EB-2014-0116

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 Toronto Hydro-Electric System Limited for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2015.

VULNERABLE ENERGY CONSUMERS COALITION
(“VECC”)
CROSS-EXAMINATION COMPENDIUM

FEBRUARY 17, 2015

TORONTO HYDRO -ELECTRIC SYSTEM

LIMITED 2015 RATE APPLICATION

(EB-2014-0116) VECC

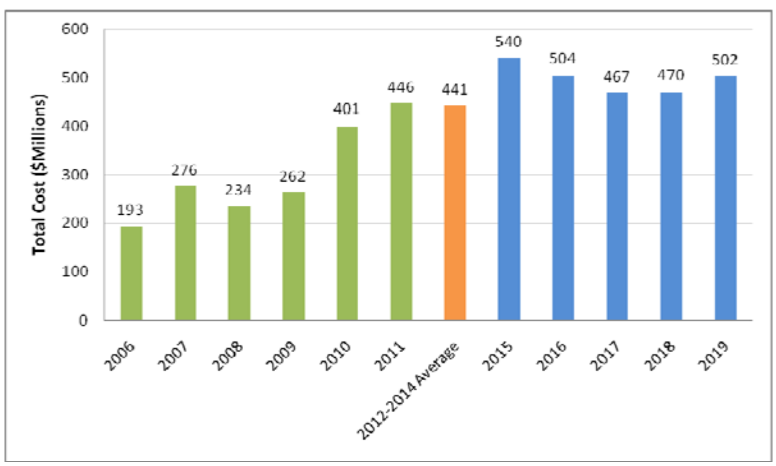
COMPENDIUM

4. SUMMARY OF KEY DETAILS OF THE APPLICATION

4.1 Capital Expenditures And Rate Base

4.1.1 Capital Expenditures

The nature and amount of capital spending in this application builds on the foundation that the OEB accepted in Toronto Hydro's 2012-2014 ICM application.[5] The majority of the capital programs are continuations of the work programs the OEB approved in the ICM application. New programs are driven by public policy responsiveness, additional system renewal needs, evolving system conditions, and enhancing customer value. Toronto Hydro's proposed capital plan has been validated by a third party expert,[6] and its pillars are accepted by the utility's customers.



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Toronto Hydro's requested Capital Expenditures for the period 2015-2019 are approximately $500 million per year, which is comparable to the average annual spending since the utility's last rebasing in 2011 (approximately $440 million per year). Forecasted capital expenditures for the 2015 test year are approximately $ 539.6 million, which represents an increase of approximately $160.8 /C

[5] EB-2012-0064, Partial Decision and Order (April 2, 2013).
[6] Exhibit 1B, Tab 2, Schedule 4, Appendix B.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 5:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p.6

Please revise Figure 1 to show 2012 and 2013 actual, and 2014 current forecast, as separate bars.

RESPONSE:

Figure 1 has been revised to include 2012 and 2013 actual, and 2014 current forecast.

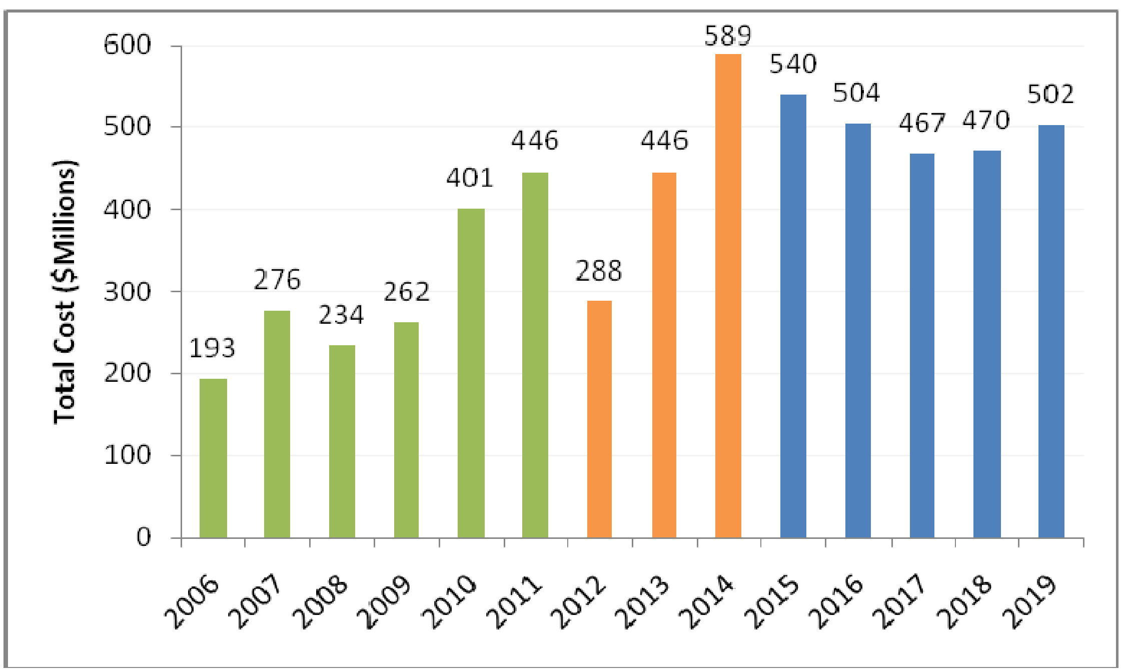


TABLE 1: PROPOSED PERFORMANCE MEASURES FRAMEWORK

Customer-Oriented Performance	Cost Efficiency/ Effectiveness of Planning and Implementation	Asset/System Operation Performance
1. System Average Interruption Duration Index (SAIDI). 2. System Average Interruption Frequency Index (SAIFI). 3. Customer Average Interruption Duration Index (CAIDI). 4. Feeders Experiencing Sustained Interruptions (FESI). 5. Momentary Average Interruption Frequency Index (MAIFI).	1. Distribution System Plan Implementation Progress. 2. Planning Efficiency: Engineering, Design and Support Costs. 3. Supply Chain Efficiency: Materials Handling On-Cost. 4. Construction Efficiency: Internal vs. Contractor Cost Benchmarking. 5. Construction Efficiency: Standard Asset Assembly Labour Input.	1. Outages caused by defective equipment. 2. Stations capacity availability.

In developing the proposed measures, Toronto Hydro referred to the Section 5.2.3, Chapter 5 of the Ontario Energy Board's (OEB) *Filing Requirements for Electricity Transmission and Distribution Applications*[1], which sets out the key parameters for measures or metrics supporting the applicants' Distribution System Plan filings. Toronto Hydro's proposed framework of measures is consistent with the OEB's expectations set out in the Chapter 5 Filing Requirements, and should provide the OEB with useful insights into the quality and sophistication of the utility's distribution planning and implementation activities, as well as Toronto Hydro's improvement in recent years.

For each proposed measure, (with the exception of new measures) Toronto Hydro provides performance results along with the associated trend over the recent years, describes the methodology used to calculate the measure and its implementation, and outlines the ways in which the measure informs and/or otherwise interacts with the utility's Distribution System Plan and the related processes. Where relevant, Toronto Hydro also describes the unique planning

[1] Ontario Energy Board, *Filing Requirements for Electricity Transmission and Distribution Applications*, (Toronto: Ontario Energy Board, 2013). ["*OEB Filing Requirements*"]

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

RESPONSE:

a) The differences are a result of an editing mistake. The numbers provided in Exhibit 2B Section A, page 4, lines 28-30 are incorrect. The correct projections are shown in Exhibit 2B, Section 00, page 8 (see also part b for the projection values.)

b) Please see the table below:

		2014	2015	2016	2017	2018	2019
SAIDI	Run To Fail	1.21	1.26	1.31	1.37	1.43	1.50
	Proposed CIR		1.23	1.17	1.12	1.08	1.02
SAIFI	Run To Fail	1.53	1.67	1.74	1.81	1.90	1.99
	Proposed CIR		1.55	1.44	1.36	1.27	1.19

Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). (A detailed discussion of these reliability forecasts is provided in Section E2).

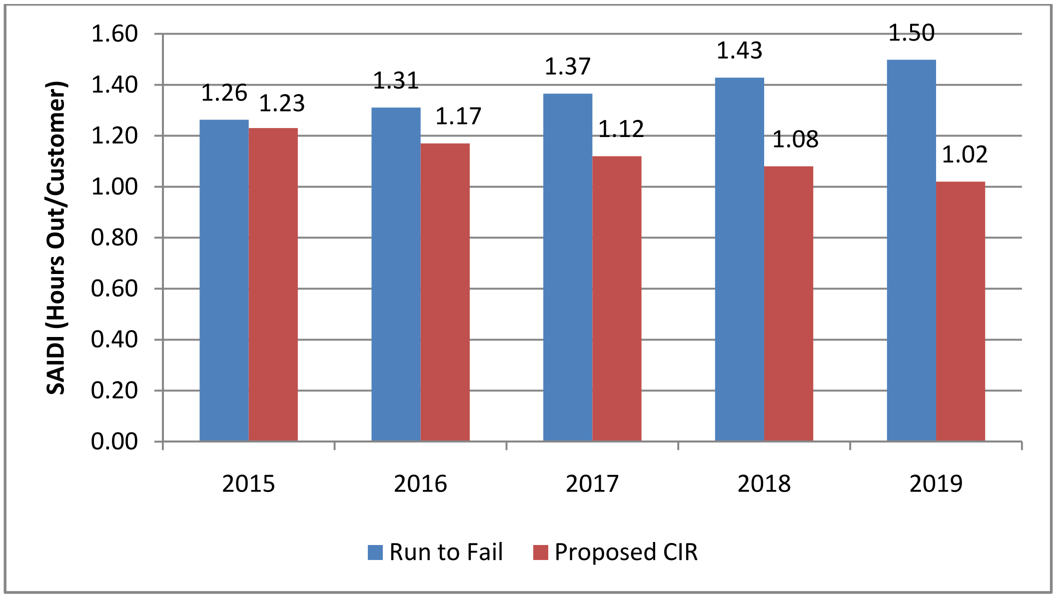


FIGURE 1: FIVE-YEAR SAIDI PROJECTION

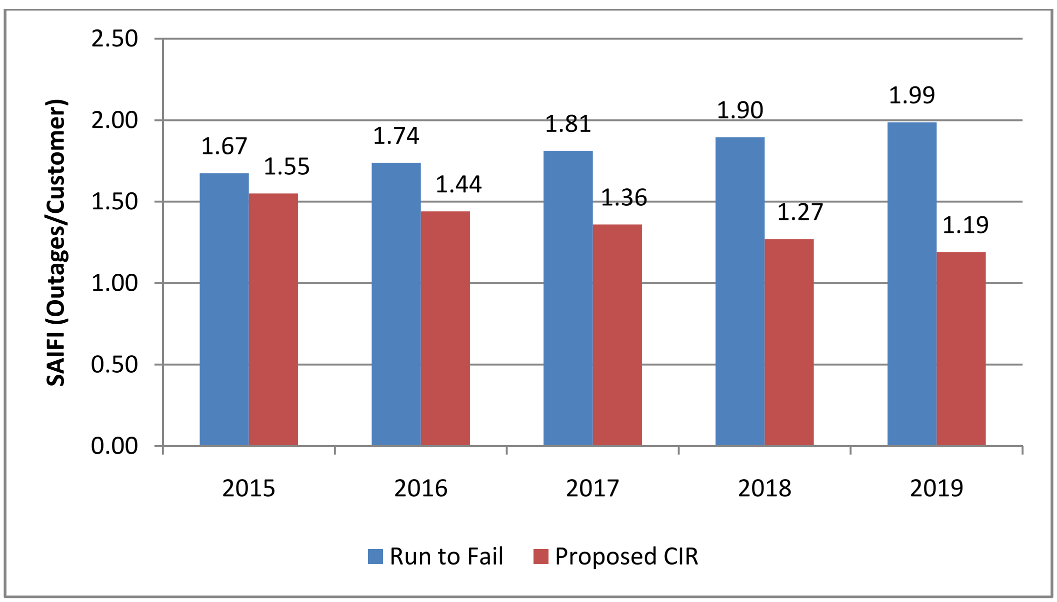


FIGURE 4: FIVE-YEAR SAIFI PROJECTION

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. J2.11:

Reference(s):

To provide the source of the projections from the mathematical model.

RESPONSE:

As referenced in the Exhibit 2B, Section D3, pages 19-20, the Reliability Projection does not rely on a specific mathematical model. Rather, the projections constitute the results of an in-depth analysis of:

a) The existing state of Toronto Hydro assets (asset demographics);
b) The reliability performance of the system (historical reliability); and
c) The expected effects of the planned programs on the future state of the system.

The actual reliability analysis is performed at the outage cause code level (e.g., defective equipment, vegetation contact etc.) using various trending and regression techniques to establish a long term trend of each cause code. The trending and reliability impacts of each program are established through an in-depth analysis of the actual work performed and the potential impacts from further work. Interdependencies between programs and benefits are combined to form an overall system-wide look at the benefit of the overall capital program.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

d) The five-year SAIDI and SAIFI for the CIR Plan (above in part c) is calculated excluding MEDs and LOS. This is appropriate given that MEDs are by their nature unpredictable and LOS events are beyond Toronto Hydro's control. However, the historical averages presented in Appendix 2-G include MEDs (in accordance with the OEB's filing requirements) and are therefore not meaningfully comparable. As an alternative, the table below presents a comparison between the 2009-2013 actual and forecast and the 2015-2019 projected SAIFI and SAIDI, without MEDs and without Loss of Supply, but including Scheduled Outages.

	5-Year Average (2009-2013)	5-Year Average of CIR Plan (2015-2019)
SAIFI	1.42	1.20
SAIDI	1.18	1.05

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

	2009	2010	2011	2012	2013
FESI	38	41	35	29	33

Toronto Hydro did not provide future year projections of this measure, as it submits that doing so is not practical for reasons that follow. The FESI metric is unique in that it targets localized events and outage trends, rather than system-wide statistics that can be normalized over a larger sample. As described in Exhibit 2B, Section C2.2.3, the metric becomes very volatile and unpredictable with respect to specific feeders experiencing outages, and the frequency of those outages in a given year. The volatility and annual shift in affected feeders, as shown in Exhibit E6.21 Figures 1 to 4, make any forecasts or projections impractical. By the very nature of its 12-month tracking window, the FESI program (and the associated measure) entails a short-term reactive mitigation approach, with long-term projects (e.g., System Renewal) to address root causes.

b) Please see the response (a) above.

c) As discussed in the Exhibit 2B, Section C and in the response to part (a) of this interrogatory, FESI is typically a volatile measure that can be affected by numerous factors (e.g. large storms or emerging failure trends) which significantly challenge Toronto Hydro's ability to forecast this measure with accuracy. In addition, Toronto Hydro notes that the OEB's policy with respect to performance measurement in the area of capital planning and implementation is in the early stages; therefore, in Toronto Hydro's respectful view, establishing firm targets on any of the proposed DSP measures is premature for the purposes of the 2015-2019 CIR period.

Table 2: Trigger Drivers for Capital Investments from 2015 to 2019 ($ Millions)

Trigger Driver	2015	2016	2017	2018	2019
Failure Risk	156.9	130.3	134.9	151.4	156.8
Functional Obsolescence	80.6	105.5	78.3	75.1	74.5
Customer Service Requests / Third Party Requests	55.3	71.7	82.9	76.6	69.8
System Maintenance & Capital Investment Support	80.3	52.1	28.9	32.1	27.9
Capacity Constraints	54.4	31.0	37.1	22.5	44.4
Failure	31.9	32.7	33.1	33.6	34.2
Other[8]	10.3	19.8	28.7	37.9	49.4
Mandated Service Obligations	30.8	21.8	18.0	13.8	15.7
Reliability	11.0	9.4	13.8	13.8	17.4
System Efficiency	11.7	16.2	11.6	13.2	12.2
Safety	16.5	13.7	0.0	0.0	0.0
Total Capital Expenditures	539.6	504.2	467.4	470.1	502.2

/C

[8] "Other" capital includes expenditures that do not fit in a discrete capital program, such as Historic Road Cut Repairs and inflation for the capital program. For more details, see Exhibit 2B, Section E4.

OEB Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

CATEGORY					**Forecast Period** (planned)					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	Actual	**Actual**	**Actual**	**Actual**	**Bridge**	**Test**	**Test**	**Test**	**Test**	**Test**
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*
System Access	44.4	58.3	53.2	86.6	76.0	86.1	93.5	100.9	90.4	85.5
System Renewal	215.0	219.3	157.2	231.1	286.4	251.7	235.0	246.3	260.1	265.5
System Service	35.3	75.6	38.4	83.7	104.1	86.8	56.5	62.5	49.5	73.9
General Plant	55.5	67.7	29.3	33.8	109.5	104.6	99.4	28.9	32.1	27.9
Others	50.4	24.6	9.9	10.5	13.3	10.3	19.8	28.6	37.9	49.4
TOTAL EXPENDITURE	**400.6**	**445.5**	**288.0**	**445.7**	**589.2**	**539.6**	**504.2**	**467.4**	**470.0**	**502.2**
System O&M	$ 114.6	$ 111.9	$ 109.0	$ 119.8	$ 118.9	$ 128.8				

Note: Variances due to rounding may exist

C1 OVERVIEW OF CONTINUOUS IMPROVEMENT PRINCIPLES AND APPROACH

C1.1 Introduction

The purpose of this exhibit is to describe Toronto Hydro's proposed Distribution System Plan (DSP) measures that the utility plans to track and periodically report on over the 2015-2019 ratemaking period.

Toronto Hydro has developed a set of 12 measures to monitor quality and drive continuous improvement in its distribution system planning and implementation work over the 2015-2019 planning horizon. The measures cover several distinct dimensions of the utility's capital planning and implementation processes and/or speak directly to the outcomes of such processes, motivated by customer needs, regulatory compliance obligations, or corporate efficiency objectives.

Table 1 outlines Toronto Hydro's proposed DSP performance measures, grouped by primary category.

values. All SAIFI, SAIDI, and CAIDI values showcased further in this document are based on year-end calculations. Toronto Hydro excludes the major event days (MEDs), as defined by IEEE 1366-2012 2.5 beta method, from all representations of reliability metrics.

C2.1.2 Historical Performance Trends

Figures 1, 2, 3, and 4 respectively illustrate Toronto Hydro's SAIDI, SAIFI and CAIDI over the past five years both including and excluding loss of supply. For SAIDI and SAIFI, the trend over the five year historical period can be attributed to the capital investments made over that time. CAIDI, on the other hand, has remained stable over the five-year historical period, as it is proportional to SAIDI and inversely proportional to SAIFI. As such, when it comes to CAIDI, the improvement of SAIDI is negated by a similar improvement to SAIFI. Toronto Hydro notes that improvements made towards SAIDI and SAIFI can lag the investments by a year or more.

Activities such as rear lot conversion and direct-buried cable replacement that reduce the number and duration of outages are among the investments that have contributed to the historical improvements shown.

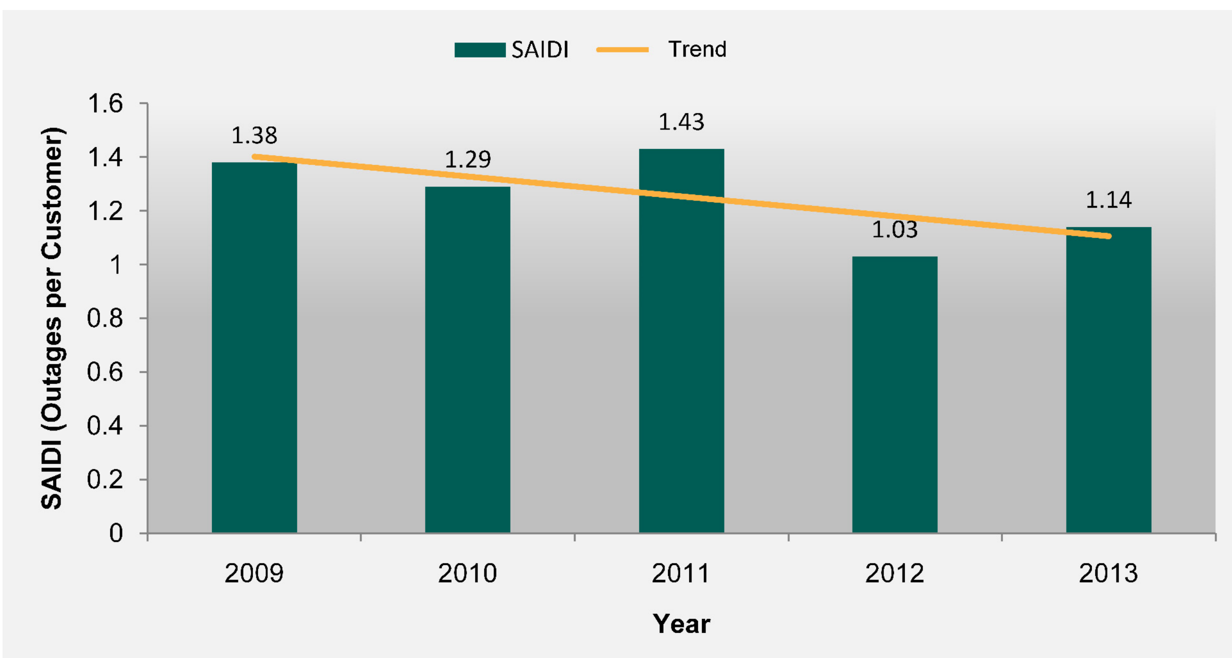
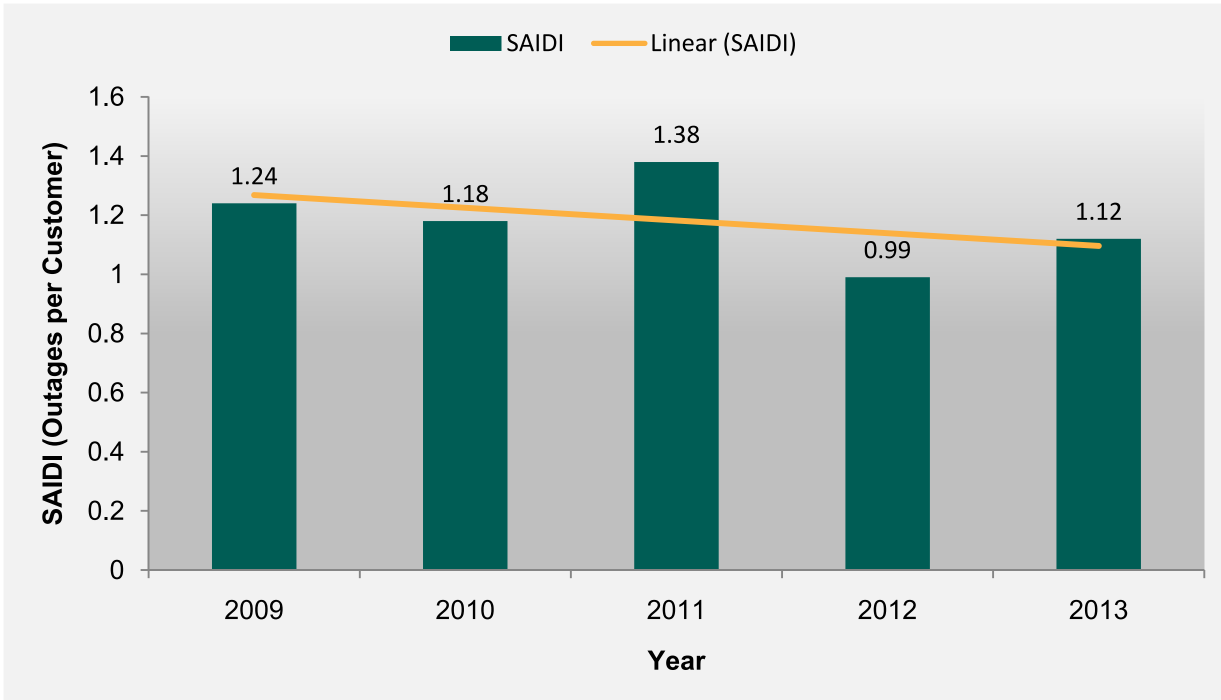
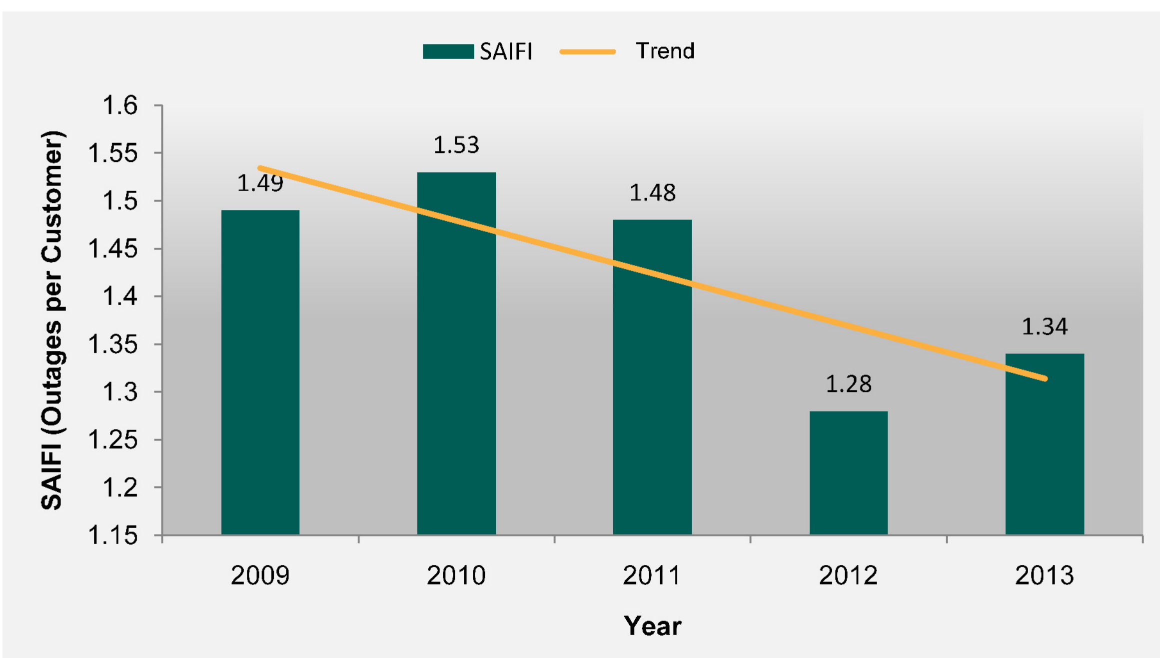


FIGURE 1: HISTORICAL SAIDI EXCLUDING MEDS – 2009-2013



1 **FIGURE 4: HISTORICAL SAIDI EXCLUDING MEDS AND LOSS OF SUPPLY – 2009-2013**



2 **FIGURE 5: HISTORICAL SAIFI EXCLUDING MEDS AND LOSS OF SUPPLY – 2009-2013**

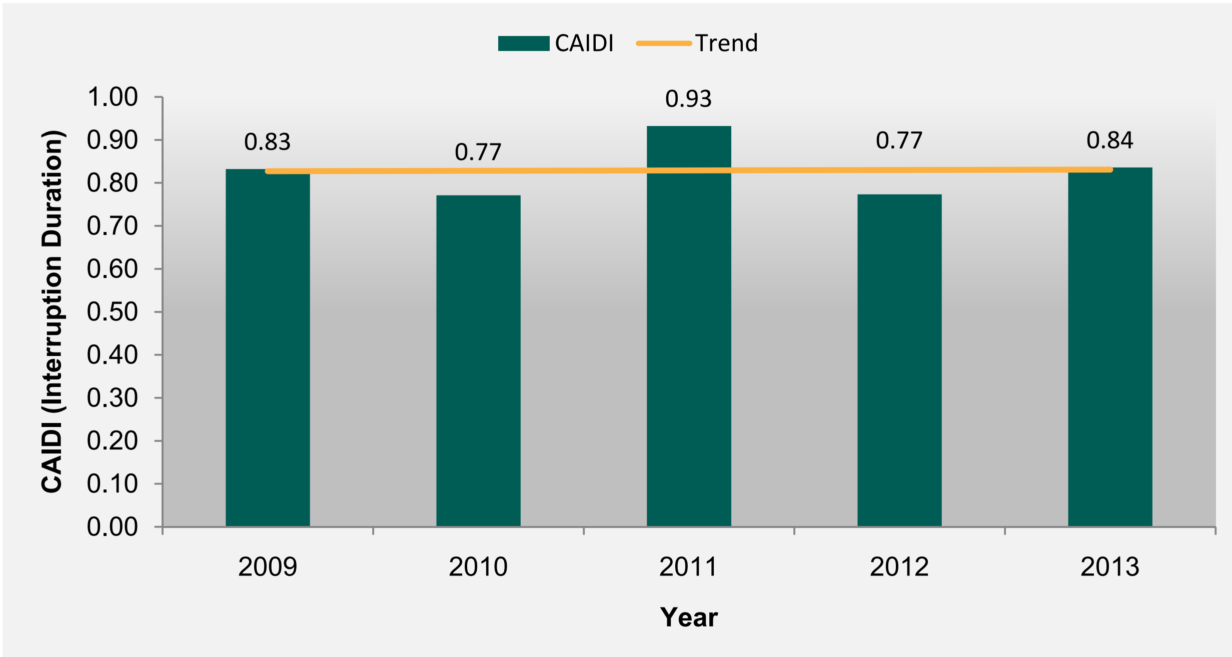


FIGURE 6: HISTORICAL CAIDI EXCLUDING MEDS AND LOSS OF SUPPLY – 2009-2013

C2.1.3 Interaction with the Distribution System Plan

Toronto Hydro uses historical reliability data as a key input into its Asset Management Process, discussed in further detail in Section D of the DSP. Within the long-term asset management policies, described in Section D3.1.1, reliability data serves as a key input to develop investment programs that will target key assets and manage critical issues. As part of short-term asset management policies, further defined in Section D3.1.2, reliability data is used at a local level to identify opportunities for capital projects.

On a system-wide level, the measures inform the asset management process to identify assets and programs required to address the root issues across the system, including activities such as direct-buried cable replacement, air insulated PMH switchgear and others. At the local or project level, historical SAIDI and SAIFI performance and anticipated improvements are considered when selecting individual assets to be replaced, enhanced or modified. On a system level, SAIDI and SAIFI are projected to improve by about 20% and 26% respectively by the end of the CIR period due to the investment programs proposed. Once again, Toronto Hydro expects CAIDI to remain relatively stable as SAIDI and SAIFI are improving in a similar trend.

decreased from 38 in 2009 to 33 in 2013, and declining to as low as 29 in 2012. The average number of feeders with seven or more interruptions in 2009-2013 was 35.

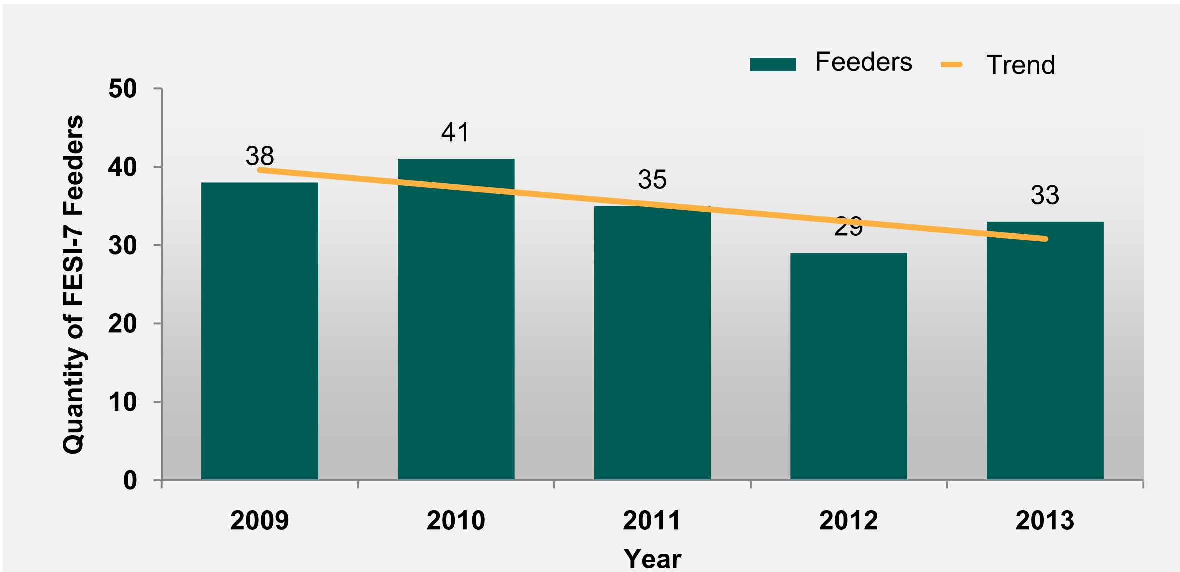


FIGURE 7: QUANTITY OF FESI-7 FEEDERS –2009-2013

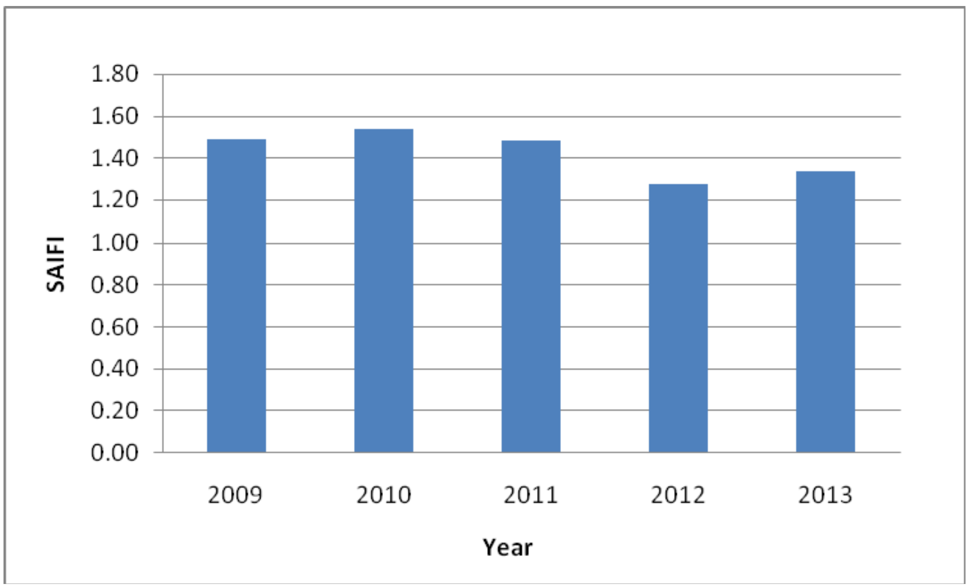
C2.2.3 Interaction with the Distribution System Plan

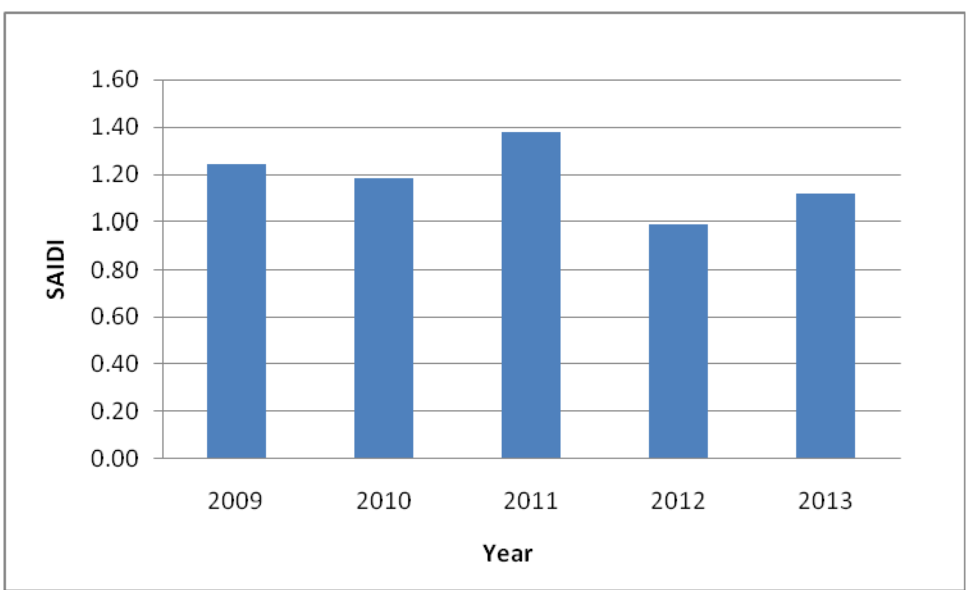
The declining trend illustrated above speaks to the effectiveness of Toronto Hydro's Worst Performing Feeder program over the recent years, including specific reliability-driven capital and maintenance programs, such as tree trimming, targeted asset replacement, insulator washing and animal guard replacement. Toronto Hydro plans to continue monitoring the outcomes of its investments targeted towards service improvements on the utility's worst performing feeders. The Worst Performing Feeder Program (E6.21) contains a detailed list of maintenance and capital work planned to target FESI feeders. However, beyond the specific work planned as part of the Worst Performing Feeder program, which deals with primarily short term mitigation, every aspect of the Toronto Hydro's Capital Expenditure plan that is driven to some degree by reliability (e.g. circuit renewal work), and will ultimately contribute to the improvement of the FESI performance.

Based on the scope and volume of investments proposed within the utility's 2015-2019 Distribution System Plan, Toronto Hydro anticipates that its average number of feeders experiencing seven or more interruptions will continue to decline, or at least remain in line with the 2009-2013 average. At the same time, and as seen from the historical data, some year-over-

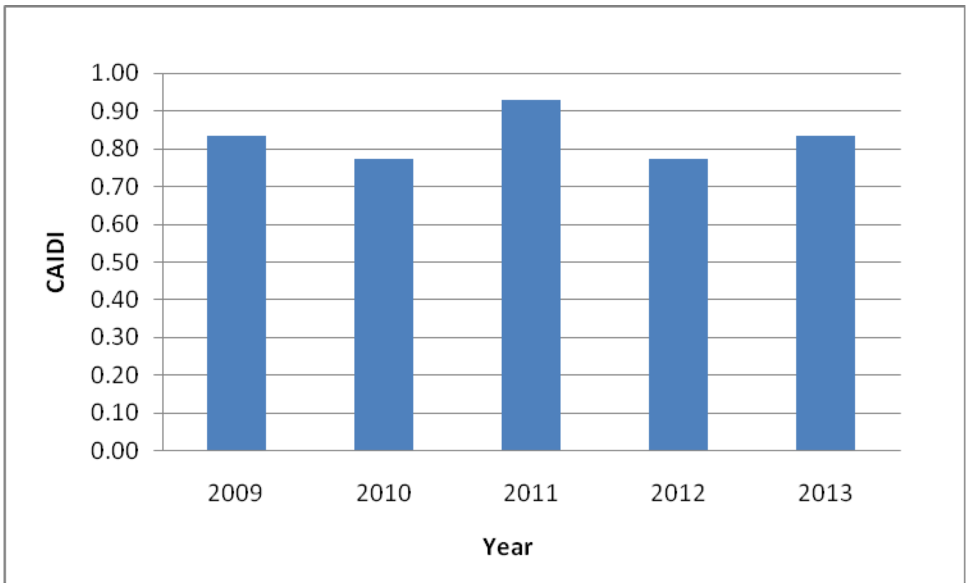
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

b) Please see the following graphs for SAIFI, SAIDI and CAIDI without MEDs and Loss of Supply, but including Scheduled Outages.





RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES



c) The below table shows the 2014 Forecast and 2015 projections for SAIDI, SAIFI and CAIDI for the period 2014-2019 including the CIR period 2016-2019, excluding LOS and MEDs, but including Scheduled Outages. Please note that 2014 is a forecast, while 2015-2019 is a projection based on the completion of the capital investment and maintenance program detailed in this application.

	2014F	2015P	2016P	2017P	2018P	2019P
SAIFI	1.31	1.39	1.28	1.20	1.11	1.03
SAIDI	0.97	1.16	1.10	1.05	1.01	0.95
CAIDI	0.74	0.83	0.86	0.87	0.91	0.92

DSP IMPLEMENATION METRICS

C4 ASSET & SYSTEM OPERATIONS PERFORMANCE

C4.1 Outages Caused By Defective Equipment

C4.1.1 Measure Description

For the purposes of measuring the performance of its equipment over the 2015-2019 planning horizon, Toronto Hydro plans to track the number of outages occurring over a rolling 12-month period due to defective or otherwise malfunctioning equipment. These outages are distinct from other outage causes such as vegetation/animal contacts, upstream supply interruptions or weather-related events. On average over the past five years, defective equipment-related outages were responsible for approximately 44% of total SAIDI and 41% of SAIFI results. Toronto Hydro tracks its equipment-related outages using ITIS, where each event is assigned a specific cause code. The count or number of outages caused by failed equipment speaks to the general condition of the utility's assets. Toronto Hydro proposes to track the number of equipment related-outages on a rolling 12-month basis.

C4.1.2 Historical Performance Trends

Figure 11 provides a summary of Toronto Hydro's historic performance on the equipment-related outages measure over the 2009-2013 timeframe. As seen in the chart, Toronto Hydro's performance on this measure has steadily improved over the past five years from 728 events in 2009 to 636 in 2013 – an improvement of over 11%. The utility attributes this performance improvement to the high level of System Renewal investments made in recent years, but notes that as with SAIDI and SAIFI, improvements in the defective equipment-caused outages often lag behind the investments to rectify them by several years. Accordingly, to maintain and/or improve on the current trend, Toronto Hydro plans to continue investing in System Renewal and other programs facilitating equipment performance improvements.

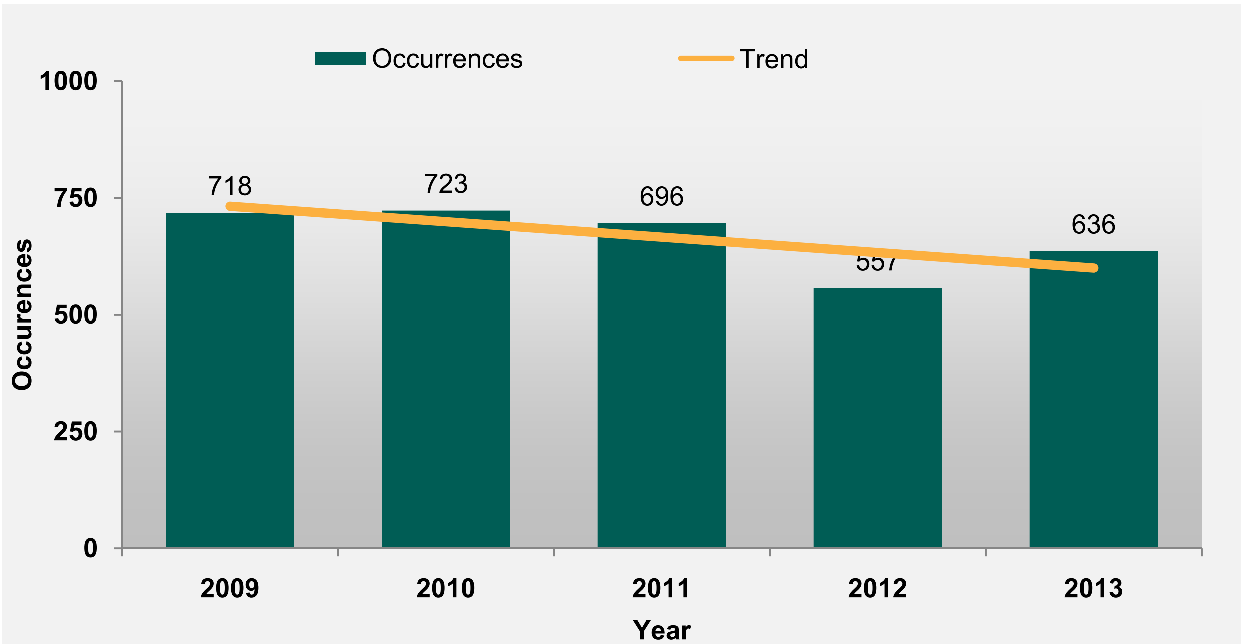


FIGURE 11: OUTAGES CAUSED BY DEFECTIVE EQUIPMENT – 2009-2013

C4.1.3 Interaction with the Distribution System Plan

As stated above, Toronto Hydro attributes performance improvement as illustrated in Figure 11 to the level of System Renewal investments made in recent years, but notes that given the current system demographics, continued focus on the system renewal investments is required to avoid a reversal of this trend.

Toronto Hydro plans to continue improving the general health of the system assets and ensure the historical trend continues so as to improve the system reliability. Given the proposed levels of System Renewal investments in its 2015-2019 Distribution System Plan, Toronto Hydro anticipates that the number of defective equipment-related outages will improve in line with the expected improvement in asset demographics. As a pure failure metric that does not consider imact and duration, the trajectory of this metric is expected to be affected by system renewal but not significantly changed by modernization. Overall, Toronto Hydro expects the historic trend to continue during the 2015-2019 period.

The results of this measure will inform Toronto Hydro as to the effectiveness of its asset replacement strategies and preventive maintenance activities. Should the results over the future years display trends significantly different from the historical levels, Toronto Hydro plans to investigate the underlying reasons and make the appropriate adjustments as necessary and feasible. Customers that are interrupted due to failed equipment can typically expect extended outages as Toronto Hydro crews replace the failed asset. By reducing the volumes of equipment at risk of failure across its system, Toronto Hydro will be assisted delivering more reliable system performance to its customers.

C4.2 Stations Capacity Availability

C4.2.1 Measure Description

As its final performance measure for the purposes of its 2015-2019 Distribution System Plan, Toronto Hydro proposes to track the availability of capacity at its Transformer Stations (TS). The utility regularly monitors its available station capacity across the service territory to ensure that sufficient capacity exists to satisfy system peak demand, accommodate new customer connections, and provide a reasonable amount of operating flexibility to the Control Centre for the purposes of load transfers. These monitoring activities enable the planned and reactive capital and maintenance work, and facilitate outage restoration efforts.

Toronto Hydro forecasts station-specific demand on an annual basis and compares the forecasts against the available equipment capacity. Where forecasts indicate potential capacity shortages, Toronto Hydro develops and executes the plans to transfer the incremental load to adjacent stations or increase the existing equipment's capacity. Given the pace of the recent and projected economic growth across the utility's service territory, stations capacity monitoring represents a crucial dimension of Toronto Hydro's asset management activities.

For the purposes of the 2015-2019 Distribution System Plan performance monitoring, Toronto Hydro proposes to track the number of stations where peak demand exceeds 90% of station capacity over the next five years. Given that a number of station expansion activities are currently underway (including construction activities at Copeland TS), Toronto Hydro proposes to track this measure based on a five-year rolling outlook starting in 2015. Since Toronto Hydro is not always in a position to unilaterally affect the station capacity limitations (e.g. due to upstream

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 9:

Reference(s): **Exhibit 2A, Tab 10, Schedule 2, pp. 10-11, Figures 10 and11**
Exhibit 2B, Section C4.1, page 28

Preamble:

Defective Equipment and Tree contacts are two of the primary causes of outage.

a) Please provide a chart showing both historic 2009-2013 and forecast 2014-2019 contributions to SAIFI and SAIDI from Defective Equipment excluding MEDs.
b) Please provide chart showing both historic and forecast 2014-2019 contributions to SAIFI and SAIDI Tree Contacts excluding MEDs.
c) Please indicate clearly how the forecast was derived, including reference to types of equipment in Figures 16 and 17 pages 15/16 of the main Reference.
d) Please provide Charts Similar to Figures 11 in the second reference showing forecasts and trends for outages caused by Defective Equipment.
e) Please comment whether reduction in SAIDI/SAIFI due outages from Defective Equipment and Tree Contacts are reasonable Metrics to judge the Outcomes of Equipment Refurbishment/Replacement and Vegetation Management Programs.
f) Please comment on whether THESL would commit to the forecast targets as a Metric for assessing its Capital Equipment Refurbishment/Replacement and Vegetation Management Programs over the CIR Plan period.
g) If not, please provide a full explanation.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

RESPONSE:

a) The following table shows historic and forecast contributions to SAIFI and SAIDI from Defective Equipment (excluding MEDs).

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SAIFI	46%	40%	38%	45%	37%	40%	39%	38%	37%	36%	35%
SAIDI	50%	38%	41%	54%	40%	54%	42%	40%	39%	37%	36%

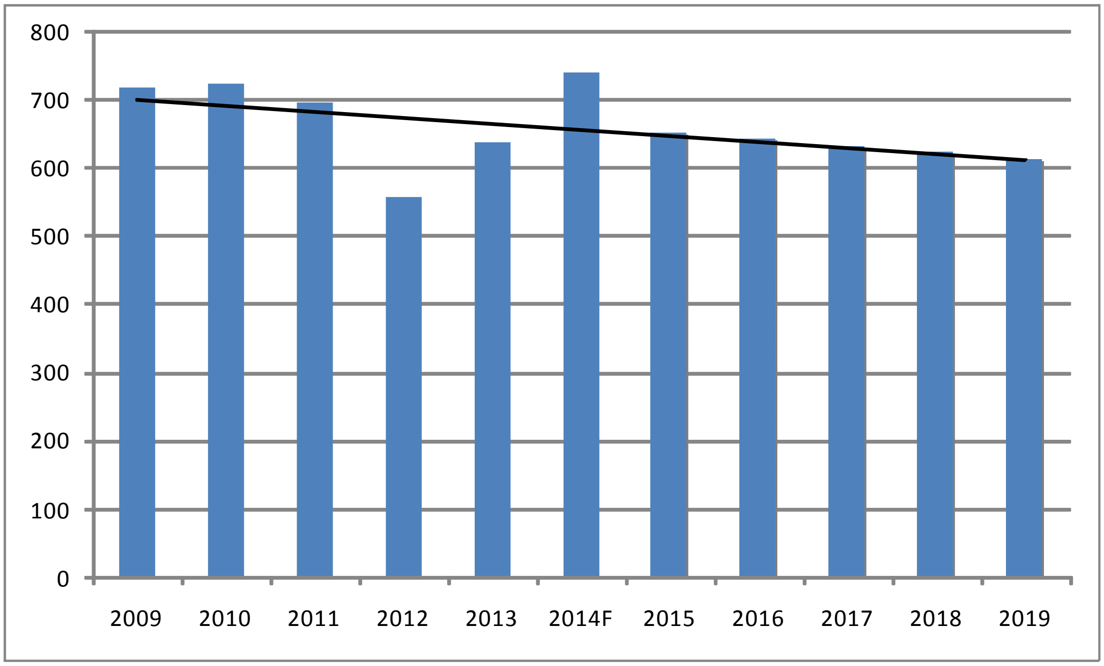
b) The following table shows the historic and forecast contributions to SAIFI and SAIDI from Tree Contacts (excluding MEDs).

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SAIFI	8%	8%	12%	6%	10%	9%	8%	7%	7%	7%	6%
SAIDI	8%	15%	19%	6%	15%	13%	13%	12%	12%	12%	11%

c) Please refer to Toronto Hydro's response to interrogatory 1A-CCC-5 part (b) for a description of how the projections are calculated. More specifically, defective equipment was reviewed at the individual asset class level and its reliability was projected based on the historical reliability, capital programs, and the Long-Term System Review Process.

d) Please see the chart on the following page.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES



The values presented for the 2015-2019 timeframe are products of a linear trend of the existing 2009 to 2014 (Forecast) number of equipment failures. However, Toronto Hydro believes that this representation of a linear trend reflects a simplified analysis for the 2015 to 2019 period, which is inappropriate for the purposes of target setting. The historical period results reflect various trends and shifts that cannot be adequately captured by a linear trend projection, but can be expected to reasonably occur over the plan term (for example, from 2012 to 2014, there has been a sharp increase in the number of asset failures, which can be explained by the post-2013 ice storm damage to Toronto Hydro assets). As described further in part (f), using this measure on an ongoing basis (rather than as a measure of performance relative to the target) allows Toronto Hydro to understand the trends, flag variances for review and recommend changes to improve the overall system.

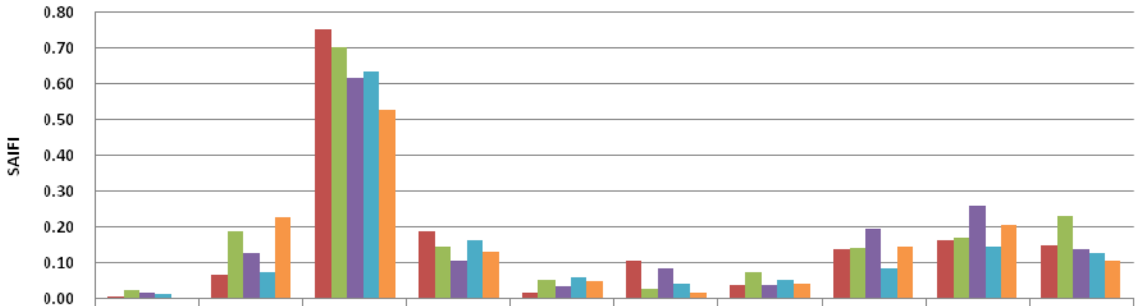
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

e) Toronto Hydro does not agree that tracking SAIDI/SAIFI attributable to Defective Equipment and Tree Contact outage cause codes would be an appropriate metric to evaluate the outcomes of Equipment Refurbishment/Replacement and Vegetation Management for the following reasons:

i) Defective Equipment – As targeted asset renewal programs progress, the failure probability is expected to be mitigated through work on the individual assets. However, this involves looking at one asset or a small subset of assets in a localized project area, and would thus not be meaningfully reflected on system-wide measures such as SAIFI and SAIDI.

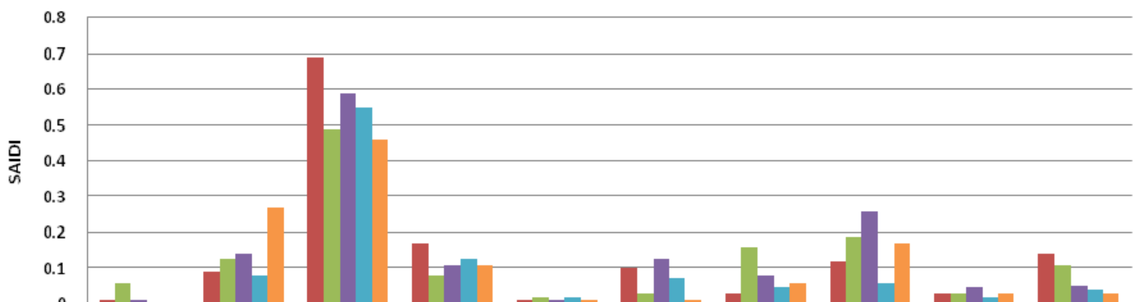
ii) Tree Contacts – The Vegetation Management program at Toronto Hydro targets feeders on a cyclical basis. While there is ongoing work towards modelling improvements and response strategy modifications, (e.g., optimal times for corrective trimming), the program itself is deployed to maintain the current level of tree-related outages, rather than improve it. Notwithstanding this ongoing work, the Vegetation Contact cause code performance itself is heavily dependent on weather conditions. As an example, 2012 saw a dramatic decrease in the number of tree-related outages, which was due to a shift in the weather pattern from the historical norm, rather than any changes to the vegetation management practices.

As described above, using the Vegetation Contact and Defective Equipment statistics to measure performance against a specific target is problematic, due to the practical considerations that can materially affect the targets' results irrespective of the utility's efforts on related capital or maintenance programs. Given the limited experience in



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN	LOSS of SUPPLY
2009	0.01	0.07	0.75	0.19	0.02	0.11	0.04	0.14	0.17	0.15
2010	0.02	0.19	0.70	0.15	0.05	0.03	0.07	0.14	0.17	0.23
2011	0.02	0.13	0.62	0.11	0.03	0.08	0.04	0.19	0.26	0.14
2012	0.01	0.08	0.64	0.16	0.06	0.04	0.05	0.09	0.15	0.13
2013	0.00	0.23	0.53	0.13	0.05	0.02	0.04	0.14	0.20	0.10

Figure 10: SAIFI Cause Code Breakdown (Excluding MEDs)



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN	LOSS of SUPPLY
2009	0.01	0.09	0.69	0.17	0.01	0.1	0.03	0.12	0.03	0.14
2010	0.06	0.13	0.49	0.08	0.02	0.03	0.16	0.19	0.03	0.11
2011	0.01	0.14	0.59	0.11	0.01	0.13	0.08	0.26	0.05	0.05
2012	0	0.08	0.55	0.13	0.02	0.07	0.05	0.06	0.02	0.04
2013	0	0.27	0.46	0.11	0.01	0.01	0.06	0.17	0.03	0.03

Figure 11: SAIDI Cause Code Breakdown (Excluding MEDs)

Table 2: Five-Year Average SAIFI and SAIDI Contribution by Cause Code

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
Defective Equipment	41.1%	44.3%
Unknown	12.0%	2.6%
Loss of Supply*	9.6%	5.9%
Foreign Interference	9.3%	9.4%
Tree Contacts	9.0%	12.8%
Adverse Weather	8.7%	11.3%
Lightning	3.5%	5.2%
Scheduled Outage*	3.2%	6.2%
Human Element	2.7%	1.0%
Adverse Environment	0.8%	1.3%

* Excluded from typical system analysis when demonstrating the true condition of THESL's system

Between 2009 and 2013, defective equipment was the main contributor to SAIFI and SAIDI, at 41.1% and 44.3% respectively. As shown in Figures 10 and 11, the majority of improvement in SAIFI and SAIDI in 2013 over the previous years is in Defective Equipment and, to a lesser extent, Adverse Environment and Lightning. Outages due to Adverse Environment and Lightning are typically not reflective of the condition of the assets in the system, but rather the environmental stresses that the assets experience. Toronto Hydro views the Defective Equipment cause code as a primary indicator of the condition of its distribution system, and tracks this cause code as a measure of continuous improvement over the course of its capital expenditure and maintenance plans. Additional analysis of various relevant cause codes is provided below.

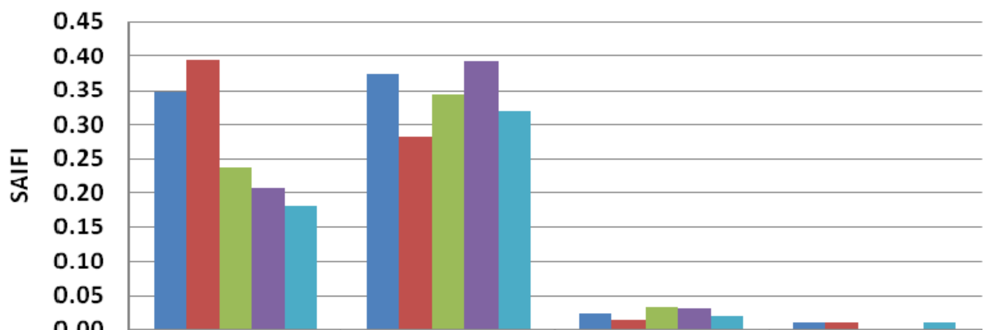
5.1. Weather Impacts

Three cause codes can generally be combined to reflect weather impacts on the system:

(a) Adverse Weather,

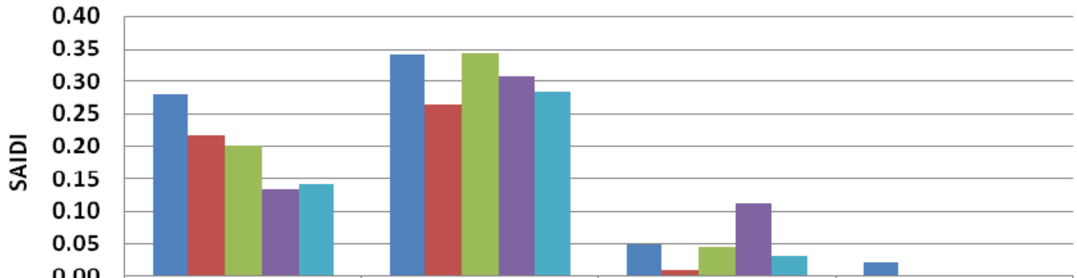
5.3. Defective Equipment Impacts

As shown in Figures 16 and 17, the contribution of defective equipment to Toronto Hydro's SAIFI and SAIDI has remained relatively stable, with the exception of the overhead system sub-cause code, which has seen a considerable reduction in outages.



	Overhead Equipment	Underground Equipment	Station Equipment	Others
2009	0.35	0.37	0.02	0.01
2010	0.39	0.28	0.01	0.01
2011	0.24	0.34	0.03	0.00
2012	0.21	0.39	0.03	0.00
2013	0.18	0.32	0.02	0.01

Figure 16: Defective Equipment SAIFI

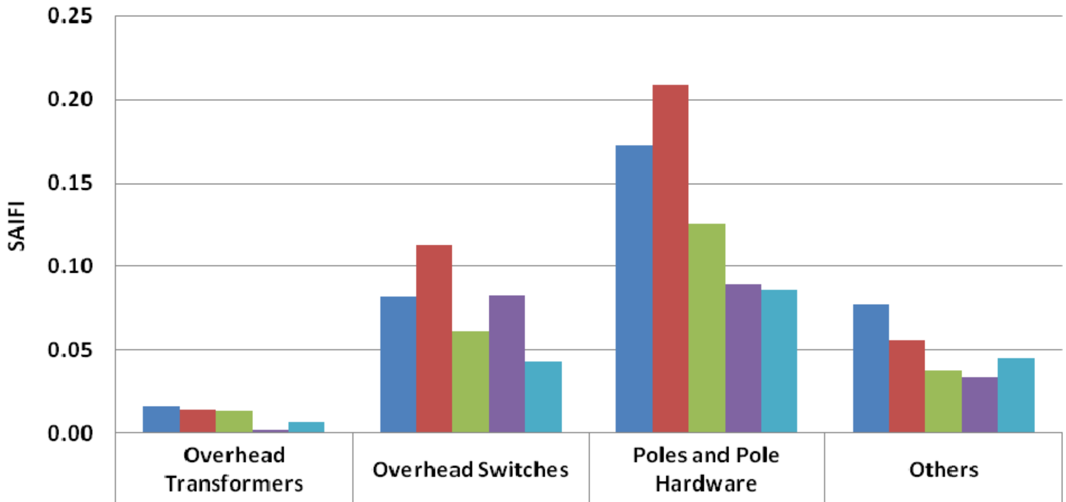


	Overhead Equipment	Underground Equipment	Station Equipment	Others
2009	0.28	0.34	0.05	0.02
2010	0.22	0.26	0.01	0.00
2011	0.20	0.34	0.04	0.00
2012	0.13	0.31	0.11	0.00
2013	0.14	0.28	0.03	0.00

Figure 17: Defective Equipment SAIDI

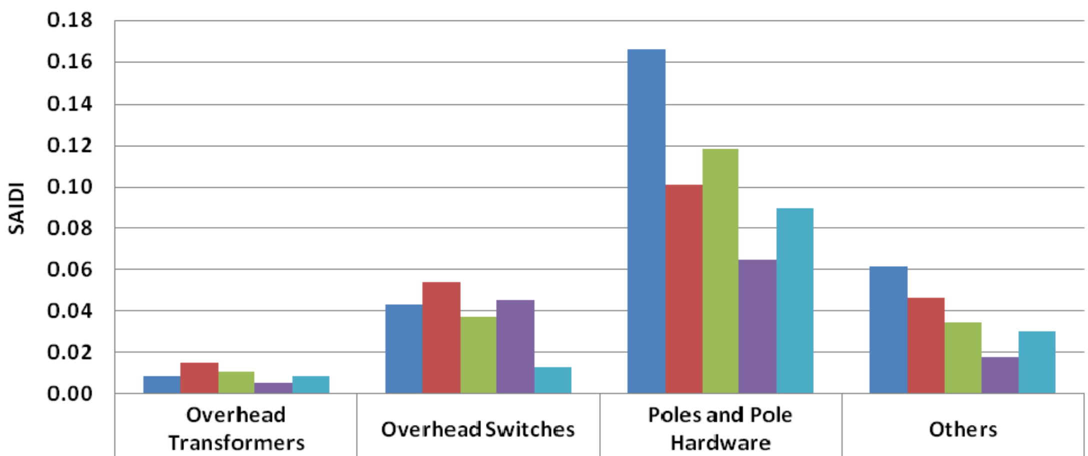
5.4. Overhead Defective Equipment

In the overhead sub-cause codes (Figures 18 and 19 below) the majority of the customer interruptions are caused by pole and pole hardware failures, as well as overhead switches. This is mainly due to the magnitude of these types of failures, which often disable large sections of feeders. Toronto Hydro has experienced an improvement in the SAIFI and SAIDI trend across all sub-categories, but particularly poles and pole hardware. This can be attributed to the extensive investment program that Toronto Hydro has been undertaking over the past years, with many overhead rebuilds and an aggressive porcelain insulator replacement program. Programs such as Rear Lot Conversion (see Exhibit 2B, E6.6) and Box Construction Conversion (see Exhibit 2B, E6.7) have also contributed to the improvement of the Overhead System. To maintain this result, Toronto Hydro plans to continue this effective replacement program throughout 2015-2019.



	Overhead Transformers	Overhead Switches	Poles and Pole Hardware	Others
2009	0.02	0.08	0.17	0.08
2010	0.01	0.11	0.21	0.06
2011	0.01	0.06	0.13	0.04
2012	0.00	0.08	0.09	0.03
2012	0.01	0.04	0.09	0.05

Figure 18: Defective Equipment SAIFI - Overhead

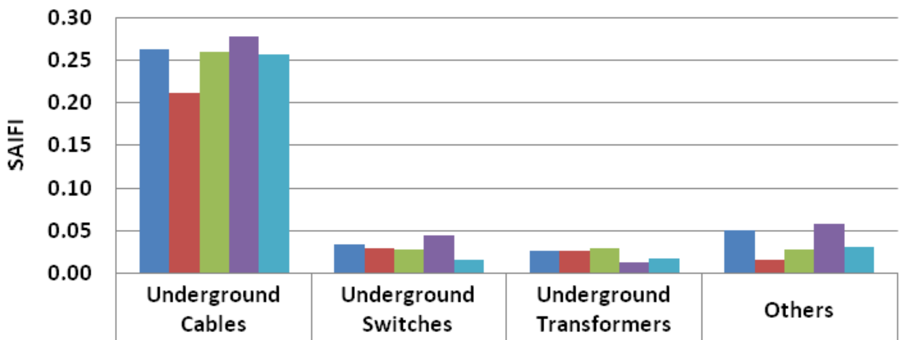


	Overhead Transformers	Overhead Switches	Poles and Pole Hardware	Others
2009	0.01	0.04	0.17	0.06
2010	0.02	0.05	0.10	0.05
2011	0.01	0.04	0.12	0.03
2012	0.01	0.05	0.06	0.02
2012	0.01	0.01	0.09	0.03

Figure 19: Defective Equipment SAIDI - Overhead

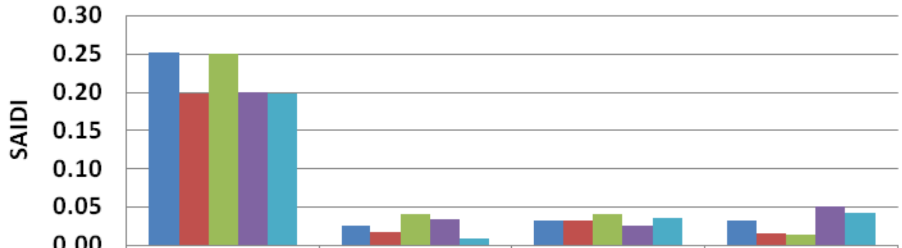
5.5. Underground Defective Equipment

In the underground sub cause code (Figures 20 and 21 below), underground cable faults dominate both the SAIFI and SAIDI indices and are the biggest equipment related cause of interruptions in Toronto Hydro's system. The majority of these failures are due to direct buried cables. Despite a heavy emphasis on the replacement of these cables over the past few years, the number of these assets reaching end of life or showing accelerated deterioration continues to increase. This trend supports the need to continue investment in replacing Direct Buried Cables, as detailed in Exhibit 2B, E6.1.



	Underground Cables	Underground Switches	Underground Transformers	Others
2009	0.26	0.03	0.03	0.05
2010	0.21	0.03	0.03	0.02
2011	0.26	0.03	0.03	0.03
2012	0.28	0.04	0.01	0.06
2013	0.26	0.01	0.02	0.03

Figure 20: Defective Equipment SAIFI - Underground



	Underground Cables	Underground Switches	Underground Transformers	Others
2009	0.25	0.02	0.03	0.03
2010	0.20	0.02	0.03	0.02
2011	0.25	0.04	0.04	0.01
2012	0.20	0.03	0.02	0.05
2013	0.20	0.01	0.03	0.04

Figure 21: Defective Equipment SAIDI - Underground

C3.1 IMPLEMENTATION PROGRESS

C3 COST EFFICIENCY & EFFECTIVENESS

C3.1 Distribution System Plan Implementation Progress

C3.1.1 Measure Description

Toronto Hydro plans to measure the overall progress of its Distribution System Plan implementation as a rolling ratio of total capital expenditures made over the plan years completed to date, divided by the five-year total amount of OEB-approved capital expenditures approved as a part of the utility's 2015-2019 Distribution System Plan, Including the System Access, System Renewal, System Service, and General Plant investment categories. The proposed measure will be calculated using the following formula:

$$\text{Implementation Progress} = \frac{\sum(\$\text{ Spend Year n} + \$\text{Spend Year n} + 1\ldots)}{\$\text{ Five Year OEB Approved Plan}}\ [\%\text{ of Plan Total}]$$

According to this formula, if Toronto Hydro's total five-year approved capital envelope was approved to be $2.47 billion and the utility's Year 1 (2015) and Year 2 (2016) capital expenditures amounted to $524 million, and $502 million respectively, then the utility's plan implementation progress metric at the end of the 2016 rate year would be:

$$\frac{(\$524\text{M} + \$502\text{M})}{\$2.47\text{B}} = 41.5\%$$

Toronto Hydro's preference for using the rolling measure of plan implementation progress stems from the fact that the utility operates in a dynamic business environment, where a number of **issues can emerge over the course of any given year that require the utility to advance,**

postpone, or otherwise amend the schedule, sequencing or pacing of projects slated for completion in that year. These considerations are often outside of the utility's control, and include the following factors:

- Major weather events (floods, ice storms);
- Atypical seasonal conditions (shorter construction seasons or limited switching capability);
- Urgent third-party work requests (e.g. plant relocations for transit);
- City and/or third-party (e.g. Hydro One Networks Inc. (HONI)) dependencies (resulting in longer project timelines);
- Changes in labour force availability (job action, higher than anticipated retirement rates, changes in the contractor community);
- Actions of HONI or the IESO (e.g. outage coordination challenges);
- Other related circumstances.

While these activities can have a significant affect on Toronto Hydro's ability to implement certain programs or projects in any specific year, that potential impact is significantly reduced over a longer (five-year) timeframe, providing the utility sufficient flexibility to adjust the pace on the affected projects, while redeploying its resources towards the work that can be completed in the immediate term. The aggregate five-year target ensures that the utility will work towards delivering the entirety of the capital program approved for the 2015-2019 planning period.

C3.1.2 Historical Performance Trends

The proposed 2015-2019 Distribution System Plan is the first time that Toronto Hydro expects to implement an approved medium-length multi-year capital plan. Accordingly, the utility is not in a position to provide the comparable historical results in a similar format, in light of the variety of circumstances under which Toronto Hydro's capital plans for 2009 through 2014 were prepared, amended and subsequently reviewed and approved by the OEB.

C3.1.3 Interaction with the Distribution System Plan

The proposed plan implementation progress measure is expected to allow Toronto Hydro and the OEB to gauge the utility's progress towards the completion of its entire 2015-2019 capital plan at

C3.2 PLANNING, ENGINERRING & SUPPORT

regular intervals. Reviewing the progress at one-year intervals will assist in providing the OEB regular updates regarding the plan progress.

C3.2 Planning, Engineering & Support Efficiency

C3.2.1 Measure Description

Planning, engineering, and other eligible administrative costs associated with capital program or project development are a component of Toronto Hydro's total capital costs. For the purposes of its 2015-2019 Distribution System Plan, Toronto Hydro proposes to track the proportion of its total capital expenditures on distribution plant and associated civil infrastructure that is comprised of indirect planning, engineering and support labour costs related to this portion of the utility's capital expenditures. By measuring the resulting ratio and taking steps to ensure that it remains within or below the historical levels, Toronto Hydro plans to drive the efficiency and productivity of these processes, ultimately resulting in more cost-effective assets being put into service.

The eligible costs to be tracked for the proposed measure include capitalized labour costs associated with long-term, short-term planning functions, including development of the long-term system studies, capital investment programs and specific projects. Section D1 provides a high level summary of each of the planning processes, while Section D3 provides details with respect to the elements and outputs produced by each planning process. The work to develop and refine the utility's decision support systems is also included in Section D3.1.2.1. The formula for the proposed performance measure is as follows:

$$\text{Planning, Engineering \&Support Cost Efficiency}(\%) = \frac{\$\ \text{Capital Planning, Engineering \& Support Spend (Dx Plant)}}{\$\ \text{Total Capital Spend (Dx Plant)}}$$

Using a hypothetical example to illustrate the mechanics of this formula, if Toronto Hydro's total capitalized indirect labour costs related to electric distribution plant amounted to $5 million in a year, while the utility's total capital expenditures attributable to the distribution plant and associated civil infrastructure were $50 million, the resulting metric for the year in question would be:

$$\frac{\$5\text{M}}{\$50\text{M}} = 10\%$$

Toronto Hydro tracks the eligible costs through a thorough time-sheeting process. This process assigns indirect labour costs to capital, operating, or blended activities, in accordance with a detailed set of pre-established criteria. These criteria are approved by Toronto Hydro's senior management and reviewed for compliance with the applicable accounting frameworks. Given that the utility has had no experience in explicitly tracking its performance on this measure in the past, Toronto Hydro proposes to track the yearly results on a rolling five-year average starting in 2015, in order to reduce the effects of any one-time events that may affect the results. While a portion of eligible indirect labour costs such as regular salary and burden of full-time employees is typically "fixed" year-over-year, subject to headcount changes, a significant portion of these costs can vary year-over-year. The variability is caused by circumstances such as overtime use, implementation of new tools or process streamlining, or additional hiring to support the changes in the utility's capital program. Accordingly, by commencing the measurement of its indirect labour costs supporting its electrical distribution plant and the associated infrastructure, Toronto Hydro plans to be in a better position to assess and improve the efficiency of its indirect labour costing and resourcing through a variety of potential management decisions.

C3.2.2 Historical Performance Trends

While Toronto Hydro has not explicitly tracked the proposed metric in the past, the application of the proposed formula to the eligible portion of the utility's historical capital expenditures produces the results presented in Figure 9.

Over the past five years, the portion of Toronto Hydro's indirect labour costs relative to the total distribution plant-related capital expenditures has decreased from 13.1% in 2009 to 7.1% in 2013, for the average five-year value of 9.9%. Toronto Hydro attributes the improvement in this measure's results to the increasing size of the utility's capital work program and subsequent optimization of the available labour resources. Although part of this improvement is attributed to the staffing reductions and certain accounting changes (2011), Toronto Hydro has generally been able to manage an increasing capital work program with the smaller work force. In addition, the performance improvements are attributable to the increased efficiency of asset management processes through automation of many manual procedures and the use of decision support systems, detailed in Section D3.

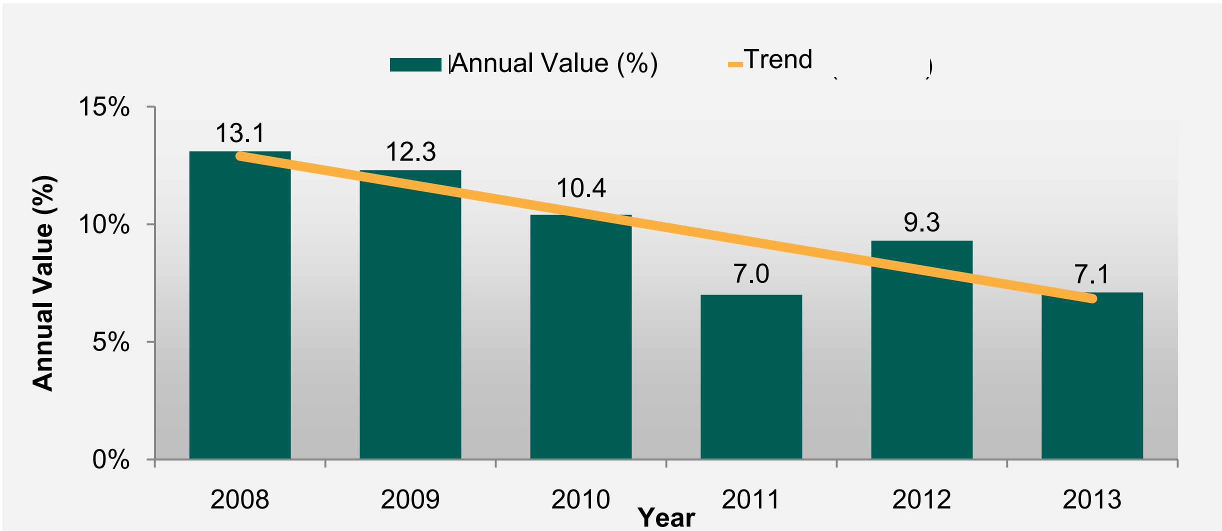


FIGURE 9: INDIRECT LABOUR % OF DX PLANT EXPENDITURES – 2009-2013

To gauge the appropriateness of its historic performance levels, Toronto Hydro consulted the 2014 edition of the *RSMeans Electrical Cost Data Book*[2] that provides the electric contractor industry with estimate ranges for a variety of electrical construction activities, including the proportion of total project costs made up of specific activities. A copy of the relevant information from this document can be found in Appendix A to this section of the DSP. According to the RSMeans data, the suggested total range of engineering costs as a portion of total project costs is within the 4.1% - 10.1% range. While Toronto Hydro's historical average result of 9.9% falls within the acceptable range, the utility notes that its indirect labour costs include other activities, such as management and support costs beyond the scope of activities captured by the RSMeans range.

For the purposes of its 2015-2019 capital plan, Toronto Hydro proposes to track the proportion of its indirect labour costs associated with electrical distribution plant relative to the total electrical distribution plant expenditures on a rolling five-year basis, with the 2009-2013 average value serving as a reference point. As the utility and the OEB gain more experience in this performance measurement area, Toronto Hydro may set more concrete targets in its future applications.

[2] RSMeans Electrical Cost Data Book, 2014 Edition, p 8.(See Appendix)

C3.3 SUPPLY CHAIN METRIC

C3.2.3 Interaction with the Distribution System Plan

Toronto Hydro has no previous experience in tracking the proposed metric. Accordingly, the utility's current Distribution System Plan was not explicitly informed by any assumptions as to the capital planning, engineering, and support efficiency. By measuring these activities over the 2015-2019 timeframe, Toronto Hydro expects to gain valuable insights into this dimension of its capital work, while ensuring that the amount of supporting labour costs included in its distribution plant capital project costs remains appropriate.

C3.3 Supply Chain Efficiency: Materials On-Cost

C3.3.1 Measure Description

In accordance with the applicable accounting frameworks, Toronto Hydro adds the eligible portion of its supply chain and warehousing activities costs directly to the capital projects and programs that these activities support. The supply chain and warehousing costs are added to the total costs of capital projects through the service charge referred to as "On-Cost," which is applied as a percentage of the project's total costs. Since capitalized warehousing activities make up a material portion of each project's final costs, Toronto Hydro proposes to track the annual On-Cost value as a measure of efficiency of the utility's supply chain and warehousing activities.

Toronto Hydro calculates the On-Cost rate as the sum of budgeted eligible expenditures (e.g. warehouse employee labour costs), divided by the budgeted dollar value of materials moving through the utility's warehouses (including the recently outsourced warehousing operation) in a given year. The utility then applies the resulting rate to the dollar value of all materials when issued to capital and operating projects. At the end of each year, Toronto Hydro calculates the final on-cost rate on the basis of actual warehouse expenditures and the value of materials processed through the warehouse, and makes the appropriate adjustments to the capital costs of all projects.

Not all warehousing expenditures are included in the on-cost rate. For example, the inventory of materials used for internal warehousing purposes, utilities and communications-related expenses, and administrative staff costs are excluded. As with the indirect labour costs measure discussed above, Toronto Hydro's On-Cost calculation methodology is based on pre-determined parameters that are periodically evaluated.

C3.3.2 Historical Performance Trends

Figure 10illustrates Toronto Hydro's historical On-Cost rates and the associated performance trend. Toronto Hydro's On-Cost charges remained relatively flat between 2009 and 2013, with a 2009-2013 historical average of 11.8%. The utility attributes its generally steady On-Cost levels to better utilization of available resources, the increase of the overall volume of capital program and a number of efficiencies detailed in the Supply Chain Program OM&A evidence (Exhibit 4A, Tab 2, Schedule 12). Over the 2015-2019 planning horizon, the utility expects its On-Cost rate to decline because of anticipated attrition and other productivity and efficiency improvements, including the deployment of a third-party warehousing outsourcing model that began in 2013.

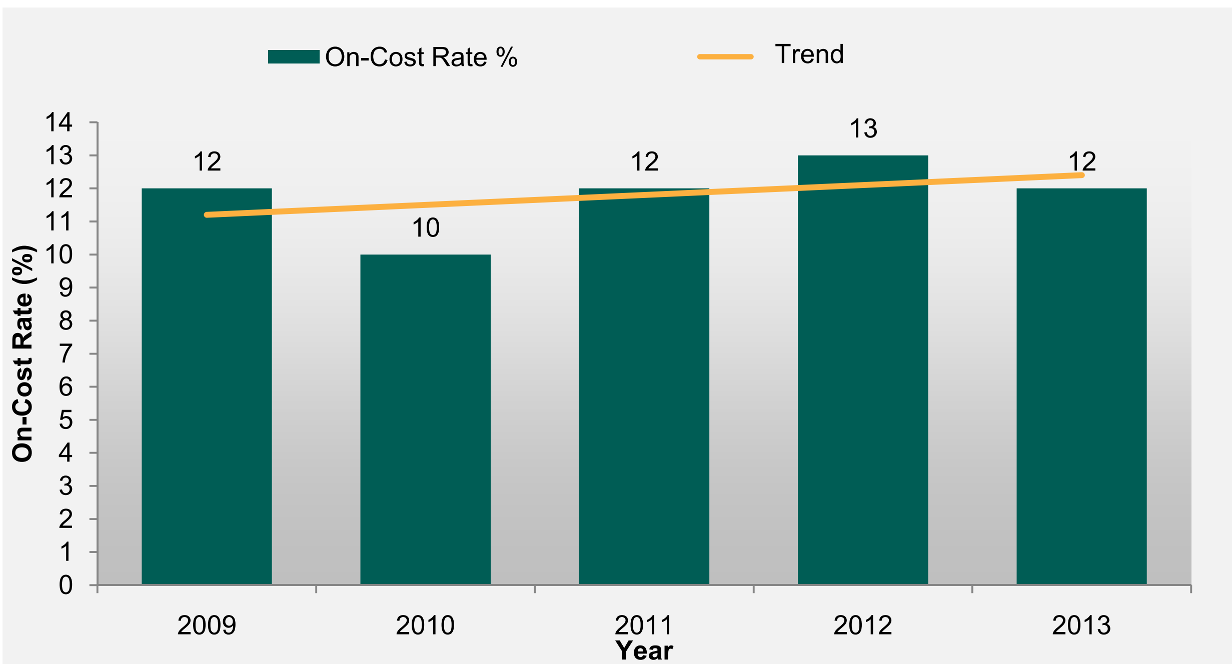


FIGURE 10: ON-COST PERFORMANCE (%) – 2009 – 2013

C3.3.3 Interaction with the Distribution System Plan

Subject to any developments outside of Toronto Hydro's control, Toronto Hydro's supply chain and warehousing efficiencies tracked through the On-Cost measure is expected to facilitate more cost-effective completion of the utility's capital program, enabling higher volumes of capital work to be completed for the same cost, thus directly benefiting Toronto Hydro ratepayers.

C3.4 CONSTRUCTION EFFICIENCY INTERNAL VS CONTRACTOR

C3.4 Construction Efficiency: Internal vs. Contractor Cost

C3.4.1 Measure Description

To assess the reasonableness of the costs of capital construction projects completed by the utility's internal construction crews, Toronto Hydro compares the cost of select projects constructed "in-house" to the unit prices charged for similar work performed by external contractor crews. Toronto Hydro currently employs six full-service design and construction contractors that provide the utility with turnkey electrical project design and construction services. This service enables the utility to complete the requisite volume of capital work in a safe and efficient manner, while providing the resourcing scalability and flexibility to account for the changing capital program funding levels.

When presented with individual project designs, contractors break down each project into the number and type of applicable activity-based units, which are based on Toronto Hydro's certified Distribution Construction Standards. The aggregation of unit prices determines the total price that the contractors are paid for delivering the project. As such, contractors are ultimately responsible for managing the variances between the unit cost estimate and their actual costs.

Once properly adjusted for the differences in cost structures between Toronto Hydro's operations and those of external contractors, the comparative results show Toronto Hydro the cost gap between internally and externally executed projects. Given that Toronto Hydro's external contractors operate in the same environment as the utility's internal crews, and use materials paid for and procured by the utility, comparisons between the costs of externally and internally constructed projects constitute an appropriate form of construction cost benchmarking. Operating in the Canadian and Toronto construction markets, the cost structures of Toronto Hydro's external contractor partners must reflect the optimal efficiency levels across both its operating and support activities in a competitive market. Accordingly, the unitized cost estimates provided to Toronto Hydro by its construction partners at the time of contract negotiation reflect the competitive market costs to complete the projects of the scope, scale and complexity characteristic of Toronto Hydro's aging and dense urban distribution system.

C3.4.1.1 Comparison Methodology

Beginning in 2011, each year Toronto Hydro selects up to ten reference capital projects constructed by its internal crews over the previous year. To date, the projects have been selected from three of the utility's larger capital portfolios, namely Direct Buried Cable Replacement, Overhead and Underground Rehabilitation. To establish a consistent baseline for cost comparison, the selected internally delivered projects have minimal cost and scope variations from the original design.

The reference project design packages are divided among several of Toronto Hydro's participating contractors, who disaggregate them into individual units. To better reflect the range of contractor costs available to Toronto Hydro, the utility applies the unit costs of all six contractors to the number and type of units identified for each project. This provides Toronto Hydro with six unique contractor cost estimates for each of the ten reference projects.

Prior to undertaking comparisons, Toronto Hydro's actual project costs and the contractor estimates require adjustments to account for a number of differences inherent in the respective entities' business models. The most significant of these adjustments is necessitated by the fact that Toronto Hydro's capital costs do not capture the full extent of the utility's expenses, as a significant portion of the utility's costs is recovered through the OM&A expenditures and other means of cost recovery available to regulated distributors in Ontario. At the same time, Toronto Hydro assumes that the contractors must recover and earn profit on the entirety of their operating activities through the prices charged for project delivery. To correct for this important distinction, Toronto Hydro's capital costs require adjustments to include the relevant overhead, burden and regulated return components.

In performing the above adjustment Toronto Hydro accounts for the fact that it performs a number of functions which the contractors do not perform at all (e.g. feeder switching), or which they perform on a smaller scale than the LDCs (customer care, finance, HR, etc). Because of these distinctions, certain components of Toronto Hydro's overhead and burden costs are either explicitly excluded from the capital cost adjustment, or are proportionally allocated to reflect the costs associated with Toronto Hydro's internally executed capital construction costs. The end product of the adjustment process is an all-in cost estimate of Toronto Hydro's construction costs for internally executed projects, inclusive of all the relevant support functions that may not be intuitively associated with construction. In other words, the resulting adjusted estimate represents a approximation of a hypothetical price that Toronto Hydro would charge its customers if it were a design and construction-only utility, as opposed to a regulated distributor.

In a similar manner, contractor project estimates require adjustments to account for the project-related cost drivers that are incremental to their project costs, including costs of audit and verification mandated by Toronto Hydro, and administration charges from the utility's Program Support Office that manages the design and construction contractors. After the completion of the adjustment process, Toronto Hydro's reference project costs are reasonably comparable to the contractor estimates..

C3.4.2 Historical Performance Trends

Based on the above comparison methodology, the costs of Toronto Hydro's internal project construction were on average [redacted] higher[3] than the costs of the same projects had they been constructed by the six design and construction contractors. The cost gap value was calculated using the weighted average of individual estimate variances commensurate to the proportion of external contract work performed by each of the six contractors in a reference year.

Toronto Hydro's analysis indicates that a significant portion of fully burdened construction cost variance stems from the higher overhead and burden expenditures associated with the scale and scope of the utility's operations as compared to the analogous cost drivers for the external contractors. Some of these costs are driven by the terms of Toronto Hydro's collective agreements and by the need for Toronto Hydro to have specialized trades to work on unique aspects of its distribution system (downtown network, lead cable, box construction etc.). Contractors, on the other hand, generally employ high voltage workers with generic qualifications and experience needed for more standard overhead and underground systems most prevalent across their customer base. However, with respect to other cost drivers, such as facilities expenditures and the On-Cost rate, Toronto Hydro anticipates overall improvement due to the planned or ongoing productivity and efficiency initiatives. For the purposes of the 2015-2019 CIR period, Toronto Hydro will use the results of its historical analysis as a general point of reference. The utility notes, however, that it has recently issued a Request for Proposals (RFP) with the goal of awarding and re-negotiating its contracts with all external design and construction service providers for the 2015 – 2018 timeframe. The outcomes of the RFP may materially affect the results of future comparative efforts relative to the past year assessments. This is especially relevant in light of the high demand for qualified services currently characterizing Toronto Hydro's electrical construction market, and expected to remain a significant factor in the medium term. This is primarily due to a large number of construction projects planned or underway in the city

[3] The redacted information has been filed confidentially pursuant to the OEB's *Practice Direction on Confidential Filings*

C3.5 STANDARD ASSET ASSEMBLY

including the residential high rise real estate developments, the PanAm/ParaPan Games construction, waterfront redevelopment, major transportation projects, and outsourcing work undertaken by other utilities.

C3.4.3 Interaction with the Distribution System Plan

Toronto Hydro uses the results of its external project construction cost benchmarking as a general reference for the reasonableness of the cost of projects completed by the utility's internal construction crews. As the utility continues conducting these comparative exercises over the 2015-2019 planning horizon, it may undertake more detailed assessments of individual cost drivers that make up the cost gap between contractor-delivered and internally constructed projects. At present, Toronto Hydro does not plan to expand the scale of this annual comparative activity, in part because of the complexity of conducting these assessments.

C3.5 Construction Efficiency: Standard Asset Assembly Labour Inputs

C3.5.1 Measure Description

Toronto Hydro is in the early stages of investigating the possibility of developing a comprehensive framework for tracking the total number of labour hours required to stage, install and energize a fully assembled unit corresponding to each major asset class of the utility's electricity distribution plant (e.g. transformers, switchgear etc). The project's envisioned scope entails developing a framework of about 25 major "Asset Assemblies," which in aggregate account for over 80% of the utility's planned capital program executed by internal resources.

At present, Toronto Hydro's engineers and designers use a fragmented framework of over 180 discrete labour activity cost estimates to prepare project scopes and develop associated designs, by taking into account the varying job-specific field conditions and circumstances that impact installation timeframes. While this framework enables Toronto Hydro to prepare extremely detailed cost estimates, it is not optimally suited for easy and effective tracking in the field by the utility's crews conducting the work. Accordingly, Toronto Hydro's objective is to augment the existing system with a more uniform, yet sufficiently flexible, labour hours input framework that would meet all of Toronto Hydro's planning, design and project tracking needs.

While the project is currently in an early testing stage, the envisioned end-state scope includes about 25 discrete estimates of total labour and “non-wrench” hours (e.g. driving, set-up/take-down, breaks) required to fully complete a single installation of a major asset class unit. The estimates of total hours will be developed based on system averages derived through analysis of past results, pilot time studies, and other activities determined as necessary during the subsequent project stages. To provide the requisite flexibility and scalability in light of the diversity of conditions and configurations inherent in Toronto Hydro’s distribution system, the core Asset Assemblies framework will be augmentable through a standardized and centrally managed set of Project Adjustment Factors. These additional estimate adjustment capabilities are expected to allow the engineers and designers to customize the expected project completion estimates to account for specific engineering, topographic or other related circumstances applicable to each individual project.

To faciliate the core labour and non-wrench hours estimates continuing to reflect the reality of field conditions, the underlying numbers will undergo periodic updates on the basis of actual results obtained from the field. This periodic update process is expected to effectively create a positive feedback loop, allowing Toronto Hydro to reflect the emerging improvements in crew productivity levels in its future estimates. This process will enable Toronto Hydro to maintain realistic capital construction targets and foster a culture of continuous improvement. To enable effective day-to-day tracking of project progress by individual construction crews, the project scope includes the development of a user-friendly IT application for use on handheld devices issued to crew leaders.

Toronto Hydro chose to focus on labour input hours rather than any other units (e.g. dollars), because labour hours are a commodity that is not affected by inflation, is generally comparable across the utility’s field resources, and has inherent potential for improvement through adoption of more efficient work execution practices and the introduction of new tools or other process improvements.

C3.5.2 Historical Performance Trends

Toronto Hydro is in the early stages of the Asset Assemblies project implementation and testing, so the utility does not have any historical results associated with this measure.

C3.5.3 Interaction with the Distribution System Plan

Given the early stages of what Toronto Hydro estimates to be a three-year project implementation timeline, Toronto Hydro's tracking of this measure will amount to annual updates on the project status, based on the following anticipated timeline:

- 2015-2016: develop and test the conceptual framework and implement the tracking system;
- 2017-2018: collect actual data and establish initial labour and non-wrench time benchmarks;
- 2019: begin reporting on performance related to a subset of specific Asset Assemblies.

While Toronto Hydro acknowledges that the above project tracking schedule is general in its nature, the utility is not in a position to provide a more detailed schedule at this time. Accordingly, Toronto Hydro plans to provide more detailed project development schedule forecasts with each annual update. Once Toronto Hydro is in a position to track the adherence to specific labour targets for Asset Assemblies completion, it plans to track approximately three to five individual asset categories for the purposes of any single Distribution System Plan performance measurement.

More generally, Toronto Hydro anticipates that the successful implementation of the Asset Assemblies framework will allow the utility to effectively benchmark its internal construction inputs (and by extension costs), thus driving continuous improvement. Among other things, the Asset Assemblies labour hours tracking framework may prove to be a useful way to inquire further into the utility's internal labour costs as compared to the results of benchmarking of its internal construction costs to the prices charged by the external construction contractors (See Section C3.4).

RESPONSES TO CANADIAN UNION OF PUBLIC EMPLOYEES LOCAL ONE INTERROGATORIES

RESPONSE:

a) This particular measure is advanced to track the effectiveness of the Distribution System Plan implementation, rather than the cost efficiency. Consistent with section 5.2.3 of the OEB's Chapter 5 Filing Requirements for Electricity Distribution Applications, Toronto Hydro presented all cost efficiency and plan implementation effectiveness measures in a single category. This measure is also consistent with the DSP plan implementation progress measure included into Toronto Hydro's 2013 OEB Distributor Scorecard.

b) Toronto Hydro considered that a single measure of Distribution Plan Implementation progress is most appropriate with respect to reporting the progress of an overall work program within the RRFE framework. As described in Exhibit 2B, Section C, pages 25-26, Toronto Hydro proposes to develop an Asset Assembly Labour Input measure which is expected to encompass 25 major "Asset Assemblies" to augment existing methods of planning and tracking program-specific work execution. As the utility and the OEB gain experience with this newly-introduced capital performance measurement and refine definitions of Asset Assemblies, Toronto Hydro may consider advancing other measures of cost efficiency and implementation effectiveness.

C4.2 STATION CAPACITY AVAILABILITY

The results of this measure will inform Toronto Hydro as to the effectiveness of its asset replacement strategies and preventive maintenance activities. Should the results over the future years display trends significantly different from the historical levels, Toronto Hydro plans to investigate the underlying reasons and make the appropriate adjustments as necessary and feasible. Customers that are interrupted due to failed equipment can typically expect extended outages as Toronto Hydro crews replace the failed asset. By reducing the volumes of equipment at risk of failure across its system, Toronto Hydro will be assisted delivering more reliable system performance to its customers.

C4.2 Stations Capacity Availability

C4.2.1 Measure Description

As its final performance measure for the purposes of its 2015-2019 Distribution System Plan, Toronto Hydro proposes to track the availability of capacity at its Transformer Stations (TS). The utility regularly monitors its available station capacity across the service territory to ensure that sufficient capacity exists to satisfy system peak demand, accommodate new customer connections, and provide a reasonable amount of operating flexibility to the Control Centre for the purposes of load transfers. These monitoring activities enable the planned and reactive capital and maintenance work, and facilitate outage restoration efforts.

Toronto Hydro forecasts station-specific demand on an annual basis and compares the forecasts against the available equipment capacity. Where forecasts indicate potential capacity shortages, Toronto Hydro develops and executes the plans to transfer the incremental load to adjacent stations or increase the existing equipment's capacity. Given the pace of the recent and projected economic growth across the utility's service territory, stations capacity monitoring represents a crucial dimension of Toronto Hydro's asset management activities.

For the purposes of the 2015-2019 Distribution System Plan performance monitoring, Toronto Hydro proposes to track the number of stations where peak demand exceeds 90% of station capacity over the next five years. Given that a number of station expansion activities are currently underway (including construction activities at Copeland TS), Toronto Hydro proposes to track this measure based on a five-year rolling outlook starting in 2015. Since Toronto Hydro is not always in a position to unilaterally affect the station capacity limitations (e.g. due to upstream transmission system constraints), the utility proposes to narrow the scope of this measure to include the stations where capacity limitations are at the station bus and/or switchgear level.

C4.2.2 Historical Performance Trends

Figure 12 shows the historical data for the proposed Stations Capacity measure for the 2009-2013 period. As evidenced by the chart, the number of stations with capacity limitations has increased from three to five over 2009-2013, with a historical high of six stations in 2011-2012. This trend reflects ongoing load growth and new connections throughout the city. Over the time period shown, no new stations or additional station busses have been put into service. The metric drops from 2012 to 2013 primarily as a result of load transfer projects that have been planned since the 2013 load forecast was issued.

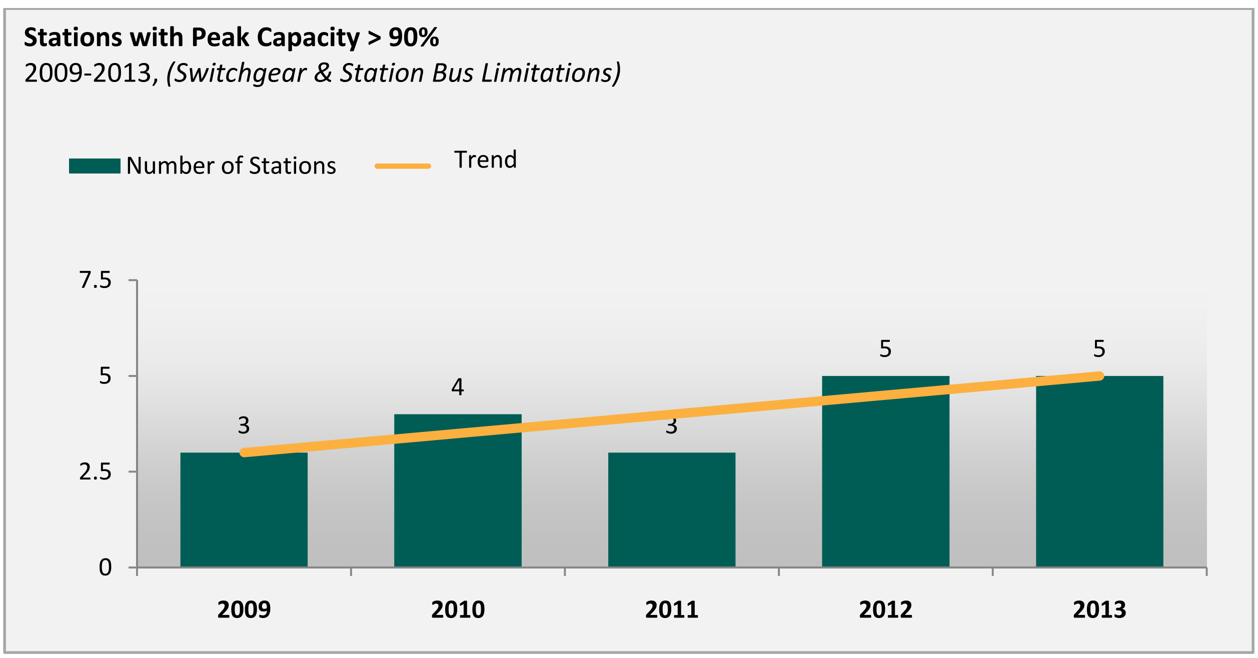


FIGURE 12: STATIONS WITH PEAK CAPACITY > 90% – 2009-2013, (SWITCHGEAR & STATION BUS LIMITATIONS)

C4.2.3 Interaction with the Distribution System Plan

Tracking the number of stations with peak capacity exceeding 90% will allow Toronto Hydro to gauge the effectiveness of its capacity planning processes and the timeliness of the associated constraint mitigation measures, including permanent load transfers, capacity increases, targeted CDM programs and other related activities. The Station Expansion Program specifically targets stations at which peak demand is approaching available capacity through upgrades and expansion of station infrastructure. The Load Demand program also aims to mitigate capacity shortfalls by balancing station bus loading through permanent load transfers.

Over the course of the 2015-2019 period, Toronto Hydro expects the measure and associated trend to remain generally constant, or potentially trend further upward, as more station busses approach their peak demand. Toronto Hydro's ability to maintain this trend is closely linked with the Station Expansion (E7.9) and Load Demand (load transfers) (E5.4) programs, which are expected to alleviate the most pressing concerns and add flexibility to the system to enable us to balance load between stations. Absent the investment levels proposed in either of these two programs, the measure would trend upward at a significantly higher pace.

CUSTOMER INTERRUPTION COSTS

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 14:

Reference(s): **Exhibit 2B, Section D3, page 14**

Preamble:

Customer Interruption Costs (CIC) values are calculated in two parts: the Event cost and the Duration cost. The Event cost represents the impact due to the occurrence of the outage whereas the Duration cost represents the costs incurred as the length of the outage increases. Toronto Hydro adopted $30 per kVA (peak load) as the Event cost to represent the CIC value due to the initial period of the outage, and $15 per kVA (peak load) per hour to represent the CIC value due to the increasing duration of the outage. These values, which were discussed at length in Toronto Hydro's 2012-2014 rates application, are established through work with consultants as well as the analysis of results from reliability valuation studies.

a) Below (Table 1 – Customer interruption cost breakdown) is list of studies referred to in Toronto Hydro's 2012-2014 rates application (EB-2012-064 Tab 6F, Schedule 1-27). Please confirm if these studies are still relied on in representing the Event and Duration costs for CIC in this application?

Table 1 – Customer Interruption Cost Breakdown

	Study Name	Duration Cost ($/kVA)	Event Cost ($/kVA)	Reference	Page Number on PDF
A	Interruption Costs Netherlands	8.721	6.579	N/A	4
B	THESL	15	30	N/A	N/A

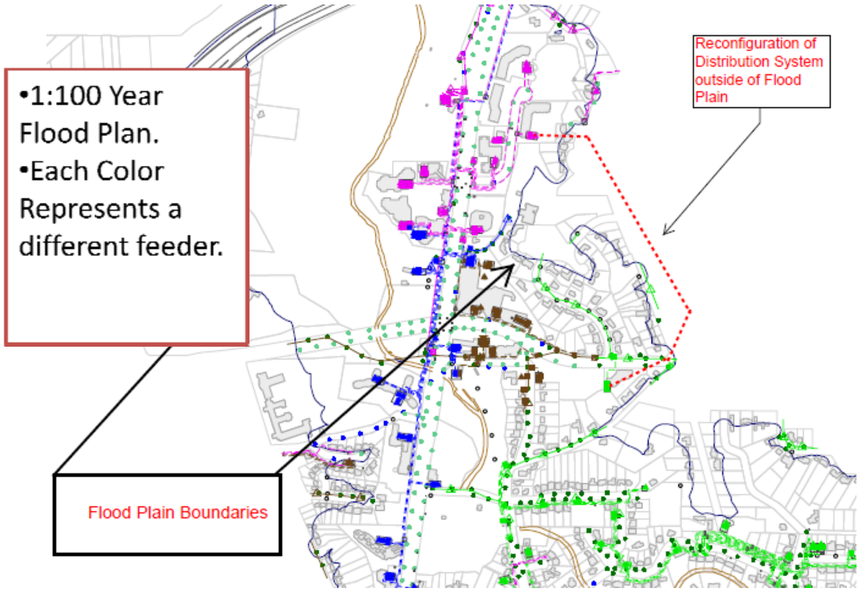


FIGURE 1: RECONFIGURING DISTRIBUTION SYSTEM OUTSIDE OF FLOOD PLAINS

E8.8.2.2 Customer Interruption Costs (CIC) Study

The proposed Customer Interruption Costs (CIC) study is a survey-based interruption cost study to estimate outage costs specific to the City of Toronto context. This study would survey various customer classes, Toronto Community Councils, and Business Improvement Areas (BIAs). Surveying across different customer demographics ensures that Toronto Hydro's diverse customer base is captured in this study. In addition, the proposed study would also ask each survey participant about their expectations (i.e. the frequency and duration of outages that customers consider acceptable) and perceptions (i.e. how satisfied customers are with the level of reliability they currently experience) of service reliability.

The selected vendor for this study would recommend outage scenarios and their proposed cost estimation methodology based on the diversity of survey participants. The different outage scenarios would include a combination of seasonal (summer/winter), weekly (weekend/weekdays), and daily (morning/afternoon/night). As shown in Figure 1, based on historical data, there is no single hour that accounts for more than 7% of outages or less than 2% of outages. Accordingly, the study must be designed to capture information across all time periods. Finally, each set of these scenarios will need to include durations of 5 minutes, 1 hour, 4 hours, 8 hours and 24 hours[1].

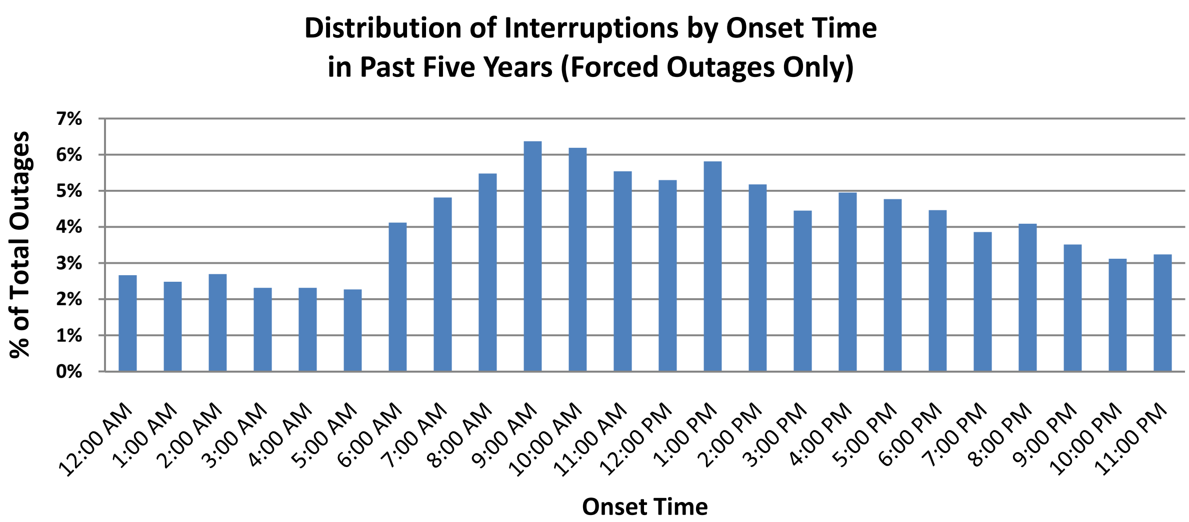


FIGURE 2: DISTRIBUTION OF INTERRUPTIONS BY ONSET TIME IN PAST FIVE YEARS

The different cost estimation methodologies are willingness-to-pay (WTP), willingness-to-accept (WTA), and direct-worth[2]. WTP cost estimations involve measuring the amount that customers would be willing to pay to avoid experiencing a service interruption; WTA involves measuring the level of compensation that customers would require to avoid a service interruption. Both of these approaches contribute to understanding how much customers would pay to avoid service interruptions. As costs for residential customers are mostly an inconvenience or hassle, they are often intangible and difficult to estimate using a direct-worth method. The combination of WTP and WTA approaches is a rigorous way of determining these implied costs. The direct-worth (DW) method involves asking customers to estimate the direct costs they would experience during a service interruption. These include outage related costs (e.g. labour and material costs incurred during an outage), lost production, cost to operate backup generation equipment,

[1] M.J. Sullivan and D.M. Keane, *Outage Cost Estimation Guidebook*, (Electric Project Research Institute Research Project 2878-04 Final Report) (San Francisco: Freeman, Sullivan and Company, 1995).

[2] Leona Lawton et al., *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*, (Berkley: Population Research Systems, LLC and Lawrence Berkeley National Laboratory, 2003), online: Consortium for Electric Reliability Technology Solutions <http://certs.lbl.gov/pdf/54365.pdf>.

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Economic Valuation of Electrical Service Reliability – Experiences from Austrian

Markus Bliem

Lisbon, 12 September 2008

Divergence between direct costs and WTP

- Respondents have no personal experience with (long) power outages → lead to overestimation of direct costs.
- Most households do not experience any tangible economic losses when an interruption occurs → direct cost values are based on subjective issues, subjective expectations, subjective well-being.
- Strategic response from the respondents → overestimate their costs in the hope of directing more investments towards quality problems.
- ???

How to Estimate the Value of Service Reliability Improvements

Michael J. Sullivan, Chairman, FSC, Matthew G. Mercurio, Senior Consultant, FSC, Josh A. Schellenberg, Senior Analyst, FSC, and Joseph H. Eto, Staff Scientist, LBNL

***Abstract*--A robust methodology for estimating the value of service reliability improvements is presented. Although econometric models for estimating value of service (interruption costs) have been established and widely accepted, analysts often resort to applying relatively crude interruption cost estimation techniques in assessing the economic impacts of transmission and distribution investments. This paper first shows how the use of these techniques can substantially impact the estimated value of service improvements. A simple yet robust methodology that does not rely heavily on simplifying assumptions is presented. When a smart grid investment is proposed, reliability improvement is one of the most frequently cited benefits. Using the best methodology for estimating the value of this benefit is imperative. By providing directions on how to implement this methodology, this paper sends a practical, usable message to the industry.**

***Index Terms*--Economics, education, planning, power distribution reliability, power system reliability, power transmission reliability, reliability, reliability estimation, statistics, technology planning**

I. Introduction

Reliability improvement is one of the most frequently cited justifications for investments in smart grid technology. Although reliability undoubtedly improves under most smart grid investments, the value of the reduction in outage frequency and/or duration is difficult to calculate. This difficulty leads many analysts to make simplifying assumptions. In a recent report by Freeman, Sullivan & Co. (FSC) and Lawrence Berkeley National Laboratory (LBNL), the authors propose a methodology for calculating the value of reliability improvements that does not as heavily rely on simplifying assumptions. This methodology has been proven to provide more reliable estimates, but has not usurped other methodologies because it is more complicated. This paper deals with that complication to guide analysts on how to apply outage cost estimates to a smart grid investment opportunity.

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II. Estimating Outage Costs

Starting in the mid-1980s, utilities in the US conducted a number of customer outage cost studies using slightly different survey methods and procedures. Survey-based methods have become the most widely used approach and are generally preferred over other measurement protocols because they can be used to obtain outage costs for a wide variety of reliability and power quality conditions not observable using other techniques.[1] Commercial customers are asked about the value of lost production, other outage related costs, and outage related savings, after taking into account their ability to make up for any lost production. For residential customers, the vast share of outage impacts are not directly observable economic costs and, as a result, they are typically asked about their willingness to pay to avoid outages with specific characteristics. However, because most US utility companies believed these studies could be used by competitors and opponents in the regulatory arena to gain advantage, few of these studies were released to the public domain.

In 2008, the U.S. Department of Energy (DOE) funded a meta-study of outage costs, making the models to estimate outage costs publicly available and subsequently employed those models to estimate outage costs for U.S. electricity consumers [2]. Twenty-eight studies, conducted by 10 electric utilities between 1989 and 2005 representing residential and commercial and industrial (C&I) customer groups were included in the analysis. The data was used to estimate customer damage functions expressing customer outage costs as a function of duration, time of day, consumption, business type, and other factors. The functions can be used to calculate customized outage costs for specific customers and specific durations, allowing the estimation of outage cost for the average residential and commercial customer in a given area.

The publicly available customer damage functions in this study can be employed to estimate customer outage costs with and without a smart grid investment – i.e., with current outage average duration and frequency and with reduced outage

[1] Two other outage cost estimation techniques have been employed: scaled macro-economic indicators (i.e., gross domestic product, wages, etc.), and market-based indicators (e.g., incremental value of reliability derived from studies of price–elasticity of demand for service offered under non-firm rates). For a detailed explanation of the different approaches, see the "Outage Cost Estimation Guidebook" [1].

duration and frequency. Table 1 displays estimated average electricity customer interruption costs for 2008 expressed in costs per event, costs per average kW, costs per un-served kWh and costs per annual kWh. Cost estimates are provided for three customer segments and for durations ranging from less than 5 minutes (momentary) to 8 hours. They are reported for three customer classes defined as follows:

- Medium and Large C&I (all non-residential customers with sales greater than 50,000 kWh per year);
- Small C&I Customers (all non-residential accounts with sales less than or equal to 50,000 kWh per year), and;
- Residential customers.

The values in the table have been calculated using the general customer damage functions described. These customer damage functions and the results in Table 1 can be found in the report prepared for DOE by FSC and LBNL [2]. Section IV below explains how to apply these outage cost estimates to a smart grid investment opportunity.

TABLE I
ESTIMATED AVERAGE ELECTRIC CUSTOMER INTERRUPTION COSTS US 2008$ BY CUSTOMER TYPE AND DURATION

Interruption Cost	Interruption Duration: Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$6,558	$9,217	$12,487	$42,506	$69,284
Cost Per Average kW	$8.0	$11.3	$15.3	$52.1	$85.0
Cost Per Un-served kWh	$96.5	$22.6	$15.3	$13.0	$10.6
Cost Per Annual kWh	9.18E-04	1.29E-03	1.75E-03	5.95E-03	9.70E-03
Small C&I					
Cost Per Event	$293	$435	$619	$2,623	$5,195
Cost Per Average kW	$133.7	$198.1	$282.0	$1,195.8	$2,368.6
Cost Per Un-served kWh	$1,604.1	$396.3	$282.0	$298.9	$296.1
Cost Per Annual kWh	1.53E-02	2.26E-02	3.22E-02	$0.137	$0.270
Residential					
Cost Per Event	$2.1	$2.7	$3.3	$7.4	$10.6
Cost Per Average kW	$1.4	$1.8	$2.2	$4.9	$6.9
Cost Per Un-served kWh	$16.8	$3.5	$2.2	$1.2	$0.9
Cost Per Annual kWh	1.60E-04	2.01E-04	2.46E-04	5.58E-04	7.92E-04

These customer damage functions are able to provide estimates of the costs of interruptions of varying duration; occurring at different times of day (morning, afternoon and evening), days of week (weekends or weekdays) and season (summer and winter). They also provide estimates of interruption costs for customers of different size; and in the case of business customers, by business type (i.e., retail, utilities, construction, etc.). It is also possible to estimate costs for planned as opposed to unannounced interruptions and for customers with and without backup generation. Thus by inserting reasonable assumptions about the interruption characteristics and customers into the customer damage functions, it is possible to use them to estimate the cost of a wide range of interruptions for a wide range of customers. Then the costs can be compared with and without a reliability investment to determine the change in value of service.

III. METHODOLOGICAL COMPARISON

There are two key findings from these outage cost estimates that have important implications for the valuation of smart grid investments:

1. Cost per un-served kWh is substantially higher for small C&I customers than medium and large C&I customers.
2. A reduction in outage duration is less valuable than a reduction in outage frequency if the reduction in un-served kWh is equal.

Depending on the customer mix in a given area or the types of technologies in consideration, analysts may drastically under- or overestimate the value of a smart grid investment if too many simplifying assumptions are made. The following two examples compare methodologies and consider the implications of these simplifying assumptions.

A. Value of Distribution Automation in California

In a recent report prepared for the California Energy Commission (CEC) [3], the authors investigate the value of a change in SAIFI that distribution automation investments in California will provide. These investments are projected to provide a 32.7 percent decrease in SAIFI where the average outage duration is 101.9 minutes. The estimated value to the customer is $127.7 million, of which $125.4 million comes from the C&I sector (see Table 2). To estimate this change in value of service, the C&I sector was split into commercial and industrial customers and assigned different dollar values per un-served kWh. Industrial customers were assumed to experience a loss of $25 per un-served kWh and $10 for commercial. The study that these values are based on is not reported.

However, as seen above, the more applicable C&I grouping methodology is between small C&I customers and medium and large C&I customers. Therefore, we take the combined C&I un-served kWh and allocate it among this alternative grouping. Based on usage data from a large California utility, we estimate that in California around 90 percent of C&I usage is among medium and large C&I customers and 10 percent among small C&I customers. Using this allocation and an approximate dollar per un-served kWh of a 101.9 minute outage, we estimate that the change in value of service is $239.6 million. This methodology leads to an estimated change in value of service nearly double that of the estimates in the CEC report.

TABLE II
ESTIMATING CHANGE IN VALUE OF SERVICE FROM AUTOMATED DISTRIBUTION INVESTMENTS IN CALIFORNIA – TWO METHODOLOGIES

C&I Grouping Methodology	Sector	Un-served kWh	$ / Un-served kWh	Change in Value of Service ($ million)
Commercial vs. Industrial	Commercial	1,655,688	$10.0	$16.6
	Industrial	4,305,287	$25.0	$107.6
	Combined C&I	**5,960,975**	**$20.8**	**$125.4**
Small C&I vs. Medium & Large C&I	Small C&I	596,098	$285.0	$169.9
	Medium & Large C&I	5,364,878	$13.0	$69.7
	Combined C&I	**5,960,975**	**$40.2**	**$239.6**

B. Problems with Un-served kWh Approach

Although we use the un-served kWh approach to compare differences in C&I groupings, this methodology does not deal