Exhibit K1.5
June 30, 2015

EB-2014-0101

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Oshawa PUC Networks Inc. for an order approving or just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015 to December 31, 2019.

VULNERABLE ENERGY CONSUMERS COALITION ("VECC") CROSS-EXAMINATION COMPENDIUM

Number (1)

June 30, 2015

TAB 1

OSHAWA PUC NETWORKS INC.

Response to School Energy Coalition (SEC)
Interrogatory 1.0-SEC-2

Please provide a table showing, for each, between 2015-2019:

a) The proposed distribution revenue to be collected under the plan.

b) The distribution revenue the Applicant would expect to receive under 4th Generation IRM using 2015 proposed rates as the base.

Response:

Please refer to the following table:

Distribution Revenue (Base Revenue Requirement)

Year	EB-2014-0101	IRM @ 1.45%
2015	21,565,264	21,565,264
2016	23,547,653	21,877,960
2017	24,391,239	22,195,190
2018	25,605,243	22,517,021
2019	26,193,843	22,843,517

OSHAWA PUC NETWORKS INC.

Undertaking TC2.4

To update the table in 1-SEC-2 to include forecast inflation and load growth.

Response:

Year	EB-2014-01	Price Escalator	Revenue From Price Escalator
2015	21,565,264	1.45%	21,565,264
2016	23,547,653	1.63%	21,916,627
2017	24,391,239	1.44%	22,232,936
2018	25,605,243	2.05%	22,688,178
2019	26,193,843	2.16%	23,177,771

Year	Inflation Rate per PEG	OEB IRM Price Escalator	OPUCN Stretch Factor	Price Escalator
2014	1.93%	1.70%	0.15%	1.55%
2015	1.74%	1.60%	0.15%	1.45%
2016	2.20%	1.93%	0.30%	1.63%
2017	2.31%	1.74%	0.30%	1.44%
2018	2.33%	2.20%	0.15%	2.05%
2019	2.27%	2.31%	0.15%	2.16%

In the first table, OPUCN assumes it rebases rates for 2015. The first column presents the base revenue requirement proposed in OPUCN's Custom IR rate application. For comparison, OPUCN was asked to provide estimated base revenue requirements for each of the Test Years using a price escalator estimated based upon the OEB's current practice for 4th Generation IRM rate applications.

In determining a price escalator, PEG provided an inflation rate based upon the OEB's methodology from data inputs used in their Benchmarking Report prepared for OPUCN (refer to Column – Inflation Rate per PEG). In the next column OPUCN is applying inflation factors from PEG's results assuming a two year lag consistent with the OEB's current practice. From the estimated OEB IRM Price escalator, OPUCN is deducting the expected stretch factor based upon the OEB's current stretch factor rates and PEG's estimate of OPUCN's performance from their Benchmarking Report to compute an estimated Price Escalator for the first table.

OSHAWA PUC NETWORKS INC.

Undertaking TC2.4

To update the table in 1-SEC-2 to include forecast inflation and load growth.

Response:

Year	EB-2014-01 Updated for TC	Price Escalator	Revenue From Price Escalator
2015	21,647	1.45%	21,647
2016	23,408	1.63%	22,113
2017	24,384	1.44%	22,854
2018	26,217	2.05%	23,779
2019	27,431	2.16%	24,680

Year	Inflation Rate per PEG	OEB IRM Price Escalator	OPUCN Stretch Factor	Price Escalator
2014	1.93%	1.70%	0.15%	1.55%
2015	1.74%	1.60%	0.15%	1.45%
2016	2.20%	1.93%	0.30%	1.63%
2017	2.31%	1.74%	0.30%	1.44%
2018	2.33%	2.20%	0.15%	2.05%
2019	2.27%	2.31%	0.15%	2.16%

In the first table, OPUCN assumes it rebases rates for 2015. The first column presents the base revenue requirement proposed in OPUCN's Custom IR rate application. For comparison, OPUCN was asked to provide estimated base revenue requirements for each of the Test Years using a price escalator estimated based upon the OEB's current practice for 4th Generation IRM rate applications.

In determining a price escalator, PEG provided an inflation rate based upon the OEB's methodology from data inputs used in their Benchmarking Report prepared for OPUCN (refer to Column – Inflation Rate per PEG). In the next column OPUCN is applying inflation factors from PEG's results assuming a two year lag consistent with the OEB's current practice. From the estimated OEB IRM Price escalator, OPUCN is deducting the expected stretch factor based upon the OEB's current stretch factor rates and PEG's estimate of OPUCN's performance from their Benchmarking Report to compute an estimated Price Escalator for the first table.

TAB 2

(collectively the Future Test Years), determined in accordance with OPUCN's forecast cost of service for each of these Future Test Years, but subject to future adjustment as described below;

d. a new Rate Smoothing Deferral Account effective January 1, 2015 to effect the smoothing of OPUCN's distribution rate changes during the rate plan period from 2015 through 2019, as proposed and evidenced in Exhibit 8;

e. an annual rate adjustment process to set final rates for each Future Test Year by adjusting the rates for each such year as approved in this application to reflect the revenue requirement impacts in the subject test year of:

   (i) updated actual and forecast costs for required contributions to Hydro One Networks Inc. for transmission upgrades to serve OPUCN's distribution area, and updated actual and forecast distribution system capital expenditures required as a result of regional planning activities;

   (ii) updated actual and forecast costs for required relocation of OPUCN distribution plant in response to 3rd party requests;

   (iii) updated customer connection and volume forecasts for the test year, and updated actual and forecast net new customer connection costs (including expansion and metering costs);

   (iv) updated cost of capital applying Board approved cost of capital parameters for capital structure, return on equity and cost of debt;

   (v) updated forecast working capital requirements based on updated cost of power forecasts for the test year; and

   (vi) material cost increases or decreases linked to unexpected, non-routine events not reasonably within the control of utility management or preventable by the exercise of due diligence, including changes in accounting or regulatory policy or changes in law having a material impact on OPUCN's cost or revenue structure (i.e. a "z-factor");

f. the following new variance accounts related to OPUCN's proposed annual rate adjustment process;

(i) a Net New Connection Cost Variance Account to capture the revenue requirement impact of the difference between forecast and actual net new customer connection costs (including expansion and metering costs);

(ii) a Distribution Plant Relocation Cost Variance Account to capture the revenue requirement impact of the difference between forecast and actual costs of OPUCN distribution plant relocations required by 3rd parties; and

(iii) an Unbudgeted Regional Planning Investment Cost Variance Account to capture the revenue requirement impact of the difference between forecast and actual costs incurred by OPUCN for contribution to Hydro One or for other unbudgeted distribution projects required as a result of regional planning;

g. an Off Ramp that will be triggered following any year from 2015 through 2018 during which OPUCN's ROE determined on the basis of weather-normalized earnings varies by 300 basis points or more above or below the ROE calculated annually in accordance with the Board's ROE formula; and

h. the following efficiency incentive mechanisms:

(i) A Controllable Capital Investment Efficiency Incentive Mechanism (CCIEIM) as proposed in this Application to incent OPUCN to control the costs of its controllable capital investment programs (its System Renewal Capital Investment Program and its investment in a new municipal substation and associated feeders) by allowing revenue requirement impacts of variances between forecast and actual capital investment for these programs to be to be shared between OPUCN and its ratepayers as proposed in the evidence filed herein; and

(ii) A Total Cost Efficiency Carryover Mechanism (TCECM) to continue to incent general efficiency initiatives late in the Custom IR rate plan period by allowing OPUCN to capture a portion of resulting sustainable cost savings for a short period of time (proposed as 2 years) following the end of the rate plan period as proposed in the evidence filed herein;

i. a new deferral account (a CCIEIM Deferral Account) to record the that portion of the variances in capital costs related to the proposed CCIEIM

efficiency incentive mechanism, for disposal at the end of the Custom IR Plan period as proposed in the evidence filed herein;

j. a new Change in Depreciation Rate Deferral Account to adjust accumulated depreciation for a change in depreciation rates resulting from an independent study obtained by OPUCN and filed in evidence with Exhibit 2 (Rate Base);

k. continuation of the following deferral accounts: Tax Rate Changes Deferral Account and Pension Cost Differential Deferral Account;

l. in all other respects the proposals described in the evidence filed in support of this Application and such modifications to those proposals as may be brought forward by OPUCN and deemed appropriate by the Board;

m. such final, interim or other orders and directions pursuant to the provisions of the *Ontario Energy Board Act, 1998* and the Board's *Rules of Practice and Procedure* as may be appropriate in relation to the Application and the proper conduct of this proceeding.

3. OPUCN is not seeking disposition of its 2013 deferral accounts, as their balances at December 31, 2013 were not material.

4. In the event that OPUCN's application is approved by the Board, the average distribution rate increase for residential customers consuming 800 kWh per year for 2015 will be approximately 5.6%, or about $1.30 per month (after smoothing).

5. The average annual distribution rate increases thereafter for the balance of the Custom IR rate plan period through 2019 will depend on the final rates set for each of the Future Test Years. Based on current forecasts, annual average rate increases for residential customers (after smoothing) are expected to be approximately as follows:

OSHAWA PUC NETWORKS INC.

Undertaking TC1.2

To advise OPUCN's percentage of revenue requirement at risk.

Response:

Estimated Percent of Revenue at Risk

	2015	2016	2017	2018	2019
OM&A	12,205	12,689	12,984	13,197	13,269
Estimated amortization	3,696	4,585	4,724	4,790	4,803
PILs	261	385	487	574	585
Estimated interest and income	5,465	5,575	5,761	6,256	6,742
Revenue offsets	- 1,334	- 1,504	- 1,628	- 1,448	- 1,513
Total revenue requirement at risk	20,293	21,730	22,328	23,368	23,887
Revenue requirement	21,649	23,427	24,581	26,343	27,368
Percent of revenue requirement at risk	94%	93%	91%	89%	87%
Rate base					
Opening fixed assets	82,729	86,209	88,066	88,989	102,990
Controllable additions	7,176	6,442	5,647	18,790	5,911
Amortization	- 3,696	- 4,585	- 4,724	- 4,790	- 4,803
Ending fixed assets	86,209	88,066	88,989	102,990	104,097
Average fixed assets	84,469	87,138	88,528	95,989	103,543
Working capital	133,021	135,203	137,142	139,070	140,060
Cost of power	- 120,817	- 122,515	- 124,158	- 125,874	- 126,791
Expenses	12,204	12,688	12,984	13,196	13,269
Working capital allowance	1,587	1,649	1,688	1,716	1,725
Rate base	86,056	88,787	90,216	97,705	105,268
Blended interest and ROE	6.35%	6.28%	6.39%	6.40%	6.40%
Interest and net income	5,465	5,575	5,761	6,256	6,742

The foregoing table reflects analysis of revenue requirement at risk which includes (see top portion of table): i) OM&A; ii) amortization on 2015 opening fixed assets and plan term controllable capital additions (derived in the second portion of the table and found at the second line of the table); and iii) working capital components net of cost of power (derived in the third portion of the table). Based upon this analysis, the estimated

revenue requirement at risk by OPUCN ranges between 94% and 87% for 2015 and 2019 respectively.

Upon removing the revenue produced by higher than normal customer growth the estimated revenue requirement at risk by OPUCN ranges between 92% and 78% for 2015 and 2019 respectively. The cumulative impact on revenue from higher than normal customer growth is approximately $6.6 million.

TAB 3

Filed: 2015-01-29
EB-2014-0101
Exhibit 2
Tab B
Schedule 4, Page 1 of 31

OSHAWA Power & Utilities Corporation

Oshawa Power & Utilities

Smart Grid Roadmap and Financial Analysis

April 17, 2014

UtiliWorks™

Building Smart Utility Solutions

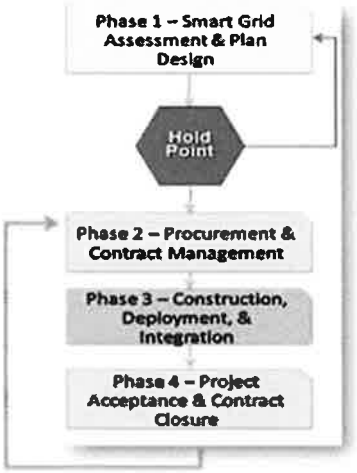
put forth by the Ontario Long Term Energy Plan. Of these 23 programs, we identified 13 that were deemed to be suitable for Oshawa's system and are recommended for further development. Of the 13 recommended programs, six (remote connect/disconnect, enhanced IVR, outage management, automated switching, demand management, and load control) have been initiated by Oshawa PUC and our recommendation is to continue to advance these programs. Seven others (prepaid metering, AMI process redesign, AMI extension, billing system redesign, SCADA upgrade, voltage monitoring, and transmission management) are not currently being pursued and UtiliWorks recommends initiating activities in these program areas. The net capital cost to enhance the existing programs and pursue the new programs is estimated at $12.22 million over a ten-year period.

The results of the recommended program offer the potential to generate significant benefits to Oshawa and the customers it serves. Some of the key findings of our analysis include:

- Reduction in system peak by between 2-4% by 2024
- Potential reduction in overall system usage by 0.2%
- Elimination of approximately one million minutes of customer outage annually
- Estimated reduction in CO_2 emissions by over 200 metric tons over a ten-year period
- Potential to reduce emissions of other greenhouse gases
- Potential job creation benefits

If Oshawa elects to proceed with this project, UWC recommends that, where possible, the goals are quantified and baselined so that Oshawa PUC can measure progress and verify that these goals are, in fact, achieved. UWC will assist with the identification and development of relevant Key Performance Indicators (KPIs) that are specific to Oshawa and to each specific project if Oshawa elects to proceed.

The figure below illustrates our standard phase progression methodology. We recommend deploying one project at a time with a narrower scope in the beginning rather than all projects at once. With this approach it is possible to get the project fundamentals working and assimilated into the utility organization before moving to the next Smart Metering project. The phase progression is repeated until all projects are installed within the Oshawa system.



TAB 4

OSHAWA PUC NETWORKS INC.

Undertaking TC1.1

1. To provide the incentive targets used by the company internally;
2. To provide the 2014 and 2015 corporate scorecard for OPUCN;
3. To add any thoughts on other potential metrics or targets.

Response:

The following table illustrates OPUCN's internal corporate targets for 2015 and 2014:

Measurement	2015 Targets	2014 Targets
Safety		
Metric	No lost time injuries	No lost time injuries
Standard	Achieve progression with IHSA ZeroQuest Program	Achieve progression with IHSA ZeroQuest Program
Reliability		
SAIDI	89.18 minutes	89.18 minutes
SAIFI	1.456	1.456
Customer Service		
Calls answered within 30 seconds	70%	70%
Paperless billing	12,000	11,000
HR		
Average sick days per employee	4.25 days or less	3.80 days or less
Financial		
Expense control	Achieve budget	Achieve budget

In addition to the internal targets, OPUCN monitors its compliance with the Board's service quality indicators and RRR reporting requirements.

OPUCN anticipates further discussion with the parties of what metrics may be appropriate for evaluation of OPUCN's performance during the proposed Custom IR plan term, and would prefer to develop a proposal for consideration by the Board through those discussions.

OSHAWA PUC NETWORKS INC.

Undertaking TC1.6

To provide the updated models as in 2-Energy Probe-14, the tables and figures shown on pages 146, 147 and 149.

Response:

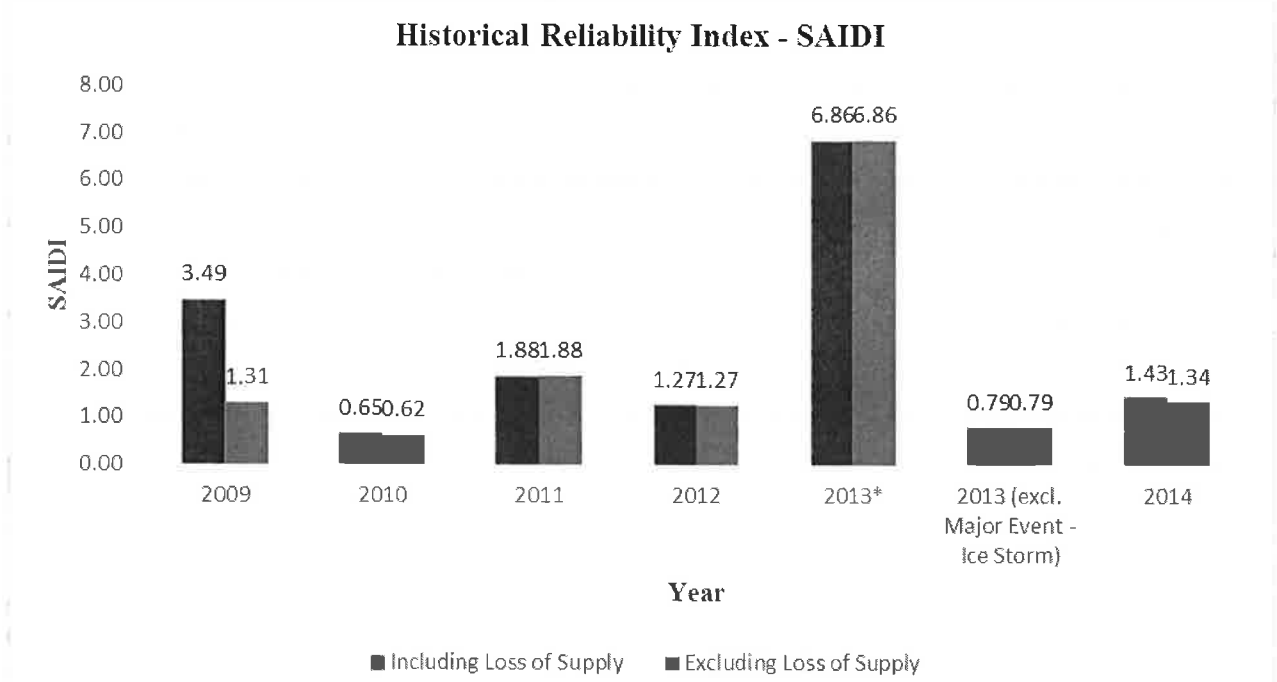
Table 2-52 – Appendix 2-G Reported Electricity Service Quality Requirements (ESQR)

Metric	OEB Minimum Standard	2009	2010	2011	2012	2013	2014
Connection of New Services (LV)	90% within 5 days	100.00%	92.30%	91.00%	96.52%	97.60%	95.60%
Connection of New Services (HV)	90% within 10 days	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Appointments Scheduling	90% on a yearly basis	100.00%	99.90%	100.00%	100.00%	100.00%	100.00%
Appointments Met	90% on a yearly basis	100.00%	99.10%	99.90%	99.90%	98.90%	100.00%
Missed Appointments Rescheduled	100% on a yearly basis	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Telephone Accessibility	65% within 30 seconds	56.10%	59.20%	71.30%	71.30%	71.50%	72.00%
Telephone Call Abandon Rate	10% or less after 30 seconds	5.50%	4.30%	2.10%	2.20%	1.60%	1.90%
Written Responses to Inquiries	80% within 10 days	100.00%	100.00%	99.40%	99.40%	100.00%	100.00%
Emergency Response (Urban)	80% within 60 minutes	100.00%	100.00%	100.00%	100.00%	85.71%	100.00%
Emergency Response (Rural)	80% within 120 minutes	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Table 2-53 – Appendix 2-G Reported Service Reliability Indicators (SAIDI & SAIFI)

	Includes Outages Caused by Loss of Supply							Excludes Outages Caused by Loss of Supply						
	2009	2010	2011	2012	2013	2013*	2014	2009	2010	2011	2012	2013	2013*	2014
SAIDI	3.49	0.65	1.88	1.27	0.79	6.86	1.43	1.31	0.62	1.88	1.27	0.79	6.86	1.34
SAIFI	1.67	0.80	1.66	1.08	0.76	2.39	1.98	1.17	0.61	1.66	1.08	0.76	2.39	1.19

* Includes December 2013 Ice Storm.


Historical Reliability Index - SAIDI
SAIDI
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
3.49
1.31
0.65
0.62
1.88
1.88
1.27
1.27
6.86
6.86
0.79
0.79
1.43
1.34
2009
2010
2011
2012
2013*
2013 (excl. Major Event - Ice Storm)
2014
Year
Including Loss of Supply
Excluding Loss of Supply

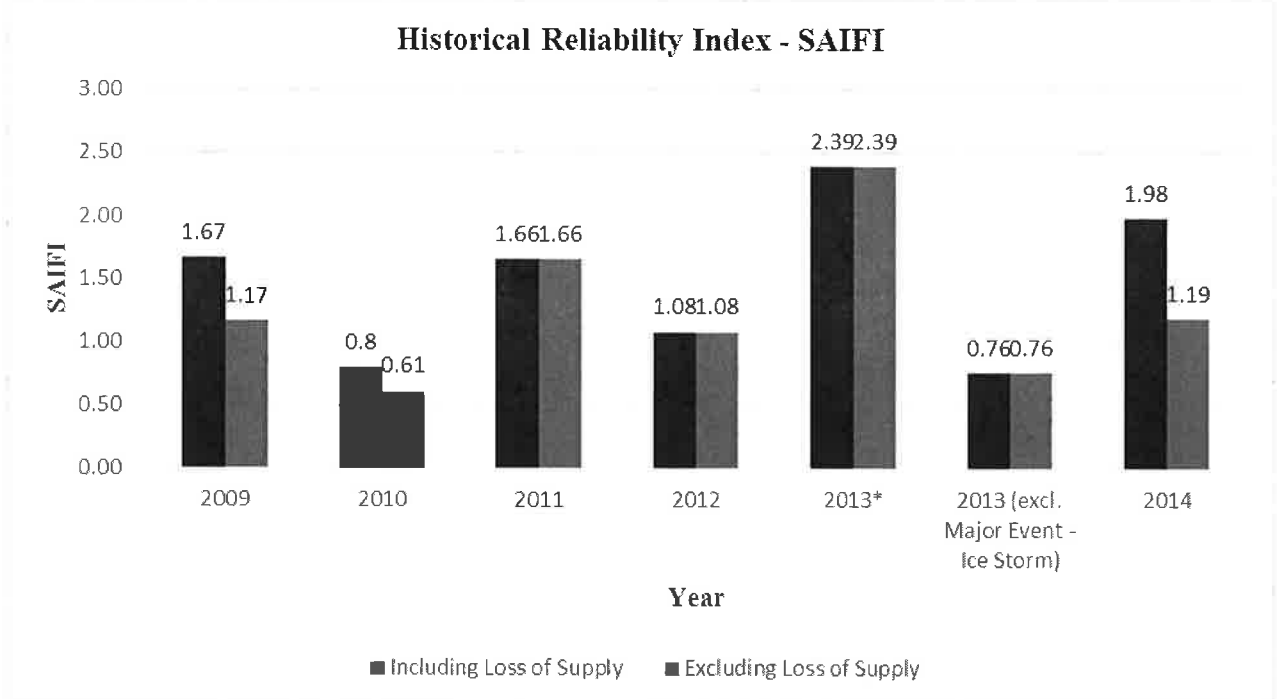
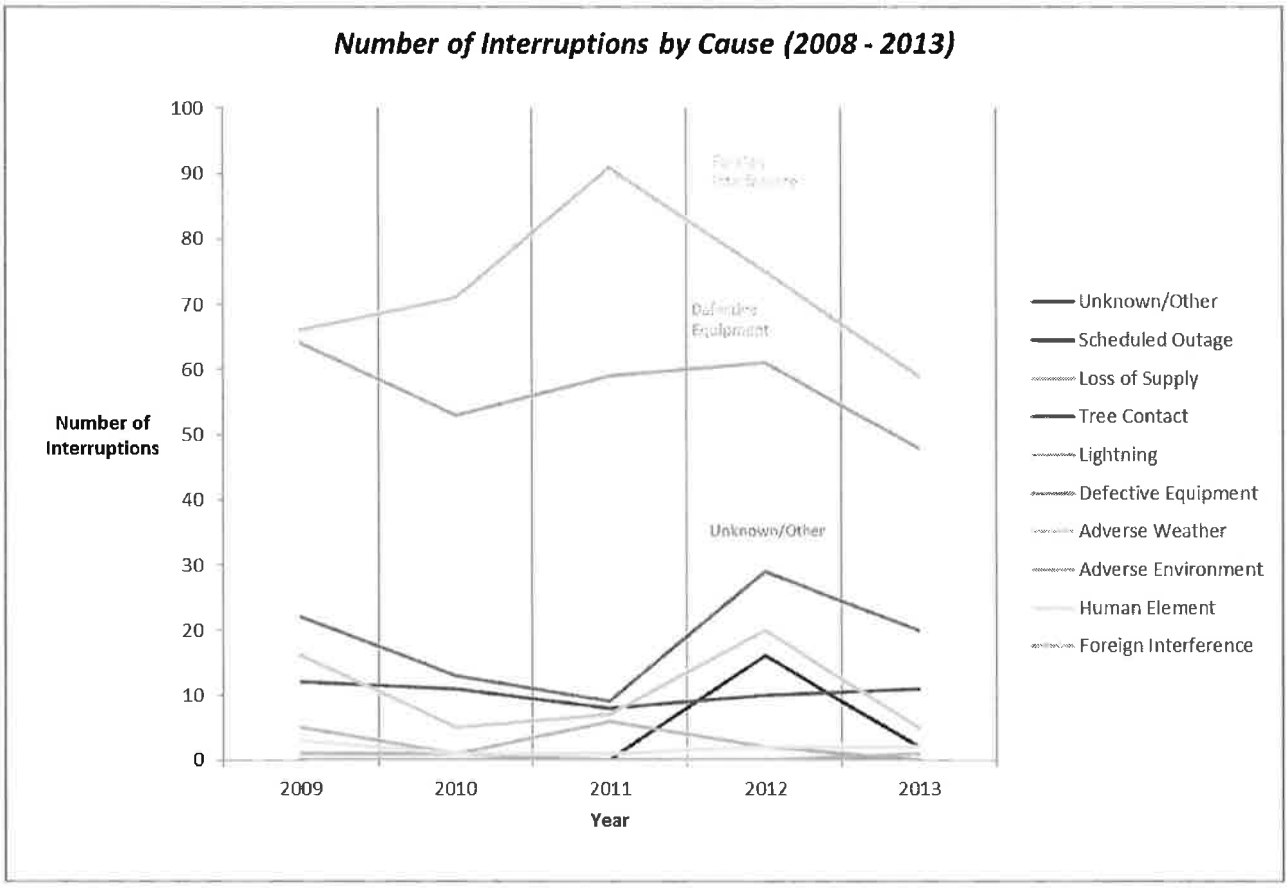

Historical Reliability Index - SAIFI
SAIFI
3.00
2.50
2.00
1.50
1.00
0.50
0.00
1.67
1.17
0.8
0.61
1.66
1.66
1.08
1.08
2.39
2.39
0.76
0.76
1.98
1.19
2009
2010
2011
2012
2013*
2013 (excl. Major Event - Ice Storm)
2014
Year
Including Loss of Supply
Excluding Loss of Supply

Figure 5: Total number of Outages by Root Cause (2008–2013)



In recent years outages were primarily due to defective equipment (identified as defective porcelain insulators and switches) or foreign interference (squirrel contact). Consequently in 2013, OPUCN completed installation of animal guards. OPUCN also implemented a two year program to replace all porcelain insulators and switches with polymer type units. This has resulted in major reductions in outages specific to these causes and hence to overall number of outages.

In 2012, OPUCN had a total of 215 outages and in 2013, it experienced a total of 148 outages, a reduction of 31%. Out of the 148 total number of outages in 2013:

- 40% were due to animal (squirrel) contact (59 out of 148). By comparison, in 2012 there were 75 outages caused by animal contact. 2013 saw a reduction of 21% in this category.