$ 1,112.43	$ 106.93	10.6%	$ 4.6761	$ 1,169.03	$ 56.60	5.1%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ 3.15	-100.0%	$ -	$ -	$ -	
Account 1575	$ -	$ -	$ 14.10	-100.0%	$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 1,250.91	$ 117.19	10.3%		$ 1,307.51	$ 56.60	4.5%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ 0.0309	$ 7.73	$ -	0.0%	$ -	$ -	$ (7.73)	-100.0%
Disposition of Global Adjustment Sub-Account (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	$ 0.4161	$ 104.03	$ -	0.0%	$ -	$ -	$ (104.03)	-100.0%
	$ -				$ -			
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.2092	$ 52.30	$ 2.58	5.2%	$ 0.2192	$ 54.80	$ 2.50	4.8%
Line Losses on Cost of Power	$ 0.0950	$ 280.44	$ -	0.0%	$ 0.0950	$ 280.44	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 1,695.40**	$ 119.76	**7.6%**		**$ 1,642.75**	$ (52.65)	**-3.1%**
RTSR - Network	$ 2.9367	$ 734.18	$ 10.18	1.4%	$ 2.9823	$ 745.58	$ 11.40	1.6%
RTSR - Line and Transformation Connection	$ 1.2538	$ 313.45	$ 4.88	1.6%	$ 1.2758	$ 318.95	$ 5.50	1.8%
Sub-Total C - Delivery (including Sub-Total B)		**$ 2,743.02**	$ 134.81	**5.2%**		**$ 2,707.27**	$ (35.75)	**-1.3%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 364.99	$ -	0.0%	$ 0.0044	$ 364.99	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 107.84	$ -	0.0%	$ 0.0013	$ 107.84	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 560.00	$ -	0.0%	$ 0.0070	$ 560.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 3,942.40	$ -	0.0%	$ 0.0770	$ 3,942.40	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 1,641.60	$ -	0.0%	$ 0.1140	$ 1,641.60	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 2,016.00	$ -	0.0%	$ 0.1400	$ 2,016.00	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 8,137.00	$ -	0.0%	$ 0.1030	$ 8,137.00	$ -	0.0%
							$ -	
Total Bill on TOU (before Taxes)		**$ 11,376.10**	$ 134.81	**1.2%**		**$ 11,340.35**	$ (35.75)	**-0.3%**
HST	13%	$ 1,478.89	$ 17.53	1.2%	13%	$ 1,474.25	$ (4.65)	-0.3%
Total Bill (including HST)		$ 12,854.99	$ 152.34	1.2%		$ 12,814.59	$ (40.40)	-0.3%
***Ontario Clean Energy Benefit* [1]**			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 12,854.99**	$ 152.34	**1.2%**		**$ 12,814.59**	$ (40.40)	**-0.3%**
							$ -	
Total Bill on RPP (before Taxes)		**$ 12,001.10**	$ 134.81	**1.1%**		**$ 11,965.35**	$ (35.75)	**-0.3%**
HST	13%	$ 1,560.14	$ 17.53	1.1%	13%	$ 1,555.50	$ (4.65)	-0.3%
Total Bill (including HST)		$ 13,561.24	$ 152.34	1.1%		$ 13,520.84	$ (40.40)	-0.3%
***Ontario Clean Energy Benefit* [1]**			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 13,561.24**	$ 152.34	**1.1%**		**$ 13,520.84**	$ (40.40)	**-0.3%**
Loss Factor (%)	3.69%				3.69%			

	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 138.48	$ 138.48	$ -	0.0%	$ 138.48	$ 138.48	$ -	0.0%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 4.8998	$ 1,224.95	$ 55.93	4.8%	$ 5.0969	$ 1,274.23	$ 49.27	4.0%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 1,363.43	$ 55.93	4.3%		$ 1,412.71	$ 49.27	3.6%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.2299	$ 57.48	$ 2.68	4.9%	$ 0.2299	$ 57.48	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 280.44	$ -	0.0%	$ 0.0950	$ 280.44	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 1,701.35**	$ 58.60	**3.6%**		**$ 1,750.62**	$ 49.27	**2.9%**
RTSR - Network	$ 3.0321	$ 758.03	$ 12.45	1.7%	$ 3.0802	$ 770.05	$ 12.03	1.6%
RTSR - Line and Transformation Connection	$ 1.2998	$ 324.95	$ 6.00	1.9%	$ 1.3234	$ 330.85	$ 5.90	1.8%
Sub-Total C - Delivery (including Sub-Total B)		**$ 2,784.32**	$ 77.05	**2.8%**		**$ 2,851.52**	$ 67.20	**2.4%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 364.99	$ -	0.0%	$ 0.0044	$ 364.99	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 107.84	$ -	0.0%	$ 0.0013	$ 107.84	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 560.00	$ -	0.0%	$ 0.0070	$ 560.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 3,942.40	$ -	0.0%	$ 0.0770	$ 3,942.40	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 1,641.60	$ -	0.0%	$ 0.1140	$ 1,641.60	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 2,016.00	$ -	0.0%	$ 0.1400	$ 2,016.00	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 8,137.00	$ -	0.0%	$ 0.1030	$ 8,137.00	$ -	0.0%
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 11,417.40**	$ 77.05	**0.7%**		**$ 11,484.60**	$ 67.20	**0.6%**
HST	13%	$ 1,484.26	$ 10.02	0.7%	13%	$ 1,493.00	$ 8.74	0.6%
Total Bill (including HST)		$ 12,901.66	$ 87.07	0.7%		$ 12,977.59	$ 75.94	0.6%
***Ontario Clean Energy Benefit* [1]**			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 12,901.66**	$ 87.07	**0.7%**		**$ 12,977.59**	$ 75.94	**0.6%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 12,042.40**	$ 77.05	**0.6%**		**$ 12,109.60**	$ 67.20	**0.6%**
HST	13%	$ 1,565.51	$ 10.02	0.6%	13%	$ 1,574.25	$ 8.74	0.6%
Total Bill (including HST)		$ 13,607.91	$ 87.07	0.6%		$ 13,683.84	$ 75.94	0.6%
***Ontario Clean Energy Benefit* [1]**			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 13,607.91**	$ 87.07	**0.6%**		**$ 13,683.84**	$ 75.94	**0.6%**
Loss Factor (%)	3.69%				3.69%			

Appendix 2-W
Bill Impacts - Large User

Customer Class: Large User

TOU / non-TOU: TOU

Consumption	**2,800,000**
Load	**7,350**

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change
Monthly Service Charge	Monthly	1	$ 5,966.29	$ 5,966.29		$ 5,966.29	$ 5,966.29	$ -	0.0%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 104.59	$ 104.59		$ 104.59	$ 104.59	$ -	0.0%
ICM Rate Rider (2014)	Monthly	1	$ 30.93	$ 30.93		$ -	$ -	$ (30.93)	-100.0%
		1	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kW	7,350	$ 1.4159	$ 10,406.87		$ 2.1550	$ 15,839.25	$ 5,432.39	52.2%
Smart Meter Disposition Rider	per kW	7,350	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kW	7,350	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kW	7,350	$ 0.0073	$ 53.66		$ -	$ -	$ (53.66)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kW	7,350	$ -	$ -		-$ 0.0353	$ (259.46)	$ (259.46)	
Account 1575	per kW	7,350	$ -	$ -		-$ 0.0311	$ (228.59)	$ (228.59)	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
			$ -			$ -			
		7,350	$ -	$ -		$ -	$ -	$ -	
		7,350	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 16,562.33			$ 21,422.09	$ 4,859.76	29.3%
Deferral/Variance Account Disposition Rate Rider (2014)	per kW	7,350	-$ 0.1973	$ (1,450.16)		$ -	$ -	$ 1,450.16	-100.0%
Disposition of Deferral/Variance Accounts (2016)	per kW	7,350	$ -	$ -		$ 0.0148	$ 108.78	$ 108.78	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
			$ -			$ -			
			$ -			$ -			
Low Voltage Service Charge	per kW	7,350	$ 0.1437	$ 1,056.20		$ 0.2040	$ 1,499.40	$ 443.21	42.0%
Line Losses on Cost of Power		96,600	$ 0.0950	$ 9,177.00	103,320	$ 0.0950	$ 9,815.40	$ 638.40	7.0%
Smart Meter Entity Charge				$ -				$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25,345.37**			**$ 32,845.67**	$ 7,500.30	**29.6%**
RTSR - Network	per kW	7350	$ 3.4638	$ 25,458.93	7350	$ 3.4798	$ 25,576.53	$ 117.60	0.5%
RTSR - Line and Transformation Connection	per kW	7350	$ 1.2027	$ 8,839.85	7350	$ 1.2820	$ 9,422.70	$ 582.86	6.6%
Sub-Total C - Delivery (including Sub-Total B)				**$ 59,644.15**			**$ 67,844.90**	$ 8,200.75	**13.7%**
Wholesale Market Service Charge (WMSC)	per kWh	2,896,600	$ 0.0044	$ 12,745.04	2903320	$ 0.0044	$ 12,774.61	$ 29.57	0.2%
Rural and Remote Rate Protection (RRRP)	per kWh	2,896,600	$ 0.0013	$ 3,765.58	2903320	$ 0.0013	$ 3,774.32	$ 8.74	0.2%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	2,800,000	$ 0.0070	$ 19,600.00		$ 0.0070	$ 19,600.00	$ -	0.0%
TOU - Off Peak	per kWh	1,792,000	$ 0.0770	$ 137,984.00		$ 0.0770	$ 137,984.00	$ -	0.0%
TOU - Mid Peak	per kWh	504,000	$ 0.1140	$ 57,456.00		$ 0.1140	$ 57,456.00	$ -	0.0%
TOU - On Peak	per kWh	504,000	$ 0.1400	$ 70,560.00		$ 0.1400	$ 70,560.00	$ -	0.0%
Energy - RPP - Tier 1	per kWh	1,000	$ 0.0880	$ 88.00		$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	per kWh	2,799,000	$ 0.1030	$ 288,297.00		$ 0.1030	$ 288,297.00	$ -	0.0%
Total Bill on TOU (before Taxes)				**$ 361,755.02**			**$ 369,994.07**	**$ 8,239.06**	**2.3%**
HST			13%	$ 47,028.15		13%	$ 48,099.23	$ 1,071.08	2.3%
Total Bill (including HST)				$ 408,783.17			$ 418,093.30	$ 9,310.14	2.3%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 408,783.17**			**$ 418,093.30**	**$ 9,310.14**	**2.3%**
Total Bill on RPP (before Taxes)				**$ 384,140.02**			**$ 392,379.07**	**$ 8,239.06**	**2.1%**
HST			13%	$ 49,938.20		13%	$ 51,009.28	$ 1,071.08	2.1%
Total Bill (including HST)				$ 434,078.22			$ 443,388.35	$ 9,310.14	2.1%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 434,078.22**			**$ 443,388.35**	**$ 9,310.14**	**2.1%**
Loss Factor (%)			3.45%			3.69%			

	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change
Monthly Service Charge	$ 5,966.29	$ 5,966.29	$ -	0.0%	$ 5,966.29	$ 5,966.29	$ -	0.0%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ (104.59)	-100.0%	$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 2.5095	$ 18,444.83	$ 2,605.58	16.5%	$ 2.7130	$ 19,940.55	$ 1,495.73	8.1%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ 259.46	-100.0%	$ -	$ -	$ -	
Account 1575	$ -	$ -	$ 228.59	-100.0%	$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 24,411.12	$ 2,989.03	14.0%		$ 25,906.84	$ 1,495.73	6.1%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ 0.0148	$ 108.78	$ -	0.0%	$ -	$ -	$ (108.78)	-100.0%
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.2146	$ 1,577.31	$ 77.91	5.2%	$ 0.2249	$ 1,653.02	$ 75.70	4.8%
Line Losses on Cost of Power	$ 0.0950	$ 9,815.40	$ -	0.0%	$ 0.0950	$ 9,815.40	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 35,912.61**	$ 3,066.94	**9.3%**		**$ 37,375.26**	$ 1,462.65	**4.1%**
RTSR - Network	$ 3.5558	$ 26,135.13	$ 558.60	2.2%	$ 3.6338	$ 26,708.43	$ 573.30	2.2%
RTSR - Line and Transformation Connection	$ 1.3123	$ 9,645.41	$ 222.71	2.4%	$ 1.3437	$ 9,876.20	$ 230.79	2.4%
Sub-Total C - Delivery (including Sub-Total B)		**$ 71,693.14**	$ 3,848.24	**5.7%**		**$ 73,959.88**	$ 2,266.74	**3.2%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 12,774.61	$ -	0.0%	$ 0.0044	$ 12,774.61	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 3,774.32	$ -	0.0%	$ 0.0013	$ 3,774.32	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 19,600.00	$ -	0.0%	$ 0.0070	$ 19,600.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 137,984.00	$ -	0.0%	$ 0.0770	$ 137,984.00	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 57,456.00	$ -	0.0%	$ 0.1140	$ 57,456.00	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 70,560.00	$ -	0.0%	$ 0.1400	$ 70,560.00	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 288,297.00	$ -	0.0%	$ 0.1030	$ 288,297.00	$ -	0.0%
							$ -	
Total Bill on TOU (before Taxes)		**$ 373,842.31**	**$ 3,848.24**	**1.0%**		**$ 376,109.05**	**$ 2,266.74**	**0.6%**
HST	13%	$ 48,599.50	$ 500.27	1.0%	13%	$ 48,894.18	$ 294.68	0.6%
Total Bill (including HST)		$ 422,441.81	$ 4,348.51	1.0%		$ 425,003.23	$ 2,561.42	0.6%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 422,441.81**	**$ 4,348.51**	**1.0%**		**$ 425,003.23**	**$ 2,561.42**	**0.6%**
							$ -	
Total Bill on RPP (before Taxes)		**$ 396,227.31**	**$ 3,848.24**	**1.0%**		**$ 398,494.05**	**$ 2,266.74**	**0.6%**
HST	13%	$ 51,509.55	$ 500.27	1.0%	13%	$ 51,804.23	$ 294.68	0.6%
Total Bill (including HST)		$ 447,736.86	$ 4,348.51	1.0%		$ 450,298.28	$ 2,561.42	0.6%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 447,736.86**	**$ 4,348.51**	**1.0%**		**$ 450,298.28**	**$ 2,561.42**	**0.6%**
Loss Factor (%)	3.69%				3.69%			

	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 5,966.29	$ 5,966.29	$ -	0.0%	$ 5,966.29	$ 5,966.29	$ -	0.0%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 2.8987	$ 21,305.45	$ 1,364.90	6.8%	$ 3.0595	$ 22,487.33	$ 1,181.88	5.5%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 27,271.74	$ 1,364.90	5.3%		$ 28,453.62	$ 1,181.88	4.3%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.2358	$ 1,733.13	$ 80.12	4.8%	$ 0.2358	$ 1,733.13	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 9,815.40	$ -	0.0%	$ 0.0950	$ 9,815.40	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 38,820.27**	$ 1,445.01	**3.9%**		**$ 40,002.15**	$ 1,181.88	**3.0%**
RTSR - Network	$ 3.7114	$ 27,278.79	$ 570.36	2.1%	$ 3.7928	$ 27,877.08	$ 598.29	2.2%
RTSR - Line and Transformation Connection	$ 1.3753	$ 10,108.46	$ 232.26	2.4%	$ 1.4086	$ 10,353.21	$ 244.76	2.4%
Sub-Total C - Delivery (including Sub-Total B)		**$ 76,207.51**	$ 2,247.63	**3.0%**		**$ 78,232.44**	$ 2,024.93	**2.7%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 12,774.61	$ -	0.0%	$ 0.0044	$ 12,774.61	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 3,774.32	$ -	0.0%	$ 0.0013	$ 3,774.32	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 19,600.00	$ -	0.0%	$ 0.0070	$ 19,600.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 137,984.00	$ -	0.0%	$ 0.0770	$ 137,984.00	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 57,456.00	$ -	0.0%	$ 0.1140	$ 57,456.00	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 70,560.00	$ -	0.0%	$ 0.1400	$ 70,560.00	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 288,297.00	$ -	0.0%	$ 0.1030	$ 288,297.00	$ -	0.0%
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 378,356.68**	**$ 2,247.63**	**0.6%**		**$ 380,381.61**	**$ 2,024.92**	**0.5%**
HST	13%	$ 49,186.37	$ 292.19	0.6%	13%	$ 49,449.61	$ 263.24	0.5%
Total Bill (including HST)		$ 427,543.05	$ 2,539.82	0.6%		$ 429,831.22	$ 2,288.17	0.5%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 427,543.05**	**$ 2,539.82**	**0.6%**		**$ 429,831.22**	**$ 2,288.17**	**0.5%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 400,741.68**	**$ 2,247.63**	**0.6%**		**$ 402,766.61**	**$ 2,024.92**	**0.5%**
HST	13%	$ 52,096.42	$ 292.19	0.6%	13%	$ 52,359.66	$ 263.24	0.5%
Total Bill (including HST)		$ 452,838.10	$ 2,539.82	0.6%		$ 455,126.27	$ 2,288.17	0.5%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 452,838.10**	**$ 2,539.82**	**0.6%**		**$ 455,126.27**	**$ 2,288.17**	**0.5%**
Loss Factor (%)	3.69%				3.69%			

File Number: #REF!
Exhibit:
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Schedule:
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Appendix 2-W
Bill Impacts - Unmetered Scattered Load

Customer Class: USL

TOU / non-TOU: TOU

Consumption 150

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)
Monthly Service Charge	Monthly	1	$ 7.01	$ 7.01		$ 8.09	$ 8.09	$ 1.08	15.4%	$ 8.70	$ 8.70
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 0.11	$ 0.11		$ 0.11	$ 0.11	$ -	0.0%	$ -	$ -
ICM Rate Rider (2014)	Monthly	1	$ 0.04	$ 0.04		$ -	$ -	$ (0.04)	-100.0%	$ -	$ -
		1	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		1	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Distribution Volumetric Rate	per kWh	150	$ 0.0159	$ 2.39		$ 0.0193	$ 2.90	$ 0.51	21.4%	$ 0.0214	$ 3.21
Smart Meter Disposition Rider	per kWh	150	$ -	$ -		$ -	$ -	$ -		$ -	$ -
LRAM & SSM Rate Rider	per kWh	150	$ -	$ -		$ -	$ -	$ -		$ -	$ -
ICM Rate Rider (2014)	per kWh	150	$ 0.0001	$ 0.02		$ -	$ -	$ (0.02)	-100.0%	$ -	$ -
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kWh	150	$ -	$ -		-$ 0.0002	$ (0.03)	$ (0.03)		$ -	$ -
Account 1575	per kWh	150	$ -	$ -		-$ 0.0005	$ (0.08)	$ (0.08)		$ -	$ -
			$ -	$ -		$ -	$ -	$ -		$ -	$ -
			$ -	$ -		$ -	$ -	$ -		$ -	$ -
			$ -	$ -		$ -	$ -	$ -		$ -	$ -
			$ -	$ -		$ -	$ -	$ -		$ -	$ -
Sub-Total A (excluding pass through)				$ 9.56			$ 10.99	$ 1.43	15.0%		$ 11.91
Deferral/Variance Account Disposition Rate Rider (2014)	per kWh	150	-$ 0.0006	$ (0.09)		$ -	$ -	$ 0.09	-100.0%	$ -	$ -
Disposition of Deferral/Variance Accounts (2016)	per kWh	150	$ -	$ -		$ 0.0002	$ 0.03	$ 0.03		$ 0.0002	$ 0.03
			$ -	$ -		$ -	$ -	$ -		$ -	$ -
			$ -	$ -		$ -	$ -	$ -		$ -	$ -
			$ -			$ -				$ -	
			$ -			$ -				$ -	
Low Voltage Service Charge	per kWh	150	$ 0.0003	$ 0.05		$ 0.0006	$ 0.09	$ 0.05	100.0%	$ 0.0006	$ 0.09
Line Losses on Cost of Power		5.17	$ 0.0950	$ 0.49	5.54	$ 0.0950	$ 0.53	$ 0.03	7.0%	$ 0.0950	$ 0.53
							$ -	$ -			$ -
Sub-Total B - Distribution (includes Sub-Total A)				**$ 10.01**			**$ 11.64**	$ 1.63	**16.3%**		**$ 12.56**
RTSR - Network	per kWh	155	$ 0.0072	$ 1.12	156	$ 0.0070	$ 1.09	$ (0.03)	-2.6%	$ 0.0069	$ 1.07
RTSR - Line and Transformation Connection	per kWh	155	$ 0.0034	$ 0.53	156	$ 0.0035	$ 0.54	$ 0.02	3.2%	$ 0.0035	$ 0.54
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.65**			**$ 13.27**	$ 1.62	**13.9%**		**$ 14.17**
Wholesale Market Service Charge (WMSC)	per kWh	155	$ 0.0044	$ 0.68	156	$ 0.0044	$ 0.68	$ 0.00	0.2%	$ 0.0044	$ 0.68
Rural and Remote Rate Protection (RRRP)	per kWh	155	$ 0.0013	$ 0.20	156	$ 0.0013	$ 0.20	$ 0.00	0.2%	$ 0.0013	$ 0.20
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25
Debt Retirement Charge (DRC)	per kWh	150	$ 0.0070	$ 1.05		$ 0.0070	$ 1.05	$ -	0.0%	$ 0.0070	$ 1.05
TOU - Off Peak	per kWh	96	$ 0.0770	$ 7.39		$ 0.0770	$ 7.39	$ -	0.0%	$ 0.0770	$ 7.39
TOU - Mid Peak	per kWh	27	$ 0.1140	$ 3.08		$ 0.1140	$ 3.08	$ -	0.0%	$ 0.1140	$ 3.08
TOU - On Peak	per kWh	27	$ 0.1400	$ 3.78		$ 0.1400	$ 3.78	$ -	0.0%	$ 0.1400	$ 3.78
Energy - RPP - Tier 1	per kWh	150	$ 0.0880	$ 13.20		$ 0.0880	$ 13.20	$ -	0.0%	$ 0.0880	$ 13.20
Energy - RPP - Tier 2	per kWh	0	$ 0.1030	$ -		$ 0.1030	$ -	$ -		$ 0.1030	$ -
Total Bill on TOU (before Taxes)				**$ 28.09**			**$ 29.71**	$ 1.62	**5.8%**		**$ 30.61**
HST			13%	$ 3.65		13%	$ 3.86	$ 0.21	5.8%	13%	$ 3.98
Total Bill (including HST)				$ 31.74			$ 33.57	$ 1.83	5.8%		$ 34.59
Ontario Clean Energy Benefit [1]								$ -			
Total Bill on TOU (including OCEB)				**$ 31.74**			**$ 33.57**	$ 1.83	**5.8%**		**$ 34.59**
Total Bill on RPP (before Taxes)				**$ 27.04**			**$ 28.66**	$ 1.62	**6.0%**		**$ 29.56**
HST			13%	$ 3.51		13%	$ 3.73	$ 0.21	6.0%	13%	$ 3.84
Total Bill (including HST)				$ 30.55			$ 32.38	$ 1.83	6.0%		$ 33.40
Ontario Clean Energy Benefit [1]								$ -			
Total Bill on RPP (including OCEB)				**$ 30.55**			**$ 32.38**	$ 1.83	**6.0%**		**$ 33.40**
Loss Factor (%)			3.45%			3.69%				3.69%	

	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 0.61	7.5%	$ 8.91	$ 8.91	$ 0.21	2.4%	$ 9.08	$ 9.08	$ 0.17	1.9%	$ 9.16	$ 9.16	$ 0.08	0.9%
Smart Meter Rate Adder	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ (0.11)	-100.0%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.32	10.9%	$ 0.0228	$ 3.42	$ 0.21	6.5%	$ 0.0243	$ 3.65	$ 0.23	6.6%	$ 0.0258	$ 3.87	$ 0.23	6.2%
Smart Meter Disposition Rider	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ 0.03	-100.0%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ 0.08	-100.0%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)	$ 0.92	8.4%		$ 12.33	$ 0.42	3.5%		$ 12.73	$ 0.40	3.2%		$ 13.03	$ 0.31	2.4%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	0.0%	$ -	$ -	$ (0.03)	-100.0%	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
			$ -				$ -				$ -			
			$ -				$ -				$ -			
Low Voltage Service Charge	$ -	0.0%	$ 0.0006	$ 0.09	$ -	0.0%	$ 0.0007	$ 0.11	$ 0.02	16.7%	$ 0.0007	$ 0.11	$ -	0.0%
Line Losses on Cost of Power	$ -	0.0%	$ 0.0950	$ 0.53	$ -	0.0%	$ 0.0950	$ 0.53	$ -	0.0%	$ 0.0950	$ 0.53	$ -	0.0%
	$ -			$ -	$ -			$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)	$ 0.92	**7.9%**		**$ 12.95**	$ 0.39	**3.1%**		**$ 13.36**	$ 0.41	**3.2%**		**$ 13.66**	$ 0.31	**2.3%**
RTSR - Network	$ (0.02)	-1.4%	$ 0.0068	$ 1.06	$ (0.02)	-1.4%	$ 0.0067	$ 1.04	$ (0.02)	-1.5%	$ 0.0067	$ 1.04	$ -	0.0%
RTSR - Line and Transformation Connection	$ -	0.0%	$ 0.0034	$ 0.53	$ (0.02)	-2.9%	$ 0.0034	$ 0.53	$ -	0.0%	$ 0.0034	$ 0.53	$ -	0.0%
Sub-Total C - Delivery (including Sub-Total B)	$ 0.90	**6.8%**		**$ 14.53**	$ 0.36	**2.5%**		**$ 14.93**	$ 0.39	**2.7%**		**$ 15.23**	$ 0.31	**2.0%**
Wholesale Market Service Charge (WMSC)	$ -	0.0%	$ 0.0044	$ 0.68	$ -	0.0%	$ 0.0044	$ 0.68	$ -	0.0%	$ 0.0044	$ 0.68	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ -	0.0%	$ 0.0013	$ 0.20	$ -	0.0%	$ 0.0013	$ 0.20	$ -	0.0%	$ 0.0013	$ 0.20	$ -	0.0%
Standard Supply Service Charge	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ -	0.0%	$ 0.0070	$ 1.05	$ -	0.0%	$ 0.0070	$ 1.05	$ -	0.0%	$ 0.0070	$ 1.05	$ -	0.0%
TOU - Off Peak	$ -	0.0%	$ 0.0770	$ 7.39	$ -	0.0%	$ 0.0770	$ 7.39	$ -	0.0%	$ 0.0770	$ 7.39	$ -	0.0%
TOU - Mid Peak	$ -	0.0%	$ 0.1140	$ 3.08	$ -	0.0%	$ 0.1140	$ 3.08	$ -	0.0%	$ 0.1140	$ 3.08	$ -	0.0%
TOU - On Peak	$ -	0.0%	$ 0.1400	$ 3.78	$ -	0.0%	$ 0.1400	$ 3.78	$ -	0.0%	$ 0.1400	$ 3.78	$ -	0.0%
Energy - RPP - Tier 1	$ -	0.0%	$ 0.0880	$ 13.20	$ -	0.0%	$ 0.0880	$ 13.20	$ -	0.0%	$ 0.0880	$ 13.20	$ -	0.0%
Energy - RPP - Tier 2	$ -		$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
					$ -				$ -				$ -	
Total Bill on TOU (before Taxes)	$ 0.90	**3.0%**		**$ 30.97**	$ 0.36	**1.2%**		**$ 31.36**	$ 0.39	**1.3%**		**$ 31.67**	$ 0.31	**1.0%**
HST	$ 0.12	3.0%	13%	$ 4.03	$ 0.05	1.2%	13%	$ 4.08	$ 0.05	1.3%	13%	$ 4.12	$ 0.04	1.0%
Total Bill (including HST)	$ 1.02	3.0%		$ 34.99	$ 0.41	1.2%		$ 35.44	$ 0.45	1.3%		$ 35.79	$ 0.34	1.0%
Ontario Clean Energy Benefit [1]	$ -				$ -				$ -				$ -	
Total Bill on TOU (including OCEB)	$ 1.02	**3.0%**		**$ 34.99**	$ 0.41	**1.2%**		**$ 35.44**	$ 0.45	**1.3%**		**$ 35.79**	$ 0.34	**1.0%**
					$ -				$ -				$ -	
Total Bill on RPP (before Taxes)	$ 0.90	**3.2%**		**$ 29.92**	$ 0.36	**1.2%**		**$ 30.31**	$ 0.39	**1.3%**		**$ 30.62**	$ 0.31	**1.0%**
HST	$ 0.12	3.2%	13%	$ 3.89	$ 0.05	1.2%	13%	$ 3.94	$ 0.05	1.3%	13%	$ 3.98	$ 0.04	1.0%
Total Bill (including HST)	$ 1.02	3.2%		$ 33.81	$ 0.41	1.2%		$ 34.25	$ 0.45	1.3%		$ 34.60	$ 0.34	1.0%
Ontario Clean Energy Benefit [1]	$ -				$ -				$ -				$ -	
Total Bill on RPP (including OCEB)	$ 1.02	**3.2%**		**$ 33.81**	$ 0.41	**1.2%**		**$ 34.25**	$ 0.45	**1.3%**		**$ 34.60**	$ 0.34	**1.0%**
Loss Factor (%)			3.69%				3.69%				3.69%			

File Number: #REF!
Exhibit:
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Schedule:
Page:
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Appendix 2-W
Bill Impacts - Sentinel Lighting

Customer Class: Sentinel

TOU / non-TOU: TOU

Consumption	180
Load	1

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change
Monthly Service Charge	Monthly	1	$ 3.41	$ 3.41		$ 3.93	$ 3.93	$ 0.52	15.2%	$ 4.36	$ 4.36	$ 0.43	10.9%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 0.09	$ 0.09		$ 0.09	$ 0.09	$ -	0.0%	$ -	$ -	$ (0.09)	-100.0%
ICM Rate Rider (2014)	Monthly	1	$ 0.02	$ 0.02		$ -	$ -	$ (0.02)	-100.0%	$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kW	1	$ 8.0172	$ 8.02		$ 9.7254	$ 9.73	$ 1.71	21.3%	$ 10.4768	$ 10.48	$ 0.75	7.7%
Smart Meter Disposition Rider	per kW	1	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kW	1	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kW	1	$ 0.0416	$ 0.04		$ -	$ -	$ (0.04)	-100.0%	$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kW	1	$ -	$ -		-$ 0.1662	$ (0.17)	$ (0.17)		$ -	$ -	$ 0.17	-100.0%
Account 1575	per kW	1	$ -	$ -		-$ 0.2470	$ (0.25)	$ (0.25)		$ -	$ -	$ 0.25	-100.0%
			$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 11.58			$ 13.33	$ 1.75	15.1%		$ 14.84	$ 1.50	11.3%
Deferral/Variance Account Disposition Rate Rider (2014)	per kW	1	-$ 0.2297	$ (0.23)		$ -	$ -	$ 0.23	-100.0%	$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	per kW	1	$ -	$ -		$ 0.0231	$ 0.02	$ 0.02		$ 0.0231	$ 0.02	$ -	0.0%
Disposition of Global Adjustment Sub-Account (2014)	per kW	1	-$ 0.0732	$ (0.07)		$ -	$ -	$ 0.07	-100.0%	$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	per kW	1	$ -	$ -		$ 0.4308	$ 0.43	$ 0.43		$ 0.4308	$ 0.43	$ -	0.0%
			$ -			$ -	$ -	$ -		$ -	$ -	$ -	
			$ -			$ -				$ -	$ -	$ -	
			$ -			$ -				$ -			
Low Voltage Service Charge	per kW	1	$ 0.1031	$ 0.10		$ 0.1464	$ 0.15	$ 0.04	42.0%	$ 0.1539	$ 0.15	$ 0.01	5.1%
Line Losses on Cost of Power		6.21	$ 0.0950	$ 0.59	6.64	$ 0.0950	$ 0.63	$ 0.04	7.0%	$ 0.0950	$ 0.63	$ -	0.0%
Smart Meter Entity Charge				$ -				$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 11.97**			**$ 14.56**	$ 2.59	**21.7%**		**$ 16.08**	$ 1.51	**10.4%**
RTSR - Network	per kW	1	$ 2.2561	$ 2.26	1	$ 2.2538	$ 2.25	$ (0.00)	-0.1%	$ 2.2870	$ 2.29	$ 0.03	1.5%
RTSR - Line and Transformation Connection	per kW	1	$ 0.8629	$ 0.86	1	$ 0.9146	$ 0.91	$ 0.05	6.0%	$ 0.9297	$ 0.93	$ 0.02	1.7%
Sub-Total C - Delivery (including Sub-Total B)				**$ 15.09**			**$ 17.73**	$ 2.64	**17.5%**		**$ 19.29**	$ 1.56	**8.8%**
Wholesale Market Service Charge (WMSC)	per kWh	186	$ 0.0044	$ 0.82	187	$ 0.0044	$ 0.82	$ 0.00	0.2%	$ 0.0044	$ 0.82	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	per kWh	186	$ 0.0013	$ 0.24	187	$ 0.0013	$ 0.24	$ 0.00	0.2%	$ 0.0013	$ 0.24	$ -	0.0%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	180	$ 0.0070	$ 1.26		$ 0.0070	$ 1.26	$ -	0.0%	$ 0.0070	$ 1.26	$ -	0.0%
TOU - Off Peak	per kWh	115	$ 0.0770	$ 8.87		$ 0.0770	$ 8.87	$ -	0.0%	$ 0.0770	$ 8.87	$ -	0.0%
TOU - Mid Peak	per kWh	32	$ 0.1140	$ 3.69		$ 0.1140	$ 3.69	$ -	0.0%	$ 0.1140	$ 3.69	$ -	0.0%
TOU - On Peak	per kWh	32	$ 0.1400	$ 4.54		$ 0.1400	$ 4.54	$ -	0.0%	$ 0.1400	$ 4.54	$ -	0.0%
Energy - RPP - Tier 1	per kWh	180	$ 0.0880	$ 15.84		$ 0.0880	$ 15.84	$ -	0.0%	$ 0.0880	$ 15.84	$ -	0.0%
Energy - RPP - Tier 2	per kWh	-	$ 0.1030	$ -		$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 34.76**			**$ 37.41**	**$ 2.65**	**7.6%**		**$ 38.97**	**$ 1.56**	**4.2%**
HST			13%	$ 4.52		13%	$ 4.86	$ 0.34	7.6%	13%	$ 5.07	$ 0.20	4.2%
Total Bill (including HST)				$ 39.28			$ 42.27	$ 2.99	7.6%		$ 44.03	$ 1.76	4.2%
Ontario Clean Energy Benefit [1]								$ -				$ -	
Total Bill on TOU (including OCEB)				**$ 39.28**			**$ 42.27**	**$ 2.99**	**7.6%**		**$ 44.03**	**$ 1.76**	**4.2%**
Total Bill on RPP (before Taxes)				**$ 33.50**			**$ 36.15**	**$ 2.65**	**7.9%**		**$ 37.71**	**$ 1.56**	**4.3%**
HST			13%	$ 4.35		13%	$ 4.70	$ 0.34	7.9%	13%	$ 4.90	$ 0.20	4.3%
Total Bill (including HST)				$ 37.85			$ 40.84	$ 2.99	7.9%		$ 42.61	$ 1.76	4.3%
Ontario Clean Energy Benefit [1]								$ -				$ -	
Total Bill on RPP (including OCEB)				**$ 37.85**			**$ 40.84**	**$ 2.99**	**7.9%**		**$ 42.61**	**$ 1.76**	**4.3%**
Loss Factor (%)			3.45%			3.69%				3.69%			

	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 4.58	$ 4.58	$ 0.22	5.0%	$ 4.80	$ 4.80	$ 0.22	4.8%	$ 4.99	$ 4.99	$ 0.19	4.0%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 10.8774	$ 10.88	$ 0.40	3.8%	$ 11.2562	$ 11.26	$ 0.38	3.5%	$ 11.5900	$ 11.59	$ 0.33	3.0%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 15.46	$ 0.62	4.2%		$ 16.06	$ 0.60	3.9%		$ 16.58	$ 0.52	3.3%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ (0.02)	-100.0%	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2014)	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	$ -	$ -	$ (0.43)	-100.0%	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -				$ -			
Low Voltage Service Charge	$ 0.1613	$ 0.16	$ 0.01	4.8%	$ 0.1692	$ 0.17	$ 0.01	4.9%	$ 0.1692	$ 0.17	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 0.63	$ -	0.0%	$ 0.0950	$ 0.63	$ -	0.0%	$ 0.0950	$ 0.63	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 16.25**	$ 0.17	**1.1%**		**$ 16.86**	$ 0.61	**3.7%**		**$ 17.38**	$ 0.52	**3.1%**
RTSR - Network	$ 2.3200	$ 2.32	$ 0.03	1.4%	$ 2.3520	$ 2.35	$ 0.03	1.4%	$ 2.3857	$ 2.39	$ 0.03	1.4%
RTSR - Line and Transformation Connection	$ 0.9450	$ 0.95	$ 0.02	1.6%	$ 0.9600	$ 0.96	$ 0.02	1.6%	$ 0.9760	$ 0.98	$ 0.02	1.7%
Sub-Total C - Delivery (including Sub-Total B)		**$ 19.51**	$ 0.22	**1.2%**		**$ 20.17**	$ 0.65	**3.3%**		**$ 20.74**	$ 0.57	**2.8%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 0.82	$ -	0.0%	$ 0.0044	$ 0.82	$ -	0.0%	$ 0.0044	$ 0.82	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 0.24	$ -	0.0%	$ 0.0013	$ 0.24	$ -	0.0%	$ 0.0013	$ 0.24	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 1.26	$ -	0.0%	$ 0.0070	$ 1.26	$ -	0.0%	$ 0.0070	$ 1.26	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 8.87	$ -	0.0%	$ 0.0770	$ 8.87	$ -	0.0%	$ 0.0770	$ 8.87	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 3.69	$ -	0.0%	$ 0.1140	$ 3.69	$ -	0.0%	$ 0.1140	$ 3.69	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 4.54	$ -	0.0%	$ 0.1400	$ 4.54	$ -	0.0%	$ 0.1400	$ 4.54	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 15.84	$ -	0.0%	$ 0.0880	$ 15.84	$ -	0.0%	$ 0.0880	$ 15.84	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
			$ -				$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 39.19**	**$ 0.22**	**0.6%**		**$ 39.84**	**$ 0.65**	**1.7%**		**$ 40.42**	**$ 0.57**	**1.4%**
HST	13%	$ 5.09	$ 0.03	0.6%	13%	$ 5.18	$ 0.08	1.7%	13%	$ 5.25	$ 0.07	1.4%
Total Bill (including HST)		$ 44.28	$ 0.25	0.6%		$ 45.02	$ 0.74	1.7%		$ 45.67	$ 0.65	1.4%
Ontario Clean Energy Benefit [1]			$ -				$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 44.28**	**$ 0.25**	**0.6%**		**$ 45.02**	**$ 0.74**	**1.7%**		**$ 45.67**	**$ 0.65**	**1.4%**
			$ -				$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 37.93**	**$ 0.22**	**0.6%**		**$ 38.58**	**$ 0.65**	**1.7%**		**$ 39.16**	**$ 0.57**	**1.5%**
HST	13%	$ 4.93	$ 0.03	0.6%	13%	$ 5.02	$ 0.08	1.7%	13%	$ 5.09	$ 0.07	1.5%
Total Bill (including HST)		$ 42.86	$ 0.25	0.6%		$ 43.60	$ 0.74	1.7%		$ 44.25	$ 0.65	1.5%
Ontario Clean Energy Benefit [1]			$ -				$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 42.86**	**$ 0.25**	**0.6%**		**$ 43.60**	**$ 0.74**	**1.7%**		**$ 44.25**	**$ 0.65**	**1.5%**
Loss Factor (%)	3.69%				3.69%				3.69%			

$ 1.00

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Appendix 2-W
Bill Impacts - Street Lighting

Customer Class: S/L

TOU / non-TOU: TOU

Consumption: 280
Load: 1

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change
Monthly Service Charge	Monthly	1	$ 1.26	$ 1.26		$ 1.45	$ 1.45	$ 0.19	15.1%	$ 1.57	$ 1.57	$ 0.12	8.3%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 0.02	$ 0.02		$ 0.02	$ 0.02	$ -	0.0%	$ -	$ -	$ (0.02)	-100.0%
ICM Rate Rider (2014)	Monthly	1	$ 0.01	$ 0.01		$ -	$ -	$ (0.01)	-100.0%	$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kW	1	$ 6.6546	$ 6.65		$ 8.1382	$ 8.14	$ 1.48	22.3%	$ 9.0858	$ 9.09	$ 0.95	11.6%
Smart Meter Disposition Rider	per kW	1	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kW	1	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kW	1	$ 0.0345	$ 0.03		$ -	$ -	$ (0.03)	-100.0%	$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kW	1	$ -	$ -		-$ 0.1296	$ (0.13)	$ (0.13)		$ -	$ -	$ 0.13	-100.0%
Account 1575	per kW	1	$ -	$ -		-$ 0.2306	$ (0.23)	$ (0.23)		$ -	$ -	$ 0.23	-100.0%
			$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 7.98			$ 9.25	$ 1.27	15.9%		$ 10.66	$ 1.41	15.2%
Deferral/Variance Account Disposition Rate Rider (2014)	per kW	1	-$ 0.2002	$ (0.20)		$ -	$ -	$ 0.20	-100.0%	$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	per kW	1	$ -	$ -		-$ 0.2075	$ (0.21)	$ (0.21)		-$ 0.2075	$ (0.21)	$ -	0.0%
Disposition of Global Adjustment Sub-Account (2014)	per kW	1	-$ 0.0653	$ (0.07)		$ -	$ -	$ 0.07	-100.0%	$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	per kW	1	$ -	$ -		$ 0.3373	$ 0.34	$ 0.34		$ 0.3373	$ 0.34	$ -	0.0%
		1	$ -	$ -		$ -				$ -			
			$ -			$ -				$ -			
			$ -			$ -				$ -			
Low Voltage Service Charge	per kW	1	$ 0.0917	$ 0.09		$ 0.1612	$ 0.16	$ 0.07	75.8%	$ 0.1695	$ 0.17	$ 0.01	5.1%
Line Losses on Cost of Power		9.66	$ 0.0950	$ 0.92	10.33	$ 0.0950	$ 0.98	$ 0.06	7.0%	$ 0.0950	$ 0.98	$ -	0.0%
Smart Meter Entity Charge				$ -				$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 8.72**			**$ 10.52**	$ 1.80	**20.6%**		**$ 11.94**	$ 1.42	**13.5%**
RTSR - Network	per kW	1	$ 2.2203	$ 2.22	1	$ 2.5104	$ 2.51	$ 0.29	13.1%	$ 2.9365	$ 2.94	$ 0.43	17.0%
RTSR - Line and Transformation Connection	per kW	1	$ 0.9503	$ 0.95	1	$ 1.1400	$ 1.14	$ 0.19	20.0%	$ 1.3359	$ 1.34	$ 0.20	17.2%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.89**			**$ 14.17**	$ 2.28	**19.1%**		**$ 16.21**	$ 2.04	**14.4%**
Wholesale Market Service Charge (WMSC)	per kWh	290	$ 0.0044	$ 1.27	290	$ 0.0044	$ 1.28	$ 0.00	0.2%	$ 0.0044	$ 1.28	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	per kWh	290	$ 0.0013	$ 0.38	290	$ 0.0013	$ 0.38	$ 0.00	0.2%	$ 0.0013	$ 0.38	$ -	0.0%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	280	$ 0.0070	$ 1.96		$ 0.0070	$ 1.96	$ -	0.0%	$ 0.0070	$ 1.96	$ -	0.0%
TOU - Off Peak	per kWh	179	$ 0.0770	$ 13.80		$ 0.0770	$ 13.80	$ -	0.0%	$ 0.0770	$ 13.80	$ -	0.0%
TOU - Mid Peak	per kWh	50	$ 0.1140	$ 5.75		$ 0.1140	$ 5.75	$ -	0.0%	$ 0.1140	$ 5.75	$ -	0.0%
TOU - On Peak	per kWh	50	$ 0.1400	$ 7.06		$ 0.1400	$ 7.06	$ -	0.0%	$ 0.1400	$ 7.06	$ -	0.0%
Energy - RPP - Tier 1	per kWh	280	$ 0.0880	$ 24.64		$ 0.0880	$ 24.64	$ -	0.0%	$ 0.0880	$ 24.64	$ -	0.0%
Energy - RPP - Tier 2	per kWh	-	$ 0.1030	$ -		$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 42.35**			**$ 44.64**	**$ 2.28**	**5.4%**		**$ 46.67**	**$ 2.04**	**4.6%**
HST			13%	$ 5.51		13%	$ 5.80	$ 0.30	5.4%	13%	$ 6.07	$ 0.26	4.6%
Total Bill (including HST)				$ 47.86			$ 50.44	$ 2.58	5.4%		$ 52.74	$ 2.30	4.6%
Ontario Clean Energy Benefit [1]								$ -				$ -	
Total Bill on TOU (including OCEB)				**$ 47.86**			**$ 50.44**	**$ 2.58**	**5.4%**		**$ 52.74**	**$ 2.30**	**4.6%**
Total Bill on RPP (before Taxes)				**$ 40.39**			**$ 42.68**	**$ 2.28**	**5.6%**		**$ 44.71**	**$ 2.04**	**4.8%**
HST			13%	$ 5.25		13%	$ 5.55	$ 0.30	5.6%	13%	$ 5.81	$ 0.26	4.8%
Total Bill (including HST)				$ 45.65			$ 48.22	$ 2.58	5.6%		$ 50.53	$ 2.30	4.8%
Ontario Clean Energy Benefit [1]								$ -				$ -	
Total Bill on RPP (including OCEB)				**$ 45.65**			**$ 48.22**	**$ 2.58**	**5.6%**		**$ 50.53**	**$ 2.30**	**4.8%**
Loss Factor (%)			3.45%			3.69%				3.69%			

	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 1.62	$ 1.62	$ 0.05	3.2%	$ 1.67	$ 1.67	$ 0.05	3.1%	$ 1.71	$ 1.71	$ 0.04	2.4%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 9.8029	$ 9.80	$ 0.72	7.9%	$ 10.4188	$ 10.42	$ 0.62	6.3%	$ 11.0145	$ 11.01	$ 0.60	5.7%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 11.42	$ 0.77	7.2%		$ 12.09	$ 0.67	5.8%		$ 12.72	$ 0.64	5.3%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ 0.21	-100.0%	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2014)	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	$ -	$ -	$ (0.34)	-100.0%	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -				$ -			
	$ -				$ -				$ -			
	$ -				$ -				$ -			
Low Voltage Service Charge	$ 0.1777	$ 0.18	$ 0.01	4.8%	$ 0.1863	$ 0.19	$ 0.01	4.8%	$ 0.1864	$ 0.19	$ 0.00	0.1%
Line Losses on Cost of Power	$ 0.0950	$ 0.98	$ -	0.0%	$ 0.0950	$ 0.98	$ -	0.0%	$ 0.0950	$ 0.98	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 12.58**	$ 0.65	**5.4%**		**$ 13.26**	$ 0.67	**5.4%**		**$ 13.89**	$ 0.64	**4.8%**
RTSR - Network	$ 3.5555	$ 3.56	$ 0.62	21.1%	$ 3.6409	$ 3.64	$ 0.09	2.4%	$ 3.7471	$ 3.75	$ 0.11	2.9%
RTSR - Line and Transformation Connection	$ 1.6206	$ 1.62	$ 0.28	21.3%	$ 1.6631	$ 1.66	$ 0.04	2.6%	$ 1.7154	$ 1.72	$ 0.05	3.1%
Sub-Total C - Delivery (including Sub-Total B)		**$ 17.76**	$ 1.55	**9.6%**		**$ 18.56**	$ 0.80	**4.5%**		**$ 19.35**	$ 0.79	**4.3%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 1.28	$ -	0.0%	$ 0.0044	$ 1.28	$ -	0.0%	$ 0.0044	$ 1.28	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 0.38	$ -	0.0%	$ 0.0013	$ 0.38	$ -	0.0%	$ 0.0013	$ 0.38	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 1.96	$ -	0.0%	$ 0.0070	$ 1.96	$ -	0.0%	$ 0.0070	$ 1.96	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 13.80	$ -	0.0%	$ 0.0770	$ 13.80	$ -	0.0%	$ 0.0770	$ 13.80	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 5.75	$ -	0.0%	$ 0.1140	$ 5.75	$ -	0.0%	$ 0.1140	$ 5.75	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 7.06	$ -	0.0%	$ 0.1400	$ 7.06	$ -	0.0%	$ 0.1400	$ 7.06	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 24.64	$ -	0.0%	$ 0.0880	$ 24.64	$ -	0.0%	$ 0.0880	$ 24.64	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
			$ -				$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 48.22**	**$ 1.55**	**3.3%**		**$ 49.03**	**$ 0.80**	**1.7%**		**$ 49.82**	**$ 0.79**	**1.6%**
HST	13%	$ 6.27	$ 0.20	3.3%	13%	$ 6.37	$ 0.10	1.7%	13%	$ 6.48	$ 0.10	1.6%
Total Bill (including HST)		$ 54.49	$ 1.75	3.3%		$ 55.40	$ 0.91	1.7%		$ 56.30	$ 0.90	1.6%
Ontario Clean Energy Benefit [1]			$ -				$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 54.49**	**$ 1.75**	**3.3%**		**$ 55.40**	**$ 0.91**	**1.7%**		**$ 56.30**	**$ 0.90**	**1.6%**
			$ -				$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 46.26**	**$ 1.55**	**3.5%**		**$ 47.07**	**$ 0.80**	**1.7%**		**$ 47.86**	**$ 0.79**	**1.7%**
HST	13%	$ 6.01	$ 0.20	3.5%	13%	$ 6.12	$ 0.10	1.7%	13%	$ 6.22	$ 0.10	1.7%
Total Bill (including HST)		$ 52.28	$ 1.75	3.5%		$ 53.18	$ 0.91	1.7%		$ 54.08	$ 0.90	1.7%
Ontario Clean Energy Benefit [1]			$ -				$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 52.28**	**$ 1.75**	**3.5%**		**$ 53.18**	**$ 0.91**	**1.7%**		**$ 54.08**	**$ 0.90**	**1.7%**
Loss Factor (%)	3.69%				3.69%				3.69%			

Summary of Bill Impacts

A Distribution Charge

Customer Class	Billing Determinant	Consumption per customer	Load per customer	TEST YEAR 1 - 2016 Monthly Distribution Charge Impact		TEST YEAR 2 - 2017 Monthly Distribution Charge Impact		TEST YEAR 3 - 2018 Monthly Distribution Charge Impact		TEST YEAR 4 - 2019 Monthly Distribution Charge Impact		TEST YEAR 5 - 2020 Monthly Distribution Charge Impact	
		kwh	kW	$	%	$	%	$	%	$	%	$	%
Residential	kWh	800		$ 4.62	16.7%	$ 2.88	8.9%	$ 1.37	3.9%	$ 0.64	1.8%	$ 1.25	3.4%
GS<50 kW	kWh	2,000		$ 10.13	16.0%	$ 5.27	7.2%	$ 2.77	3.5%	$ 2.10	2.6%	$ 2.36	2.8%
GS>50 kW	kW	80,000	250	$ 368.60	30.5%	$ 119.76	7.6%	$ (52.65)	(3.1%)	$ 58.60	3.6%	$ 49.27	2.9%
Large Use	kW	2,800,000	7,350	$ 7,500.30	29.6%	$ 3,066.94	9.3%	$ 1,462.65	4.1%	$ 1,445.01	3.9%	$ 1,181.88	3.0%
Unmetered Scattered Load	kWh	150		$ 1.63	16.3%	$ 0.92	7.9%	$ 0.39	3.1%	$ 0.41	3.2%	$ 0.31	2.3%
Sentinel Lights	kW	180	1	$ 2.59	21.7%	$ 1.51	10.4%	$ 0.17	1.1%	$ 0.61	3.7%	$ 0.52	3.1%
Street Lighting	kW	280	1	$ 1.80	20.6%	$ 1.42	13.5%	$ 0.65	5.4%	$ 0.67	5.4%	$ 0.64	4.8%

B Delivery Charge

Customer Class	Billing Determinant	Consumption per customer	Load per customer	Monthly Delivery Charge Impact		Monthly Delivery Charge Impact		Monthly Delivery Charge Impact		Monthly Delivery Charge Impact		Monthly Delivery Charge Impact	
		kwh	kW	$	%	$	%	$	%	$	%	$	%
Residential	kWh	800	-	$ 4.81	12.9%	$ 3.05	7.3%	$ 1.54	3.4%	$ 0.81	1.7%	$ 1.50	3.2%
GS<50 kW	kWh	2,000	-	$ 10.59	12.6%	$ 5.48	5.8%	$ 3.39	3.4%	$ 2.52	2.4%	$ 2.77	2.6%
GS>50 kW	kW	80,000	250	$ 378.22	17.0%	$ 134.81	5.2%	$ (35.75)	(1.3%)	$ 77.05	2.8%	$ 67.20	2.4%
Large Use	kW	2,800,000	7,350	$ 8,200.75	13.7%	$ 3,848.24	5.7%	$ 2,266.74	3.2%	$ 2,247.63	3.0%	$ 2,024.93	2.7%
Unmetered Scattered Load	kWh	150	-	$ 1.62	13.9%	$ 0.90	6.8%	$ 0.36	2.5%	$ 0.39	2.7%	$ 0.31	2.0%
Sentinel Lights	kW	180	1	$ 2.64	17.5%	$ 1.56	8.8%	$ 0.22	1.2%	$ 0.65	3.3%	$ 0.57	2.8%
Street Lighting	kW	280	1	$ 2.28	17.5%	$ 2.04	14.4%	$ 1.55	9.6%	$ 0.80	4.5%	$ 0.79	4.3%

C Total Bill

Customer Class	Billing Determinant	Consumption per customer	Load per customer	Total Monthly Bill Impact		Total Monthly Bill Impact		Total Monthly Bill Impact		Total Monthly Bill Impact		Total Monthly Bill Impact	
		kwh	kW	$	%	$	%	$	%	$	%	$	%
Residential	kWh	800	-	$ 5.45	3.9%	$ 3.44	2.4%	$ 1.74	1.2%	$ 0.91	0.6%	$ 1.69	1.1%
GS<50 kW	kWh	2,000	-	$ 12.00	3.5%	$ 6.19	1.8%	$ 3.84	1.1%	$ 2.85	0.8%	$ 3.13	0.9%
GS>50 kW	kW	80,000	250	$ 428.63	3.5%	$ 152.34	1.2%	$ (40.40)	(0.3%)	$ 87.07	0.7%	$ 75.94	0.6%
Large Use	kW	2,800,000	7,350	$ 9,310.14	2.3%	$ 4,348.51	1.0%	$ 2,561.42	0.6%	$ 2,539.82	0.6%	$ 2,288.17	0.5%
Unmetered Scattered Load	kWh	150	-	$ 1.83	5.8%	$ 1.02	3.0%	$ 0.41	1.2%	$ 0.45	1.3%	$ 0.34	1.0%
Sentinel Lights	kW	180	1	$ 2.99	7.6%	$ 1.76	4.2%	$ 0.25	0.6%	$ 0.74	1.7%	$ 0.65	1.4%
Street Lighting	kW	280	1	$ 2.58	5.4%	$ 2.30	4.6%	$ 1.75	3.3%	$ 0.91	1.7%	$ 0.90	1.6%

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Appendix 2-W
Bill Impacts - Residential

Customer Class: RESIDENTIAL

TOU / non-TOU: TOU

Consumption 800

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change
Monthly Service Charge	Monthly	1	$ 12.67	$ 12.67		$ 14.62	$ 14.62	$ 1.95	15.4%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 0.20	$ 0.20		$ 0.20	$ 0.20	$ -	0.0%
ICM Rate Rider (2014)	Monthly	1	$ 0.07	$ 0.07		$ -	$ -	$ (0.07)	-100.0%
		1	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kWh	800	$ 0.0140	$ 11.20		$ 0.0170	$ 13.60	$ 2.40	21.4%
Smart Meter Disposition Rider	per kWh	800	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	800	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kWh	800	$ 0.0001	$ 0.08		$ -	$ -	$ (0.08)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	per kWh	800	$ 0.0001	$ 0.08		$ -	$ -	$ (0.08)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kWh	800	$ -	$ -		-$ 0.0001	$ (0.08)	$ (0.08)	
Recovery of Stranded Meter Assets (2016)	per kWh	800	$ -	$ -		$ 0.0001	$ 0.08	$ 0.08	
Account 1575	per kWh	800	$ -	$ -		-$ 0.0005	$ (0.40)	$ (0.40)	
Lost Revenue Adjustment Mechanism (LRAM)	per kWh	800	$ 0.0002	$ 0.16		$ -	$ -	$ (0.16)	-100.0%
		800	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 24.46			$ 28.02	$ 3.56	14.6%
Deferral/Variance Account Disposition Rate Rider (2014)	per kWh	800	-$ 0.0006	$ (0.48)		$ -	$ -	$ 0.48	-100.0%
Disposition of Deferral/Variance Accounts (2016)	per kWh	800	$ -	$ -		$ 0.0002	$ 0.16	$ 0.16	
		800	$ -	$ -		$ -	$ -	$ -	
		800	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	per kWh	800	$ 0.0003	$ 0.24		$ 0.0006	$ 0.48	$ 0.24	100.0%
Line Losses on Cost of Power		27.60	$ 0.0950	$ 2.62	29.52	$ 0.0950	$ 2.80	$ 0.18	7.0%
Smart Meter Entity Charge	Monthly	1	$ 0.7900	$ 0.79		$ 0.7900	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 27.63**			**$ 32.25**	$ 4.62	**16.7%**
RTSR - Network	per kWh	828	$ 0.0080	$ 6.62	830	$ 0.0080	$ 6.64	$ 0.02	0.2%
RTSR - Line and Transformation Connection	per kWh	828	$ 0.0035	$ 2.90	830	$ 0.0037	$ 3.07	$ 0.17	6.0%
Sub-Total C - Delivery (including Sub-Total B)				**$ 37.15**			**$ 41.96**	$ 4.81	**12.9%**
Wholesale Market Service Charge (WMSC)	per kWh	828	$ 0.0044	$ 3.64	830	$ 0.0044	$ 3.65	$ 0.01	0.2%
Rural and Remote Rate Protection (RRRP)	per kWh	828	$ 0.0013	$ 1.08	830	$ 0.0013	$ 1.08	$ 0.00	0.2%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	800	$ 0.0070	$ 5.60		$ 0.0070	$ 5.60	$ -	0.0%
TOU - Off Peak	per kWh	512	$ 0.0770	$ 39.42		$ 0.0770	$ 39.42	$ -	0.0%
TOU - Mid Peak	per kWh	144	$ 0.1140	$ 16.42		$ 0.1140	$ 16.42	$ -	0.0%
TOU - On Peak	per kWh	144	$ 0.1400	$ 20.16		$ 0.1400	$ 20.16	$ -	0.0%
Energy - RPP - Tier 1	per kWh	800	$ 0.0880	$ 70.40		$ 0.0880	$ 70.40	$ -	0.0%
Energy - RPP - Tier 2	per kWh	0	$ 0.1030	$ -		$ 0.1030	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 123.72**			**$ 128.54**	$ 4.82	**3.9%**
HST			13%	$ 16.08		13%	$ 16.71	$ 0.63	3.9%
Total Bill (including HST)				$ 139.80			$ 145.25	$ 5.45	3.9%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 139.80**			**$ 145.25**	$ 5.45	**3.9%**
Total Bill on RPP (before Taxes)				**$ 118.12**			**$ 122.94**	$ 4.82	**4.1%**
HST			13%	$ 15.36		13%	$ 15.98	$ 0.63	4.1%
Total Bill (including HST)				$ 133.47			$ 138.92	$ 5.45	4.1%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 133.47**			**$ 138.92**	$ 5.45	**4.1%**
Loss Factor (%)			3.45%			3.69%			

	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change
Monthly Service Charge	$ 15.78	$ 15.78	$ 1.16	7.9%	$ 16.27	$ 16.27	$ 0.49	3.1%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ (0.20)	-100.0%	$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0189	$ 15.12	$ 1.52	11.2%	$ 0.0201	$ 16.08	$ 0.96	6.3%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ 0.08	-100.0%	$ -	$ -	$ -	
Recovery of Stranded Meter Assets (2016)	$ -	$ -	$ (0.08)	-100.0%	$ -	$ -	$ -	
Account 1575	$ -	$ -	$ 0.40	-100.0%	$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism (LRAM)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 30.90	$ 2.88	10.3%		$ 32.35	$ 1.45	4.7%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ 0.0002	$ 0.16	$ -	0.0%	$ -	$ -	$ (0.16)	-100.0%
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$ 0.0006	$ 0.48	$ -	0.0%	$ 0.0007	$ 0.56	$ 0.08	16.7%
Line Losses on Cost of Power	$ 0.0950	$ 2.80	$ -	0.0%	$ 0.0950	$ 2.80	$ -	0.0%
Smart Meter Entity Charge	$ 0.7900	$ 0.79	$ -	0.0%	$ 0.7900	$ 0.79	$ -	0.0%
Sub-Total B - Distribution (includes Sub-Total A)		**$ 35.13**	$ 2.88	**8.9%**		**$ 36.50**	$ 1.37	**3.9%**
RTSR - Network	$ 0.0081	$ 6.72	$ 0.08	1.2%	$ 0.0083	$ 6.89	$ 0.17	2.5%
RTSR - Line and Transformation Connection	$ 0.0038	$ 3.15	$ 0.08	2.7%	$ 0.0038	$ 3.15	$ -	0.0%
Sub-Total C - Delivery (including Sub-Total B)		**$ 45.01**	$ 3.05	**7.3%**		**$ 46.54**	$ 1.54	**3.4%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 3.65	$ -	0.0%	$ 0.0044	$ 3.65	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 1.08	$ -	0.0%	$ 0.0013	$ 1.08	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 5.60	$ -	0.0%	$ 0.0070	$ 5.60	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 39.42	$ -	0.0%	$ 0.0770	$ 39.42	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 16.42	$ -	0.0%	$ 0.1140	$ 16.42	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 20.16	$ -	0.0%	$ 0.1400	$ 20.16	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 70.40	$ -	0.0%	$ 0.0880	$ 70.40	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
							$ -	
Total Bill on TOU (before Taxes)		**$ 131.58**	$ 3.05	**2.4%**		**$ 133.12**	$ 1.54	**1.2%**
HST	13%	$ 17.11	$ 0.40	2.4%	13%	$ 17.31	$ 0.20	1.2%
Total Bill (including HST)		$ 148.69	$ 3.44	2.4%		$ 150.43	$ 1.74	1.2%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 148.69**	$ 3.44	**2.4%**		**$ 150.43**	$ 1.74	**1.2%**
							$ -	
Total Bill on RPP (before Taxes)		**$ 125.98**	$ 3.05	**2.5%**		**$ 127.52**	$ 1.54	**1.2%**
HST	13%	$ 16.38	$ 0.40	2.5%	13%	$ 16.58	$ 0.20	1.2%
Total Bill (including HST)		$ 142.36	$ 3.44	2.5%		$ 144.10	$ 1.74	1.2%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 142.36**	$ 3.44	**2.5%**		**$ 144.10**	$ 1.74	**1.2%**
Loss Factor (%)	3.69%				3.69%			

	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 16.74	$ 16.74	$ 0.47	2.9%	$ 17.11	$ 17.11	$ 0.37	2.2%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0213	$ 17.04	$ 0.96	6.0%	$ 0.0224	$ 17.92	$ 0.88	5.2%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Stranded Meter Assets (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism (LRAM)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 33.78	$ 1.43	4.4%		$ 35.03	$ 1.25	3.7%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$ 0.0007	$ 0.56	$ -	0.0%	$ 0.0007	$ 0.56	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 2.80	$ -	0.0%	$ 0.0950	$ 2.80	$ -	0.0%
Smart Meter Entity Charge		$ -	$ (0.79)	-100.0%		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 37.14**	$ 0.64	**1.8%**		**$ 38.39**	$ 1.25	**3.4%**
RTSR - Network	$ 0.0084	$ 6.97	$ 0.08	1.2%	$ 0.0086	$ 7.13	$ 0.17	2.4%
RTSR - Line and Transformation Connection	$ 0.0039	$ 3.24	$ 0.08	2.6%	$ 0.0040	$ 3.32	$ 0.08	2.6%
Sub-Total C - Delivery (including Sub-Total B)		**$ 47.35**	$ 0.81	**1.7%**		**$ 48.85**	$ 1.50	**3.2%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 3.65	$ -	0.0%	$ 0.0044	$ 3.65	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 1.08	$ -	0.0%	$ 0.0013	$ 1.08	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 5.60	$ -	0.0%	$ 0.0070	$ 5.60	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 39.42	$ -	0.0%	$ 0.0770	$ 39.42	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 16.42	$ -	0.0%	$ 0.1140	$ 16.42	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 20.16	$ -	0.0%	$ 0.1400	$ 20.16	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 70.40	$ -	0.0%	$ 0.0880	$ 70.40	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 133.93**	$ 0.81	**0.6%**		**$ 135.42**	$ 1.50	**1.1%**
HST	13%	$ 17.41	$ 0.10	0.6%	13%	$ 17.61	$ 0.19	1.1%
Total Bill (including HST)		$ 151.34	$ 0.91	0.6%		$ 153.03	$ 1.69	1.1%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 151.34**	$ 0.91	**0.6%**		**$ 153.03**	$ 1.69	**1.1%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 128.33**	$ 0.81	**0.6%**		**$ 129.82**	$ 1.50	**1.2%**
HST	13%	$ 16.68	$ 0.10	0.6%	13%	$ 16.88	$ 0.19	1.2%
Total Bill (including HST)		$ 145.01	$ 0.91	0.6%		$ 146.70	$ 1.69	1.2%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 145.01**	$ 0.91	**0.6%**		**$ 146.70**	$ 1.69	**1.2%**
Loss Factor (%)	3.69%				3.69%			

File Number: #REF!
Exhibit:
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Appendix 2-W
Bill Impacts - GS>50

Customer Class: GS<50

TOU / non-TOU: TOU

Consumption: 2,000

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change
Monthly Service Charge	Monthly	1	$ 26.08	$ 26.08		$ 30.09	$ 30.09	$ 4.01	15.4%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 0.55	$ 0.55		$ 0.55	$ 0.55	$ -	0.0%
ICM Rate Rider (2014)	Monthly	1	$ 0.14	$ 0.14		$ -	$ -	$ (0.14)	-100.0%
		1	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kWh	2,000	$ 0.0139	$ 27.80		$ 0.0167	$ 33.40	$ 5.60	20.1%
Smart Meter Disposition Rider	per kWh	2,000	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	2,000	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kWh	2,000	$ 0.0001	$ 0.20		$ -	$ -	$ (0.20)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	per kWh	2,000	$ 0.0004	$ 0.80		$ -	$ -	$ (0.80)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kWh	2,000	$ -	$ -		$ 0.0001	$ 0.20	$ 0.20	
Account 1575	per kWh	2,000	$ -	$ -		-$ 0.0003	$ (0.60)	$ (0.60)	
Recovery of Stranded Meter Assets (2014 balance)	per kWh	2,000	$ -	$ -		$ 0.0002	$ 0.40	$ 0.40	
Lost Revenue Adjustment Mechanism (LRAM)	per kWh	2,000	$ 0.0004	$ 0.80		$ -	$ -	$ (0.80)	-100.0%
		2,000	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 56.37			$ 64.04	$ 7.67	13.6%
Deferral/Variance Account Disposition Rate Rider (2014)	per kWh	2,000	-$ 0.0006	$ (1.20)		$ -	$ -	$ 1.20	-100.0%
Disposition of Deferral/Variance Accounts (2016)	per kWh	2,000	$ -	$ -		$ 0.0002	$ 0.40	$ 0.40	
		2,000	$ -	$ -		$ -	$ -	$ -	
		2,000	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	per kWh	2,000	$ 0.0003	$ 0.60		$ 0.0005	$ 1.00	$ 0.40	66.7%
Line Losses on Cost of Power		69.00	$ 0.0950	$ 6.56	73.80	$ 0.0950	$ 7.01	$ 0.46	7.0%
Smart Meter Entity Charge	Monthly	1	$ 0.7900	$ 0.79		$ 0.7900	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 63.12**			**$ 73.24**	$ 10.13	**16.0%**
RTSR - Network	per kWh	2,069	$ 0.0072	$ 14.90	2074	$ 0.0072	$ 14.93	$ 0.03	0.2%
RTSR - Line and Transformation Connection	per kWh	2,069	$ 0.0030	$ 6.21	2074	$ 0.0032	$ 6.64	$ 0.43	6.9%
Sub-Total C - Delivery (including Sub-Total B)				**$ 84.22**			**$ 94.81**	$ 10.59	**12.6%**
Wholesale Market Service Charge (WMSC)	per kWh	2,069	$ 0.0044	$ 9.10	2074	$ 0.0044	$ 9.12	$ 0.02	0.2%
Rural and Remote Rate Protection (RRRP)	per kWh	2,069	$ 0.0013	$ 2.69	2074	$ 0.0013	$ 2.70	$ 0.01	0.2%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	2,000	$ 0.0070	$ 14.00		$ 0.0070	$ 14.00	$ -	0.0%
TOU - Off Peak	per kWh	1,280	$ 0.0770	$ 98.56		$ 0.0770	$ 98.56	$ -	0.0%
TOU - Mid Peak	per kWh	360	$ 0.1140	$ 41.04		$ 0.1140	$ 41.04	$ -	0.0%
TOU - On Peak	per kWh	360	$ 0.1400	$ 50.40		$ 0.1400	$ 50.40	$ -	0.0%
Energy - RPP - Tier 1	per kWh	1,000	$ 0.0880	$ 88.00		$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	per kWh	1,000	$ 0.1030	$ 103.00		$ 0.1030	$ 103.00	$ -	0.0%
Total Bill on TOU (before Taxes)				**$ 300.26**			**$ 310.88**	$ 10.62	**3.5%**
HST			13%	$ 39.03		13%	$ 40.41	$ 1.38	3.5%
Total Bill (including HST)				$ 339.30			$ 351.29	$ 12.00	3.5%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 339.30**			**$ 351.29**	$ 12.00	**3.5%**
Total Bill on RPP (before Taxes)				**$ 301.26**			**$ 311.88**	$ 10.62	**3.5%**
HST			13%	$ 39.16		13%	$ 40.54	$ 1.38	3.5%
Total Bill (including HST)				$ 340.43			$ 352.42	$ 12.00	3.5%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 340.43**			**$ 352.42**	$ 12.00	**3.5%**
Loss Factor (%)			3.45%			3.69%			

	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change
Monthly Service Charge	$ 32.71	$ 32.71	$ 2.62	8.7%	$ 33.48	$ 33.48	$ 0.77	2.4%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ (0.55)	-100.0%	$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0183	$ 36.60	$ 3.20	9.6%	$ 0.0194	$ 38.80	$ 2.20	6.0%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ (0.20)	-100.0%	$ -	$ -	$ -	
Account 1575	$ -	$ -	$ 0.60	-100.0%	$ -	$ -	$ -	
Recovery of Stranded Meter Assets (2014 balance)	$ -	$ -	$ (0.40)	-100.0%	$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism (LRAM)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 69.31	$ 5.27	8.2%		$ 72.28	$ 2.97	4.3%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ 0.0002	$ 0.40	$ -	0.0%	$ -	$ -	$ (0.40)	-100.0%
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$ 0.0005	$ 1.00	$ -	0.0%	$ 0.0006	$ 1.20	$ 0.20	20.0%
Line Losses on Cost of Power	$ 0.0950	$ 7.01	$ -	0.0%	$ 0.0950	$ 7.01	$ -	0.0%
Smart Meter Entity Charge	$ 0.7900	$ 0.79	$ -	0.0%	$ 0.7900	$ 0.79	$ -	0.0%
Sub-Total B - Distribution (includes Sub-Total A)		**$ 78.51**	$ 5.27	**7.2%**		**$ 81.28**	$ 2.77	**3.5%**
RTSR - Network	$ 0.0073	$ 15.14	$ 0.21	1.4%	$ 0.0075	$ 15.55	$ 0.41	2.7%
RTSR - Line and Transformation Connection	$ 0.0032	$ 6.64	$ -	0.0%	$ 0.0033	$ 6.84	$ 0.21	3.1%
Sub-Total C - Delivery (including Sub-Total B)		**$ 100.29**	$ 5.48	**5.8%**		**$ 103.68**	$ 3.39	**3.4%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 9.12	$ -	0.0%	$ 0.0044	$ 9.12	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 2.70	$ -	0.0%	$ 0.0013	$ 2.70	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 14.00	$ -	0.0%	$ 0.0070	$ 14.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 98.56	$ -	0.0%	$ 0.0770	$ 98.56	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 41.04	$ -	0.0%	$ 0.1140	$ 41.04	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 50.40	$ -	0.0%	$ 0.1400	$ 50.40	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 103.00	$ -	0.0%	$ 0.1030	$ 103.00	$ -	0.0%
							$ -	
Total Bill on TOU (before Taxes)		**$ 316.36**	$ 5.48	**1.8%**		**$ 319.75**	$ 3.39	**1.1%**
HST	13%	$ 41.13	$ 0.71	1.8%	13%	$ 41.57	$ 0.44	1.1%
Total Bill (including HST)		$ 357.48	$ 6.19	1.8%		$ 361.32	$ 3.84	1.1%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 357.48**	$ 6.19	**1.8%**		**$ 361.32**	$ 3.84	**1.1%**
							$ -	
Total Bill on RPP (before Taxes)		**$ 317.36**	$ 5.48	**1.8%**		**$ 320.75**	$ 3.39	**1.1%**
HST	13%	$ 41.26	$ 0.71	1.8%	13%	$ 41.70	$ 0.44	1.1%
Total Bill (including HST)		$ 358.61	$ 6.19	1.8%		$ 362.45	$ 3.84	1.1%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 358.61**	$ 6.19	**1.8%**		**$ 362.45**	$ 3.84	**1.1%**
Loss Factor (%)	3.69%				3.69%			

	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 33.58	$ 33.58	$ 0.09	0.3%	$ 33.73	$ 33.73	$ 0.16	0.5%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0208	$ 41.60	$ 2.80	7.2%	$ 0.0219	$ 43.80	$ 2.20	5.3%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Stranded Meter Assets (2014 balance)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism (LRAM)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 75.18	$ 2.89	4.0%		$ 77.53	$ 2.36	3.1%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$ 0.0006	$ 1.20	$ -	0.0%	$ 0.0006	$ 1.20	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 7.01	$ -	0.0%	$ 0.0950	$ 7.01	$ -	0.0%
Smart Meter Entity Charge		$ -	$ (0.79)	-100.0%		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 83.39**	$ 2.10	**2.6%**		**$ 85.74**	$ 2.36	**2.8%**
RTSR - Network	$ 0.0076	$ 15.76	$ 0.21	1.3%	$ 0.0077	$ 15.97	$ 0.21	1.3%
RTSR - Line and Transformation Connection	$ 0.0034	$ 7.05	$ 0.21	3.0%	$ 0.0035	$ 7.26	$ 0.21	2.9%
Sub-Total C - Delivery (including Sub-Total B)		**$ 106.20**	$ 2.52	**2.4%**		**$ 108.97**	$ 2.77	**2.6%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 9.12	$ -	0.0%	$ 0.0044	$ 9.12	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 2.70	$ -	0.0%	$ 0.0013	$ 2.70	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 14.00	$ -	0.0%	$ 0.0070	$ 14.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 98.56	$ -	0.0%	$ 0.0770	$ 98.56	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 41.04	$ -	0.0%	$ 0.1140	$ 41.04	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 50.40	$ -	0.0%	$ 0.1400	$ 50.40	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 103.00	$ -	0.0%	$ 0.1030	$ 103.00	$ -	0.0%
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 322.27**	$ 2.52	**0.8%**		**$ 325.04**	$ 2.77	**0.9%**
HST	13%	$ 41.90	$ 0.33	0.8%	13%	$ 42.26	$ 0.36	0.9%
Total Bill (including HST)		$ 364.16	$ 2.85	0.8%		$ 367.30	$ 3.13	0.9%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 364.16**	$ 2.85	**0.8%**		**$ 367.30**	$ 3.13	**0.9%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 323.27**	$ 2.52	**0.8%**		**$ 326.04**	$ 2.77	**0.9%**
HST	13%	$ 42.03	$ 0.33	0.8%	13%	$ 42.39	$ 0.36	0.9%
Total Bill (including HST)		$ 365.29	$ 2.85	0.8%		$ 368.43	$ 3.13	0.9%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 365.29**	$ 2.85	**0.8%**		**$ 368.43**	$ 3.13	**0.9%**
Loss Factor (%)	3.69%				3.69%			

Appendix 2-W
Bill Impacts - GS > 50

Customer Class: GS > 50

TOU / non-TOU: TOU

Consumption	**80,000**
Load	**250**

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change
Monthly Service Charge	Monthly	1	$ 138.48	$ 138.48		$ 138.48	$ 138.48	$ -	0.0%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 6.99	$ 6.99		$ 6.99	$ 6.99	$ -	0.0%
ICM Rate Rider (2014)	Monthly	1	$ 0.72	$ 0.72		$ -	$ -	$ (0.72)	-100.0%
		1	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kW	250	$ 3.3278	$ 831.95		$ 4.0220	$ 1,005.50	$ 173.55	20.9%
Smart Meter Disposition Rider	per kW	250	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kW	250	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kW	250	$ 0.0173	$ 4.33		$ -	$ -	$ (4.33)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	per kW	250	$ 0.0134	$ 3.35		$ -	$ -	$ (3.35)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kW	250	$ -	$ -		-$ 0.0126	$ (3.15)	$ (3.15)	
Account 1575	per kW	250	$ -	$ -		-$ 0.0564	$ (14.10)	$ (14.10)	
Lost Revenue Adjustment Mechanism (LRAM)	per kW	250	$ 0.0099	$ 2.48		$ -	$ -	$ (2.48)	-100.0%
		250	$ -	$ -		$ -	$ -	$ -	
		250	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 988.29			$ 1,133.72	$ 145.43	14.7%
Deferral/Variance Account Disposition Rate Rider (2014)	per kW	250	-$ 0.2207	$ (55.18)		$ -	$ -	$ 55.18	-100.0%
Disposition of Deferral/Variance Accounts (2016)	per kW	250	$ -	$ -		$ 0.0309	$ 7.73	$ 7.73	
Disposition of Global Adjustment Sub-Account (2014)	per kW	250	-$ 0.0720	$ (18.00)		$ -	$ -	$ 18.00	-100.0%
Disposition of Global Adjustment Sub-Account (2016)	per kW	250	$ -	$ -		$ 0.4161	$ 104.03	$ 104.03	
		250	$ -			$ -			
			$ -			$ -			
			$ -			$ -			
Low Voltage Service Charge	per kW	250	$ 0.1189	$ 29.73		$ 0.1989	$ 49.73	$ 20.00	67.3%
Line Losses on Cost of Power		2,760.00	$ 0.0950	$ 262.20	2,952.00	$ 0.0950	$ 280.44	$ 18.24	7.0%
Smart Meter Entity Charge				$ -				$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,207.04**			**$ 1,575.64**	$ 368.60	**30.5%**
RTSR - Network	per kW	250	$ 2.9192	$ 729.80	250	$ 2.8960	$ 724.00	$ (5.80)	-0.8%
RTSR - Line and Transformation Connection	per kW	250	$ 1.1726	$ 293.15	250	$ 1.2343	$ 308.58	$ 15.43	5.3%
Sub-Total C - Delivery (including Sub-Total B)				**$ 2,229.99**			**$ 2,608.21**	$ 378.22	**17.0%**
Wholesale Market Service Charge (WMSC)	per kWh	82,760	$ 0.0044	$ 364.14	82952	$ 0.0044	$ 364.99	$ 0.84	0.2%
Rural and Remote Rate Protection (RRRP)	per kWh	82,760	$ 0.0013	$ 107.59	82952	$ 0.0013	$ 107.84	$ 0.25	0.2%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	80,000	$ 0.0070	$ 560.00		$ 0.0070	$ 560.00	$ -	0.0%
TOU - Off Peak	per kWh	51,200	$ 0.0770	$ 3,942.40		$ 0.0770	$ 3,942.40	$ -	0.0%
TOU - Mid Peak	per kWh	14,400	$ 0.1140	$ 1,641.60		$ 0.1140	$ 1,641.60	$ -	0.0%
TOU - On Peak	per kWh	14,400	$ 0.1400	$ 2,016.00		$ 0.1400	$ 2,016.00	$ -	0.0%
Energy - RPP - Tier 1	per kWh	1,000	$ 0.0880	$ 88.00		$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	per kWh	79,000	$ 0.1030	$ 8,137.00		$ 0.1030	$ 8,137.00	$ -	0.0%
Total Bill on TOU (before Taxes)				**$ 10,861.97**			**$ 11,241.29**	$ 379.31	**3.5%**
HST			13%	$ 1,412.06		13%	$ 1,461.37	$ 49.31	3.5%
Total Bill (including HST)				$ 12,274.03			$ 12,702.65	$ 428.63	3.5%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 12,274.03**			**$ 12,702.65**	$ 428.63	**3.5%**
Total Bill on RPP (before Taxes)				**$ 11,486.97**			**$ 11,866.29**	$ 379.31	**3.3%**
HST			13%	$ 1,493.31		13%	$ 1,542.62	$ 49.31	3.3%
Total Bill (including HST)				$ 12,980.28			$ 13,408.90	$ 428.63	3.3%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 12,980.28**			**$ 13,408.90**	$ 428.63	**3.3%**
Loss Factor (%)			3.45%			3.69%			

	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change
Monthly Service Charge	$ 138.48	$ 138.48	$ -	0.0%	$ 138.48	$ 138.48	$ -	0.0%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ (6.99)	-100.0%	$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 4.4497	$ 1,112.43	$ 106.93	10.6%	$ 4.6761	$ 1,169.03	$ 56.60	5.1%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ 3.15	-100.0%	$ -	$ -	$ -	
Account 1575	$ -	$ -	$ 14.10	-100.0%	$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism (LRAM)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 1,250.91	$ 117.19	10.3%		$ 1,307.51	$ 56.60	4.5%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ 0.0309	$ 7.73	$ -	0.0%	$ -	$ -	$ (7.73)	-100.0%
Disposition of Global Adjustment Sub-Account (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	$ 0.4161	$ 104.03	$ -	0.0%	$ -	$ -	$ (104.03)	-100.0%
	$ -				$ -			
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.2092	$ 52.30	$ 2.58	5.2%	$ 0.2192	$ 54.80	$ 2.50	4.8%
Line Losses on Cost of Power	$ 0.0950	$ 280.44	$ -	0.0%	$ 0.0950	$ 280.44	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 1,695.40**	$ 119.76	**7.6%**		**$ 1,642.75**	$ (52.65)	**-3.1%**
RTSR - Network	$ 2.9367	$ 734.18	$ 10.18	1.4%	$ 2.9823	$ 745.58	$ 11.40	1.6%
RTSR - Line and Transformation Connection	$ 1.2538	$ 313.45	$ 4.88	1.6%	$ 1.2758	$ 318.95	$ 5.50	1.8%
Sub-Total C - Delivery (including Sub-Total B)		**$ 2,743.02**	$ 134.81	**5.2%**		**$ 2,707.27**	$ (35.75)	**-1.3%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 364.99	$ -	0.0%	$ 0.0044	$ 364.99	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 107.84	$ -	0.0%	$ 0.0013	$ 107.84	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 560.00	$ -	0.0%	$ 0.0070	$ 560.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 3,942.40	$ -	0.0%	$ 0.0770	$ 3,942.40	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 1,641.60	$ -	0.0%	$ 0.1140	$ 1,641.60	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 2,016.00	$ -	0.0%	$ 0.1400	$ 2,016.00	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 8,137.00	$ -	0.0%	$ 0.1030	$ 8,137.00	$ -	0.0%
							$ -	
Total Bill on TOU (before Taxes)		**$ 11,376.10**	$ 134.81	**1.2%**		**$ 11,340.35**	$ (35.75)	**-0.3%**
HST	13%	$ 1,478.89	$ 17.53	1.2%	13%	$ 1,474.25	$ (4.65)	-0.3%
Total Bill (including HST)		$ 12,854.99	$ 152.34	1.2%		$ 12,814.59	$ (40.40)	-0.3%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 12,854.99**	$ 152.34	**1.2%**		**$ 12,814.59**	$ (40.40)	**-0.3%**
							$ -	
Total Bill on RPP (before Taxes)		**$ 12,001.10**	$ 134.81	**1.1%**		**$ 11,965.35**	$ (35.75)	**-0.3%**
HST	13%	$ 1,560.14	$ 17.53	1.1%	13%	$ 1,555.50	$ (4.65)	-0.3%
Total Bill (including HST)		$ 13,561.24	$ 152.34	1.1%		$ 13,520.84	$ (40.40)	-0.3%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 13,561.24**	$ 152.34	**1.1%**		**$ 13,520.84**	$ (40.40)	**-0.3%**
Loss Factor (%)	3.69%				3.69%			

	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 138.48	$ 138.48	$ -	0.0%	$ 138.48	$ 138.48	$ -	0.0%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 4.8998	$ 1,224.95	$ 55.93	4.8%	$ 5.0969	$ 1,274.23	$ 49.27	4.0%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism (LRAM)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 1,363.43	$ 55.93	4.3%		$ 1,412.71	$ 49.27	3.6%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.2299	$ 57.48	$ 2.68	4.9%	$ 0.2299	$ 57.48	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 280.44	$ -	0.0%	$ 0.0950	$ 280.44	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 1,701.35**	$ 58.60	**3.6%**		**$ 1,750.62**	$ 49.27	**2.9%**
RTSR - Network	$ 3.0321	$ 758.03	$ 12.45	1.7%	$ 3.0802	$ 770.05	$ 12.03	1.6%
RTSR - Line and Transformation Connection	$ 1.2998	$ 324.95	$ 6.00	1.9%	$ 1.3234	$ 330.85	$ 5.90	1.8%
Sub-Total C - Delivery (including Sub-Total B)		**$ 2,784.32**	$ 77.05	**2.8%**		**$ 2,851.52**	$ 67.20	**2.4%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 364.99	$ -	0.0%	$ 0.0044	$ 364.99	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 107.84	$ -	0.0%	$ 0.0013	$ 107.84	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 560.00	$ -	0.0%	$ 0.0070	$ 560.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 3,942.40	$ -	0.0%	$ 0.0770	$ 3,942.40	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 1,641.60	$ -	0.0%	$ 0.1140	$ 1,641.60	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 2,016.00	$ -	0.0%	$ 0.1400	$ 2,016.00	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 8,137.00	$ -	0.0%	$ 0.1030	$ 8,137.00	$ -	0.0%
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 11,417.40**	$ 77.05	**0.7%**		**$ 11,484.60**	$ 67.20	**0.6%**
HST	13%	$ 1,484.26	$ 10.02	0.7%	13%	$ 1,493.00	$ 8.74	0.6%
Total Bill (including HST)		$ 12,901.66	$ 87.07	0.7%		$ 12,977.59	$ 75.94	0.6%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 12,901.66**	$ 87.07	**0.7%**		**$ 12,977.59**	$ 75.94	**0.6%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 12,042.40**	$ 77.05	**0.6%**		**$ 12,109.60**	$ 67.20	**0.6%**
HST	13%	$ 1,565.51	$ 10.02	0.6%	13%	$ 1,574.25	$ 8.74	0.6%
Total Bill (including HST)		$ 13,607.91	$ 87.07	0.6%		$ 13,683.84	$ 75.94	0.6%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 13,607.91**	$ 87.07	**0.6%**		**$ 13,683.84**	$ 75.94	**0.6%**
Loss Factor (%)	3.69%				3.69%			

Power Stream

Appendix 2-W
Bill Impacts - Large User

Customer Class: Large User

TOU / non-TOU: TOU

Consumption	**2,800,000**
Load	**7,350**

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change
Monthly Service Charge	Monthly	1	$ 5,966.29	$ 5,966.29		$ 5,966.29	$ 5,966.29	$ -	0.0%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 104.59	$ 104.59		$ 104.59	$ 104.59	$ -	0.0%
ICM Rate Rider (2014)	Monthly	1	$ 30.93	$ 30.93		$ -	$ -	$ (30.93)	-100.0%
		1	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kW	7,350	$ 1.4159	$ 10,406.87		$ 2.1550	$ 15,839.25	$ 5,432.39	52.2%
Smart Meter Disposition Rider	per kW	7,350	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kW	7,350	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kW	7,350	$ 0.0073	$ 53.66		$ -	$ -	$ (53.66)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kW	7,350	$ -	$ -		-$ 0.0353	$ (259.46)	$ (259.46)	
Account 1575	per kW	7,350	$ -	$ -		-$ 0.0311	$ (228.59)	$ (228.59)	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
			$ -			$ -			
		7,350	$ -	$ -		$ -	$ -	$ -	
		7,350	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 16,562.33			$ 21,422.09	$ 4,859.76	29.3%
Deferral/Variance Account Disposition Rate Rider (2014)	per kW	7,350	-$ 0.1973	$ (1,450.16)		$ -	$ -	$ 1,450.16	-100.0%
Disposition of Deferral/Variance Accounts (2016)	per kW	7,350	$ -	$ -		$ 0.0148	$ 108.78	$ 108.78	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
			$ -			$ -			
			$ -			$ -			
Low Voltage Service Charge	per kW	7,350	$ 0.1437	$ 1,056.20		$ 0.2040	$ 1,499.40	$ 443.21	42.0%
Line Losses on Cost of Power		96,600	$ 0.0950	$ 9,177.00	103,320	$ 0.0950	$ 9,815.40	$ 638.40	7.0%
Smart Meter Entity Charge				$ -				$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25,345.37**			**$ 32,845.67**	$ 7,500.30	**29.6%**
RTSR - Network	per kW	7350	$ 3.4638	$ 25,458.93	7350	$ 3.4798	$ 25,576.53	$ 117.60	0.5%
RTSR - Line and Transformation Connection	per kW	7350	$ 1.2027	$ 8,839.85	7350	$ 1.2820	$ 9,422.70	$ 582.86	6.6%
Sub-Total C - Delivery (including Sub-Total B)				**$ 59,644.15**			**$ 67,844.90**	$ 8,200.75	**13.7%**
Wholesale Market Service Charge (WMSC)	per kWh	2,896,600	$ 0.0044	$ 12,745.04	2903320	$ 0.0044	$ 12,774.61	$ 29.57	0.2%
Rural and Remote Rate Protection (RRRP)	per kWh	2,896,600	$ 0.0013	$ 3,765.58	2903320	$ 0.0013	$ 3,774.32	$ 8.74	0.2%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	2,800,000	$ 0.0070	$ 19,600.00		$ 0.0070	$ 19,600.00	$ -	0.0%
TOU - Off Peak	per kWh	1,792,000	$ 0.0770	$ 137,984.00		$ 0.0770	$ 137,984.00	$ -	0.0%
TOU - Mid Peak	per kWh	504,000	$ 0.1140	$ 57,456.00		$ 0.1140	$ 57,456.00	$ -	0.0%
TOU - On Peak	per kWh	504,000	$ 0.1400	$ 70,560.00		$ 0.1400	$ 70,560.00	$ -	0.0%
Energy - RPP - Tier 1	per kWh	1,000	$ 0.0880	$ 88.00		$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	per kWh	2,799,000	$ 0.1030	$ 288,297.00		$ 0.1030	$ 288,297.00	$ -	0.0%
Total Bill on TOU (before Taxes)				**$ 361,755.02**			**$ 369,994.07**	**$ 8,239.06**	**2.3%**
HST			13%	$ 47,028.15		13%	$ 48,099.23	$ 1,071.08	2.3%
Total Bill (including HST)				$ 408,783.17			$ 418,093.30	$ 9,310.14	2.3%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 408,783.17**			**$ 418,093.30**	**$ 9,310.14**	**2.3%**
Total Bill on RPP (before Taxes)				**$ 384,140.02**			**$ 392,379.07**	**$ 8,239.06**	**2.1%**
HST			13%	$ 49,938.20		13%	$ 51,009.28	$ 1,071.08	2.1%
Total Bill (including HST)				$ 434,078.22			$ 443,388.35	$ 9,310.14	2.1%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 434,078.22**			**$ 443,388.35**	**$ 9,310.14**	**2.1%**
Loss Factor (%)			3.45%			3.69%			

	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change
Monthly Service Charge	$ 5,966.29	$ 5,966.29	$ -	0.0%	$ 5,966.29	$ 5,966.29	$ -	0.0%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ (104.59)	-100.0%	$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 2.5095	$ 18,444.83	$ 2,605.58	16.5%	$ 2.7130	$ 19,940.55	$ 1,495.73	8.1%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ 259.46	-100.0%	$ -	$ -	$ -	
Account 1575	$ -	$ -	$ 228.59	-100.0%	$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 24,411.12	$ 2,989.03	14.0%		$ 25,906.84	$ 1,495.73	6.1%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ 0.0148	$ 108.78	$ -	0.0%	$ -	$ -	$ (108.78)	-100.0%
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.2146	$ 1,577.31	$ 77.91	5.2%	$ 0.2249	$ 1,653.02	$ 75.70	4.8%
Line Losses on Cost of Power	$ 0.0950	$ 9,815.40	$ -	0.0%	$ 0.0950	$ 9,815.40	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 35,912.61**	$ 3,066.94	**9.3%**		**$ 37,375.26**	$ 1,462.65	**4.1%**
RTSR - Network	$ 3.5558	$ 26,135.13	$ 558.60	2.2%	$ 3.6338	$ 26,708.43	$ 573.30	2.2%
RTSR - Line and Transformation Connection	$ 1.3123	$ 9,645.41	$ 222.71	2.4%	$ 1.3437	$ 9,876.20	$ 230.79	2.4%
Sub-Total C - Delivery (including Sub-Total B)		**$ 71,693.14**	$ 3,848.24	**5.7%**		**$ 73,959.88**	$ 2,266.74	**3.2%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 12,774.61	$ -	0.0%	$ 0.0044	$ 12,774.61	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 3,774.32	$ -	0.0%	$ 0.0013	$ 3,774.32	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 19,600.00	$ -	0.0%	$ 0.0070	$ 19,600.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 137,984.00	$ -	0.0%	$ 0.0770	$ 137,984.00	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 57,456.00	$ -	0.0%	$ 0.1140	$ 57,456.00	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 70,560.00	$ -	0.0%	$ 0.1400	$ 70,560.00	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 288,297.00	$ -	0.0%	$ 0.1030	$ 288,297.00	$ -	0.0%
							$ -	
Total Bill on TOU (before Taxes)		**$ 373,842.31**	**$ 3,848.24**	**1.0%**		**$ 376,109.05**	**$ 2,266.74**	**0.6%**
HST	13%	$ 48,599.50	$ 500.27	1.0%	13%	$ 48,894.18	$ 294.68	0.6%
Total Bill (including HST)		$ 422,441.81	$ 4,348.51	1.0%		$ 425,003.23	$ 2,561.42	0.6%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 422,441.81**	**$ 4,348.51**	**1.0%**		**$ 425,003.23**	**$ 2,561.42**	**0.6%**
							$ -	
Total Bill on RPP (before Taxes)		**$ 396,227.31**	**$ 3,848.24**	**1.0%**		**$ 398,494.05**	**$ 2,266.74**	**0.6%**
HST	13%	$ 51,509.55	$ 500.27	1.0%	13%	$ 51,804.23	$ 294.68	0.6%
Total Bill (including HST)		$ 447,736.86	$ 4,348.51	1.0%		$ 450,298.28	$ 2,561.42	0.6%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 447,736.86**	**$ 4,348.51**	**1.0%**		**$ 450,298.28**	**$ 2,561.42**	**0.6%**
Loss Factor (%)	3.69%				3.69%			

	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 5,966.29	$ 5,966.29	$ -	0.0%	$ 5,966.29	$ 5,966.29	$ -	0.0%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 2.8987	$ 21,305.45	$ 1,364.90	6.8%	$ 3.0595	$ 22,487.33	$ 1,181.88	5.5%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 27,271.74	$ 1,364.90	5.3%		$ 28,453.62	$ 1,181.88	4.3%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.2358	$ 1,733.13	$ 80.12	4.8%	$ 0.2358	$ 1,733.13	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 9,815.40	$ -	0.0%	$ 0.0950	$ 9,815.40	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 38,820.27**	$ 1,445.01	**3.9%**		**$ 40,002.15**	$ 1,181.88	**3.0%**
RTSR - Network	$ 3.7114	$ 27,278.79	$ 570.36	2.1%	$ 3.7928	$ 27,877.08	$ 598.29	2.2%
RTSR - Line and Transformation Connection	$ 1.3753	$ 10,108.46	$ 232.26	2.4%	$ 1.4086	$ 10,353.21	$ 244.76	2.4%
Sub-Total C - Delivery (including Sub-Total B)		**$ 76,207.51**	$ 2,247.63	**3.0%**		**$ 78,232.44**	$ 2,024.93	**2.7%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 12,774.61	$ -	0.0%	$ 0.0044	$ 12,774.61	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 3,774.32	$ -	0.0%	$ 0.0013	$ 3,774.32	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 19,600.00	$ -	0.0%	$ 0.0070	$ 19,600.00	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 137,984.00	$ -	0.0%	$ 0.0770	$ 137,984.00	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 57,456.00	$ -	0.0%	$ 0.1140	$ 57,456.00	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 70,560.00	$ -	0.0%	$ 0.1400	$ 70,560.00	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 88.00	$ -	0.0%	$ 0.0880	$ 88.00	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ 288,297.00	$ -	0.0%	$ 0.1030	$ 288,297.00	$ -	0.0%
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 378,356.68**	**$ 2,247.63**	**0.6%**		**$ 380,381.61**	**$ 2,024.92**	**0.5%**
HST	13%	$ 49,186.37	$ 292.19	0.6%	13%	$ 49,449.61	$ 263.24	0.5%
Total Bill (including HST)		$ 427,543.05	$ 2,539.82	0.6%		$ 429,831.22	$ 2,288.17	0.5%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 427,543.05**	**$ 2,539.82**	**0.6%**		**$ 429,831.22**	**$ 2,288.17**	**0.5%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 400,741.68**	**$ 2,247.63**	**0.6%**		**$ 402,766.61**	**$ 2,024.92**	**0.5%**
HST	13%	$ 52,096.42	$ 292.19	0.6%	13%	$ 52,359.66	$ 263.24	0.5%
Total Bill (including HST)		$ 452,838.10	$ 2,539.82	0.6%		$ 455,126.27	$ 2,288.17	0.5%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 452,838.10**	**$ 2,539.82**	**0.6%**		**$ 455,126.27**	**$ 2,288.17**	**0.5%**
Loss Factor (%)	3.69%				3.69%			

File Number: #REF!
Exhibit:
Tab:
Schedule:
Page:
Date:

Appendix 2-W
Bill Impacts - Unmetered Scattered Load

Customer Class: USL

TOU / non-TOU: TOU

Consumption 150

			2015 Current Board-Approved			2016 TEST YEAR 1 Proposed		Impact 2016 TEST vs. 2015 Bridge	
	Charge Unit	Volume	Rate ($)	Charge ($)		Rate ($)	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	1	$ 7.01	$ 7.01		$ 8.09	$ 8.09	$ 1.08	15.4%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 0.11	$ 0.11		$ 0.11	$ 0.11	$ -	0.0%
ICM Rate Rider (2014)	Monthly	1	$ 0.04	$ 0.04		$ -	$ -	$ (0.04)	-100.0%
		1	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kWh	150	$ 0.0159	$ 2.39		$ 0.0193	$ 2.90	$ 0.51	21.4%
Smart Meter Disposition Rider	per kWh	150	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	150	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kWh	150	$ 0.0001	$ 0.02		$ -	$ -	$ (0.02)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kWh	150	$ -	$ -		-$ 0.0002	$ (0.03)	$ (0.03)	
Account 1575	per kWh	150	$ -	$ -		-$ 0.0005	$ (0.08)	$ (0.08)	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 9.56			$ 10.99	$ 1.43	15.0%
Deferral/Variance Account Disposition Rate Rider (2014)	per kWh	150	-$ 0.0006	$ (0.09)		$ -	$ -	$ 0.09	-100.0%
Disposition of Deferral/Variance Accounts (2016)	per kWh	150	$ -	$ -		$ 0.0002	$ 0.03	$ 0.03	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
			$ -			$ -			
			$ -			$ -			
Low Voltage Service Charge	per kWh	150	$ 0.0003	$ 0.05		$ 0.0006	$ 0.09	$ 0.05	100.0%
Line Losses on Cost of Power		5.17	$ 0.0950	$ 0.49	5.54	$ 0.0950	$ 0.53	$ 0.03	7.0%
							$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 10.01**			**$ 11.64**	$ 1.63	**16.3%**
RTSR - Network	per kWh	155	$ 0.0072	$ 1.12	156	$ 0.0070	$ 1.09	$ (0.03)	-2.6%
RTSR - Line and Transformation Connection	per kWh	155	$ 0.0034	$ 0.53	156	$ 0.0035	$ 0.54	$ 0.02	3.2%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.65**			**$ 13.27**	$ 1.62	**13.9%**
Wholesale Market Service Charge (WMSC)	per kWh	155	$ 0.0044	$ 0.68	156	$ 0.0044	$ 0.68	$ 0.00	0.2%
Rural and Remote Rate Protection (RRRP)	per kWh	155	$ 0.0013	$ 0.20	156	$ 0.0013	$ 0.20	$ 0.00	0.2%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	150	$ 0.0070	$ 1.05		$ 0.0070	$ 1.05	$ -	0.0%
TOU - Off Peak	per kWh	96	$ 0.0770	$ 7.39		$ 0.0770	$ 7.39	$ -	0.0%
TOU - Mid Peak	per kWh	27	$ 0.1140	$ 3.08		$ 0.1140	$ 3.08	$ -	0.0%
TOU - On Peak	per kWh	27	$ 0.1400	$ 3.78		$ 0.1400	$ 3.78	$ -	0.0%
Energy - RPP - Tier 1	per kWh	150	$ 0.0880	$ 13.20		$ 0.0880	$ 13.20	$ -	0.0%
Energy - RPP - Tier 2	per kWh	0	$ 0.1030	$ -		$ 0.1030	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 28.09**			**$ 29.71**	$ 1.62	**5.8%**
HST			13%	$ 3.65		13%	$ 3.86	$ 0.21	5.8%
Total Bill (including HST)				$ 31.74			$ 33.57	$ 1.83	5.8%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 31.74**			**$ 33.57**	$ 1.83	**5.8%**
Total Bill on RPP (before Taxes)				**$ 27.04**			**$ 28.66**	$ 1.62	**6.0%**
HST			13%	$ 3.51		13%	$ 3.73	$ 0.21	6.0%
Total Bill (including HST)				$ 30.55			$ 32.38	$ 1.83	6.0%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 30.55**			**$ 32.38**	$ 1.83	**6.0%**
Loss Factor (%)			3.45%			3.69%			

	2017 TEST YEAR 2 Proposed		Impact 2017 TEST vs. 2016 TEST		2018 TEST YEAR 3 Proposed		Impact 2018 TEST vs. 2017 TEST	
	Rate ($)	Charge ($)	$ Change	% Change	Rate ($)	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 8.70	$ 8.70	$ 0.61	7.5%	$ 8.91	$ 8.91	$ 0.21	2.4%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ (0.11)	-100.0%	$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0214	$ 3.21	$ 0.32	10.9%	$ 0.0228	$ 3.42	$ 0.21	6.5%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ 0.03	-100.0%	$ -	$ -	$ -	
Account 1575	$ -	$ -	$ 0.08	-100.0%	$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 11.91	$ 0.92	8.4%		$ 12.33	$ 0.42	3.5%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ 0.0002	$ 0.03	$ -	0.0%	$ -	$ -	$ (0.03)	-100.0%
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.0006	$ 0.09	$ -	0.0%	$ 0.0006	$ 0.09	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 0.53	$ -	0.0%	$ 0.0950	$ 0.53	$ -	0.0%
		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 12.56**	$ 0.92	**7.9%**		**$ 12.95**	$ 0.39	**3.1%**
RTSR - Network	$ 0.0069	$ 1.07	$ (0.02)	-1.4%	$ 0.0068	$ 1.06	$ (0.02)	-1.4%
RTSR - Line and Transformation Connection	$ 0.0035	$ 0.54	$ -	0.0%	$ 0.0034	$ 0.53	$ (0.02)	-2.9%
Sub-Total C - Delivery (including Sub-Total B)		**$ 14.17**	$ 0.90	**6.8%**		**$ 14.53**	$ 0.36	**2.5%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 0.68	$ -	0.0%	$ 0.0044	$ 0.68	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 0.20	$ -	0.0%	$ 0.0013	$ 0.20	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 1.05	$ -	0.0%	$ 0.0070	$ 1.05	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 7.39	$ -	0.0%	$ 0.0770	$ 7.39	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 3.08	$ -	0.0%	$ 0.1140	$ 3.08	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 3.78	$ -	0.0%	$ 0.1400	$ 3.78	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 13.20	$ -	0.0%	$ 0.0880	$ 13.20	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
							$ -	
Total Bill on TOU (before Taxes)		**$ 30.61**	$ 0.90	**3.0%**		**$ 30.97**	$ 0.36	**1.2%**
HST	13%	$ 3.98	$ 0.12	3.0%	13%	$ 4.03	$ 0.05	1.2%
Total Bill (including HST)		$ 34.59	$ 1.02	3.0%		$ 34.99	$ 0.41	1.2%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 34.59**	$ 1.02	**3.0%**		**$ 34.99**	$ 0.41	**1.2%**
							$ -	
Total Bill on RPP (before Taxes)		**$ 29.56**	$ 0.90	**3.2%**		**$ 29.92**	$ 0.36	**1.2%**
HST	13%	$ 3.84	$ 0.12	3.2%	13%	$ 3.89	$ 0.05	1.2%
Total Bill (including HST)		$ 33.40	$ 1.02	3.2%		$ 33.81	$ 0.41	1.2%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 33.40**	$ 1.02	**3.2%**		**$ 33.81**	$ 0.41	**1.2%**
Loss Factor (%)	3.69%				3.69%			

	2019 TEST YEAR 4 Proposed		Impact 2019 TEST vs. 2018 TEST		2020 TEST YEAR 5 Proposed		Impact 2020 TEST vs. 2019 TEST	
	Rate ($)	Charge ($)	$ Change	% Change	Rate ($)	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 9.08	$ 9.08	$ 0.17	1.9%	$ 9.16	$ 9.16	$ 0.08	0.9%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0243	$ 3.65	$ 0.23	6.6%	$ 0.0258	$ 3.87	$ 0.23	6.2%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 12.73	$ 0.40	3.2%		$ 13.03	$ 0.31	2.4%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.0007	$ 0.11	$ 0.02	16.7%	$ 0.0007	$ 0.11	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 0.53	$ -	0.0%	$ 0.0950	$ 0.53	$ -	0.0%
		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 13.36**	$ 0.41	**3.2%**		**$ 13.66**	$ 0.31	**2.3%**
RTSR - Network	$ 0.0067	$ 1.04	$ (0.02)	-1.5%	$ 0.0067	$ 1.04	$ -	0.0%
RTSR - Line and Transformation Connection	$ 0.0034	$ 0.53	$ -	0.0%	$ 0.0034	$ 0.53	$ -	0.0%
Sub-Total C - Delivery (including Sub-Total B)		**$ 14.93**	$ 0.39	**2.7%**		**$ 15.23**	$ 0.31	**2.0%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 0.68	$ -	0.0%	$ 0.0044	$ 0.68	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 0.20	$ -	0.0%	$ 0.0013	$ 0.20	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 1.05	$ -	0.0%	$ 0.0070	$ 1.05	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 7.39	$ -	0.0%	$ 0.0770	$ 7.39	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 3.08	$ -	0.0%	$ 0.1140	$ 3.08	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 3.78	$ -	0.0%	$ 0.1400	$ 3.78	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 13.20	$ -	0.0%	$ 0.0880	$ 13.20	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 31.36**	$ 0.39	**1.3%**		**$ 31.67**	$ 0.31	**1.0%**
HST	13%	$ 4.08	$ 0.05	1.3%	13%	$ 4.12	$ 0.04	1.0%
Total Bill (including HST)		$ 35.44	$ 0.45	1.3%		$ 35.79	$ 0.34	1.0%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 35.44**	$ 0.45	**1.3%**		**$ 35.79**	$ 0.34	**1.0%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 30.31**	$ 0.39	**1.3%**		**$ 30.62**	$ 0.31	**1.0%**
HST	13%	$ 3.94	$ 0.05	1.3%	13%	$ 3.98	$ 0.04	1.0%
Total Bill (including HST)		$ 34.25	$ 0.45	1.3%		$ 34.60	$ 0.34	1.0%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 34.25**	$ 0.45	**1.3%**		**$ 34.60**	$ 0.34	**1.0%**
Loss Factor (%)	3.69%				3.69%			

File Number: #REF!
Exhibit:
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Schedule:
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Appendix 2-W
Bill Impacts - Sentinel Lighting

Customer Class: Sentinel

TOU / non-TOU: TOU

Consumption	180
Load	1

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)		2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change
Monthly Service Charge	Monthly	1	$ 3.41	$ 3.41		$ 3.93	$ 3.93	$ 0.52	15.2%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 0.09	$ 0.09		$ 0.09	$ 0.09	$ -	0.0%
ICM Rate Rider (2014)	Monthly	1	$ 0.02	$ 0.02		$ -	$ -	$ (0.02)	-100.0%
		1	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kW	1	$ 8.0172	$ 8.02		$ 9.7254	$ 9.73	$ 1.71	21.3%
Smart Meter Disposition Rider	per kW	1	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kW	1	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kW	1	$ 0.0416	$ 0.04		$ -	$ -	$ (0.04)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kW	1	$ -	$ -		-$ 0.1662	$ (0.17)	$ (0.17)	
Account 1575	per kW	1	$ -	$ -		-$ 0.2470	$ (0.25)	$ (0.25)	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 11.58			$ 13.33	$ 1.75	15.1%
Deferral/Variance Account Disposition Rate Rider (2014)	per kW	1	-$ 0.2297	$ (0.23)		$ -	$ -	$ 0.23	-100.0%
Disposition of Deferral/Variance Accounts (2016)	per kW	1	$ -	$ -		$ 0.0231	$ 0.02	$ 0.02	
Disposition of Global Adjustment Sub-Account (2014)	per kW	1	-$ 0.0732	$ (0.07)		$ -	$ -	$ 0.07	-100.0%
Disposition of Global Adjustment Sub-Account (2016)	per kW	1	$ -	$ -		$ 0.4308	$ 0.43	$ 0.43	
			$ -			$ -	$ -	$ -	
			$ -			$ -			
			$ -			$ -			
Low Voltage Service Charge	per kW	1	$ 0.1031	$ 0.10		$ 0.1464	$ 0.15	$ 0.04	42.0%
Line Losses on Cost of Power		6.21	$ 0.0950	$ 0.59	6.64	$ 0.0950	$ 0.63	$ 0.04	7.0%
Smart Meter Entity Charge				$ -				$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 11.97**			**$ 14.56**	$ 2.59	**21.7%**
RTSR - Network	per kW	1	$ 2.2561	$ 2.26	1	$ 2.2538	$ 2.25	$ (0.00)	-0.1%
RTSR - Line and Transformation Connection	per kW	1	$ 0.8629	$ 0.86	1	$ 0.9146	$ 0.91	$ 0.05	6.0%
Sub-Total C - Delivery (including Sub-Total B)				**$ 15.09**			**$ 17.73**	$ 2.64	**17.5%**
Wholesale Market Service Charge (WMSC)	per kWh	186	$ 0.0044	$ 0.82	187	$ 0.0044	$ 0.82	$ 0.00	0.2%
Rural and Remote Rate Protection (RRRP)	per kWh	186	$ 0.0013	$ 0.24	187	$ 0.0013	$ 0.24	$ 0.00	0.2%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	180	$ 0.0070	$ 1.26		$ 0.0070	$ 1.26	$ -	0.0%
TOU - Off Peak	per kWh	115	$ 0.0770	$ 8.87		$ 0.0770	$ 8.87	$ -	0.0%
TOU - Mid Peak	per kWh	32	$ 0.1140	$ 3.69		$ 0.1140	$ 3.69	$ -	0.0%
TOU - On Peak	per kWh	32	$ 0.1400	$ 4.54		$ 0.1400	$ 4.54	$ -	0.0%
Energy - RPP - Tier 1	per kWh	180	$ 0.0880	$ 15.84		$ 0.0880	$ 15.84	$ -	0.0%
Energy - RPP - Tier 2	per kWh	-	$ 0.1030	$ -		$ 0.1030	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 34.76**			**$ 37.41**	**$ 2.65**	**7.6%**
HST			13%	$ 4.52		13%	$ 4.86	$ 0.34	7.6%
Total Bill (including HST)				$ 39.28			$ 42.27	$ 2.99	7.6%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 39.28**			**$ 42.27**	**$ 2.99**	**7.6%**
Total Bill on RPP (before Taxes)				**$ 33.50**			**$ 36.15**	**$ 2.65**	**7.9%**
HST			13%	$ 4.35		13%	$ 4.70	$ 0.34	7.9%
Total Bill (including HST)				$ 37.85			$ 40.84	$ 2.99	7.9%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 37.85**			**$ 40.84**	**$ 2.99**	**7.9%**
Loss Factor (%)			3.45%			3.69%			

	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change
Monthly Service Charge	$ 4.36	$ 4.36	$ 0.43	10.9%	$ 4.58	$ 4.58	$ 0.22	5.0%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ (0.09)	-100.0%	$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 10.4768	$ 10.48	$ 0.75	7.7%	$ 10.8774	$ 10.88	$ 0.40	3.8%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ 0.17	-100.0%	$ -	$ -	$ -	
Account 1575	$ -	$ -	$ 0.25	-100.0%	$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 14.84	$ 1.50	11.3%		$ 15.46	$ 0.62	4.2%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ 0.0231	$ 0.02	$ -	0.0%	$ -	$ -	$ (0.02)	-100.0%
Disposition of Global Adjustment Sub-Account (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	$ 0.4308	$ 0.43	$ -	0.0%	$ -	$ -	$ (0.43)	-100.0%
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
Low Voltage Service Charge	$ 0.1539	$ 0.15	$ 0.01	5.1%	$ 0.1613	$ 0.16	$ 0.01	4.8%
Line Losses on Cost of Power	$ 0.0950	$ 0.63	$ -	0.0%	$ 0.0950	$ 0.63	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 16.08**	$ 1.51	**10.4%**		**$ 16.25**	$ 0.17	**1.1%**
RTSR - Network	$ 2.2870	$ 2.29	$ 0.03	1.5%	$ 2.3200	$ 2.32	$ 0.03	1.4%
RTSR - Line and Transformation Connection	$ 0.9297	$ 0.93	$ 0.02	1.7%	$ 0.9450	$ 0.95	$ 0.02	1.6%
Sub-Total C - Delivery (including Sub-Total B)		**$ 19.29**	$ 1.56	**8.8%**		**$ 19.51**	$ 0.22	**1.2%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 0.82	$ -	0.0%	$ 0.0044	$ 0.82	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 0.24	$ -	0.0%	$ 0.0013	$ 0.24	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 1.26	$ -	0.0%	$ 0.0070	$ 1.26	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 8.87	$ -	0.0%	$ 0.0770	$ 8.87	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 3.69	$ -	0.0%	$ 0.1140	$ 3.69	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 4.54	$ -	0.0%	$ 0.1400	$ 4.54	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 15.84	$ -	0.0%	$ 0.0880	$ 15.84	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
							$ -	
Total Bill on TOU (before Taxes)		**$ 38.97**	**$ 1.56**	**4.2%**		**$ 39.19**	**$ 0.22**	**0.6%**
HST	13%	$ 5.07	$ 0.20	4.2%	13%	$ 5.09	$ 0.03	0.6%
Total Bill (including HST)		$ 44.03	$ 1.76	4.2%		$ 44.28	$ 0.25	0.6%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 44.03**	**$ 1.76**	**4.2%**		**$ 44.28**	**$ 0.25**	**0.6%**
							$ -	
Total Bill on RPP (before Taxes)		**$ 37.71**	**$ 1.56**	**4.3%**		**$ 37.93**	**$ 0.22**	**0.6%**
HST	13%	$ 4.90	$ 0.20	4.3%	13%	$ 4.93	$ 0.03	0.6%
Total Bill (including HST)		$ 42.61	$ 1.76	4.3%		$ 42.86	$ 0.25	0.6%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 42.61**	**$ 1.76**	**4.3%**		**$ 42.86**	**$ 0.25**	**0.6%**
Loss Factor (%)	3.69%				3.69%			

	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 4.80	$ 4.80	$ 0.22	4.8%	$ 4.99	$ 4.99	$ 0.19	4.0%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 11.2562	$ 11.26	$ 0.38	3.5%	$ 11.5900	$ 11.59	$ 0.33	3.0%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 16.06	$ 0.60	3.9%		$ 16.58	$ 0.52	3.3%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
Low Voltage Service Charge	$ 0.1692	$ 0.17	$ 0.01	4.9%	$ 0.1692	$ 0.17	$ -	0.0%
Line Losses on Cost of Power	$ 0.0950	$ 0.63	$ -	0.0%	$ 0.0950	$ 0.63	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 16.86**	$ 0.61	**3.7%**		**$ 17.38**	$ 0.52	**3.1%**
RTSR - Network	$ 2.3520	$ 2.35	$ 0.03	1.4%	$ 2.3857	$ 2.39	$ 0.03	1.4%
RTSR - Line and Transformation Connection	$ 0.9600	$ 0.96	$ 0.02	1.6%	$ 0.9760	$ 0.98	$ 0.02	1.7%
Sub-Total C - Delivery (including Sub-Total B)		**$ 20.17**	$ 0.65	**3.3%**		**$ 20.74**	$ 0.57	**2.8%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 0.82	$ -	0.0%	$ 0.0044	$ 0.82	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 0.24	$ -	0.0%	$ 0.0013	$ 0.24	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 1.26	$ -	0.0%	$ 0.0070	$ 1.26	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 8.87	$ -	0.0%	$ 0.0770	$ 8.87	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 3.69	$ -	0.0%	$ 0.1140	$ 3.69	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 4.54	$ -	0.0%	$ 0.1400	$ 4.54	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 15.84	$ -	0.0%	$ 0.0880	$ 15.84	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 39.84**	**$ 0.65**	**1.7%**		**$ 40.42**	**$ 0.57**	**1.4%**
HST	13%	$ 5.18	$ 0.08	1.7%	13%	$ 5.25	$ 0.07	1.4%
Total Bill (including HST)		$ 45.02	$ 0.74	1.7%		$ 45.67	$ 0.65	1.4%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 45.02**	**$ 0.74**	**1.7%**		**$ 45.67**	**$ 0.65**	**1.4%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 38.58**	**$ 0.65**	**1.7%**		**$ 39.16**	**$ 0.57**	**1.5%**
HST	13%	$ 5.02	$ 0.08	1.7%	13%	$ 5.09	$ 0.07	1.5%
Total Bill (including HST)		$ 43.60	$ 0.74	1.7%		$ 44.25	$ 0.65	1.5%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 43.60**	**$ 0.74**	**1.7%**		**$ 44.25**	**$ 0.65**	**1.5%**
Loss Factor (%)	3.69%				3.69%			

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$ 1.00

PowerStream

Appendix 2-W
Bill Impacts - Street Lighting

Customer Class: S/L

TOU / non-TOU: TOU

Consumption	280
Load	1

	Charge Unit	Volume	2015 Current Board-Approved Rate ($)	2015 Current Board-Approved Charge ($)	2016 Volume	2016 TEST YEAR 1 Proposed Rate ($)	2016 TEST YEAR 1 Proposed Charge ($)	Impact 2016 TEST vs. 2015 Bridge $ Change	Impact 2016 TEST vs. 2015 Bridge % Change
Monthly Service Charge	Monthly	1	$ 1.26	$ 1.26		$ 1.45	$ 1.45	$ 0.19	15.1%
Smart Meter Rate Adder	Monthly	1	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	Monthly	1	$ 0.02	$ 0.02		$ 0.02	$ 0.02	$ -	0.0%
ICM Rate Rider (2014)	Monthly	1	$ 0.01	$ 0.01		$ -	$ -	$ (0.01)	-100.0%
		1	$ -	$ -		$ -	$ -	$ -	
		1	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kW	1	$ 6.6546	$ 6.65		$ 8.1382	$ 8.14	$ 1.48	22.3%
Smart Meter Disposition Rider	per kW	1	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	per kW	1	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	per kW	1	$ 0.0345	$ 0.03		$ -	$ -	$ (0.03)	-100.0%
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	per kW	1	$ -	$ -		-$ 0.1296	$ (0.13)	$ (0.13)	
Account 1575	per kW	1	$ -	$ -		-$ 0.2306	$ (0.23)	$ (0.23)	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
			$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 7.98			$ 9.25	$ 1.27	15.9%
Deferral/Variance Account Disposition Rate Rider (2014)	per kW	1	-$ 0.2002	$ (0.20)		$ -	$ -	$ 0.20	-100.0%
Disposition of Deferral/Variance Accounts (2016)	per kW	1	$ -	$ -		-$ 0.2075	$ (0.21)	$ (0.21)	
Disposition of Global Adjustment Sub-Account (2014)	per kW	1	-$ 0.0653	$ (0.07)		$ -	$ -	$ 0.07	-100.0%
Disposition of Global Adjustment Sub-Account (2016)	per kW	1	$ -	$ -		$ 0.3373	$ 0.34	$ 0.34	
		1	$ -	$ -		$ -			
			$ -			$ -			
			$ -			$ -			
Low Voltage Service Charge	per kW	1	$ 0.0917	$ 0.09		$ 0.1612	$ 0.16	$ 0.07	75.8%
Line Losses on Cost of Power		9.66	$ 0.0950	$ 0.92	10.33	$ 0.0950	$ 0.98	$ 0.06	7.0%
Smart Meter Entity Charge				$ -				$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 8.72**			**$ 10.52**	$ 1.80	**20.6%**
RTSR - Network	per kW	1	$ 2.2203	$ 2.22	1	$ 2.5104	$ 2.51	$ 0.29	13.1%
RTSR - Line and Transformation Connection	per kW	1	$ 0.9503	$ 0.95	1	$ 1.1400	$ 1.14	$ 0.19	20.0%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.89**			**$ 14.17**	$ 2.28	**19.1%**
Wholesale Market Service Charge (WMSC)	per kWh	290	$ 0.0044	$ 1.27	290	$ 0.0044	$ 1.28	$ 0.00	0.2%
Rural and Remote Rate Protection (RRRP)	per kWh	290	$ 0.0013	$ 0.38	290	$ 0.0013	$ 0.38	$ 0.00	0.2%
Standard Supply Service Charge	Monthly	1	$ 0.25	$ 0.25		$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	per kWh	280	$ 0.0070	$ 1.96		$ 0.0070	$ 1.96	$ -	0.0%
TOU - Off Peak	per kWh	179	$ 0.0770	$ 13.80		$ 0.0770	$ 13.80	$ -	0.0%
TOU - Mid Peak	per kWh	50	$ 0.1140	$ 5.75		$ 0.1140	$ 5.75	$ -	0.0%
TOU - On Peak	per kWh	50	$ 0.1400	$ 7.06		$ 0.1400	$ 7.06	$ -	0.0%
Energy - RPP - Tier 1	per kWh	280	$ 0.0880	$ 24.64		$ 0.0880	$ 24.64	$ -	0.0%
Energy - RPP - Tier 2	per kWh	-	$ 0.1030	$ -		$ 0.1030	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 42.35**			**$ 44.64**	**$ 2.28**	**5.4%**
HST			13%	$ 5.51		13%	$ 5.80	$ 0.30	5.4%
Total Bill (including HST)				$ 47.86			$ 50.44	$ 2.58	5.4%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 47.86**			**$ 50.44**	**$ 2.58**	**5.4%**
Total Bill on RPP (before Taxes)				**$ 40.39**			**$ 42.68**	**$ 2.28**	**5.6%**
HST			13%	$ 5.25		13%	$ 5.55	$ 0.30	5.6%
Total Bill (including HST)				$ 45.65			$ 48.22	$ 2.58	5.6%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 45.65**			**$ 48.22**	**$ 2.58**	**5.6%**
Loss Factor (%)			3.45%			3.69%			

	2017 TEST YEAR 2 Proposed Rate ($)	2017 TEST YEAR 2 Proposed Charge ($)	Impact 2017 TEST vs. 2016 TEST $ Change	Impact 2017 TEST vs. 2016 TEST % Change	2018 TEST YEAR 3 Proposed Rate ($)	2018 TEST YEAR 3 Proposed Charge ($)	Impact 2018 TEST vs. 2017 TEST $ Change	Impact 2018 TEST vs. 2017 TEST % Change
Monthly Service Charge	$ 1.57	$ 1.57	$ 0.12	8.3%	$ 1.62	$ 1.62	$ 0.05	3.2%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ (0.02)	-100.0%	$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 9.0858	$ 9.09	$ 0.95	11.6%	$ 9.8029	$ 9.80	$ 0.72	7.9%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ 0.13	-100.0%	$ -	$ -	$ -	
Account 1575	$ -	$ -	$ 0.23	-100.0%	$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 10.66	$ 1.41	15.2%		$ 11.42	$ 0.77	7.2%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	-$ 0.2075	$ (0.21)	$ -	0.0%	$ -	$ -	$ 0.21	-100.0%
Disposition of Global Adjustment Sub-Account (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	$ 0.3373	$ 0.34	$ -	0.0%	$ -	$ -	$ (0.34)	-100.0%
	$ -				$ -			
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.1695	$ 0.17	$ 0.01	5.1%	$ 0.1777	$ 0.18	$ 0.01	4.8%
Line Losses on Cost of Power	$ 0.0950	$ 0.98	$ -	0.0%	$ 0.0950	$ 0.98	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 11.94**	$ 1.42	**13.5%**		**$ 12.58**	$ 0.65	**5.4%**
RTSR - Network	$ 2.9365	$ 2.94	$ 0.43	17.0%	$ 3.5555	$ 3.56	$ 0.62	21.1%
RTSR - Line and Transformation Connection	$ 1.3359	$ 1.34	$ 0.20	17.2%	$ 1.6206	$ 1.62	$ 0.28	21.3%
Sub-Total C - Delivery (including Sub-Total B)		**$ 16.21**	$ 2.04	**14.4%**		**$ 17.76**	$ 1.55	**9.6%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 1.28	$ -	0.0%	$ 0.0044	$ 1.28	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 0.38	$ -	0.0%	$ 0.0013	$ 0.38	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 1.96	$ -	0.0%	$ 0.0070	$ 1.96	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 13.80	$ -	0.0%	$ 0.0770	$ 13.80	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 5.75	$ -	0.0%	$ 0.1140	$ 5.75	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 7.06	$ -	0.0%	$ 0.1400	$ 7.06	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 24.64	$ -	0.0%	$ 0.0880	$ 24.64	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
							$ -	
Total Bill on TOU (before Taxes)		**$ 46.67**	**$ 2.04**	**4.6%**		**$ 48.22**	**$ 1.55**	**3.3%**
HST	13%	$ 6.07	$ 0.26	4.6%	13%	$ 6.27	$ 0.20	3.3%
Total Bill (including HST)		$ 52.74	$ 2.30	4.6%		$ 54.49	$ 1.75	3.3%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 52.74**	**$ 2.30**	**4.6%**		**$ 54.49**	**$ 1.75**	**3.3%**
							$ -	
Total Bill on RPP (before Taxes)		**$ 44.71**	**$ 2.04**	**4.8%**		**$ 46.26**	**$ 1.55**	**3.5%**
HST	13%	$ 5.81	$ 0.26	4.8%	13%	$ 6.01	$ 0.20	3.5%
Total Bill (including HST)		$ 50.53	$ 2.30	4.8%		$ 52.28	$ 1.75	3.5%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 50.53**	**$ 2.30**	**4.8%**		**$ 52.28**	**$ 1.75**	**3.5%**
Loss Factor (%)	3.69%				3.69%			

	2019 TEST YEAR 4 Proposed Rate ($)	2019 TEST YEAR 4 Proposed Charge ($)	Impact 2019 TEST vs. 2018 TEST $ Change	Impact 2019 TEST vs. 2018 TEST % Change	2020 TEST YEAR 5 Proposed Rate ($)	2020 TEST YEAR 5 Proposed Charge ($)	Impact 2020 TEST vs. 2019 TEST $ Change	Impact 2020 TEST vs. 2019 TEST % Change
Monthly Service Charge	$ 1.67	$ 1.67	$ 0.05	3.1%	$ 1.71	$ 1.71	$ 0.04	2.4%
Smart Meter Rate Adder	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of CGAAP/CWIP Differential	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 10.4188	$ 10.42	$ 0.62	6.3%	$ 11.0145	$ 11.01	$ 0.60	5.7%
Smart Meter Disposition Rider	$ -	$ -	$ -		$ -	$ -	$ -	
LRAM & SSM Rate Rider	$ -	$ -	$ -		$ -	$ -	$ -	
ICM Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Account 1575	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 12.09	$ 0.67	5.8%		$ 12.72	$ 0.64	5.3%
Deferral/Variance Account Disposition Rate Rider (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Deferral/Variance Accounts (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2014)	$ -	$ -	$ -		$ -	$ -	$ -	
Disposition of Global Adjustment Sub-Account (2016)	$ -	$ -	$ -		$ -	$ -	$ -	
	$ -				$ -			
	$ -				$ -			
	$ -				$ -			
Low Voltage Service Charge	$ 0.1863	$ 0.19	$ 0.01	4.8%	$ 0.1864	$ 0.19	$ 0.00	0.1%
Line Losses on Cost of Power	$ 0.0950	$ 0.98	$ -	0.0%	$ 0.0950	$ 0.98	$ -	0.0%
Smart Meter Entity Charge		$ -	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 13.26**	$ 0.67	**5.4%**		**$ 13.89**	$ 0.64	**4.8%**
RTSR - Network	$ 3.6409	$ 3.64	$ 0.09	2.4%	$ 3.7471	$ 3.75	$ 0.11	2.9%
RTSR - Line and Transformation Connection	$ 1.6631	$ 1.66	$ 0.04	2.6%	$ 1.7154	$ 1.72	$ 0.05	3.1%
Sub-Total C - Delivery (including Sub-Total B)		**$ 18.56**	$ 0.80	**4.5%**		**$ 19.35**	$ 0.79	**4.3%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 1.28	$ -	0.0%	$ 0.0044	$ 1.28	$ -	0.0%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 0.38	$ -	0.0%	$ 0.0013	$ 0.38	$ -	0.0%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.0%	$ 0.2500	$ 0.25	$ -	0.0%
Debt Retirement Charge (DRC)	$ 0.0070	$ 1.96	$ -	0.0%	$ 0.0070	$ 1.96	$ -	0.0%
TOU - Off Peak	$ 0.0770	$ 13.80	$ -	0.0%	$ 0.0770	$ 13.80	$ -	0.0%
TOU - Mid Peak	$ 0.1140	$ 5.75	$ -	0.0%	$ 0.1140	$ 5.75	$ -	0.0%
TOU - On Peak	$ 0.1400	$ 7.06	$ -	0.0%	$ 0.1400	$ 7.06	$ -	0.0%
Energy - RPP - Tier 1	$ 0.0880	$ 24.64	$ -	0.0%	$ 0.0880	$ 24.64	$ -	0.0%
Energy - RPP - Tier 2	$ 0.1030	$ -	$ -		$ 0.1030	$ -	$ -	
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 49.03**	**$ 0.80**	**1.7%**		**$ 49.82**	**$ 0.79**	**1.6%**
HST	13%	$ 6.37	$ 0.10	1.7%	13%	$ 6.48	$ 0.10	1.6%
Total Bill (including HST)		$ 55.40	$ 0.91	1.7%		$ 56.30	$ 0.90	1.6%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on TOU (including OCEB)		**$ 55.40**	**$ 0.91**	**1.7%**		**$ 56.30**	**$ 0.90**	**1.6%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 47.07**	**$ 0.80**	**1.7%**		**$ 47.86**	**$ 0.79**	**1.7%**
HST	13%	$ 6.12	$ 0.10	1.7%	13%	$ 6.22	$ 0.10	1.7%
Total Bill (including HST)		$ 53.18	$ 0.91	1.7%		$ 54.08	$ 0.90	1.7%
Ontario Clean Energy Benefit [1]			$ -				$ -	
Total Bill on RPP (including OCEB)		**$ 53.18**	**$ 0.91**	**1.7%**		**$ 54.08**	**$ 0.90**	**1.7%**
Loss Factor (%)	3.69%				3.69%			

Appendix B-2-1

TO RATE ORDER

PowerStream Inc.

Proposed 2016 Electrcity Distribution Rates

EB-2015-0103

January 1, 2016

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2016

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2015-0103

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	14.62
Rate Rider for Recovery of CGAAP/CWIP Differential - efective until December 31, 2016	$	0.20
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0170
Low Voltage Service Rate	$/kWh	0.0006
Rate Rider for Disposition of Global Adjustment Sub-Account (2016) - effective until December 31, 2017		
Applicable only for Non-RPP Customers	$/kWh	0.0011
Rate Rider for Disposition of Deferral/Variance Account (2016) - effective until December 31, 2017	$/kWh	0.0002
Rate Rider for Recovery of Lost Revenenue Adjustment Mechanism Variance Account		
(2013 balance) - effective until December 31, 2016	$/kWh	(0.0001)
Rate Rider for Recovery of Stranded Meter Assets (2016) - effective until December 31, 2016	$/kWh	0.0001
Rate Rider for Recovery of Account 1575 - effective until December 31, 2016	$/kWh	(0.0005)

RESIDENTIAL SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Retail Transmission Rate - Network Service Rate	$/kWh	0.0080
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0037

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	30.09
Rate Rider for Recovery of CGAAP/CWIP Differential - in effect until December 31, 2016	$	0.55
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0167
Low Voltage Service Rate	$/kWh	0.0005
Rate Rider for Disposition of Global Adjustment Sub-Account (2016) - effective until December 31, 2017		
Applicable only for Non-RPP Customers	$/kWh	0.0011
Rate Rider for Disposition of Deferral/Variance Account (2016) - effective until December 31, 2017	$/kWh	0.0002
Rate Rider for Recovery of Lost Revenenue Adjustment Mechanism Variance Account		
(2013 balance) - effective until December 31, 2016	$/kWh	0.0001
Rate Rider for Recovery of Stranded Meter Assets (2016) - effective until December 31, 2016	$/kWh	0.0002
Rate Rider for Recovery of Account 1575 - effective until December 31, 2016	$/kWh	(0.0003)

MONTHLY RATES AND CHARGES - Delivery Component

Retail Transmission Rate - Network Service Rate	$/kWh	0.0072
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0032

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW, both regular and interval metered. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	138.48
Rate Rider for Recovery of CGAAP/CWIP Differential - in effect until December 31, 2016	$	6.99
Distribution Volumetric Rate	$/kW	4.0220
Low Voltage Service Rate	$/kW	0.1989
Rate Rider for Disposition of Global Adjustment Sub-Account (2016) - effective until December 31, 2017		
Applicable only for Non-RPP Customers	$/kW	0.4161
Rate Rider for Disposition of Deferral/Variance Account (2016) - effective until December 31, 2017	$/kW	0.0309
Rate Rider for Recovery of Lost Revenenue Adjustment Mechanism Variance Account		
(2013 balance) - effective until December 31, 2016	$/kW	(0.0126)
Rate Rider for Recovery of Account 1575 - effective until December 31, 2016	$/kW	(0.0564)

MONTHLY RATES AND CHARGES - Delivery Component

Retail Transmission Rate - Network Service Rate	$/kW	2.8960
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2343
Retail Transmission Rate - Network Service Rate - Interval-Metered	$/kW	3.0358
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval-Metered	$/kW	1.3354

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5,966.29
Rate Rider for Recovery of CGAAP/CWIP Differential - in effect until December 31, 2016	$	104.59
Distribution Volumetric Rate	$/kW	2.1550
Low Voltage Service Rate	$/kW	0.2040
Rate Rider for Disposition of Deferral/Variance Account (2016) - effective until December 31, 2017	$/kW	0.0148
Rate Rider for Recovery of Lost Revenenue Adjustment Mechanism Variance Account (2013 balance) - effective until December 31, 2016	$/kW	(0.0353)
Rate Rider for Recovery of Account 1575 - effective until December 31, 2016	$/kW	(0.0311)

MONTHLY RATES AND CHARGES - Delivery Component

Retail Transmission Rate - Network Service Rate	$/kW	3.47980
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.28200

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of the generation facility).	$/kW	2.7584

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	8.09
Rate Rider for Recovery of CGAAP/CWIP Differential - in effect until December 31, 2016	$	0.11
Distribution Volumetric Rate	$/kWh	0.0193
Low Voltage Service Rate	$/kWh	0.0006
Rate Rider for Disposition of Global Adjustment Sub-Account (2016) - effective until December 31, 2017		
Applicable only for Non-RPP Customers	$/kWh	0.0011
Rate Rider for Disposition of Deferral/Variance Account (2016) - effective until December 31, 2017	$/kWh	0.0002
Rate Rider for Recovery of Lost Revenenue Adjustment Mechanism Variance Account		
(2013 balance) - effective until December 31, 2016	$/kWh	(0.0002)
Rate Rider for Recovery of Account 1575 - effective until December 31, 2016	$/kWh	(0.0005)

MONTHLY RATES AND CHARGES - Delivery Component

Retail Transmission Rate - Network Service Rate	$/kWh	0.0070
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0035

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.93
Rate Rider for Recovery of CGAAP/CWIP Differential - in effect until December 31, 2016	$	0.09
Distribution Volumetric Rate	$/kW	9.7254
Low Voltage Service Rate	$/kW	0.1464
Rate Rider for Disposition of Global Adjustment Sub-Account (2016) - effective until December 31, 2017		
Applicable only for Non-RPP Customers	$/kW	0.4308
Rate Rider for Disposition of Deferral/Variance Account (2016) - effective until December 31, 2017	$/kW	0.0231
Rate Rider for Recovery of Lost Revenenue Adjustment Mechanism Variance Account		
(2013 balance) - effective until December 31, 2016	$/kW	(0.1662)
Rate Rider for Recovery of Account 1575 - effective until December 31, 2016	$/kW	(0.2470)

MONTHLY RATES AND CHARGES - Delivery Component

Retail Transmission Rate - Network Service Rate	$/kW	2.2538
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.9146

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.45
Rate Rider for Recovery of CGAAP/CWIP Differential - in effect until December 31, 2016	$	0.02
Distribution Volumetric Rate	$/kW	8.1382
Low Voltage Service Rate	$/kW	0.1612
Rate Rider for Disposition of Global Adjustment Sub-Account (2016) - effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	0.3373
Rate Rider for Disposition of Deferral/Variance Account (2016) - effective until December 31, 2017	$/kW	(0.2075)
Rate Rider for Recovery of Lost Revenenue Adjustment Mechanism Variance Account (2013 balance) - effective until December 31, 2016	$/kW	(0.1296)
Rate Rider for Recovery of Account 1575 - effective until December 31, 2016	$/kW	(0.2306)

MONTHLY RATES AND CHARGES - Delivery Component

Retail Transmission Rate - Network Service Rate	$/kW	2.5104
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.1400

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

MICROFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Customer Administration

Arrears certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter - during regular hours (for non-payment)	$	65.00
Disconnect/Reconnect at meter - after regular hours (for non-payment)	$	185.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35
Temporary Service – Install & remove – overhead – no transformer	$	500.00

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0369
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0266
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

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Appendix 2-V
Revenue Reconciliation - 2016 TEST YEAR 1

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	323,639	327,907	325,773	2,750,618,680		$ 14.62	$ 0.0170		$ 103,914,108	$ 103,949,352		$ 103,949,352	$ 35,243
GS < 50 kW	Customers	32,258	32,594	32,426	1,040,222,607		$ 30.09	$ 0.0167		$ 29,080,098	$ 29,072,068		$ 29,072,068	-$ 8,030
GS > 50 to 4,999 kW	Customers	4,902	5,005	4,954	4,574,077,591	12,212,781	$ 138.48		$ 4.0220	$ 57,351,425	$ 55,200,240	$ 2,150,523	$ 57,350,763	-$ 662
Large Use	Customers	2	2	2	76,536,992	150,807	$ 5,966.29		$ 2.1550	$ 468,179	$ 377,696	$ 90,484	$ 468,180	$ 0
Streetlighting	Connections	87,506	88,953	88,230	53,007,707	148,205	$ 1.45		$ 8.1382	$ 2,741,315	$ 2,741,259		$ 2,741,259	-$ 55
Sentinel Lighting	Connections	209	207	208	378,080	975	$ 3.93		$ 9.7254	$ 19,293	$ 19,316		$ 19,316	$ 23
Unmetered Scattered Load	Customers	2,948	3,006	2,977	14,169,725		$ 8.09	$ 0.0193		$ 562,483	$ 561,975		$ 561,975	-$ 507
Total										$ 194,136,901	$ 191,921,907	$ 2,241,007	$ 194,162,913	$ 26,012

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Appendix 2-V
Revenue Reconciliation - 2017 TEST YEAR 2

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	330,096	333,673	331,885	2,739,228,627		$ 15.78	$ 0.0189		$ 114,617,078	$ 114,664,499		$ 114,664,499	$ 47,421
GS < 50 kW	Customers	32,626	32,973	32,800	1,034,670,626		$ 32.71	$ 0.0183		$ 31,808,932	$ 31,846,479		$ 31,846,479	$ 37,547
GS > 50 to 4,999 kW	Customers	5,007	5,116	5,062	4,574,818,701	12,214,760	$ 138.48		$ 4.4497	$ 62,763,152	$ 60,611,765	$ 2,150,871	$ 62,762,636	-$ 516
Large Use	Customers	2	2	2	75,964,677	149,679	$ 5,966.29		$ 2.5095	$ 518,810	$ 429,009	$ 89,807	$ 518,817	$ 6
Streetlighting	Connections	89,087	90,575	89,831	45,961,281	128,504	$ 1.57		$ 9.0858	$ 2,859,975	$ 2,859,938		$ 2,859,938	-$ 37
Sentinel Lighting	Connections	207	207	207	377,900	975	$ 4.36		$ 10.4768	$ 21,043	$ 21,043		$ 21,043	$ 0
Unmetered Scattered Load	Customers	3,011	3,077	3,044	14,542,385		$ 8.70	$ 0.0214		$ 629,001	$ 629,589		$ 629,589	$ 588
Total										$ 213,217,992	$ 211,062,322	$ 2,240,678	$ 213,303,001	$ 85,009

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Appendix 2-V
Revenue Reconciliation - 2018 TEST YEAR 3

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	336,730	339,480	338,105	2,734,798,535		$ 16.27	$ 0.0201		$ 120,981,114	$ 120,954,444		$ 120,954,444	-$ 26,670
GS < 50 kW	Customers	33,004	33,354	33,179	1,029,394,754		$ 33.48	$ 0.0194		$ 33,301,038	$ 33,326,163		$ 33,326,163	$ 25,125
GS > 50 to 4,999 kW	Customers	5,115	5,227	5,171	4,569,273,124	12,199,953	$ 138.48		$ 4.6761	$ 65,641,344	$ 63,492,444	$ 2,148,264	$ 65,640,708	-$ 636
Large Use	Customers	2	2	2	75,397,535	148,561	$ 5,966.29		$ 2.7130	$ 546,238	$ 457,103	$ 89,137	$ 546,240	$ 1
Streetlighting	Connections	90,712	92,207	91,460	38,502,066	107,648	$ 1.62		$ 9.8029	$ 2,833,240	$ 2,833,244		$ 2,833,244	$ 5
Sentinel Lighting	Connections	207	207	207	377,840	975	$ 4.58		$ 10.8774	$ 21,979	$ 21,979		$ 21,979	$ 0
Unmetered Scattered Load	Customers	3,084	3,160	3,122	14,924,845		$ 8.91	$ 0.0228		$ 674,091	$ 674,628		$ 674,628	$ 537
Total										$ 223,999,043	$ 221,760,005	$ 2,237,401	$ 223,997,406	-$ 1,638

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Appendix 2-V
Revenue Reconciliation - 2019 TEST YEAR 4

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	343,395	345,362	344,378	2,726,183,601		$ 16.74	$ 0.0213		$ 127,246,444	$ 127,154,938		$ 127,154,938	-$ 91,507
GS < 50 kW	Customers	33,385	33,739	33,562	1,023,938,204		$ 33.58	$ 0.0208		$ 34,820,549	$ 34,776,163		$ 34,776,163	-$ 44,386
GS > 50 to 4,999 kW	Customers	5,222	5,339	5,280	4,555,886,909	12,164,212	$ 138.48		$ 4.8998	$ 68,376,526	$ 66,234,869	$ 2,141,970	$ 68,376,839	$ 313
Large Use	Customers	2	2	2	74,835,513	147,454	$ 5,966.29		$ 2.8987	$ 570,616	$ 482,149	$ 88,472	$ 570,622	$ 5
Streetlighting	Connections	92,344	93,857	93,101	38,115,123	106,567	$ 1.67		$ 10.4188	$ 2,976,030	$ 2,975,973		$ 2,975,973	-$ 57
Sentinel Lighting	Connections	207	207	207	377,820	975	$ 4.80		$ 11.2562	$ 22,894	$ 22,894		$ 22,894	-$ 0
Unmetered Scattered Load	Customers	3,167	3,255	3,211	15,317,364		$ 9.08	$ 0.0243		$ 722,082	$ 722,052		$ 722,052	-$ 30
Total										$ 234,735,141	$ 232,369,037	$ 2,230,443	$ 234,599,480	-$ 135,661

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Appendix 2-V
Revenue Reconciliation - 2020 TEST YEAR 5

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	350,149	351,406	350,778	2,713,502,642		$ 17.11	$ 0.0224		$ 132,804,113	$ 132,736,209		$ 132,736,209	-$ 67,904
GS < 50 kW	Customers	33,772	34,134	33,953	1,020,971,584		$ 33.73	$ 0.0219		$ 36,103,078	$ 36,105,371		$ 36,105,371	$ 2,293
GS > 50 to 4,999 kW	Customers	5,332	5,453	5,393	4,549,129,870	12,146,171	$ 138.48		$ 5.0969	$ 70,869,131	$ 68,730,268	$ 2,138,793	$ 70,869,061	-$ 70
Large Use	Customers	2	2	2	74,278,555	146,357	$ 5,966.29		$ 3.0595	$ 590,969	$ 503,149	$ 87,814	$ 590,963	-$ 6
Streetlighting	Connections	93,997	95,547	94,772	37,566,265	105,032	$ 1.71		$ 11.0145	$ 3,101,597	$ 3,101,559		$ 3,101,559	-$ 38
Sentinel Lighting	Connections	207	207	207	377,820	975	$ 4.99		$ 11.5900	$ 23,691	$ 23,691		$ 23,691	$ 0
Unmetered Scattered Load	Customers	3,263	3,363	3,313	15,720,206		$ 9.16	$ 0.0258		$ 769,746	$ 768,992		$ 768,992	-$ 755
Total										$ 244,262,325	$ 241,969,238	$ 2,226,607	$ 244,195,845	-$ 66,480

2016 Deferral/Variance Account Workform

Version 2.3

Utility Name	PowerStream Inc.
Service Territory	York Region & Simcoe County
Assigned EB Number	EB-2015-0003
Name of Contact and Title	Tom Barrett, Manager, Rates Application
Phone Number	(905) 532-4640
Email Address	Tom.Barrett@powerstream.ca

General Notes

1. Please ensure that your macros have been enabled. (Tools -> Macro -> Security)

2. Due to the time lag of deferral/variance account dispositions, this model assumes that all opening balances include previously disposed of amounts. Accordingly, all "Board Approved Dispositions" are deducted from the opening balance.

3. Please provide information in this model since the last time your balances were disposed.

4. For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

2016 Deferral/Variance Account Workform

2015 - Bridge Year

No.	Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-15	Board-Approved Disposition during 2015	Adjustments during 2015 - other 2	Closing Principal Balances as of Dec 31-15 Adjusted for Dispositions during 2015	Opening Interest Amounts as of Jan-1-15	Adjustments during 2015 - other 2	Closing Interest Amounts as of Dec-31-15	Projected Interest on Dec-31-14 Balances: Projected Interest from Jan 1, 2015 to December 31, 2015 on Dec 31 -14 balance adjusted for disposition during 2015 [6]	Total Claim	Prinicple	1.47%	1.10%	combined
													0.0036247	0.0075342	
	Group 1 Accounts														
1	LV Variance Account	1550	-$245,591			-$245,591	-$1,933		-$1,933	-2,741	-$250,265	-$245,591	-890	-1,850	-2,741
	SME Variance account	1551	$91,650			$91,650	$3,860		$3,860	1,023	$96,533	$91,650	332	691	1,023
2	RSVA - Wholesale Market Service Charge	1580	-$5,943,451			-$5,943,451	-$102,926		-$102,926	-66,322	-$6,112,699	-$5,943,451	-21,543	-44,779	-66,322
3	RSVA - Retail Transmission Network Charge	1584	$3,905,273			$3,905,273	$63,406		$63,406	$43,579	$4,012,258	$3,905,273	14,155	29,423	43,579
4	RSVA - Retail Transmission Connection Charge	1586	$1,453,322			$1,453,322	$13,222		$13,222	$16,217	$1,482,761	$1,453,322	5,268	10,950	16,217
5	RSVA - Power (excluding Global Adjustment)	1588	$562,771			$562,771	$66,350		$66,350	$6,280	$635,401	$562,771	2,040	4,240	6,280
7	RSVA - Global Adjustment	1589	$10,179,573			$10,179,573	$92,878		$92,878	$113,593	$10,386,044	$10,179,573	36,897	76,695	113,593
8	Recovery of Regulatory Asset Balances	1590	$2			$2	$0		$0	$0	$2				0
9	Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0			$0	$0		$0	$0	$0				0
10	Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0			$0	$0		$0	$0	$0				0
11	Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0			$0	$0		$0	$0	$0				0
12	Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	-$3,723,755		$3,723,755	$0	-$2,316,002	$2,316,002	$0	$0	$0				0
															0
	Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$6,279,794	$0	$3,723,755	$10,003,549	-$2,181,145	$2,316,002	$134,857	$111,629	$10,250,034				111,629
	Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$3,899,779	$0	$3,723,755	-$176,024	-$2,274,023	$2,316,002	$41,979	-$1,964	-$136,010				-1,964
	RSVA - Global Adjustment	**1589**	$10,179,573	$0	$0	$10,179,573	$92,878	$0	$92,878	$113,593	$10,386,044				113,593
	Group 2 Accounts														0
13	Other Regulatory Assets - Sub-Account - OEB Cost Assessments /Hone charges	1508	$241,000			$241,000	$29,327		$29,327	$2,689	$273,016	$241,000	874	1,816	2,689
14	Other Regulatory Assets - Sub-Account - Pension Contributions	1508	-$2,062,259		$2,062,259	$0	$0		$0	$0	$0				0
15	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1509	-$136,421			-$136,421	-$7,897		-$7,897	-$1,522	-$145,840	-$136,421	-494	-1,028	-1,522
16	Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$9,832,485		-$9,839,867	-$7,382	$7,764	-$22,479	-$14,715	$0	-$22,097	$9,832,485			0
17	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$0			$0	$0		$0	$0	$0	$0			0
18	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$0			$0	$0		$0	$0	$0	$0			0
19	Other Regulatory Assets - Sub-Account - Other : CGAAP CWIP differential[4]	1508	$2,665,445		-$2,665,445	$0	$94,305	-$94,305	$0	$0	$0				0
20	Retail Cost Variance Account - Retail	1518	$211,588			$211,588	$3,181		$3,181	$2,361	$217,130	$211,588	767	1,594	2,361
21	Misc. Deferred Debits	1525	$0			$0	$0		$0	$0	$0	$0			0
22	Renewable Generation Connection Capital Deferral Account	1531	$999,054		-$999,054	$0	$57,339	-$57,339		$0	$0				0
23	Renewable Generation Connection OM&A Deferral Account	1532	$273,326			$273,326	$4,232		$4,232	$3,050	$280,608	$273,326	991	2,059	3,050
24	Renewable Generation Connection Funding Adder Deferral Account	1533	$0			$0	$0		$0	$0	$0				0
25	Smart Grid Capital Deferral Account	1534	$2,501,002		-$2,501,002	$0	$44,966	-$44,966		$0	$0				0
26	Smart Grid OM&A Deferral Account	1535	$2,227,487			$2,227,487	$43,826		$43,826	$24,856	$2,296,169	$2,227,487	8,074	16,782	24,856
27	Smart Grid Funding Adder Deferral Account	1536	-$872,000		$346,239	-$525,761	-$4,803	$4,803	$0	$0	-$525,761				0
28	Retail Cost Variance Account - STR	1548	$0			$0	$1		$1	$0	$1	$0			0
29	Board-Approved CDM Variance Account	1567	-$383,965		$383,965	$0	-$12,251	$12,251	$0	$0	$0				0
30	Extra-Ordinary Event Costs	1572	$0			$0	$0		$0	$0	$0	$0			0
31	Deferred Rate Impact Amounts	1574	$0			$0	$0		$0	$0	$0	$0			0
32	RSVA - One-time	1582	-$1			-$1	$3		$3	-$0	$2	-$1			0
	Other Regulatory Liaiblities / Credits	2405	-$24,531,485		$24,531,485	$0	$0	$0	$0	$0	$0	-$24,531,485			0
33	Other Deferred Credits	2425	$0			$0	$2		$2	$0	$2	$0			0
	Group 2 Sub-Total		-$9,034,745	$0	$11,318,580	$2,283,836	$259,996	-$202,035	$57,961	$31,434	$2,373,231				31,434
34	Deferred Payments in Lieu of Taxes	1562	$0			$0	$0		$0	$0	$0				0
35	PILs and Tax Variance for 2006 and Subsequent Years	1592	-$988			-$988	-$9		-$9	-$11	-$1,008	-$988	-4	-7	-11
36	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0			$0	$0		$0	$0	$0				0
							$0								0
	Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$2,755,939	$0	$15,042,336	$12,286,397	-$1,921,158	$2,113,967	$192,809	$143,052	$12,622,257				143,052
															0
															0
37	**LRAM Variance Account**	**1568**	$276,945	$801,680		-$524,735	$16,407		$16,407	$3,090	-$505,238	$276,945	1,004	2,087	3,090
38	**Special purpose Charge Assessment Variance Account**	**1521**													0
															0
	Total including Account 1568 and 1521		-$2,478,994	$801,680	$15,042,336	$11,761,662	-$1,904,751	$2,113,967	$209,216	$146,142	$12,117,020				146,142
															0
36	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0			$0	$0		$0	$0	$0				0
37	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0			$0	$0		$0	$0	$0				0
38	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Co	1555	$406,435			$406,435	$186,701		$186,701	$4,535	$597,671	$406,435	1,473	3,062	4,535
39	Smart Meter OM&A Variance[10]	1556	$0			$0	$0		$0	$0	$0				0
						$0	$0		$0		$0				0
40	IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575	-$4,785,497		$2,392,750	-$2,392,747	$0		$0	$0	-$2,392,747				0
41	Accounting Changes Under CGAAP Balance + Return Component[9]	1576	$0			$0	$0		$0	$0	$0				
						$0			$0						
	The following is not included in the total claim but are included on a memo basis:					$0			$0						
42	Deferred PILs Contra Account [5]	1563	$0			$0	$0		$0	$0	$0				
43	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0			$0	$0		$0	$0	$0				
44	Disposition and Recovery of Regulatory Balances[7]	1595	$0			$0	$0		$0	$0	$0				
															150,678
	Total Check		-$6,858,056.09	$801,680.00	$17,435,085.82	$9,775,349.73	-$1,718,050.38	$2,113,967.05	$395,916.67	150,678	10,321,944				

[ok same as amended

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

model for IR - chg cc to 1.1%

10,633,026 [Total revd claim per IR EP# 50 - interest chg to 1.1%]

-$311,082.01 [difference = due to this Settlement model includes

addl change for ICM adj. From original amount of 288,985 to (22,097)]

[1] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, etc.

[1A] Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 2006 EDR and account 1595 during the 2008 EDR and subsequent years as ordered by the Board.

[2] Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

2016 Deferral/Variance Account Workform

Accounts that produced a variance on the 2016 continuity schedule are listed below.

	Account Descriptions	Account Number	Variance RRR vs. 2014 Balance *(Principal + Interest)*	Explanation
	Group 1 Accounts			
1	LV Variance Account	1550	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
2	RSVA - Wholesale Market Service Charge	1580	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
3	RSVA - Retail Transmission Network Charge	1584	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
4	RSVA - Retail Transmission Connection Charge	1586	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
5	RSVA - Power (excluding Global Adjustment)	1588	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
6	RSVA - Global Adjustment	1589	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
7	Recovery of Regulatory Asset Balances	1590	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
8	Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
9	Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
9	Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
10	Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
	Group 2 Accounts		$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
11	Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
12	Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
13	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
14	Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
15	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
16	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
17	Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
18	Retail Cost Variance Account - Retail	1518	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
19	Misc. Deferred Debits	1525	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
20	Renewable Generation Connection Capital Deferral Account	1531	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
21	Renewable Generation Connection OM&A Deferral Account	1532	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
22	Renewable Generation Connection Funding Adder Deferral Account	1533	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
23	Smart Grid Capital Deferral Account	1534	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
24	Smart Grid OM&A Deferral Account	1535	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
25	Smart Grid Funding Adder Deferral Account	1536	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
26	Retail Cost Variance Account - STR	1548	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
27	Board-Approved CDM Variance Account	1567	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
28	Extra-Ordinary Event Costs	1572	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
29	Deferred Rate Impact Amounts	1574	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
30	RSVA - One-time	1582	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
31	Other Deferred Credits	2425	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
32	Deferred Payments in Lieu of Taxes	1562	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
33	PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
34	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
35	LRAM Variance Account	1568	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
36	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
37	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
38	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
39	Smart Meter OM&A Variance[10]	1556	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
40	IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
41	Accounting Changes Under CGAAP Balance + Return Component[9]	1576	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
42	Deferred PILs Contra Account [5]	1563	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
43	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing
44	Disposition and Recovery of Regulatory Balances[7]	1595	$ -	RRR not filed until Feb 28,2015. However, 2014 activity and closing balances are from PowerStream's general ledger and not expected to be any diffferent from the RRR filing

2016 Deferral/Variance Account Workform

In the green shaded cells, enter the most recent Board Approved volumetric forecast. If there is a material difference between the latest Board-approved volumetric forecast and the most recent 12-month actual volumetric data, use the most recent 12-month actual data. Do not enter data for the MicroFit class.

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion	1595 Recovery Share Proportion (2012) [2]	1596 Recovery Share Proportion (2013) [2]	1597 Recovery Share Proportion (2014) [2]	1568 LRAM Variance Account Class Allocation ($ amounts)
RESIDENTIAL	kWh	325,759	2,750,618,680		159,139,043	-	103,190,106	100%	27.70%			
GENERAL SERVICE LESS THAN 50 KW	kWh	32,425	1,040,222,607		170,983,976	-	28,859,421		11.15%			
GENERAL SERVICE 50 TO 4,999 KW	kW	4,953	4,574,077,591	12,212,781	4,282,552,338	11,434,409	54,796,480		59.66%			
LARGE USER	kW	2	76,536,992	150,807		-	373,845		0.84%			
STANDBY POWER	kW	-	-		-	-	-		0.00%			
UNMETERED SCATTERED LOAD	kWh	2,976	14,169,725		274,430	-	557,865		0.00%			
SENTINEL LIGHTING	kW	208	378,080	975	46,212	119	19,175		0.03%			
STREET LIGHTING	kW	88,226	53,007,707	148,205	61,554,572	172,101	2,721,209		0.62%			
Total		**454,549**	**8,509,011,382**	**12,512,768**	**4,674,550,571**	**11,606,629**	**$ 190,518,101**	**100%**	**100.00%**	**0%**	**0%**	**$ -**
												-$ 505,238
												$ 505,238

[1] For Account 1562, the allocation to customer classes should be performed on the basis of the test year distribution revenue allocation to customer classes found in the Applicant's Cost of Service application that was most recently approved at the time of disposition of the 1562 account balances

[2] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

2016 Deferral/Variance Account Workform

		Amounts from Sheet 2	Allocator	RESIDENTIAL	GENERAL SERVICE LESS THAN 50 KW	GENERAL SERVICE 50 TO 4,999 KW	LARGE USER	STANDBY POWER	UNMETERED SCATTERED LOAD	SENTINEL LIGHTING	STREET LIGHTING
LV Variance Account	1550	(250,265)	kWh	(80,901)	(30,595)	(134,532)	(2,251)	0	(417)	(11)	(1,559)
SME - Smart meter entity	1551	96,533	kWh	31,205	11,801	51,892	868	0	161	4	601
RSVA - Wholesale Market Service Charge	1580	(6,112,699)	kWh	(1,975,988)	(747,275)	(3,285,924)	(54,983)	0	(10,179)	(272)	(38,080)
RSVA - Retail Transmission Network Charge	1584	4,012,258	kWh	1,297,000	490,497	2,156,817	36,090	0	6,681	178	24,995
RSVA - Retail Transmission Connection Charge	1586	1,482,761	kWh	479,317	181,267	797,069	13,337	0	2,469	66	9,237
RSVA - Power (excluding Global Adjustment)	1588	635,401	kWh	205,399	77,677	341,564	5,715	0	1,058	28	3,958
RSVA - Global Adjustment	1589	10,386,044	Non-RPP kWh	353,579	379,897	9,515,092	0	0	610	103	136,764
Recovery of Regulatory Asset Balances	1590	2	kWh	1	0	1	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	0	%	0	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	%	0	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	%	0	0	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(136,010)**		**(43,966)**	**(16,627)**	**(73,113)**	**(1,223)**	**0**	**(226)**	**(6)**	**(847)**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	273,016	Distribution Rev	147,874	41,356	78,524	536	0	799	27	3,900
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0	Distribution Rev	0	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	(145,840)	Distribution Rev	(78,991)	(22,092)	(41,946)	(286)	0	(427)	(15)	(2,083)
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	(22,097)	Distribution Rev	(11,968)	(3,347)	(6,356)	(43)	0	(65)	(2)	(316)
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	Distribution Rev	0	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0		0	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0	Distribution Rev	0	0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	217,130	Distribution Rev	117,604	32,891	62,451	426	0	636	22	3,101
Misc. Deferred Debits	1525	0		0	0	0	0	0	0	0	0
Renewable Generation Connection Capital Deferral Account	1531	0		0	0	0	0	0	0	0	0
Renewable Generation Connection OM&A Deferral Account	1532	280,608	Distribution Rev	151,985	42,506	80,708	551	0	822	28	4,008
Renewable Generation Connection Funding Adder Deferral Account	1533	0		0	0	0	0	0	0	0	0
Smart Grid Capital Deferral Account	1534	0		0	0	0	0	0	0	0	0
Smart Grid OM&A Deferral Account	1535	2,296,169	Distribution Rev	1,243,672	347,821	660,420	4,506	0	6,724	231	32,797
Smart Grid Funding Adder Deferral Account	1536	(525,761)		(376,794)	(37,505)	(5,729)	(2)	0	(3,442)	(241)	(102,048)
Retail Cost Variance Account - STR	1548	1		1	0	0	0	0	0	0	0
Board-Approved CDM Variance Account	1567	0	Distribution Rev	0	0	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0		0	0	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0		0	0	0	0	0	0	0	0
RSVA - One-time	1582	2		2	0	0	0	0	0	0	0
Other Deferred Credits	2425	2		1	0	0	0	0	0	0	0
Total of Group 2 Accounts		**2,373,231**		**1,193,385**	**401,630**	**828,072**	**5,686**	**0**	**5,046**	**51**	**(60,640)**
Deferred Payments in Lieu of Taxes	1562	0		0	0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	(1,008)	Distribution Rev	(546)	(153)	(290)	(2)	0	(3)	(0)	(14)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0		0	0	0	0	0	0	0	0
Total of Account 1562 and Account 1592		**(1,008)**		**(546)**	**(153)**	**(290)**	**(2)**	**0**	**(3)**	**(0)**	**(14)**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	(505,238)		(377,952)	55,770	(154,035)	(5,320)	0	(3,344)	(162)	(19,214)
(Account 1568 - total amount allocated to classes)		(504,257)									
Variance		(981)									
Total Balance Allocated to each class (excluding 1589 and 1568)		**2,236,214**		**1,148,872**	**384,850**	**754,670**	**4,461**	**0**	**4,817**	**45**	**(61,502)**
Total Balance Allocated to each class from Account 1589		**10,386,044**		**353,579**	**379,897**	**9,515,092**	**0**	**0**	**610**	**103**	**136,764**
Total Balance Allocated to each class (including 1589)		**12,117,020**		**1,124,500**	**820,517**	**10,115,726**	**(859)**	**0**	**2,083**	**(14)**	**56,048**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	(2,392,747)	Distribution Rev	(1,295,981)	(362,450)	(688,198)	(4,695)	0	(7,006)	(241)	(34,176)
Accounting Changes Under CGAAP Balance + Return Component	1576	0		0	0	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**(2,392,747)**		**(1,295,981)**	**(362,450)**	**(688,198)**	**(4,695)**	**0**	**(7,006)**	**(241)**	**(34,176)**
SMART METERS [STRANDED ASSETS] - Inserted [Resid and GS<50 only]		597,671		407,018	192,093						
Grand total		**10,321,944**		**235,536**	**650,160**	**9,427,529**	**(5,554)**	**0**	**(4,924)**	**(255)**	**21,872**
cross check		10,324,364									
variance		(2,420)									

2016 Deferral/Variance Account Work

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj., Smart meters, PPE and LRAMVA)

based on 2 years

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589 and 1568)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL	kWh	2,750,618,680	$1,148,872	**$0.0002**
GENERAL SERVICE LESS THAN 50 KW	kWh	1,040,222,607	$384,850	**$0.0002**
GENERAL SERVICE 50 TO 4,999 KW	kW	12,212,781	$754,670	**$0.0309**
LARGE USER	kW	150,807	$4,461	**$0.0148**
STANDBY POWER		-	$0	**$0.0000**
UNMETERED SCATTERED LOAD	kWh	14,169,725	$4,817	**$0.0002**
SENTINEL LIGHTING	kW	975	$45	**$0.0231**
STREET LIGHTING	kW	148,205	($61,502)	**($0.2075)**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
Total		**3,817,523,780**	**$2,236,214**	

Rate Rider Calculation for RSVA - Power - Global Adjustment

based on 2 years

Rate Class (Enter Rate Classes in cells below)	Units	Non-RPP kW / kWh / # of Customers	Balance of RSVA - Power - Global Adjustment	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL	kWh	159,139,043	$ 353,579	**$0.0011**
GENERAL SERVICE LESS THAN 50 KW	kWh	170,983,976	$ 379,897	**$0.0011**
GENERAL SERVICE 50 TO 4,999 KW	kW	11,434,409	$ 9,515,092	**$0.4161**
LARGE USER	kW	-	$ -	**$0.0000**
STANDBY POWER		-	$ -	**$0.0000**
UNMETERED SCATTERED LOAD	kWh	274,430	$ 610	**$0.0011**
SENTINEL LIGHTING	kW	119	$ 103	**$0.4308**
STREET LIGHTING	kW	172,101	$ 136,764	**$0.3973**
		-	$ -	**$0.0000**
		-	$ -	**$0.0000**
		-	$ -	**$0.0000**
		-	$ -	**$0.0000**
		-	$ -	**$0.0000**
		-	$ -	**$0.0000**
		-	$ -	**$0.0000**
		-	$ -	**$0.0000**
		-	$ -	**$0.0000**
		-	$ -	**$0.0000**
		-	$ -	**$0.0000**
		-	$ -	**$0.0000**
Total		**342,004,078**	**$ 10,386,044**	

Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Accounts 1575 and 1576	Rate Rider for Accounts 1575 and 1576
RESIDENTIAL	kWh	2,750,618,680	($1,295,981)	**($0.0005)**
GENERAL SERVICE LESS THAN 50 KW	kWh	1,040,222,607	($362,450)	**($0.0003)**
GENERAL SERVICE 50 TO 4,999 KW	kW	12,212,781	($688,198)	**($0.0564)**
LARGE USER	kW	150,807	($4,695)	**($0.0311)**
STANDBY POWER		-	$0	**$0.0000**
UNMETERED SCATTERED LOAD	kWh	14,169,725	($7,006)	**($0.0005)**
SENTINEL LIGHTING	kW	975	($241)	**($0.2470)**
STREET LIGHTING	kW	148,205	($34,176)	**($0.2306)**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
Total		**3,817,523,780**	**($2,392,747)**	

2016 Deferral/Variance Account Work

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in years) 1

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Account 1568	Rate Rider for Account 1568
RESIDENTIAL	kWh	2,750,618,680	($377,952)	**($0.0001)**
GENERAL SERVICE LESS THAN 50 KW	kWh	1,040,222,607	$55,770	**$0.0001**
GENERAL SERVICE 50 TO 4,999 KW	kW	12,212,781	($154,035)	**($0.0126)**
LARGE USER	kW	150,807	($5,320)	**($0.0353)**
STANDBY POWER		-	$0	**$0.0000**
UNMETERED SCATTERED LOAD	kWh	14,169,725	($3,344)	**($0.0002)**
SENTINEL LIGHTING	kW	975	($162)	**($0.1662)**
STREET LIGHTING	kW	148,205	($19,214)	**($0.1296)**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
Total		**3,817,523,780**	**($504,257)**	

Rate Rider Calculation for Accounts 1555

Please indicate the Rate Rider Recovery Period (in years) 1

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Accounts 1575 and 1576	Rate Rider for Accounts 1575
RESIDENTIAL	kWh	2,750,618,680	$407,018	**$0.0001**
GENERAL SERVICE LESS THAN 50 KW	kWh	1,040,222,607	$192,093	**$0.0002**
GENERAL SERVICE 50 TO 4,999 KW	kW	12,212,781	$0	**$0.0000**
LARGE USER	kW	150,807	$0	**$0.0000**
STANDBY POWER		-	$0	**$0.0000**
UNMETERED SCATTERED LOAD	kWh	14,169,725	$0	**$0.0000**
SENTINEL LIGHTING	kW	975	$0	**$0.0000**
STREET LIGHTING	kW	148,205	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
		-	$0	**$0.0000**
Total		**$ 3,817,523,780**	**$599,111**	

Reconciliation of all the riders compared to allocation ws

main rider		$2,236,214	
global ajdjust		$10,386,044	
1575 IFRS		($2,392,747)	
1568 - LRAM		($504,257)	
Stranded meters		$599,111	
Totals		$10,324,364	[agrees w required
			Allocation of bal]

	Res	GS<50
Disposition of Deferral/Variance Accounts (2016)	0.0002	0.0002
Disposition of Global Adjustment Sub-Account (2016)	0.0011	0.0011
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2013 balance)	(0.0001)	0.0001
Dispostion of CGAAP/CWIP	(0.0005)	(0.0003)
Recovery of Stranded Meter Assets (2014 balance)	0.0001	0.0002

GS>50	LU	USL	Sentinel	S/L	
0.0309	0.0148	0.0002	0.0231	(0.2075)	2 years
0.4161	0.0000	0.0011	0.4308	0.3973	2 years
(0.0126)	(0.0353)	(0.0002)	(0.1662)	(0.1296)	
(0.0564)	(0.0311)	(0.0005)	(0.2470)	(0.2306)	
0.0000	0.0000	0.0000	0.0000	0.0000	

Asset	Population	Typical End of Life IFRS (Years)
Transformer Station Power Transformers	24	40
Municipal Station Power Transformers	72	40
Transformer and Municipal Station Circuit Breakers	398	40
Transformer Station 230 kV Primary Switches	22	40
Municipal Station Primary Switches	58	No Data*
Transformer Station Capacitor Banks	9	30
Transformer Station Reactors	34	No Data*
TS Station Service Transformers	20	No Data*
TS 230 kV Primary Metering Units	18 combined 12 separate	No Data*
TS P&C Relays - Electromechanical	35	30
TS P&C Relays - Solid State	45	30
TS P&C Relays - Microprocessor	115	No Data*
Underground Cable	8,137.5 (km)	25
Distribution Transformers	44,192	30 - Underground TX 40 - Overhead TX
Switchgear	1,847	45
Mini-Rupter Switches	433	30
Automated Switches	360	40
Wood Poles	38,070	45

Switchgear - There is no separate category for the Switchgear and hence they are lum
45 year life

Distribution Transformer -EOL (IFRS) Life is 30 years for Underground Transformer anc
useful life is 40 year. However this asset is run to failure for the overhead and undergr

Inspection.

Automated Switch Useful Life is 30 years vs EOL (IFRS) of 40 years. The asset age is on
is primararily driven by inspection, condition assessment and other issues (obsolesenc

** - No EOL IFRS exist in the system.

Population Equal to or beyond TUL at December 31, 2014	% Population Equal to or beyond TUL at December 31, 2014
0	0
18	25
41	10.3
0	0
N/A	N/A
0	0
N/A	N/A
N/A	N/A
N/A	N/A
4	11.4
9	20
N/A	N/A
2,746	33.4
777	1.8
0	0
73	16.9
8	2.2
3301	8.7

ped under the U/G conduit and Devices with

l 40 years for Overhead Transformer. The
round except as determined through

ıly one factor for replacement. The replacement
:e) etc.

G-AMPCO G-Tab 2-5.3.2 Overview of Assets Managed
Undertakings AIP #12

Asset	Population	Condition				Number of Units Planned for Replacement						
		Good	Fair	Poor	N/A (1)	2015	2016	2017	2018	2019	2020	
Transformer Station Power Transformers	24	24	0	0	0	0	0	0	0	0	0	
Municipal Station Power Transformers	72	60	1	0	11	0	0	0	0	0	0	
Transformer and Municipal Station Circuit Breakers	398	337	3	53	5	7	12	12	10	8	4	
Transformer Station 230 kV Primary Switches	22	22	0	0	0	0	0	0	0	0	0	
Municipal Station Primary Switches	58	58	0	0	0	0	0	0	0	0	0	
Transformer Station Capacitor Banks	9	9	0	0	0	0	0	0	0	0	0	
Transformer Station Reactors	34	34	0	0	0	0	0	0	0	0	0	
TS Station Service Transformers	20	20	0	0	0	0	0	0	0	0	0	
230 kV Primary Metering Units - Combined	18	18	0	0	0	0	0	0	0	0	0	
230 kV Primary Metering Units - Separate	12	12	0	0	0	0	0	0	0	0	0	
TS P&C Relays (2) - Electromechanical	35	21	6	8	0	4	0	0	2	6	4	
TS P&C Relays (2) – Solid State	45	24	17	4	0	0	0	0	9	7	7	
TS P&C Relays (2) - Microprocessor	115	106	9	0	0	2	0	0	2	9	0	
Underground Cable	8,137.5 (km)	4568	1107	2371	0	105-115	105-115	105-115	105-115	105-115	105-115	Cable Injection
						25-30	25-30	25-30	25-30	25-30	25-30	Cable Replacement
Distribution Transformers	44192	22187	9026	6285	6694	68	64	60	60	60	60	
Switchgear	1847	1530	105	180	32	31	36	36	36	36	36	
Mini-Rupter Switches	433	270	123	38	2	15	15	15	15	15	15	
Automated Switches	360	327	19	14	0	5	5	5	5	5	5	
Wood Poles (3)	38070	29872	7064	1134	0	370	370	370	370	370	370	Pole Replacement
						30	30	30	30	30	30	Pole Reinforcement

(1) ACA test results not available or involves spare inventory.
(2) Includes relays associated with line, transformer and bus protections at transformer stations only.
(3) Condition is Projected based on tested poles

Originator:	**Dennis Cuzzolino** **Manager, Strategic Sourcing & Facilities**	**Date:**	**December 1 2014**
Reviewed By:	**Rob Antenucci** **Director, Supply Chain Services**	**Date:**	**December 1, 2014**
Approved By:	**Dennis Nolan** **EVP, Corporate Service & Secretary**	**Date:**	**December 1, 2014**
Approved By:	**Brian Bentz** **President & CEO**	**Date:**	**December 1, 2014**
To Be Reviewed By:	**Rob Antenucci** **Director, Supply Chain Services**	**Date:**	**December 1, 2016**

Policy Statement

The purpose of this policy is to define the responsibilities and accountabilities associated with the acquisition of goods and services required in the day to day operations of PowerStream Inc. Those responsible will commit to the actions which ensure financial accountability, conserve and protect the environment, avoid conflicts of interest while complying with all other PowerStream Inc. policies.

PowerStream Inc. is committed to establishing and maintaining a procurement system that is in compliance with all applicable laws.

Application

All procurements made by PowerStream Inc. shall be administered by Procurement Department and authorized by the Director of Supply Chain Services or his/her authorized delegate and executed in accordance with this Procurement Policy. All Executives of PowerStream Inc. shall ensure compliance with this Procurement Policy within their respective business units and shall not authorize any procurement outside of this policy.

This Procurement Policy shall be read and applied in accordance with PowerStream Inc.'s ADM-22 - Approval Policy and Procedures list on Inflow.

Definitions

Capitalized terms not otherwise defined in this policy shall have the meanings indicated below.

Confidential Information means any PowerStream data, information concerning trade secrets, methods, processes or procedures or any other business or technical information including any information relating to a past or present customer of PowerStream, including for the avoidance of doubt such customer's and a PowerStream employee's Personal Information (as such term is defined in the *Municipal Freedom of Information and Protection of Privacy Act* ("**MFIPPA**"), which it receives during the course of its performance of Services to PowerStream.

Policy Guidelines

The Procurement Department's role is to ensure that goods and/or services are acquired so that PowerStream Inc.:

- Obtains value in the fulfillment of specified needs with appropriate levels of quality and service;
- Uses a fair and open process when calling for, receiving, and evaluating quotations and tenders;
- Meets its legal and ethical obligations in the acquisition of goods and services.

The Procurement Department shall also ensure that PowerStream Inc. employs trained staff skilled in the purchasing techniques including negotiating, contractual terms and conditions, cost reduction techniques, and cooperative buying.

Goods and/or Services shall be acquired according to the following principles:

- Planning — Goods and/or Services shall be acquired only after consideration of needs, alternatives, timing, and availability of funds.

- Safety — Safety shall be considered in all PowerStream Inc. purchases. Goods and/or Services must meet or exceed the requirements of appropriate safety standards, legislation, regulations, rules, procedures and safe work practices.

- Environment — In keeping with PowerStream Inc's environmental goals and objectives, conserving and protecting the environment shall be considered in all PowerStream Inc. purchases.

- Sourcing — Except as set out in Procedure No. COR-P 06 Single/Sole Sourcing, goods and services shall be sourced from multiple vendors. Vendors shall compete for PowerStream Inc. business in an open, fair, consistent, and non-discriminatory manner. An exception where prior written approval is given by the Senior Executive Management team to enter into a strategic alliance / partnership agreement with an specific vendor.

- Purchasing — Goods and/or Services shall be acquired competitively from qualified vendors to meet specific needs and to achieve the greatest possible value for the money extended.

- Accountability — Appropriate approvals shall be obtained prior to purchase. Documentation shall be retained for appropriate lengths of time as determined by PowerStream Inc. retention policy requirements.

- Conflicts of Interest — Users and Procurement staff shall declare conflicts of interest up front and appropriately remove themselves from the process.

- Contract — Goods and/or Services shall only be obtained when a contract is entered into between PowerStream and the vendor with terms and conditions suitable for the goods and/or services being procured.

- Purchase Order — Purchase orders shall be processed for the purchase of goods or services in accordance with this Policy No. ADM-37 and are subject to approval.

Roles and Responsibilities

1. The responsibility for the identification of the need and specification is the responsibility of the User Department.

2. The Procurement Department in discharging its responsibilities shall have the final decision in the selection of the vendor and establishing the price, terms, and conditions of the purchase.

3. The Procurement Department may delegate its responsibilities to the User Group in specific instances while retaining the remaining responsibilities outlined below under Responsibilities.

4. All PowerStream Departments and staff will strive to ensure that all qualified vendors have an opportunity to participate in the procurement process on PowerStream Inc. business requirements in a fair, open, and competitive process

5. The Procurement Department may enter into co-operative purchasing arrangements with other organizations. The co-operative purchasing arrangement shall be consistent with the intent of PowerStream Inc. policies and be approved by the Director, Supply Chain Services

6. Under no circumstances will PowerStream Inc. entertain purchasing goods and /or services for subsequent sale by individuals for personal consumption or utilization.

In the discharge of its responsibilities, the Procurement Department undertakes to:

(a) Be a major point which vendor contact is initiated and maintained. Direct technical contact between users and vendors is essential; however, any vendor proposals resulting from technical discussions with the vendor are to be directed to the Procurement Department, with copies to the requestor.

(b) Be responsible for managing Vendor and any other related shows/displays involving vendors unless otherwise delegated by the Procurement Department.

(c) Keep abreast of developments in the major commodity fields and provide pertinent information to others.

(d) Evaluate vendor performance for inventory and non-inventory items through a matrix system and in consultation with the User Department may remove or place on hold a vendor for poor performance or non-performance.

(e) Identify sources of required goods and services, select vendors, obtain quotations and negotiate terms of purchase and payment. The User Department will be involved in the process.

(f) Expedite the procurement of goods and services and provide for customs clearance.

(g) Place orders and arrange details of delivery.

(h) Handle all adjustments of price, terms, and returns.

(i) Interpret and apply all applicable government regulations including sales taxes.

(j) Setup of any Procurement and Credit Agreements with Vendors

In the discharge of its responsibilities, the User Department undertakes to:

(a) Appropriately plan for the purchase of goods and services by considering needs, alternatives, timing, and availability of funds.

(b) Consult with Procurement to determine the appropriate competitive bid requirement and purchasing methodology.

(c) Create specifications that define the needs and requirements of goods and services purchased.

(d) Participate with Procurement to obtain verbal quotes, and evaluate the competitive procurement vendor submission received.

(e) Complete purchase requisitions for all purchases not made using a FPO (over the counter purchases only) and obtain appropriate approvals prior to the purchase of any goods and or services.

(k) Manage the contract (throughout its duration) for services provided including where applicable evaluation of the vendor performance for inventory and non-inventory items through a matrix system and in consultation with the Procurement Department may remove or place on hold a vendor for poor performance or non-performance.

Purchasing Methodologies

Purchase Order Value Procedure
$0 - $2,999
Purchases may be obtained using approved field purchase orders (FPO) or petty cash.
$3,000 - $9,999
No formal quote is necessary, however the normal process for requisitioning and the issuing of a purchase order is still required.
$10,000 - $100,000
The Procurement Department shall ensure that written quotations from at least three (3) approved vendors are obtained and will forward the results to the Using Department for review and selection
Greater than$100,000
The competitive bid process may take the form of an oral quotation, written request for quote, and/or a written request for Proposal or Tender. The most appropriate method will be decided by the Procurement Department in consultation with the requesting User and/or as is required by law. For any purchasing request please refer to COR-P-03 RFP Process Procedure located in Inflow under Procurement.
Notes:
Amounts above based on total annual procurement **Reference COR-P Table of Procedures**

Supplier/Vendor Setup

All new Supplier/Vendors requests to be set up in the PowerStream Supplier Master File must follow the procedure as set out in COR-P-02 Request for New Vendor located on Inflow.

Purchase Requisitions and Purchase Orders

Purchase orders are required for all transactions except:

- CDM rebates
- Corporate procurement/credit card purchases except as outlined in Employee Business Expense Policy ADM-21
- Corporate sponsorship/donations
- Customer refunds
- Developer rebates and construction deposit refunds
- DRC payments
- Employee expense/mileage forms and employee clothing/footwear purchases
- Facility lease/rent payments
- Wholesale electricity, transmission and connection invoices
- Legal fees, auditor fees, banking fees, joint use agreement fees, insurance premium
- OEB (Regulatory Payments)
- Payroll related payments, federal, provincial, municipal taxes and fees, and PIL's
- Hydro One Third Party - Cost Connection Estimate Study Payments
- Utility Payments (hydro, cable, water…)
- Payments to Shareholders

Purchase requisitions are a written (Manual Requisition Form) or electronic request to purchase goods or services that is required by the end user. Purchase requisitions are subject to approval (as outlined in Policy FCS-A-01) prior to the Procurement Department being permitted to issue a purchase order. Please refer to COR-P-04 Requisition Process Procedure in Inflow under Procurement.

Purchase orders are a commercial document used to request a company to supply goods and/or services in return for payment and for providing specifications, quantities, delivery timeline of products and services.

The only authorization given by PowerStream for a vendor to provide goods and/or services is through the issuance of a purchase order by the Procurement Department. The purchase order can be verbal, written, or a faxed purchase order. The only instance in which a purchase order can be issued verbally is if the following conditions are met: (i) value of goods and/or services is under $3,000.00; or, (ii) the vendor will not have access to Confidential

Information; or, (iii) there is no potential reputational risk to PowerStream. Otherwise, all purchase orders are to be in writing or a faxed purchase order. Procurement is responsible for preparing, signing, printing, and issuing purchase orders. Please refer to COR-P-05 Purchase Order Process in Inflow under Procurement

A formal agreement in writing is required (except if written approval is obtained by the applicable EVP) along with a Purchase Order if one or more of the following criteria are met:

- the anticipated dollar spend exceeds $100,000; or
- the vendor has access to Confidential Information; or,
- the vendor is performing construction or maintenance activities that may present a risk of personal injury or damage to property; or,
- the vendor has access to PowerStream physical property; or,
- if there is any uncommon business involved that may pose a risk to PowerStream; or,
- if there is potential reputational risk to PowerStream.

Procurement of Standard Inventory Items

JD Edwards will be the main tool used to manage inventory.

Inventory Management will purchase inventory when stock levels reach reorder points. The amount purchased will be according to best business practices. This implies if demand is increasing the reorder amounts will be increased dependant on demand, lead-time, economic reorder quantities, and market conditions at the time of purchase. Likewise the reverse will occur for decreased demand.

Inventory Management will endeavor to enter into Material Supply Agreements for commodity groups within the inventory.

Inventory Management will, in cooperation with the User groups; endeavor to maintain optimal inventory levels to meet the needs of PowerStream. Procurement will also work with the User groups to continuously improve demand management, which in effect will drive down inventory levels and associated costs.

Strategic Alliance

Strategic alliances are partnerships in which two or more companies work together to achieve objectives that are mutually beneficial while remaining independent organizations. Companies may share resources, information, capabilities and risks to achieve this. The strategic alliance is a co-operation or collaboration which aims for a synergy where each partner hopes that the benefits from the alliance will be greater than those from individual efforts. The alliance often involves technology transfer (access to knowledge and expertise), products, distribution channels, manufacturing capability, capital equipment, knowledge and or expertise.

Strategic Alliance Criteria:

The general criterion below differentiates strategic alliances from conventional alliances for PowerStream. Anyone of these criteria may be considered strategic.

1. Critical to the success of PowerStream's business goals or objectives.
2. Critical to the development or maintenance of a PowerStream core competency or other source of competitive advantage.
3. The partner's company culture and management team are compatible with PowerStream
4. Creates or maintains strategic choices for PowerStream.
5. Partner's goals and strategies are in line with PowerStream's.

PowerStream may enter into a strategic alliance with another partner for the purposes of providing goods and services. A strategic alliance may be considered in order to reduce tendering and administration costs; improve efficiencies when working with the partners. The strategic alliance differs from a normal entity that provides services in that the terms of providing goods and services may change over the duration of the contract in ways that are mutually beneficial to both parties.

A formal contract is required between the two parties and is to be updated as necessary or in accordance with the contract. Regular meetings with the partner shall be held to discuss ongoing improvements. All strategic alliances shall be approved based on the signing authority as per ADM-22.

Street Lighting Load Adjustment

Year	Forecasted SL Connection	Forecasted SL Connections (Vaughan, Markham, Barrie)	Forecasted SL Connections to be converted to LED
2016	88,226.26	57,347	19,116
2017	89,829.32	58,389	38,926
2018	91,459.76	59,449	59,449
2019	93,097.79	60,514	60,514
2020	94,770.15	61,601	61,601

Average Use per Street Light Connection

Year	Average Use per SL Connection (kWh)
2012	741
2013	733
2014	706
Average	**727**

Reduction on Average Use (kWh)	Total SL Adjustment (kWh)
363	6,947,824
363	14,148,129
363	21,607,386
363	21,994,372
363	22,389,467

Ontario Energy Board

Chapter 2 Appendices

Filing Requirements for Electricity Distribution Rate Applications

	2015	2016	2017	2018	2019	2020
System Renewal	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
UG Lines - Planned Asset Replacement	20,687	21,601	22,862	23,781	24,666	25,186
Cable Injection Program	4,024,219	4,138,312	4,255,465	4,375,771	4,499,323	4,626,219
Cable Replacement Program	11,718,862	12,538,684	13,607,273	14,288,297	15,085,861	15,340,181
Emerging Cable Replacement Projects	491,687	520,801	1,050,756	1,081,576	1,113,287	1,145,915
Major repair, refurbishment, or conversions of distribution transformers	30,000	30,000	29,999	30,000	30,000	30,000
Pad Mount Transformer Replacement	494,105	507,763	521,766	536,122	550,844	565,941
Submersible Transformer Replacement	1,040,300	620,000	-	-	-	-
Wye Transformer Supplying Delta Service Remediation	206,965	225,439	227,610	214,000	42,800	42,800
Major repairs, refurbishment, or modifications to switches/switchgear	100,000	100,000	100,000	100,000	100,000	100,000
Mini-Rupter Switch Replacement	577,736	592,267	607,090	622,214	637,649	653,406
Switchgear Replacement Program	2,003,445	2,327,404	2,462,129	2,533,373	2,606,624	2,681,945
Distribution Lines - Emergency/Reactive Replace	8,416	8,636	8,730	8,888	8,925	8,504
LIS - Unscheduled Replacement of Failed (end of useful Life) Distribution Equip	350,776	346,168	331,291	321,119	276,190	275,612
Non Recoverable replacement of Distribution Equipment due to accident/vand	210,775	220,581	220,973	220,972	211,281	191,499
Recoverable Replacement of distribution equipment due to Accidents/Vandali	530,442	530,601	545,432	560,876	570,984	580,023
Storm damage - Replacement of distribution equipment due to storm.	999,785	1,000,232	1,005,603	1,005,624	1,010,352	1,010,159
Switchgears - Unscheduled Replacement of Failed (end of useful Life) Distribut	1,420,148	1,431,384	1,420,148	1,421,218	1,400,444	1,140,858
Unscheduled Replacement of Other Failed Distribution Equip	4,904,357	5,107,035	5,206,156	5,358,281	5,455,354	5,305,986
Overhead Lines - Planned Asset Replace	7,698	7,907	9,082	8,558	9,144	9,022
44kV Insulators Replacement Program	66,000	68,000	69,000	71,000	71,000	71,000
Fault Indicator Installation and Replacement	503,725	508,425	513,124	517,823	522,523	527,222
Joint Use Pole Removal	470,149	480,036	495,312	510,961	515,697	519,952
Pole Replacement Program	4,645,383	4,933,143	5,570,700	5,870,246	6,241,483	6,244,377
Replacement of End of Life Automated Switches/Reclosers	435,912	447,130	458,595	470,301	482,308	494,628
Concord MS Conversion to 27.6 kV - Phase 3	-	-	481,500	-	-	-
Convert the 8.32kV Ccts into a 27.6kV Cct on Hwy 27 from Major Mack to Nash	-	-	400,000	-	-	-
Elder Mill MS Conversion - 8.32kV conductors Removal	-	-	-	-	169,597	-
Elder Mill MS Conversion- Part 2 (3F2)	280,062	-	-	-	-	-
Radial Supply Remediation/Conversion - 13.8 kV to 27.6 kV on Miller Ave	250,000	400,000	-	-	-	-
Unforeseen Projects Initiated by PowerStream	1,046,472	1,070,527	1,093,812	1,117,360	1,141,172	1,165,266
Storm Hardening	3,500	7,900	8,000	7,500	6,901	7,200
Storm Hardening & Rear Lot Supply	3,499,998	7,900,017	7,999,752	7,499,834	6,900,540	7,200,072
Stations/P&C - Planned & Emergency	2,087	2,671	2,827	3,325	3,336	2,493
Low Voltage Bushing Replacement - Transformer Station MTS#3 - T1/T2	-	-	-	257,114	300,445	-
Planned Circuit Breaker Replacement Markham TS#2 J Bus, Markham TS#1 Y B	747,766	-	-	1,087,788	1,119,281	-
Planned Circuit Breaker Replacement Markham TS#3 - E & Z Buses	-	370,682	396,733	-	-	-
Refurbish 13.8 kV Portion of Aurora MS1 - yr 1 of 2	-	-	-	-	-	322,362
Replacement of Legacy RTU and Recloser Controllers at Morgan MS	107,244	-	-	-	-	-
Building Structural Repair to Ferndale MS	99,322	-	-	-	-	-
Capital Corrective Equipment Replacement - Stations	262,325	263,654	264,982	266,311	267,640	268,969
Station Switchgear Replacement (ACA) 8th Line MS323	-	-	412,339	1,106,666	-	-
Station Switchgear Replacement (ACA) Anne St. MS301	235,714	683,581	-	-	-	-
Station Switchgear Replacement (ACA) Big Bay Point MS304	-	242,675	703,403	-	-	-
Station Switchgear Replacement (ACA) Duckworth MS409	-	-	-	-	-	202,204
Station Switchgear Replacement (ACA) Ferndale South MS303	-	242,675	703,403	-	-	-
Station Switchgear Replacement (ACA) Innisfil MS411	-	-	-	-	192,752	577,983
Station Switchgear Replacement (ACA) Patterson MS336	-	-	-	421,896	895,805	-
Station Switchgear Replacement (ACA) Saunders MS302	235,714	683,581	-	-	-	-
Station Switchgear replacements (ACA) Cundles West MS408	-	-	-	-	195,568	587,128
Emergency Corrective Capital Funds for Emergency P&C Purchases	37,801	38,109	38,417	38,725	39,034	39,342
KDU-10 Replacement MTS#1 and #2	114,486	-	-	-	-	-
RTU Replacement Program (Proactive)	-	-	-	-	178,185	178,841
RTU Replacement Program (Reactive)	96,721	97,091	97,461	97,830	98,200	98,570
Purchase of a Critical Spare - 2000A Siemens SPS2-38-31.5 outdoor SF6 breake	149,800	-	-	-	-	-
Spare Gas Insulated Switchgear Cells for VTS3, VTS2 & MTS4	-	-	-	-	-	168,687
Spare HD4 Circuit Breakers and Ground & Test Devices (GTD) for Greenwood T	-	-	161,314	-	-	-
Purchase of Critical Spare Parts - MultiYear	-	48,631	48,632	48,632	48,631	48,632
Total System Renewal	42,388	48,715	51,500	52,052	52,971	52,406

System Access	2015 ($ 000)	2016 ($ 000)	2017 ($ 000)	2018 ($ 000)	2019 ($ 000)	2020 ($ 000)
New Connections and Subdivisions	13,671	14,718	15,801	16,404	17,037	17,674
Locating for Capital Projects.	59,010	59,009	59,009	59,009	59,009	59,009
New Commercial Subdivision Development Place Holder (May not happen eve	1,600,010	1,601,908	1,603,808	1,605,707	1,607,607	1,609,506
NEW OVER HEAD AND UNDERGROUND SECONDARY RESIDENTIAL SERVICE CO	371,774	394,081	417,725	442,789	469,356	497,518
New Residential Subdivision Development	7,895,964	8,633,109	9,392,346	9,759,944	10,135,066	10,517,394
New Services - new and upgrades - COMMERCIAL, INDUSTRIAL, INSTITUTIONA	197,602	209,720	222,004	235,575	249,748	264,784
New Services (new and upgrades) - Commercial, Industrial and Institutional (IC	74,323	78,616	83,372	88,331	93,600	99,306
New Subdivision Development - Secondary Service Lateral	1,989,034	2,173,796	2,364,815	2,458,773	2,554,113	2,650,954
O/H and U/G Residential Service Upgrades	928,921	984,657	1,043,737	1,106,360	1,172,741	1,243,109
Open work order for ICI meter installations.	395,939	419,695	444,877	471,570	513,960	544,574
SMALL NEW AND UPGRADE COMMERCIAL SERVICES	60,593	64,229	68,082	72,168	76,497	81,086
Subdivision - Underground Residential Distribution System Final Close out and	97,520	99,467	101,414	103,362	105,309	107,257
Road Authority	6,259	9,702	8,679	8,357	5,719	6,222
Road Authority Expenditures	6,258,891	6,258,891	6,258,891	6,258,891	6,258,891	6,258,891
Metering	3,887	3,025	3,060	3,720	4,715	6,556
Advanced Metering Infrastructure (AMI) Security Audit	-	-	63,027	-	-	63,258
Buttonville Metering Upgrade	100,000	-	-	-	-	-
Commercial and Industrial Meter Re-Verification Program (Commercial meters	486,225	350,000	350,000	506,243	512,915	519,588
Failed Meter Replacement	171,115	172,355	173,597	174,838	176,079	81,465
Feeder 63M2 Metering Unit Relocation	81,022	-	-	-	-	-
Firmware Upgrades in Smart Meters	30,752	20,886	21,271	16,242	16,531	33,641
GS>50 MIST Meter Program Implementation	1,592,952	1,196,859	1,303,795	1,308,610	1,195,725	574,761
Metering customer facing Interface Improvements - Planning	-	-	-	-	-	61,240
Obsolete Revenue Metering Removal from TSs	-	-	-	-	20,198	20,572
Open work order for ICI meter installations.	148,001	156,881	166,294	176,270	186,847	198,057
Residential Meter "ICON F" Meter Replacement Program	411,051	494,361	494,746	872,435	2,280,384	4,517,454
Smart Meter Network Expansion and Enhancements	100,000	265,546	100,000	250,000	100,000	266,016
Suite Meter Installation	379,625	-	-	-	-	-
Suite Meter Re-Verification Program	127,951	122,400	200,000	200,000	200,000	200,000
Upgrade 2.5 Element Services to 3 Element Services.	157,986	159,858	161,730	163,603	-	-
Smart Meter Test Facility	-	85,946	25,811	51,779	25,968	19,670
Wholesale Meter Replacement with TCP/IP	99,853	-	-	-	-	-
Other Customer Initiated Work	329	787	929	1,080	1,256	1,415
Unforeseen Projects Initiated by the customer Total	329,005	786,802	929,401	1,080,390	1,255,781	1,414,541
RGEN FIT/microFIT (Net Rate Base)	-	-	-	-	-	-
Total System Access (Rate Base)	24,145	28,232	28,470	29,561	28,726	31,867

General Plant	2015 ($ 000)	2016 ($ 000)	2017 ($ 000)	2018 ($ 000)	2019 ($ 000)	2020 ($ 000)
Customer Information System (CIS)	11,703	3,991	6,816	2,996	2,996	3,103
CIS Modifications	1,403,400	3,884,100	6,708,900	2,996,000	2,996,000	2,996,000
CIS Replacement Project	10,300,000	-	-	-	-	-
CS integration services with Outage Contact Centre	-	107,000	107,000	-	-	107,000
IT & Info/Communication Systems	5,302	7,560	7,016	4,587	7,244	8,318
All Out Security Upgrade	-	10,807	-	-	10,807	-
Application Review	-	96,300	-	-	-	-
Asset Analytic in C55	-	-	243,158	-	-	-
BizTalk Upgrade	-	-	-	-	252,500	-
Business Intelligence - Dashboards	-	-	-	-	-	123,704
C55 Phase 2 (Performance Management)	-	146,348	-	-	-	-
C55 Phase 2 (Replacement of CBMS)	398,810	-	-	-	-	-
Client Computing	411,950	400,000	425,000	425,000	441,667	454,167
Complete Sonet Loop at YorkTech/Addiscott	-	34,633	-	-	-	-
Control Room Map Cabinet Panel upgrade	80,250	-	-	-	-	-
Customer Experience Plan Outcomes	26,750	-	-	-	-	-
Customer Web Portal, Integrated Self-Serve & Mobile Applications	-	267,500	374,500	-	-	107,000
Cyber Security Audit & Upgrades	-	-	-	52,244	63,441	65,265
Data Loss Prevention - Phase 1	90,950	-	-	-	-	-
Disaster Recovery	-	50,290	50,290	50,290	50,290	50,290
Electronic MMR (Material Movement Record)	-	-	-	-	55,672	167,017
Enterprise Content Management	-	-	-	-	-	624,309
Expansion of Link between Addiscott & Cityview	96,300	-	-	-	-	-
Fieldworker System Changes & Equipment Replacement	80,250	-	-	64,200	80,250	-
File Share POC - Mobility file share	-	54,035	-	-	-	-
Finance Emerging Projects	135,000	219,000	241,000	266,000	293,000	323,000
GIS Emerging Projects	150,000	158,000	166,000	175,000	184,000	194,000
GIS Landbase Data (Parcels, Streets & Points of Interest. (Year 5 of a 5 year con	54,125	56,047	56,047	56,047	56,047	56,047
GIS StreetScape Images (Year 4 of 4)	112,350	112,350	112,350	112,350	-	-
Global Positioning System (GPS)for As Built Data Collection	-	-	-	-	35,278	-
Identity and Access Management	96,300	-	-	-	-	-
Implementation of a new ADMS Platform for Operations - Phase 1	-	-	-	-	-	121,365
Implementation Of GE PulseNET Network Management System for Scada Licen	-	25,269	-	-	-	-
Intergrate GPS technology with Responder OMS	-	-	-	-	-	74,452
IT Management System (Phase III)	-	-	-	-	-	197,715
IVR Corporate Directory replacement	53,500	-	-	-	-	-
IVR Replacement	-	-	-	-	-	540,350
IVR/OMS changes Customer Call Back Solution and Regional Granularity	80,250	-	-	-	-	-
JD Edwards Application Upgrade	-	-	-	-	2,396,800	-
JD Edwards High Availability Design Planning	-	214,000	-	10,700	-	-
JD Edwards System Hardware Upgrade (2019)	-	-	-	-	-	605,733
JD Edwards version Upgrade Design Planning	-	-	-	-	162,105	-
JDE Workload Automation	-	97,263	-	-	-	-
JDEdwards Enhancements	53,500	133,750	101,650	133,750	100,045	200,090
Legacy Easement Transactions for Capital	13,921	13,995	14,071	14,145	14,220	14,295
Major Upgrade to Ent. System	-	-	-	49,969	-	100,045
Migration of Operations WAN to a PowerStream Owned Solution - Phase 1	134,101	-	-	-	-	-
Misc Software Upgrades (FormScape, AutoCAD, etc.)	-	-	-	-	20,606	51,515
MSBPI	-	10,000	60,000	899,999	50,000	10,000
Netmotion	53,500	-	-	-	-	-
OM&A Budget Development (database & optimization process)	-	86,456	510,090	-	-	-
Phone System enhancement Upgrade	-	-	-	-	50,500	908,999
PowerStream Website Planning/Development and Enhancement to existing Sit	-	-	-	-	-	33,403
PowerStream Website Upgrade Project	214,000	-	-	-	-	-
Printer & Copier Fleet Replacement	42,800	200,000	250,000	40,000	40,000	40,000
RFGen Upgrade	10,700	-	-	10,700	-	-
Security - Additions & Enhancements	-	200,090	200,090	200,090	200,090	200,090
Server Refresh	267,500	319,999	340,000	360,000	380,000	400,000
SIP POC (Voice SIP Trunking)	-	96,300	-	-	-	-
Softphone Technology	-	-	-	-	-	108,070
SQL Expansion	90,950	100,000	-	50,000	-	100,000
CASCADE System Interface to New Operations Work Management System	-	-	86,456	-	-	-
CMMS Mobile Application Upgrade (Tablet solution)	-	85,171	-	-	-	-
PI System Hardware and System Upgrade	-	-	-	82,682	-	-
Purchase PI Enterprise Agreement	-	-	-	-	-	457,505
Storage Expansion (Data)	321,000	300,000	300,000	300,000	1,000,000	400,000
Talent Management System	-	25,000	-	-	-	-
Technology changes in Control Room.	-	-	-	-	-	272,877
Technology Upgrades Improving the System Control Room Environment	52,601	52,986	53,371	53,757	54,142	54,527
Third Party Contact Centre Systems Integration- Day to Day	-	-	432,280	-	-	-
Upgrade of the Electronic Visual Display Wall (EVDW) to LED Light Engines - Pha	-	-	-	-	175,546	175,789
Upgrade of the Radio over Internet Protocol (RoIP) Environment of the Operati	-	-	197,008	-	-	-
Upgrade OMS to Advanced Distribution Management System (ADMS)	-	-	-	-	-	223,925
Upgrade Responder to 11.X	-	133,673	-	-	-	-
Upgrade Server O/S	-	300,000	-	50,000	-	-
Upgrade to IVR and Outage Communications Systems.	-	-	151,298	-	-	-
Upgrade to PowerStream's Operations Network CyberSecurity Posture - Phase	257,502	258,118	258,735	-	-	-
Upgrade/Expand Tape Library (DR and PROD)	-	-	600,000	-	-	200,000
UPK Upgrade	-	10,807	-	-	10,807	-
VDI Project – Phase 4 XenApp & Virtual Desktops Expansion	96,300	50,000	50,000	-	300,000	50,000
Contact Centre Workforce Management	-	214,000	321,000	-	-	-
Lines Mobile Equipment	119,840	150,870	120,910	77,818	77,818	77,818
Metering WFM - Enhancements	-	-	53,500	-	53,500	-

Metering WFM - Planning	58,850	-	-	-	-	-
Mobile Workforce	42,800	202,016	445,120	250,059	100,259	-
Work Force Management / Mobile Dispatch	1,605,000	2,675,000	802,500	802,500	535,000	535,000
Buildings & Emerging Operations	3,696	655	713	779	899	1,208
Barrie Building Renovation Project 2015	3,149,489	-	-	-	-	-
Emergency Capital work as required for facilities	390,037	398,168	402,555	406,942	411,543	417,027
Lazenby Storage Facility	-	-	-	-	68,985	244,116
Markham TS#4 Heating Improvements	-	-	-	7,727	-	-
Connect Lazenby 1 to City Water and Sewer	-	-	-	-	-	75,330
Upgrade to Station Facilities (Building / Civil work) MultiYear	103,251	49,982	50,213	50,444	50,675	50,906
Emerging Issues - Operations Capital	53,500	207,000	260,500	314,000	367,500	421,000
Fleet	2,274	2,600	2,161	2,386	2,573	2,424
Backhoe/Loader	-	-	123,050	-	-	-
Bucket Truck	-	428,000	-	-	-	-
Bucket Truck	481,500	-	-	-	-	-
Bucket Truck	-	428,000	-	-	-	-
Bucket Truck	-	428,000	-	-	-	-
Bucket Truck	-	428,000	-	-	-	-
Bucket Truck	-	428,000	-	-	-	-
Bucket Truck	-	-	374,500	-	-	-
Bucket Truck	-	-	428,000	-	-	-
Bucket Truck	481,500	-	-	-	-	-
Bucket Truck	379,850	-	-	-	-	-
Bucket Trucks	-	-	-	2,193,500	1,605,000	1,391,000
Car/SUV	-	-	48,150	-	-	-
Cargo Van	-	-	48,150	-	-	-
Cargo Van	-	-	48,150	-	-	-
Emergency Fleet Breakdown Repairs	128,400	128,400	128,400	128,400	128,400	133,750
Flatbed with crane	321,000	-	-	-	-	-
Install Cargo Area Protectors	48,150	-	-	-	-	-
Pickup	53,500	-	-	-	-	-
Pickup	-	-	58,850	-	-	-
Pickup	-	58,850	-	-	-	-
Pickup	-	58,850	-	-	-	-
Pickup	-	58,850	-	-	-	-
Pickup	-	-	58,850	-	-	-
Pickup	-	-	58,850	-	-	-
Pickup	-	-	58,850	-	-	-
Pickup	-	58,850	-	-	-	-
Pickup	-	-	58,850	-	-	-
Pickups	149,800	-	-	-	-	-
Pickups	-	-	117,700	-	-	-
Pickups	-	-	107,000	-	-	-
Pickups and misc light duty vehicles	-	-	-	-	829,250	888,100
SUV	-	-	48,150	-	-	-
SUV	-	-	48,150	-	-	-
SUV	-	-	48,150	-	-	-
SUV	-	-	48,150	-	-	-
SUV	-	-	48,150	-	-	-
SUV	-	-	48,150	-	-	-
SUV	-	-	48,150	-	-	-
SUV	-	-	42,800	-	-	-
Tools	10,700	10,700	10,700	10,700	10,700	10,700
Van	37,450	-	-	-	-	-
Van	37,450	-	-	-	-	-
Van	-	37,450	-	-	-	-
Van Pool Van	48,150	48,150	53,500	53,500	-	-
Van Pool Vans	96,300	-	-	-	-	-
Tools	570	467	473	820	709	711
Go Pro Video Cameras and accessories	3,210	-	-	-	-	-
Load Limiters	-	-	-	26,750	-	-
Metering Tools and Equipment	77,040	77,040	77,040	77,040	77,040	77,040
Mobile Office Equipment Enhancements	2,140	-	2,354	-	2,589	-
Mobile Tablets for Design Techs	3,638	-	-	-	-	-
P&C Specific Tools and Testing Equipment	10,700	10,700	10,700	10,700	10,700	10,700
Purchase Cable Locate Equipment	-	7,062	-	7,490	-	-
Purchase ground grid resistance meter	4,280	-	-	-	-	4,708
Purchase of Major Tools	362,691	362,691	362,691	362,691	362,691	362,691
Purchase of Remote Disconnection Meters	-	-	-	300,164	245,589	245,589
Purchase of the EnoServe Protective Relay Asset Management System	95,932	-	-	-	-	-
Purchase Plotter for Addiscott Office	-	-	10,700	-	-	-
Purchase Protective Equipment for Inspectors	-	-	-	2,269	-	-
Purchase Scanner for Addiscott Office	-	-	-	21,614	-	-
Purchase of Major Tools	10,000	10,000	10,000	10,000	10,000	10,000
Voltmeters - Cat4	-	-	-	1,177	-	-
Interest Capitalization	1,000	1,020	1,040	1,061	1,082	1,104
Interest Capitalization	1,000,000	1,020,000	1,040,000	1,061,000	1,082,000	1,104,000
Smart Grid - Other		1,338	1,338	1,338	1,338	1,338
Data Analytics	-	267,500	267,500	267,500	267,500	267,500
Electrical Vehicle Technologies	-	535,000	535,000	535,000	535,000	535,000
Home Technologies	-	535,000	535,000	535,000	535,000	535,000
Total General Plant	24,545	17,631	19,558	13,967	16,841	18,206

System Service	2015 ($ 000)	2016 ($ 000)	2017 ($ 000)	2018 ($ 000)	2019 ($ 000)	2020 ($ 000)
Additional Capacity - Stations	14,115	16,175	9,439	12,261	2,629	4,296
Aurora MS4 Expansion	-	-	-	-	489,783	182,428
Aurora MS6 Expansion	-	456,529	147,739	-	-	-
Hydro One Asset Purchase - Vaughan	50,000	-	-	-	-	-
Letitia MS (MS413)- Increase Capacity from 5MVA to 10MVA	-	-	-	644,864	1,389,927	-
Markham TS #5 - Land Purchase	-	-	-	-	-	481,500
Painswick South MS: New 44-13.8kV, 20 MVA, 4-Feeder Substation	2,690,054	-	-	-	-	-
Patterson MS#2 - New 44-13.8kV, 2x5 MVA, 2-feeders MS	-	-	-	-	749,000	1,931,978
New MS, Dufferin South MS#2 - Alliston	-	749,000	2,299,074	4,899,189	-	-
New MS, Harvie Rd. MS - Barrie	-	749,000	-	-	-	1,700,333
New MS, Little Lake MS#2 - Barrie	1,125,311	1,603,656	3,095,457	-	-	-
New MS, Melbourne MS#2 - Bradford	-	749,000	1,651,393	3,187,430	-	-
New MS, Mill Street MS#2 - Tottenham	-	642,000	1,821,953	3,529,079	-	-
Vaughan TS #4 - Build Station	10,249,162	11,226,183	422,915	-	-	-
Additional Capacity -Lines	9,203	17,769	17,232	11,698	18,182	12,153
2x44kV circuits (23M22 & 23M23) from Midhurst TS2 to Essa Rd. and Maplevi	5,011,705	3,606,692	4,460,060	-	-	-
44kV Supply to Dufferin St. South MS#2 - Alliston	-	-	-	268,977	-	-
Add one 27.6 kV Cct on Steeles Ave From Jane St to Keele St	-	-	-	-	1,110,310	-
Add one additional 27.6 kV Cct on 19th Ave from Bayview to Bathurst St	-	-	-	340,923	-	-
Add one Additional 27.6 kV Cct on Major Mack and 9th Line	-	-	-	-	-	1,248,939
Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview	-	-	1,221,747	-	-	-
Dufferin South MS#2 - 13.8 kV Feeder Integration	-	-	-	304,842	-	-
Extend 23M8 Circuit on Bayfield from Livingstone to Cundles	-	-	-	-	495,457	-
Hydro One Asset Purchase - Barrie (23M3)	278,200	-	-	-	-	-
Install 2 Ccts Pole Line on Langstaff Rd from Huntington Rd to Hwy 50	-	-	-	-	546,339	-
Install 2nd 27.6 kV Cct on Woodbine Ave from Elgin Mills Rd to 19th Ave	-	-	-	218,498	-	-
Install 2x13.8kV ccts Pole Line on Leslie St from Wellington St to St.John's Sdrd	-	1,131,418	-	-	-	-
Install a new 4 ccts CNR yard overhead crossing on the south side of Hwy 7	510,232	-	-	-	-	-
Install Double Cct Pole Line on Major Mackenzie - Hwy 27 to Huntington Rd	-	-	-	1,819,608	-	-
Install Double Ccts 27.6 kV Pole Line on 16th Ave from 9th Line to Reesor Road	-	-	-	-	1,302,301	-
Install one 13.8kV Cct on Bryne Dr - Mapleview to Ardagh	-	-	-	-	-	285,157
Install one 13.8kV Cct on Dunlop St W - Miller to Ferndale	-	-	-	-	-	351,370
Install one 44kV cct on Mapleview Drive West - Essa to Veterans	-	-	-	855,914	-	-
Install One Additional 27.6 kV Cct on Elgin Mills Rd - Part 1 Leslie St to Bayview	-	337,938	-	-	-	-
Install One Additional 27.6 kV Cct on Elgin Mills Rd - Part 2 Leslie St to Woodbi	-	361,312	-	-	-	-
Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave	-	1,108,593	-	-	-	-
Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd	-	-	-	-	-	2,084,275
Installation of two new circuits on Leslie Street - 19th Ave to Stouffville Sdrd	-	-	-	-	-	1,392,644
Little Lake MS#2 - 13.8kV Feeder Integration	-	-	294,935	-	-	-
Little Lake MS#2- 44 kV Supply	-	-	289,328	-	-	-
Markham TS #4 Feeder Egress Part 3	-	-	-	-	-	4,910,872
Melbourne MS#2 - 44 kV Supply	-	-	-	125,300	-	-
Melbourne MS#2-13.8kV Feeder Integration	-	-	-	346,945	-	-
Mill St. MS#2 - 44 kV supply to Mill St. MS#2	-	-	-	377,077	-	-
Mill St. MS#2 - 8.32 kV Feeder Integration	-	-	-	393,105	-	-
New 27.6kV Pole Line on 19th Ave from Leslie to Woodbine Ave	-	-	-	-	1,020,587	-
New 44 kV Feeder (13M7) Barrie TS X Huronia & Big Bay Pt. Rd	76,925	4,726,805	-	-	-	-
Painswick South MS-13.8kV Feeder Integration	257,569	-	-	-	-	-
Painswick South MS-44kV Supply to Painswick South MS	279,034	-	-	-	-	-
Pole Line Installation Double Cct on Major Mack - Huntington Rd to Hwy 50	-	-	-	-	1,307,147	-
Rebuild 27.6 kV pole line for 4 Ccts on Warden Ave from Major Mack to Elgin I	-	-	-	2,061,719	-	-
Rebuild 27.6 kV pole line into 4 Ccts on Warden Ave from Hwy 7 to 16th Ave	-	2,039,163	-	-	-	-
Rebuild 27.6 kV pole line into 4 Ccts on Warden Ave from Hwy 7 to Major Mac	128,400	-	-	-	-	-
Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major M	-	-	2,050,441	-	-	-
Rebuild Pole Line on 14th Ave into 4 cct -From Warden Ave to Kennedy Rd	-	-	1,206,790	-	-	-
Two Ccts on Birchmount Rd from ROW to 14th Ave	-	-	-	-	-	1,502,063
Two Ccts on Birchmount Rd from ROW to Enterprise	1,201,150	-	-	-	-	-
Vaughan TS#4 Feeder Integration - Part 1	-	-	7,341,955	-	-	-
Vaughan TS#4 Feeder Integration - Part 2	-	-	-	3,176,402	-	-
Vaughan TS#4 Feeder Integration - Part 3	-	-	-	-	9,630,000	-
27.6 kV Pole Line on 14th Ave from Hwy 48 to 9th Line	-	2,039,163	-	-	-	-

27.6 kV Pole Line on Reesor Rd from Hwy 7 to 14th Ave	-	1,496,942	-	-	-	-
Double Circuit existing 23M8 Circuit from Bayfield & Livingstone to Little Lake	-	-	-	-	2,395,509	-
Highway Crossing Remediation - Hwy 400/ Anne St.	-	475,014	-	-	-	-
Highway Crossing Remediation - Hwy 400/ Brock St.	-	-	-	1,038,486	-	-
Highway Crossing Remediation - Hwy 400/ Wellington St.	-	82,788	-	-	-	-
Highway Crossing Remediation - Hwy 407/ East of Dufferin	1,100,409	-	-	-	-	-
Design Only budget for Controllable Capital Projects	358,985	362,730	366,475	370,220	373,965	377,710
Reliability including Dist. Auto.	3,943	3,159	4,183	4,658	4,550	5,161
Automatic Feeder Restoration Program	490,112	500,776	515,473	528,595	541,286	550,254
Centennial MS-Penetang-install OH reclosers 4.16kV feeders outside station S	-	-	468,235	-	-	-
Distribution Automation Switches / Reclosers	1,850,276	1,530,249	2,080,457	2,283,805	2,354,895	2,409,740
IntelliTEAM Pilot Project - Phase 2	214,000	-	-	-	-	-
Amber MS - RTU Upgrade	42,637	-	-	-	-	-
Communication & Automation Upgrades	-	-	-	88,305	90,720	93,196
Convert Three MS's in Barrie to WiMax Communications	-	-	-	44,805	22,454	22,555
Convert Two MS's in Barrie to WiMax Communications	22,050	22,151	-	-	-	-
DACS Inverters and RTU's removal	-	-	-	-	20,198	20,572
Expand Communication Network to issolated Stations in Tottenham and Pene	60,000	60,738	-	-	-	-
FDIR - Scada and Smartgrid	-	-	62,851	-	63,170	-
HMI Upgrades	-	-	-	85,489	87,127	88,784
Markham TS#3 Substation Communications upgrade	-	-	-	-	-	46,878
Markham TS#3E Substation Communications upgrade	-	-	-	-	-	46,878
Redundent Fibre Path to Aurora MS#4 Sub-Station	-	216,610	-	-	-	-
Richmond Hill TS#1 Substation Communications upgrade	-	-	-	-	45,644	-
Separate Transformer & Breaker SCADA Alarms - Markham TS # 1 & TS # 2	-	75,161	-	-	-	-
System Remote Fault Indicator Deployment	90,520	90,613	90,705	90,798	90,890	90,982
Upgrade of Communications to WiMAX - AMS2 and AMS3	20,971	-	-	-	-	-
Upgrade of Communications to WiMAX - AMS7 and AMS8	-	21,063	-	-	-	-
Upgrade of RTUS in 2 PMH Switchgear to Support Smart Grid Initiatives,	61,427	61,778	62,129	62,479	-	-
230kV Line Protection Upgrade Markham TS#3	-	-	-	85,133	-	-
Aurora MS2 Feeder Protection Upgrades	-	-	-	72,264	64,759	-
Bus Differential Protection Upgrades	-	-	-	252,221	257,041	261,913
Decommission Capacitor Bank - MTS#3	-	-	-	-	19,517	-
Feeder Protection Upgrade at MTS#3, RHTS#2	156,859	158,425	314,370	305,051	-	-
MS Feeder Protection Upgrades - AMS5	-	-	-	125,527	128,567	-
Purchase and Installation of Animal Guards at Various Stations	15,121	15,244	15,367	15,490	15,613	15,737
Installation of Transformer Bushing Monitoring on TS and MS txmrs	-	229,000	229,000	229,000	229,000	232,000
On-Line Dissolved Gas Oil Monitoring of MS and CS transformers	121,548	122,432	123,315	-	-	-
Purchase & Installation 8 Self Recharging Transformer Air Breathers on TS trar	-	-	-	-	-	73,037
Purchase & Installation of 7 online Transformer Tap Changer Oil Filtration Syst	55,000	55,000	55,000	55,000	-	-
Purchase and Installation of Online Dissolved Gas Monitoring on 4 TS Power T	240,652	-	-	-	-	-
Purchase of new High Resolution FLIR Infrared camera to replace existing unit	-	-	-	-	-	67,475
Purchase of a Mobile Unit Station	-	-	-	-	-	885,481
T1/T2 Differential Protection Upgrade	-	-	-	246,471	251,176	255,927
Transformer Temperature Monitoring - Aurora MS# 1,2,3&4	-	-	165,642	87,231	-	-
Upgrade Bus, Line & Transformer protections - Richmond Hill TS #2	-	-	-	-	267,706	-
Upgrade of Richmond Hill TS2's Legacy Integrated Station Control System	131,404	-	-	-	-	-
Walker MTS#2 - drainage remediation	370,751	-	-	-	-	-
Station Safety & Security	62	149	149	234	533	341
Arc Flash Mitigation Projects	11,515	11,740	12,006	26,177	26,898	27,637
Ground Grid Refurbishments	-	-	-	-	111,045	-
Sorbweb Oil Containment Systems	50,000	60,000	60,000	60,000	60,000	60,000
Station Brand Imaging - Nomenclature, Signage	-	16,914	17,068	17,223	-	-
Installation/Retrofit of SWI Video security system TS stations	-	60,000	60,000	60,000	60,000	60,000
Installation of SWI Video security system at MS stations	-	-	-	-	119,722	120,223
Station Security - Station Card Access at Jackson TS, Lazenby 1 and Lazenby 2	-	-	-	-	41,597	-
Station Security - Station Card Access Cockburn TS, and Walker TS and Fry TS	-	-	-	-	41,640	-
Station Vegetation Enhancements at TS's and MS's	-	-	-	70,684	72,091	73,524
Smart Grid/RGEN - System Related	-	1,070	1,070	1,070	1,070	1,070
Operations Technologies Rate Based	-	535,000	535,000	535,000	535,000	535,000
Storage Technologies Rate Based	-	535,000	535,000	535,000	535,000	535,000
Total System Service	27,322	38,322	32,072	29,920	26,963	23,022

Financial statements of

PowerStream Inc.

December 31, 2014

PowerStream Inc.

December 31, 2014

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Deloitte.

Deloitte LLP
5140 Yonge Street
Suite 1700
Toronto ON M2N 6L7
Canada

Tel: 416-601-6150
Fax: 416-601-6151
www.deloitte.ca

Independent Auditor's Report

To the Shareholder of
PowerStream Inc.

We have audited the accompanying financial statements of PowerStream Inc., which comprise the balance sheet as at December 31, 2014, the statements of income and other comprehensive income, changes in equity and of cash flows for the year ended December 31, 2014, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

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

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

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of PowerStream Inc. as at December 31, 2014, and its financial performance and its cash flows for the year then ended, in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
April 8, 2015

PowerStream Inc.

Balance sheet
as at December 31, 2014
(In thousands of dollars)

	2014	2013
	$	$
Assets		
Current assets		
Cash	**23,110**	-
Accounts receivable (Note 17(c))	**95,963**	90,629
Unbilled revenue	**112,582**	115,840
Due from related parties (Note 10)	**6,737**	2,739
Inventories (Note 6)	**3,085**	2,956
Income taxes receivable	**6,208**	-
Prepaids and other assets	**4,129**	3,896
	251,814	216,060
Long-term assets		
Property, plant and equipment (Note 7)	**1,032,551**	910,784
Intangible assets (Note 8)	**42,621**	28,833
Investment in a joint venture (Note 5)	**7,536**	7,256
Deferred tax assets (Note 20)	**14,239**	22,537
Goodwill (Note 8(b))	**42,543**	42,543
	1,391,304	1,228,013
Liabilities		
Current liabilities		
Bank indebtedness (Note 11(a))	**-**	7,368
Short-term debt (Note 11(a))	**25,000**	70,000
Infrastructure Ontario financing (Note 11(b))	**67,656**	48,315
Customer deposits	**14,436**	13,357
Accounts payable and accrued liabilities (Note 9)	**134,179**	136,694
Due to related parties (Note 10)	**16,942**	15,775
Income taxes payable	**-**	1,351
Liability for subdivision development	**5,268**	5,600
Current portion of finance lease obligation (Note 16)	**337**	315
	263,818	298,775
Long-term liabilities		
Notes payable (Note 12)	**182,430**	182,430
Debentures payable (Note 12)	**347,288**	198,221
Finance lease obligation (Note 16)	**16,455**	16,792
Post-employment benefits (Note 13)	**17,362**	19,317
Deferred revenue	**120,651**	101,342
	684,186	518,102
Shareholders' equity		
Share capital (Note 14)	**327,184**	288,718
Accumulated other comprehensive income	**1,819**	(739)
Retained earnings	**114,297**	123,157
	443,300	411,136
	1,391,304	1,228,013

Approved on behalf of the Board on April 8, 2015.

Director

Director

PowerStream Inc.

Statement of income and other comprehensive income year ended December 31, 2014

(In thousands of dollars)

	2014	2013
	$	$
Revenue (Note 10(a))		
Sale of energy	**927,323**	888,218
Distribution revenue	**157,584**	156,993
Other revenue	**26,053**	20,965
Total revenue	**1,110,960**	1,066,176
Cost of power purchased	**941,260**	883,876
Operating expenses (Note 19)	**90,355**	85,583
Depreciation and amortization	**42,416**	36,939
	36,929	59,778
Loss on derecognition of property, plant and equipment	**(2,078)**	(1,462)
Share in income/(loss) from joint venture (Note 5)	**463**	(987)
Interest income	**1,851**	1,452
Interest expense	**(23,474)**	(21,809)
Income before income taxes	**13,691**	36,972
Income tax (recovery) expense (Note 20)	**(183)**	8,832
Net income	**13,874**	28,140
Other comprehensive income		
Remeasurement of defined benefit obligation, net of tax of $922 (Note 13(b))	**2,558**	-
Total income and other comprehensive income for the year	**16,432**	28,140

PowerStream Inc.

Statement of changes in equity
year ended December 31, 2014

(In thousands of dollars)

	Share capital	Accumulated other comprehensive income	Retained earnings	Total
	$	$	$	$
As at January 1, 2013	280,301	(739)	109,933	389,495
Net income	-	-	28,140	28,140
Total income and other comprehensive income for the year	280,301	(739)	138,073	417,635
Dividends paid	-	-	(14,916)	(14,916)
Issuance of Class A common shares (Note 14)	8,417	-	-	8,417
Balance at December 31, 2013	**288,718**	**(739)**	**123,157**	**411,136**
Net income	-	-	13,874	13,874
Other comprehensive income, (net of tax of $922)	-	2,558	-	2,558
Total income and other comprehensive income for the year	-	2,558	13,874	16,432
Dividends paid	-	-	(22,734)	(22,734)
Issuance of common shares (Note 14)	20,001	-	-	20,001
Issuance of Class A common shares (Note 14)	18,465	-	-	18,465
Balance at December 31, 2014	**327,184**	**1,819**	**114,297**	**443,300**

PowerStream Inc.
Statement of cash flows
year ended December 31, 2014
(In thousands of dollars)

	2014	2013
	$	$
Operating activities		
Total income and other comprehensive income for the year	**16,432**	28,140
Adjustments to determine cash provided by operating activities		
Share of loss/(income) from joint venture (net of 2014 dividend of $183)	**(280)**	987
Depreciation of property, plant and equipment	**41,298**	35,999
Amortization of intangible assets	**3,323**	2,940
Post-employment benefits	**(1,955)**	1,269
Loss on disposal of property, plant and equipment	**3,759**	1,386
Amortization of deferred revenue	**(2,454)**	(1,888)
Finance costs	**21,622**	20,357
Capital tax expense	**-**	129
Income tax expense	**739**	8,832
	82,484	98,151
Net change in non-cash operating working capital (Note 21)	**(5,445)**	(4,802)
Cash generated from operating activities	**77,039**	93,349
Interest paid	**(22,661)**	(21,418)
	54,378	71,931
Financing activities		
Repayment of bank term loan	**-**	(50,000)
Dividends paid	**(22,734)**	(14,916)
Proceeds from Infrastructure Ontario financing	**19,341**	39,792
Proceeds from the issuance of common shares	**38,465**	8,417
Proceeds from issuance of debenture (net)	**149,034**	-
(Repayment)/proceeds of short-term debt	**(45,000)**	45,000
Payment of finance lease obligation	**(315)**	(295)
	138,791	27,998
Investing activities		
Contributions received from customers	**21,763**	20,471
Purchase of intangible assets	**(17,111)**	(12,951)
Purchase of property, plant and equipment	**(167,343)**	(134,780)
	(162,691)	(127,260)
Increase/(decrease) in cash during the year	**30,478**	(27,331)
(Bank indebtedness)/cash, beginning of year	**(7,368)**	19,963
Cash/(bank indebtedness), end of year (Note 11(a))	**23,110**	(7,368)

1. Description of the business

PowerStream Inc. (the "Corporation") was amalgamated on January 1, 2009, under the Business Corporations Act (Ontario) and is wholly owned by PowerStream Holdings Inc., which in turn is owned by the Corporation of the City of Vaughan (the "City of Vaughan"), through its wholly owned subsidiary, Vaughan Holdings Inc.; the Corporation of the City of Markham (the "City of Markham"), through its wholly owned subsidiary, Markham Enterprises Corporation; and the Corporation of the City of Barrie (the "City of Barrie"), through its wholly owned subsidiary, Barrie Hydro Holdings Inc. PowerStream Holdings Inc. is jointly controlled by these three municipalities. The Corporation is incorporated and domiciled in Canada with its head and registered office located at 161 Cityview Boulevard, Vaughan, ON L4H 0A9.

The principal activity of the Corporation is distribution of electricity in the service areas of Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan in the Province of Ontario, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated under the OEB and adjustments to the distribution rates require OEB approval. Collingwood PowerStream Utility Services Corp. ("Collus PowerStream") is a joint venture between the Corporation and the Town of Collingwood. It distributes electricity in Collingwood, Thornbury, Stayner and Creemore.

As a condition of its distribution license, the Corporation is required to meet specified Conservation and Demand Management ("CDM") targets for reductions in electricity consumption and peak electricity demand. As part of this initiative, the Corporation is delivering Ontario Power Authority ("OPA") funded programs in order to meet its targets.

Under the Green Energy and Green Economy Act, 2009, the Corporation and other Ontario electricity distributors have new opportunities and responsibilities for enabling renewable generation.
The Corporation has commenced operations of a Solar Generation Business unit, in 2010, as permitted by these changes.

2. Basis of preparation

(a) *Statement of compliance*

These financial statements are prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board (IASB).

(b) *Basis of measurement*

The financial statements have been prepared on a historical cost basis.

(c) *Presentation currency*

The financial statements are presented in Canadian dollars, which is also the Corporation's functional currency. All financial information has been rounded to the nearest thousand, except when otherwise noted.

(d) *Use of estimates and judgments*

The preparation of financial statements in conformity with IFRS requires management to make estimates, assumptions and judgments that affect the application of accounting policies and the amounts reported and disclosed in the financial statements. Estimates and underlying assumptions are continually reviewed and are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

2. Basis of preparation (continued)

(d) Use of estimates and judgments (continued)

Significant sources of estimation uncertainty, assumptions and judgments include the following:

(i) Unbilled revenue

The measurement of unbilled revenue is based on an estimate of the amount of electricity delivered to customers between the date of the last bill and the end of the year.

(ii) Useful lives of depreciable assets

Depreciation and amortization expense is based on estimates of the useful lives of property, plant and equipment and intangible assets. The Corporation estimates the useful lives of its property, plant and equipment and intangible assets based on management's judgment, historical experience and an asset study conducted by an independent consulting firm.

(iii) Cash Generating Units ("CGU")

Determining CGU's for impairment testing is based on Management's judgment. This requires an estimation of the value in use. The value in use calculation requires an estimate of the future cash flows expected to arise from the CGU and a suitable discount rate in order to calculate the present value.

(iv) Valuation of financial instruments

As described in Note 17, the Corporation uses the discounted cash flow model to estimate the fair value of the financial instruments for disclosure purposes.

(v) Other areas

There are a number of other areas in which the Corporation makes estimates; these include accounts receivable, inventories, post-employment benefits and income taxes. These amounts are reported based on the amounts expected to be recovered/refunded and an appropriate allowance has been provided based on the Corporation's best estimate of unrecoverable amounts.

3. Significant accounting policies

The Corporation's financial statements are the representations of management, prepared in accordance with IFRS. The accounting policies set out below have been applied consistently to all years presented in these financial statements, unless otherwise indicated.

The financial statements reflect the following significant accounting policies:

(a) Rate regulation

The Ontario Energy Board Act, 1998 gave the Ontario Energy Board ("OEB") increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may prescribe license requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, and filing process requirements for rate-setting purposes.

The Corporation recognizes revenue when electricity is delivered to customers based on OEB approved rates. Operating costs and expenses are recorded when incurred, unless such costs qualify for recognition as part of an item of property, plant and equipment or as an intangible asset.

3. Significant accounting policies (continued)

(b) Revenue recognition

(i) Electricity distribution and sale

Revenue from the sale and distribution of electricity is recorded on the basis of cyclical billings based on electricity usage and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. Revenue is generally comprised of the following:

- Electricity Price and Related Rebates. The electricity price and related rebates represent a pass through of the commodity cost of electricity.
- Distribution Rate. The distribution rate is designed to recover the costs incurred by the Corporation in delivering electricity to customers, as well as the ability to earn the OEB allowed rate of return. Distribution charges are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.
- Retail Transmission Rate. The retail transmission rate represents a pass through of costs charged to the Corporation for the transmission of electricity from generating stations to the Corporation's service area. Retail transmission rates are regulated by the OEB.
- Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market support costs charged by the Independent Electricity System Operator (IESO).

(ii) Other revenue

Other revenue includes revenue from the sale of other services, contributions from customers and performance incentive payments.

Revenue related to the sale of other services is recognized as services are rendered.

Certain items of property, plant and equipment are acquired or constructed with financial assistance in the form of contributions from developers or customers ("customer contributions"). Such contributions, whether in cash or in-kind, are recognized as deferred revenue and amortized into income over the life of the related assets. Contributions in-kind are valued at their fair value at the date of their contribution.

Performance incentive payments under Conservation and Demand Management ("CDM") programs are recognized by the Corporation when there is reasonable assurance that the program conditions have been satisfied and the incentive payment will be received.

Government grants under CDM programs are recognized when there is reasonable assurance that the grant will be received and all attached conditions will be complied with. When the grant relates to an expense item, it is recognized as income over the period necessary to match the grant on a systematic basis to the costs that it is intended to compensate.

(c) Finance and borrowing costs

Finance costs comprise interest expense on borrowings and are recognized on an accrual basis using the effective interest rate method.

Borrowing costs are calculated using the effective interest rate method and are recognized as finance costs, unless they are capitalized as part of the cost of a qualifying asset, which is an asset that takes a substantial period of time to get ready for its intended use.

3. Significant accounting policies (continued)

(d) Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and are subsequently accounted for based on their classification as loans and receivables or as other liabilities. Transaction costs for financial assets classified as loans and receivables and financial liabilities classified as other liabilities are capitalized as part of the carrying value at initial recognition.

(i) Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Subsequent to initial recognition, such financial assets are carried at amortized cost using the effective interest rate method, less any impairment losses. Losses are recognized in net income when the loans and receivables are derecognized or impaired.

Loans and receivables are assessed at each reporting date to determine whether there is objective evidence of impairment. A financial asset is impaired if objective evidence indicates that a loss event has occurred after the initial recognition of the asset and the loss event has had a negative effect on estimated future cash flows of the asset which are reliably measureable.

Loans and receivables are comprised of cash, accounts receivable, unbilled revenue and amounts due from related parties.

(ii) Other liabilities

All non-derivative financial liabilities are classified as other liabilities. Subsequent to initial recognition, other liabilities are measured at amortized cost using the effective interest method.

Financial liabilities are derecognized when either the Corporation is discharged from its obligation, the obligation expires, or the obligation is cancelled or replaced by a new financial liability with substantially modified terms.

Financial liabilities are further classified as current or non-current depending on whether they will fall due within twelve months after the balance sheet date or beyond.

Other liabilities are comprised of bank indebtedness, short-term debt, Infrastructure Ontario financing, customer deposits, accounts payable and accrued liabilities, amounts due to related parties, notes payable, debentures payable, bank term loan, Infrastructure Ontario debentures, and liability for subdivision development.

(e) Inventories

Inventories, which consist of parts and supplies acquired for internal construction or consumption, are valued at the lower of cost and net realizable value. Cost is determined on a weighted-moving average basis and includes expenditures incurred in acquiring the inventories and other costs to bring the inventories to their existing location and condition.

(f) Property, plant and equipment

Property, plant and equipment ("PP&E") is measured at cost less accumulated depreciation and accumulated impairment losses. Cost includes expenditures that are directly attributable to the acquisition of the asset and includes contracted services, cost of materials, direct labour and borrowing costs incurred in respect of qualifying assets constructed subsequent to January 1, 2011. When parts of an item of PP&E have different useful lives, they are accounted for as separate components of PP&E.

Major spare parts and standby equipment are recognized as items of PP&E.

3. Significant accounting policies (continued)

(f) Property, plant and equipment (continued)

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal with the carrying amount of the item and is included in net income.

Depreciation of PP&E is recognized on a straight-line basis over the estimated useful life of each component of PP&E. The estimated useful lives for the current and comparative years are as follows:

Land and buildings	
Land	Indefinite
Buildings	10 to 60 years
Distribution and other assets	
Transformer stations	20 to 40 years
Transformers and meters	15 to 40 years
Plant and equipment	3 to 20 years
Other	3 to 37.5 years

Depreciation methods and useful lives are reviewed at each financial year-end and any changes are adjusted prospectively.

(g) Intangible assets

Intangible assets include land rights, computer software and capital contributions. Capital contributions relate to the contributions made to Hydro One for a transformer station that was built outside the City of Barrie.

Land rights held by the Corporation are effective in perpetuity and there is no foreseeable limit to the period over which the rights are expected to provide benefit to the Corporation. Land rights have therefore been assessed as having an indefinite useful life and are not amortized. Land rights are measured at cost.

Computer software and capital contributions are measured at cost less accumulated amortization and accumulated impairment losses.

Computer software and capital contributions are amortized on a straight-line basis over the estimated useful lives from the date that they are available for use. The estimated useful lives for the current and comparative periods are as follows:

Computer software	4 years
Capital contributions	17 years

Amortization methods and useful lives are reviewed at each financial year-end and adjusted prospectively.

(h) Goodwill

Goodwill represents the excess of the purchase price over the fair value assigned to the Corporation's interest of the net identifiable assets acquired on the acquisition, by predecessor corporations, of the former Richmond Hill Hydro Inc., Penetanguishene Hydro, Essa Hydro, New Tecumseth Hydro and Bradford West Gwillimbury Hydro.

Goodwill is measured at cost and is not amortized. The Corporation's policy on goodwill arising on acquisition of an associate is described in note 3(n).

3. Significant accounting policies (continued)

(i) Impairment of non-financial assets

The carrying amounts of the Corporation's non-financial assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Goodwill and intangible assets with indefinite lives are tested annually for impairment and when circumstances indicate that the carrying value may be impaired. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount.

The Corporation has two CGU's, the rate regulated business and the Permitted Generation Business unit. Two CGU's were determined, as Management views the Corporation as having two distinct lines of business.

The recoverable amount of an asset or CGU is the greater of its value in use and fair value less costs of disposal. Value in use is calculated as the present value of the estimated future cash flows expected to be derived from an asset or CGU.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows that are largely independent of those from other assets or CGUs. Goodwill acquired in a business combination is allocated to groups of CGUs that are expected to benefit from the synergies of the combination.

Impairment losses are recognized in net income. Impairment losses relating to CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(j) Employee benefits

The Corporation provides both short-term employee benefits and post-employment benefits. The post-employment benefits are provided through a defined benefit plan.

A defined benefit plan is a post-retirement benefit plan that specifies either the benefits to be received by an employee, or the method of determining those benefits.

(i) <u>Short-term employee benefits</u>

Short-term employee benefit obligations are recognized as the related services are rendered to the Corporation. Short-term employee benefit obligations are measured on an undiscounted basis and recognized as an expense unless the amount qualifies for capitalization as part of the cost of an item of inventory, PP&E or an intangible asset.

(ii) <u>Multi-employer defined benefit pension plan</u>

The Corporation provides a pension plan to its full-time employees through the Ontario Municipal Employees Retirement System ("the OMERS plan"). The OMERS plan is a multi-employer defined benefit plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The OMERS plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund.

3. Significant accounting policies (continued)

(j) Employee benefits (continued)

(ii) <u>Multi-employer defined benefit pension plan</u> (continued)

It is not practicable to determine the present value of the Corporation's obligation or the related current service cost under the OMERS plan as OMERS computes its obligations in accordance with an actuarial valuation in which all the benefit plans are co-mingled and therefore information for individual plans cannot be determined. As a result, the Corporation accounts for the OMERS plan as a defined contribution plan where contributions to the OMERS plan are recognized as an employee benefit expense in the periods during which services are rendered by employees.

(iii) <u>Non-pension defined benefit plans</u>

The Corporation provides certain health, dental and life insurance benefits under unfunded defined benefit plans to its eligible retired employees (the "defined benefit plans").

The Corporation's net obligation in respect of the defined benefit plans is calculated by estimating the amount of future benefit that employees have earned in return for their service in the current and prior periods. The calculated benefit is discounted to determine its present value. The discount rate is the yield at the reporting date on corporate bonds that have maturity dates approximating the terms of the Corporation's obligations and that are denominated in the same currency in which the benefits are expected to be paid. The calculation of the defined benefit obligation is performed by an independent qualified actuary using the projected unit credit method.

Remeasurement of the net defined benefit liability, which is comprised of actuarial gains and losses, is recognized immediately in the balance sheet with a charge or credit to other comprehensive income in the year in which they occur.

Past service costs arising from plan amendments is recognized immediately in net income at the earlier of the date the plan amendment occurs or when any related restructuring costs or termination benefits are recognized.

(k) Customer deposits

Customer deposits are collections from customers to guarantee the payment of energy bills. Deposits that are refundable to customers on demand are classified as a current liability. Interest is paid on customer deposits.

(l) Leases

Leases in which the Corporation assumes substantially all of the risks and rewards of ownership are classified as finance leases. On initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset. Payments under finance leases are apportioned between interest expense and a reduction of the outstanding liability.

Other leases are operating leases and are not recognized in the Corporation's balance sheet. Payments made under operating leases are recognized as an expense on a straight-line basis over the term of the lease.

3. Significant accounting policies (continued)

(m) Payment in lieu of corporate income taxes ("PILs")

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). The payments in lieu of taxes are calculated on a basis as if the Corporation was a taxable company under the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario).

Income tax expense comprises current and deferred tax and is recognized in net income except to the extent that it relates to items recognized directly in other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized, using the liability method, on temporary differences arising between the carrying amount of balance sheet items and their corresponding tax basis, using the substantively enacted income tax rates for the years in which the differences are expected to reverse.

In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill.

A deferred tax asset is recognized for deductible temporary differences, to the extent that it is probable that future taxable income will be available against which they can be utilized.

(n) Investments in joint ventures

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. The Group owns 50% of Collingwood PowerStream Utility Services Corp. ("Collus PowerStream"). This investment is accounted for using the equity method and is recognized initially at cost.

Any excess cost over the acquisition of the Group's share of the net fair value of the identifiable assets and liabilities of Collus PowerStream is recognized as goodwill and included in the carrying value of the investment.

If Collus PowerStream is in a loss position, then when the Group's share of losses in Collus PowerStream equals or exceeds its interest, the Group would discontinue recognizing its share of further losses.

The financial statements include the Corporations's share of the (loss)/income and other comprehensive (loss)/income of Collus PowerStream for the year ended December 31, 2014.

4. Changes in accounting policies

Future accounting changes

There are new standards, amendments to standards and interpretations which have not been applied in preparing these financial statements. In particular, this includes IFRS 9 *Financial Instruments* which is tentatively effective from periods beginning on or after January 1, 2018 and amendments to IFRS 7 and IFRS 9 which are effective at the date of adoption of IFRS 9.

IFRS 15, Revenue from Contracts with customers is a new standard on revenue recognition, superseding IAS 18, Revenue, IAS II, Construction Contracts, and related interpretations. IFRS 15 specifies how and when an entity will recognize revenue and additional disclosure requirements. This new standard is effective on January 1, 2017. The Corporation has not yet assessed the impact of this new standard.

All of the above standards or amendments relate to the measurement and disclosure of financial assets and liabilities. The extent of the impact on adoption of these standards and amendments has not yet been determined.

5. Investment in a joint venture

The Corporation owns a 50% interest in Collus PowerStream, a joint venture of which the Corporation has joint control. The cost of the investment includes transaction costs and the share of Collus PowerStream's (loss)/income and other comprehensive (loss)/income since the acquisition. Collus PowerStream is involved in the distribution of electricity in Collingwood, Thornbury, Stayner and Creemore, as well as the provision of other utility services in the service area of Clearview and the Town of The Blue Mountains in the Province of Ontario. Collus PowerStream's principal place of business is the Town of Collingwood.

The following judgments were used in determining that the investment was a joint venture:

- Joint control was established by assessing that both the Corporation and the City of Collingwood have unanimous consent over relevant activities within Collus PowerStream. This was done through the agreements that were signed.
- This classification of the investment in Collus PowerStream as a joint venture was determined through analysis of the rights and obligations of the investment, specifically the legal structure.

Summarized financial information for Collus PowerStream follows. There were no significant restrictions from borrowing arrangements or any commitments incurred on behalf of Collus PowerStream in relation to the Corporation.

	2014	2013
	$	$
Total assets	**27,709**	26,126
Total liabilities	**20,876**	19,429
Net revenue	**7,452**	5,156
Total income/(loss) and other comprehensive income/(loss)	**925**	(1,974)
Share of income/(loss) and other comprehensive income/(loss)	**463**	(987)

6. Inventories

During fiscal 2014, an amount of ($59) (2013 - $12) was recorded as an expense for the write-down of obsolete or damaged inventory to net realizable value.

7. Property, plant and equipment

	Land and buildings	Distribution and other assets	Work-in-progress	Total (Note 23)
	$	$	$	$
Cost				
Balance at January 1, 2013	65,004	750,880	58,773	874,657
Additions	1,259	144,226	-	145,485
Disposals	-	(1,715)	(5,663)	(7,378)
Balance at December 31, 2013	66,263	893,391	53,110	1,012,764
Additions	6,202	134,477	26,146	166,825
Disposals	(19)	(4,219)	-	(4,238)
Balance at December 31, 2014	**72,446**	**1,023,649**	**79,256**	**1,175,351**
Accumulated depreciation				
Balance at January 1, 2013	2,234	63,950	-	66,184
Depreciation expense	1,148	34,851	-	35,999
Disposals	-	(203)	-	(203)
Balance at December 31, 2013	3,382	98,598	-	101,980
Depreciation expense	1,191	40,107	-	41,298
Disposals	-	(478)	-	(478)
Balance at December 31, 2014	**4,573**	**138,227**	**-**	**142,800**
Carrying amounts				
At December 31, 2013	62,881	794,793	53,110	910,784
At December 31, 2014	**67,873**	**885,422**	**79,256**	**1,032,551**

Included in PP&E costs is $16,910 (2013 - $15,415) of capitalized expenses and $654 (2013 - $683) of interest capitalized during the year. Interest costs have been capitalized at a rate of 5.81% (2013 - 5.87%) for rate-regulated business and at a rate of 1.82% for Permitted Generation Business.

The Corporation leases its operations centre under a finance lease agreement. The leased operations centre is secured as collateral against the lease obligation. At December 31, 2014, the net carrying amount of the operations centre was $14,624 (2013 - $15,355).

8. Intangible assets and goodwill

(a) Intangible assets

	Land rights	Computer software	Capital contributions	Work in progress	Total (Note 23)
	$	$	$	$	$
Cost					
Balance at January 1, 2013	797	12,071	4,972	5,973	23,813
Additions	30	3,236	-	9,713	12,979
Disposals	-	-	-	-	-
Balance at December 31, 2013	827	15,307	4,972	15,686	36,792
Additions	46	1,488	-	15,577	17,111
Disposals					-
Balance at December 31, 2014	**873**	**16,795**	**4,972**	**31,263**	**53,903**
Accumulated amortization					
Balance at January 1, 2013	-	4,674	317	-	4,991
Amortization expense	-	2,679	289	-	2,968
Disposals	-	-	-	-	-
Balance at December 31, 2013	-	7,353	606	-	7,959
Amortization expense	-	3,035	288	-	3,323
Disposals	-	-	-	-	-
Balance at December 31, 2014	**-**	**10,388**	**894**	**-**	**11,282**
Carrying amounts					
At December 31, 2013	827	7,954	4,366	15,686	28,833
At December 31, 2014	**873**	**6,407**	**4,078**	**31,263**	**42,621**

Included in intangible assets is $797 (2013 - $422) of interest capitalized during the year.

(b) Impairment testing of goodwill and indefinite life intangible assets

For the purpose of impairment testing, goodwill with a carrying amount of $42,543 (2013 - $42,543) and land rights with a carrying amount of $873 (2013 - $827) are allocated to the Corporation's rate regulated and Permitted Generation Business unit CGUs. The Corporation tested goodwill and land rights for impairment as at December 31, 2014, in accordance with its policy described in Note 3.

The total recoverable amount of $1,272,000, being $1,129,000 and $143,000 for the rate regulated and Permitted Generation Business unit CGUs respectively, was determined based on its value-in-use.

The Corporation has used discounted cash flow analysis to determine value-in-use. The value-in-use was determined in the same manner at December 31, 2014, and December 31, 2013.

8. Intangible assets and goodwill (continued)

(b) Impairment testing of goodwill and indefinite life intangible assets (continued)

The calculation of value in use for the rate regulated CGU was based on the following key assumptions:

- Cash flows were projected based on past experience and actual operating results using a 5 year forecast with growth rates of 2.50% (2013 - 2.50%) built into the forecast. Growth rates were determined using the Bank of Canada inflation forecast.
- A pre-tax discount rate of 5.66% (2013 - 5.87%) and terminal value was used to discount the cash flows; this is derived from the Weighted Average Cost of Capital calculation. A discount rate increase of 0.4% would result in the carrying amount of the regulated CGU exceeding the recoverable amount by $4 million.

The calculation of value in use for the Permitted Generation Business unit CGU was based on the following key assumptions:

- Cash flows were projected based on past experience and actual operating results using a 5 year forecast with growth rates of 2.5% (2013 - 2.50%) built into the forecast. Growth rates were determined using the Bank of Canada inflation forecast.
- A pre-tax discount rate of 5.50% (2013 - 8.93%) and terminal value was used to discount the cash flows; this is derived from the Weighted Average Cost of Capital calculation. A discount rate increase of 2.5% would result in the carrying amount of the Permitted Generation Business unit CGU exceeding the recoverable amount by $1 million.

Guidance was applied by IAS 36 Impairment of Assets Appendix A, in determining the Weighted Average Cost of Capital ("WACC") which is not asset specific.

9. Accounts payable and accrued liabilities

	2014	2013
	$	$
Accounts payable - energy purchases	**82,881**	73,982
Debt retirement charge payable - OEFC	**4,600**	4,494
Payroll payable	**6,131**	5,956
Interest payable	**3,844**	3,298
Commodity taxes payable	**(41)**	(871)
Customer receivables in credit balances	**4,279**	3,809
Other accounts payable and accrued liabilities	**32,485**	46,026
	134,179	136,694

10. Related party balances and transactions

(a) Balances and transactions with jointly controlling shareholders

The amount due to/(from) related parties is comprised of amounts payable to/(receivable from) the City of Vaughan, the City of Markham, the City of Barrie and their wholly-owned subsidiaries.

Components of the amounts due to/(from) related parties are as follows:

	2014	2013
	$	$
Due from:		
City of Vaughan	**778**	824
City of Markham	**1,083**	1,000
City of Barrie	**1,032**	709
	2,893	2,533
Due to:		
City of Vaughan	**(8,266)**	(7,241)
City of Markham	**(8,381)**	(8,252)
City of Barrie	**(282)**	(282)
	(16,929)	(15,775)

Significant related party transactions with the jointly controlling shareholders not otherwise disclosed separately in the financial statements, are summarized below:

			2014			2013
	City of Vaughan	**City of Markham**	**City of Barrie**	City of Vaughan	City of Markham	City of Barrie
	$	**$**	**$**	$	$	$
Revenue						
Energy and distribution	**6,233**	**6,189**	**7,256**	5,985	9,544	6,921
Shared services	**1,727**	**2,029**	**-**	1,676	1,939	-
Total revenue	**7,960**	**8,218**	**7,256**	7,661	11,483	6,921
Expenses						
Realty taxes	**640**	**502**	**268**	713	554	269
Facilities rental and other	**5**	**66**	**42**	19	59	53
Total	**7,315**	**7,650**	**6,946**	6,929	10,870	6,599

These transactions are in the normal course of operations and are recorded at the exchange amount. The Corporation has certain operating leases with the City of Vaughan, City of Markham and City of Barrie to lease rooftops on a number of buildings for which feed-in tariff contracts have been obtained. The current year lease expense has been included in the ‘Facilities rental and other’ line on the table above, and the future operating lease commitments have been disclosed in Note16(b).

10. Related party balances and transactions (continued)

(b) Inter-company balances

The amount due from inter-company related parties, which is comprised of a receivable from PowerStream Energy Services Inc., a subsidiary of PowerStream Holdings Inc., and a payable to PowerStream Holdings Inc., is as follows:

	2014	2013
	$	$
Due from:		
PowerStream Energy Services Inc.	**3,844**	206
Due to:		
PowerStream Holdings Inc.	**(13)**	-

(c) Key management personnel compensation

Key management personnel are comprised of the Corporation's senior management team. The compensation paid or payable to key management personnel is as follows:

	2014	2013
	$	$
Short-term employment benefits and salaries	**8,225**	7,946
Post-employment benefits	**1,006**	954
Termination benefits	**-**	21
	9,231	8,921

11. Short-term debt

(a) Credit facilities

On December 17, 2008, the Corporation executed an unsecured credit facility with a Canadian chartered bank. The credit facility is renewable annually. The credit facility agreement provides an extendible 364-day committed revolving credit facility of $75,000, an uncommitted demand facility of $25,000, and uncommitted Letter of Guarantee facilities of $20,000 and $364 respectively. As at December31, 2014, the Corporation utilized $Nil (2013 - $7,368) of the 364-day committed revolving credit facilities.

In addition to the above, the Corporation entered into a second unsecured credit facility agreement that provided for a committed line of credit of up to $150,000. This committed facility matures on February 12, 2015. As at December 31, 2014, the Corporation utilized $25,000 (2013 - $70,000) of this facility.

11 Short-term debt (continued)

(a) Credit facilities (continued)

As at December 31, 2014, the Corporation had utilized $14,999 (2013 - $14,999) of the uncommitted Letter of Guarantee facility for a letter of credit that was provided to the IESO to mitigate the risk of default on energy payments. With the opening of Ontario's electricity market to wholesale and retail competition on May 1, 2002 ("Open Access"), the IESO requires all purchasers of electricity in Ontario to provide security to mitigate the risk of their default based on their expected purchases from the IESO administered spot market. The IESO could draw on the letter of credit if the Corporation defaults on its payment. Further, as at December 31, 2014, an additional $364 (2013 - $336) of the uncommitted Letter of Guarantee facility was utilized as security for operating projects.

The 364-day committed revolving credit facility can be drawn upon by direct advances, bearing interest at the lower of prime plus 0% or Bankers' Acceptance of a stamping fee plus 95 basis points (0.95% per annum). The uncommitted demand facility bears an interest rate at the lower of prime minus 0.30% or Bankers' Acceptance of a stamping fee plus 68 basis points (0.68% per annum). The Letter of Guarantee facility bears a charge of 50 basis points (0.50%) per annum.

The second committed credit facility bears an interest rate at Bankers' Acceptance stamping fee plus 70 basis points (0.70% per annum), with commitment fee of 10.5 basis points applied to the unutilized balance.

The amount of short-term debt drawn on the available credit facilities consists of:

	2014	2013
	$	$
Committed credit facility	**25,000**	70,000

(b) Ontario Infrastructure and Lands Corporation ("Infrastructure Ontario") financing

On October 15, 2010 the Corporation secured financing with Infrastructure Ontario for its Permitted Generation Business unit. The funding is available for up to 5 years from the date that the agreement was signed.

As at December 31, 2014, the Corporation has utilized $68,015 (2013 - $48,315) of the $90,000 financing facility, of which $4,293 (2013 - $4,457) has been transferred to a long-term debenture and $359 in principal repayments have been made to date. Each advance bears interest at a floating rate per annum as determined by Infrastructure Ontario. The advance interest rate at December 31, 2014 was 1.86% (2013 - 1.79%) and interest expense for the year was $654 (2013 - $277).

A note in the amount of $980 bears interest at a rate of 4.09% per annum, payable on May 15 and November 15 each year, and matures on November 17, 2031.

A note in the amount of $964 bears interest at a rate of 3.54% per annum, payable on February 15 and August 15 each year, and matures on August 1, 2032.

A note in the amount of $2,709 bears interest at a rate of 3.85% per annum, payable on March 1 and September 1 each year, and matures on March 1, 2033.

11 Short-term debt (continued)

(b) Ontario Infrastructure and Lands Corporation ("Infrastructure Ontario") financing (continued)

The Corporation will pay Infrastructure Ontario a stand-by fee calculated at a rate of 25 basis points (0.25%) on the advanced balance of the committed amount should the Corporation fail to draw any funds pursuant to the agreement from Infrastructure Ontario during any period of 12 consecutive months commencing initially from October 15, 2010, and subsequently from the date of the draw of any such funds until the earlier of the facility termination date October 15, 2015, or the full advance of the committed amount. Infrastructure Ontario financing is secured by the assets of the Permitted Generation Business unit. The financial covenants require a debt service coverage ratio of 1:1 or higher, a debt to capital ratio of 70% or lower, and a current ratio of 1:1 or higher.

The long-term debenture portion in the amount of $4,293 (2013 - $4,457) is presented as a current liability as a waiver related to non-compliance with the current ratio of 1:1 or higher covenant was not received.

12. Long-term debt

(a) Debentures payable

	2014	2013
	$	$
3.958% unsecured Series A debentures due July 30, 2042, interest payable in arrears semi-annually on January 30 and July 30	**198,256**	198,221
3.239% unsecured Series B debentures due November 21, 2024, interest payable in arrears semi-annually on May 21 and November 21	**149,032**	-
	347,288	198,221

On November 21, 2014, PowerStream, under the existing trust indenture, issued 3.239% unsecured Series B debentures for $150,000,000, which are due November 21, 2024, with interest payable in arrears semi-annually on May 21st and November 21st. The debentures rank *pari passu* with all of the Corporation's other senior unsubordinated and unsecured obligations.

The debentures are subject to a financial covenant. This covenant requires that neither the Corporation nor any designated subsidiary may incur any funded obligation (other than non-recourse debt, capital lease obligations, intercompany indebtedness and purchase money obligations) unless the aggregate principal amount of the consolidated funded obligations does not exceed 75% of the total consolidated capitalization. As at December 31, 2014, the Corporation is in compliance with this covenant.

(b) Notes payable

	2014	2013
	$	$
Promissory note issued to the City of Vaughan	**78,236**	78,236
Deferred interest on promissory note issued to the City of Vaughan	**8,743**	8,743
Promissory note issued to the City of Markham	**67,866**	67,866
Deferred interest on promissory note issued to the City of Markham	**7,585**	7,585
Promissory note issued to the City of Barrie	**20,000**	20,000
	182,430	182,430

12. Long-term debt (continued)

(b) Notes payable (continued)

On June 1, 2004, an unsecured 20 year term promissory note was issued to the City of Vaughan in the amount of $78,236. Interest thereon commenced on June 1, 2004, at an annual rate of 5.58%.

On June 1, 2004, an unsecured 20 year term promissory note was issued to the City of Markham in the amount of $67,866. Interest thereon commenced on June 1, 2004, at an annual rate of 5.58%.

On December 31, 2008, an unsecured 16 year term promissory note was issued to the City of Barrie in the amount of $20,000. Interest thereon commenced on January 1, 2009, is at an annual rate of 5.58%.

The three promissory notes are repayable 90 days following demand by the City of Vaughan, the City of Markham, and the City of Barrie, with subordination and conditions. These notes have been classified as long-term, as the City of Vaughan, the City of Markham, or the City of Barrie, will not demand repayment before January 1, 2017.

At the request of the City of Vaughan and the City of Markham, eight quarters of interest were deferred commencing October 1, 2006, and initially payable October 31, 2013. In 2013, it was agreed that this deferred interest will be repayable in full on October 31, 2018, and is subject to 4.03% interest rate.

13. Post-employment benefits

(a) Multi-employer defined benefit pension plan

During fiscal 2014, the expense recognized in conjunction with the OMERS plan, which is equal to contributions due for the year was $5,782 (2013 - $5,466). At December 31, 2014, $853 (2013 - $812) of contributions were payable to the OMERS plan and were included in accounts payable and accrued liabilities on the balance sheet.

As at December 31, 2014, OMERS had approximately 450,000 members, of whom approximately 550 are current employees of the Corporation. The accrued benefit obligation of the OMERS plan as shown in OMERS financial statements as at December 31, 2014, is $76,924 million, with a funding deficit of $7,078 million. The funding deficit will result in future payments by the participating employers.

The Corporation shares in the actuarial risks of the other participating entities in the OMERS plan and its future contributions may therefore be increased due to actuarial losses relating to the other participating entities. In addition, the withdrawal of other participating entities from the OMERS plan may also result in an increase to the Corporation’s future contribution requirements.

13. Post-employment benefits (continued)

(b) Non-pension defined benefit pension plans

A reconciliation of the obligation for the defined benefit plans is as follows:

	2014	2013
	$	$
Defined benefit obligation, beginning of the year	**19,317**	18,048
Amounts recognized in net income:		
Current service cost	**915**	1,099
Interest expense	**909**	798
	1,824	1,897
Amounts recognized in other comprehensive income:		
Actuarial (gains)/losses arising from changes in demographic assumptions	**(1,364)**	-
Actuarial (gains)/losses arising from changes in financial assumptions	**(2,116)**	-
	(3,480)	-
Payments from the plan	**(299)**	(628)
Defined benefit obligation, end of the year	**17,362**	19,317

The obligation for the defined benefit plans is presented in the balance sheet as post-employment benefits.

The significant actuarial assumptions used to determine the present value of the obligation for the defined benefit plans are as follows:

	2014	2013
	%	%
Discount rate	**4.00**	4.50
Rate of compensation increase	**3.50**	3.50
Medical benefits costs escalation	**4.60 - 7. 00**	5.00 - 7.25
Dental benefits costs escalation	**4.60**	5.00

14. Share capital

The Corporation's authorized share capital is made up of an unlimited number of common shares, and an unlimited number of Class A non-voting common shares, all of which are without nominal or par value.

The share capital issued during the period is as follows:

	Common shares		Class A common shares		Total
	Shares issued	$	Shares issued	$	$
Balance at January 1, 2013	100,000	247,183	55,195	33,118	280,301
Issued for cash	-	-	14,028	8,417	8,417
Balance at December 31, 2013	100,000	247,183	69,223	41,535	288,718
Issued for cash	8,091	20,001	30,774	18,465	38,466
Balance at December 31, 2014	**108,091**	**267,184**	**99,997**	**60,000**	**327,184**

On November 23, 2010, a Subscription Agreement was signed between the Corporation and its Shareholders for new Class A common shares for the purposes of the Shareholders providing equity for the Corporation's Permitted Generation business unit. The articles of incorporation and shareholders agreement were amended in order to proceed with the subscription agreement. This Subscription Agreement expired on December 31, 2011 and as such, a revised Subscription Agreement was signed between the Corporation and its Shareholders on January 1, 2012 to extend the equity financing in respect of the Corporation's Permitted Generation Business unit. The maximum amount of Class A common shares that are available under the subscription agreement is 100,000.

On November 1, 2013, a Unanimous Shareholders Agreement was signed between the Corporation and its Shareholders, superseding the existing revised Subscription Agreement. This ensured a reorganization of the Corporation becoming a wholly owned subsidiary of the newly established Group, PowerStream Holdings Inc. In effect, the total 108,091 common shares and 99,997 Class A common shares of the Corporation are wholly owned by PowerStream Holdings Inc.

During 2014, an additional 30,774 (2013 - 14,028) of the Class A common shares were issued for an amount of $18,465 (2013 - $8,417).

Also, during 2014, an additional 8,091 (2013 - Nil) of the common shares were issued for an amount of $20,001 (2013 - $Nil).

Dividends

The Corporation has established a dividend policy to pay a minimum of 50% of Modified IFRS ("MIFRS", framework used for reporting to the OEB) net income to PowerStream Holdings Inc., excluding the Permitted Generation Business unit 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.

The Corporation paid a dividend of $165.75 per share (2013 - $149.16) on the common shares during the year, amounting to a total dividend of $16,575 (2013 - $14,916). The Corporation is proposing to continue to follow the practice of paying a dividend on common shares, representing 50% of the MIFRS net income. The proposed 2015 dividend would amount to $157.59 per share, resulting in a total dividend of $17,034. In addition, there is a proposed special dividend of $0.68 per share, resulting in a total special dividend of $74 for 2015. There is no tax effect as the dividends are paid out on an after tax basis.

14. Share capital (continued)

Dividends (continued)

The Corporation has also established a dividend policy for its Permitted Generation Business unit to distribute a dividend on the Class A common shares to PowerStream Holdings Inc. 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 of Directors ("Board") and may be greater or lesser than the below having regard to the financial and operating results of the Corporation as a whole;
  - For purposes of the dividend declaration that follows receipt of the unaudited IFRS financial statements for the Permitted Generation Business unit at mid-year, such amounts shall be the greater of:
    - the amounts reported in the most recent unaudited year-end IFRS financial statements for the Permitted Generation Business unit, or
    - the sum of fifty percent (50%) of the amounts reported in the most recent unaudited year-end IFRS financial statements for the Permitted Generation Business unit plus 100% of the amounts reported in the most recent unaudited mid-year IFRS financial statements for the Permitted Generation Business unit (i.e. for a six-month period).
- 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 below:
  - 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.

In 2014, The Corporation paid a dividend of $88.97 per share (2013 - $Nil) on the Class A common shares during the year, amounting to a total dividend of $6,159 (2013 - $Nil). The Corporation is proposing to continue to follow the established practice of paying a dividend on Class A common shares in 2015, based on the net free cash flow, in accordance with the dividend policy. The proposed 2015 dividend would amount to $48.08 per share, resulting in a dividend of $4,808. There is no tax effect as the dividends are paid out on an after tax basis.

15. Insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members.

15. Insurance (continued)

Insurance premiums charged to each member consist of a levy per thousands of dollars of service revenue subject to a credit or surcharge based on each member's claims experience. The maximum coverage is $24,000 for liability insurance, $464,309 for property insurance, $15,000 for vehicle insurance, and $4,500 for credit insurance; plus $10,000 excess coverage on top of the regular liability and vehicle coverage.

16. Leases

(a) Finance leases

The Corporation leases its operations centre under a 25 year lease agreement. The lease agreement includes both land and building elements. Upon entering into this lease arrangement, the Corporation classified the building element of the lease as a finance lease since it was determined that substantially all of the benefits and risks incidental to ownership of the operation centre were transferred to the Corporation (the lessee). The component of the annual basic rent related to the land is classified and recorded as an operating lease and the component related to the building is classified as a finance lease.

			2014
	Future minimum lease payments (including interest)	**Interest**	**Present value of minimum lease payments**
	$	**$**	**$**
Less than one year	**1,430**	**1,093**	**337**
Between one and five years	**7,257**	**5,088**	**2,168**
More than five years	**22,029**	**7,743**	**14,287**
	30,716	**13,924**	**16,792**

			2013
	Future minimum lease payments (including interest)	Interest	Present value of minimum lease payments
	$	$	$
Less than one year	1,430	1,115	315
Between one and five years	7,150	5,222	1,928
More than five years	23,566	8,702	14,864
	32,146	15,039	17,107

Interest on the lease obligation during fiscal 2014 amounted to $1,115 (2013 - $1,135) based on the rate of 6.57% per annum (2013 - 6.57%). Amortization of the corresponding PP&E during fiscal 2014 amounted to $731 (2013 - $731) based on the straight-line method with a useful life equal to the term of the lease (25 years). The Corporation has the option to purchase within twelve months before the expiry of the original lease in 2034, or an option of three five year lease extensions.

16. Leases (continued)

(b) Operating leases

The Corporation is also committed to lease agreements for various vehicles, equipment, rooftops and the land portion of the finance lease for solar projects that have been classified as operating leases. The leases typically run for a period of 5 to 20 years.

The future minimum, non-cancellable annual lease payments (including the land portion of the operating centre lease referred to in (a) above) are as follows:

	2014	2013
	$	$
Less than one year	**3,141**	3,097
Between one and five years	**15,548**	15,351
More than five years	**34,363**	37,473
	53,052	55,921

During the year ended December 31, 2014, an expense of $3,126 (2013 - $3,105) was recognized in net income in respect of operating leases.

17. Financial instruments and risk management

(a) Fair value of financial instruments

The Corporation's accounting policies relating to the recognition and measurement of financial instruments are disclosed in Note 3(d).

The carrying amount of cash, accounts receivable, unbilled revenue, amounts due from related parties, bank indebtedness, liability for subdivision development, short-term debt, short- term Infrastructure Ontario financing, customer deposits, accounts payable and accrued liabilities and amounts due to related parties approximates fair value because of the short maturity of these instruments. The carrying value and fair value of the Corporation's other financial instruments are as follows:

		2014		2013
Description	**Carrying value**	**Fair value**	Carrying value	Fair value
	$	**$**	$	$
Liabilities				
Notes payable	**182,430**	**219,338**	182,430	206,990
Debentures payable	**347,288**	**353,756**	198,221	176,865
	529,718	**573,094**	380,651	383,855

The carrying amounts shown in the table are included in the balance sheet under the indicated captions. In addition, the fair value of the $4,293 (2013 - $4,457) Infrastructure Ontario debentures which have been reclassified as a current liability (see Note 11) is $4,324 (2013 - $3,997) as at December 31, 2014.

17. Financial instruments and risk management (continued)

(a) Fair value of financial instruments (continued)

Financial instruments which are disclosed at fair value are to be classified using a three - level hierarchy. Each level reflects the inputs used to measure the fair values disclosed of the financial liabilities, and are as follows:

- Level 1: inputs are unadjusted quoted prices of identical instruments in active markets,
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly, and
- Level 3: inputs for the liabilities that are not based on observable market data (unobservable inputs).

The Corporation's fair value hierarchy is classified as Level 2 for notes and debentures payable. The classification for disclosure purposes has been determined in accordance with generally accepted pricing models, based on discounted cash flow analysis, with the most significant inputs being the contractual terms of the instrument discounted, and the market discount rates that reflects the credit risk of counterparties.

(b) Risk factors

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk and liquidity risk as well as related mitigation strategies have been discussed below. However, the risks described below are not exhaustive of all the risks nor will the mitigation strategies eliminate the Corporation's exposure to all risks listed.

(c) Credit risk

The Corporation's primary source of credit risk to its accounts receivable result from customers failing to discharge their dues for electricity consumed and billed.

The Corporation has approximately 370,000 (2013 - 365,000) residential and commercial customers. In order to mitigate such potential credit risks, the Corporation has taken various measures in respect of its Energy customers such as collecting security deposits amounting to $15,964 (2013 - $14,830) in accordance with OEB guidelines, reviewing Dun & Bradstreet ("D&B") reports for the top 3000 commercial customers with an outstanding balance of $5 or more, in-house collection department as well as external collection agencies and a bad debt insurance policy for $4,500 (2013 - $4,500) related to energy receivables. Thus, the Corporation monitors and limits its exposure to such credit risks on an ongoing basis.

Pursuant to their respective terms, accounts receivable are aged as follows at December 31:

	2014		2013	
	Total		Total	
	$	**%**	$	%
Less than 30 days	**78,146**	**80**	78,987	86
30 - 60 days	**12,803**	**13**	8,129	9
61 - 90 days	**3,469**	**4**	1,955	2
Greater than 91 days	**3,186**	**3**	2,902	3
Total outstanding	**97,604**	**100**	91,973	100
Less: allowance for doubtful accounts	**(1,641)**	**(2)**	(1,344)	(1)
	95,963	**98**	90,629	99

As at December 31, 2014, there was no significant concentration of credit risk with respect to any financial assets.

17. Financial instruments and risk management (continued)

(d) Interest rate risk

The Corporation manages its exposure to interest rate risk by issuing long term fixed rate debt in the form of debentures, promissory notes and bank loans. It also ensures that all payment obligations are met by adopting proper capital planning.

As part of the Corporations' revolving demand operating credit facility, the Corporation may utilize the line of credit for working capital and/or capital expenditure purposes. Such short-term borrowing may expose the Corporation to short-term interest rate fluctuations as follows:

	2014	2013
364 day revolving facility		
Prime based loans	**PR*+0.0% p.a.**	PR*+0.0% p.a.
Bankers Acceptances	**SF*+0.95% p.a.**	SF*+0.95% p.a.
Demand facility		
Prime based loans	**PR*–0.30% p.a.**	PR*–0.30% p.a.
Bankers acceptances	**SF*+0.68% p.a.**	SF*+0.68% p.a.
Bankers acceptances (Secondary)	**SF*+0.70% p.a.**	SF*+0.70% p.a.
Letter of guarantee facility	**0.50% p.a.**	0.50% p.a.
Infrastructure Ontario financing	**Floating rate p.a.**	Floating rate p.a.

Note: PR - Prime Rate, SF* - Stamping Fee*

A sensitivity analysis was conducted to examine the impact of a change in the prime rate or stamping fee on the short-term debt. A variation of 1% (100 basis points), with all other variables held constant, would increase or decrease the annual interest expense by approximately $1,500.

Cash balances that are not required for day to day obligations earn an interest of Prime minus 1.7% per annum. Fluctuations in this interest rate could impact the level of interest income earned by the Corporation.

(e) Liquidity risk

Liquidity risks are those risks associated with the Corporation's inability to meet obligations associated with financial liabilities such as repayment of principal or interest payments on debts.

The Corporation monitors its liquidity risks on a regular basis to ensure there is sufficient cash flow to meet the obligations as they fall due as well as minimize the interest expense. Cash flow forecasts are prepared to monitor liquidity risks. Liquidity risks associated with financial liabilities are as follows:

			2014			2013
Maturity period	**Principal***	**Interest**	**Total**	Principal*	Interest	Total
	$	**$**	**$**	$	$	$
Less than 1 year	**254,072**	**24,533**	**278,605**	296,126	20,789	316,915
1-5 years	**17,283**	**112,299**	**129,582**	920	86,320	87,240
6-10 years	**316,291**	**90,242**	**406,533**	1,113	80,721	81,834
Over 10 years	**200,315**	**130,442**	**330,757**	366,600	138,328	504,928
	787,961	**357,516**	**1,145,477**	664,759	326,158	990,917

* The principal includes $2,712 (2013 - $1,778) of unamortized deferred issuing cost.

17. Financial instruments and risk management (continued)

(f) Hedging/derivative risk

The Corporation has a swap and derivative transaction policy to enable the Corporation to enter into agreements such as interest rate swaps where 100% of the floating rate risk is hedged into a fixed rate. This is done for prudent risk management purposes and not speculative purposes.

The Corporation has not entered into any such transactions during the current year or prior years.

18. Capital structure

The Corporation's main objectives in the management of capital are to:

(i) Ensure that there is access to various funding options at the lowest possible rates for the various capital initiatives and working capital requirements necessary for the rate-regulated business;

(ii) Ensure compliance with various covenants related to its short-term debt, Infrastructure Ontario financing, bank term loan, debentures payable and Infrastructure Ontario debentures;

(iii) Consistently maintain a high credit rating for the Corporation;

(iv) Maintain a split of approximately 60% debt, 40% equity as recommended by the OEB;

(v) Ensure interest rate fluctuations are mitigated primarily by long term borrowings as well as capital planning; and

(vi) Deliver appropriate financial returns to shareholders.

The Corporation considers shareholders' equity, long-term debt and certain short-term debt as its capital. The capital structure as at December 31, 2014 is as follows:

	2014	2013
	$	$
Short-term debt		
Short-term debt (Note 11)	**25,000**	70,000
Infrastructure Ontario financing (Note 11)	**67,656**	48,315
Long-term debt		
Debentures payable (Note 12)	**347,288**	198,221
Notes payable (Note 12)	**182,430**	182,430
Total debt	**622,374**	498,966
Shareholders' equity		
Share capital (Note 14)	**327,184**	288,718
Accumulated other comprehensive income	**1,819**	(739)
Retained earnings	**114,297**	123,157
Total equity	**443,300**	411,136
Total	**1,065,674**	910,102

As at December 31, 2014, the Corporation was in compliance with covenants related to its short-term debt, Infrastructure Ontario financing, bank term loan and debentures payable. Details relating to covenants are disclosed in Note 11 and Note 12.

The Corporation is within the debt and equity requirements of the OEB. The Corporation's dividend policy is disclosed in Note 14.

19. Operating expenses

Operating expenses comprise:

	2014	2013
	$	$
Labour	**49,747**	44,121
Contract/consulting	**15,710**	13,931
Materials	**1,651**	1,183
Vehicle	**1,579**	1,264
Other	**21,667**	25,084
	90,355	85,583

20. Income taxes

(a) *Income tax expense*

PILs recognized in net income comprise the following:

	2014	2013
	$	$
Current tax (recovery)	**(7,559)**	(995)
Deferred tax expense	**7,376**	9,827
Income tax (recovery) expense	**(183)**	8,832

(b) *Reconciliation of effective tax rate*

The PILs income tax expense differs from the amount that would have been recorded using the combined Canadian federal and provincial statutory income tax rates. The reconciliation between the statutory and effective tax rates is as follows:

	2014	2013
	$	$
Income before taxes	**13,691**	36,972
Statutory Canadian federal and provincial income tax rates	**26.50%**	26.50%
Expected tax provision on income at statutory rates	**3,628**	9,798
Increase (decrease) in income taxes resulting from:		
Permanent differences	**(5)**	60
Adjustments in respect of prior years	**(1,929)**	-
Scientific Research & Experimental Development tax credit	**(1,374)**	(1,202)
Other	**(503)**	176
Total income tax expense	**(183)**	8,832

Statutory Canadian federal and provincial income tax rates for the current year comprise 15% (2013: 15%) for federal corporate tax and a rate of 11.5% (2013: 11.5%) for corporate tax in Ontario. There was no change in the federal and provincial corporate tax rates in 2014 (no change in 2013).

20. Income taxes (continued)

(c) Deferred tax balances

Deferred tax assets/(liabilities) are attributable to the following:

	2014	2013*
	$	$
Employee future benefits	**4,601**	5,119
Property, plant and equipment	**3,154**	18,611
Intangible assets	**1,203**	1,367
Non-capital loss	**1,314**	-
Tax credit carryovers	**2,482**	1,486
Other deductible temporary differences	**1,485**	(4,046)
	14,239	22,537

* Prior year comparatives have been changed to conform to current year presentation

Movement in deferred tax balances during the year were as follows:

	2014	2013
	$	$
Balance at January 1	**22,537**	32,364
Recognized in net income	**(7,376)**	(9,827)
Recognized in OCI related to employee future benefits	**(922)**	-
Balance at December 31	**14,239**	22,537

* Prior year comparatives have been changed to conform to current year presentation

21. Net change in non-cash operating working capital

	2014	2013
	$	$
Accounts receivable	**(5,334)**	(8,206)
Unbilled revenue	**3,258**	(19,453)
Due from related parties	**(3,998)**	275
Inventories	**(129)**	(10)
Prepaids and other assets	**(233)**	(61)
Customer deposits	**1,079**	293
Accounts payable and accrued liabilities	**(1,442)**	24,228
Due to related parties	**1,167**	1,825
Liability for subdivision development	**(332)**	1,349
Capital accruals in prior year	**10,122**	5,080
Capital accruals in current year	**(9,603)**	(10,122)
	(5,445)	(4,802)

22. Contingencies, commitments and guarantees

(a) Contingencies- legal claims

The Corporation has been named as a defendant in several actions. No provision has been recorded in the financial statements for these potential liabilities as the Corporation expects that these claims are adequately covered by its insurance.

(b) Commitments

As at December 31, 2014, the Corporation has entered into agreements for capital projects and is committed to making payments of $38,520 in 2015.

(c) Guarantees

In the normal course of business, the Corporation enters into agreements that meet the definition of a guarantee as follows:

(i) The Corporation has provided indemnities under lease agreements for the use of various operating facilities. Under the terms of these agreements the Corporation agrees to indemnify the counterparties for various items including, but not limited to, all liabilities, loss, suits, and damages arising during, on or after the term of the agreement. The maximum amount of any potential future payment cannot be reasonably estimated.

(ii) Indemnity has been provided to all directors and/or officers of the Corporation for various items including, but not limited to, all costs to settle suits or actions due to association with the Corporation, subject to certain restrictions. The Corporation has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The term of the indemnification is not explicitly defined, but is limited to the period over which the indemnified party served as a trustee, director or officer of the Corporation. The maximum amount of any potential future payment cannot be reasonably estimated.

(iii) In the normal course of business, the Corporation has entered into agreements that include indemnities in favor of third parties, such as purchase and sale agreements, confidentiality agreements, engagement letters with advisors and consultants, outsourcing agreements, leasing contracts, information technology agreements and service agreements. These indemnification agreements may require the Corporation to compensate counterparties for losses incurred by the counterparties as a result of breaches in representation and regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The terms of these indemnities are not explicitly defined and the maximum amount of any potential reimbursement cannot be reasonably estimated.

The nature of these indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability which stems from the unpredictability of future events and the unlimited coverage offered to counterparties. Historically, the Corporation has not made any significant payments under such or similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements.

23. Comparative figures

The prior year's comparative figures for property, plant and equipment and intangibles have been reclassified by an amount of $15,686 related to work-in-progress for computer software which should have been reflected as an intangible in the prior year. In addition an amount of $1,462 which was previously netted in other revenue has been shown separately on the statement of income and other comprehensive income.