RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 2:
Reference(s):
Exhibit 1B, Tab 2, Schedule 1, pp. 23-24
Exhibit 1B, Tab 2, Schedule 1, Appendix B

Question(s):

a) Please provide a discussion of the purpose of the unit cost benchmarking study with respect to Toronto Hydro’s application. Please advise, specifically, whether the UMS Group study is intended to support the custom stretch factor proposed by Toronto Hydro.

RESPONSE:
As described at Exhibit 1B, Tab 2, Schedule 1, pp. 23-24, the purpose of the unit cost benchmarking study was to assess the actual efficiency with which Toronto Hydro executes its investment and maintenance programs, thereby facilitating an evaluation of the reasonableness of Toronto Hydro’s actual and proposed costs in these areas. The study is also one of the ways in which Toronto Hydro’s application fulfils the Ontario Energy Board’s expectation that the utility provide “measurement of units of activity and their costs.”

While the study was not initiated to support the proposed stretch factor, the study results are consistent with the conclusions in the “Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels” report produced by Power System Engineering Inc. Within this report, it is stated that “Toronto Hydro is certainly not a poor total cost

1 EB-2014-0116, Decision and Order (December 29, 2015) at page 6.

Panel: General Plant, Operations, and Administration
performer” and that “the company should certainly not receive the most extreme stretch factor of 0.6 percent, which should be reserved for the poorest total cost performers.”

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2 Exhibit 1B, Tab 4, Schedule 2, p. 12.

Panel: General Plant, Operations, and Administration
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 3:
Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B

a) Please advise for how many years the results of the study should be considered valid.

b) Please advise if Toronto Hydro intends to update the study as part of each rebasing proceeding. If not, please explain.

c) In the opinion of UMS Group, what, if any, limitations to the study’s findings exist? Please describe any limitations as well as how the OEB should consider those limitations when assessing the applicability of the report’s findings to Toronto Hydro and its current application.

RESPONSE (PREPARED BY UMS GROUP):
a) UMS Group typically considers benchmarking results valid for 2 to 5 years, reflecting the time between identifying an opportunity to improve, defining and taking appropriate action, and the realization of notable improvement. Given the relatively immature state of industry in addressing productivity, particularly unit cost, UMS Group would recommend the latter end of the range (i.e. 4 or 5 years).

RESPONSE (PREPARED BY TORONTO HYDRO):
b) As noted in response to 1B-Staff-2, the purpose of the unit cost benchmarking study was to facilitate an evaluation of the reasonableness of Toronto Hydro’s actual and
proposed costs in this application. The study is also one of the ways in which Toronto Hydro’s application fulfils the Ontario Energy Board’s expectation that the utility provide “measurement of units of activity and their costs.” Toronto Hydro intends to provide salient benchmarking analysis to support its plans and programs and to demonstrate continuous improvement in its future rebasing applications.

RESPONSE (PREPARED BY UMS GROUP):

c) There are inherent limitations to benchmarking, as (1) the formulation of any peer group panel will not provide a perfect match in terms of demographics, and (2) accounting practices across the industry vary slightly from utility to utility. However, data normalization like the one performed for this study narrows this gap sufficiently enough to achieve the industry standard of “directional accuracy” as described in the Summary of Results section of the UMS Group Benchmarking Study:

- “Benchmarking is directionally [as opposed to precisely] accurate in identifying opportunities for improvement of and/or validating current cost and service levels,” and
- “It [Benchmarking] points towards areas where well-targeted intervention can result in improved performance (in this case reduced unit costs), and provides a point for real-time performance comparisons.”

In light of the foregoing, and given the consistency and stability of THESL’s relative position among the peer group panel (with and without normalization), UMS Group sees no limitations in assessing the applicability of the report’s findings to THESL and its current application.

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1 EB-2014-0116, Decision and Order (December 29, 2015) at page 6.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 4:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B, p. 7

a) Please provide revised versions of Table II-1 (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 7) based on Phase 1 and Phase 2 normalizations.

RESPONSE (PREPARED BY UMS):

a) Please refer to Tables 1 and 2 below.

Table 1: Phase 1 Normalized Benchmark Comparisons

<table>
<thead>
<tr>
<th>Category / Program</th>
<th>THESL Unit Cost 3-YR Weighted Average</th>
<th>Quartile</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Top</td>
</tr>
<tr>
<td>Wood Pole</td>
<td>$7,434</td>
<td>X</td>
</tr>
<tr>
<td>UG Cable (XLPE)</td>
<td>$96</td>
<td>X</td>
</tr>
<tr>
<td>OH Switches</td>
<td>$21,062</td>
<td>X</td>
</tr>
<tr>
<td>Pole Top Transformer</td>
<td>$11,761</td>
<td>X</td>
</tr>
<tr>
<td>Padmount/UG Transformer</td>
<td>$21,454</td>
<td>X</td>
</tr>
<tr>
<td>Network Transformer / Protector</td>
<td>$88,943</td>
<td>X</td>
</tr>
<tr>
<td>Breaker (SF6, Oil and Vacuum)</td>
<td>$85,242</td>
<td>X</td>
</tr>
<tr>
<td>Vegetation Management</td>
<td>$2,111</td>
<td>X</td>
</tr>
<tr>
<td>Pole Test and Treat</td>
<td>$18</td>
<td></td>
</tr>
<tr>
<td>Overhead Line Patrol</td>
<td>$44</td>
<td></td>
</tr>
<tr>
<td>Vault Inspection</td>
<td>$253</td>
<td></td>
</tr>
</tbody>
</table>

Note 1: In applying the normalizers, adjustments, UMS Group made adjustments, using THESL as the base (i.e.; no adjustment to THESL’s unit costs)

Note 2: In preparing these tables, UMS Group noted that it inadvertently understated THESL’s comparative position in Vegetation Management (should have been “Top Quartile” in contrast to “2nd Quartile” indicated in Table II-1).
Table 2: Phase 2 Normalized Benchmark Comparisons

<table>
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<tr>
<th>Category / Program</th>
<th>THESL Unit Cost 3-YR Weighted Average</th>
<th>Quartile</th>
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</thead>
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<tr>
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<td>Top</td>
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<td>Wood Pole</td>
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<td>UG Cable (XLPE)</td>
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<td>Network Transformer / Protector</td>
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<td>Breaker (SF6, Oil and Vacuum)</td>
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<td>$2,111</td>
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<td>Overhead Line Patrol</td>
<td>$44</td>
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<tr>
<td>Vault Inspection</td>
<td>$253</td>
<td></td>
</tr>
</tbody>
</table>

Note 1: In applying the normalizers, adjustments, UMS Group made adjustments, using THESL as the base (i.e.; no adjustment to THESL’s unit costs)

Note 2: In preparing these tables, UMS Group noted that it inadvertently understated THESL’s comparative position for Vegetation Management (should have been “Top Quartile” in contrast to “2nd Quartile” indicated in Table II-1).
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 5:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B, p. 11

Preamble:
UMS Group states that the seven asset categories represent approximately 60% of the maintenance capital budget over the 2014-2016 period and the four maintenance programs represent 50% of the preventative and predicative maintenance costs.

a) Please provide the percentage that the seven asset categories constitute relative to the entire capital budget for 2014-2016 (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 11).

b) Please provide the percentage that the four maintenance programs constitute relative to the entire OM&A budget for 2014-2016 (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 11).

RESPONSE:

a) The seven asset categories represent approximately 27 percent of the entire capital budget over the 2014-2016 period.

b) The four maintenance programs represent approximately 2 percent of the entire OM&A budget over the 2014-2016 period.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 6:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B, p. 11

Preamble:

UMS Group states that in considering other Ontario local distribution companies (LDCs), with the exception of the recently formed Alectra Utilities, Toronto Hydro stands unique.

a) Please discuss the degree to which the inclusion of one or more Ontario LDCs in the benchmarking study would have increased the robustness of the findings (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 11). Specifically, please discuss whether the inclusion of one or more Ontario’s LDCs would have provided UMS Group with a logical reference point to compare Toronto Hydro’s unit cost estimates.

b) The report states that Toronto Hydro stands unique given, amongst other factors, its ordinances, higher cost of living, and population density. The report contends that these differences drove the need for a non-Ontario peer group (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 11). In the context of the regulatory, environmental, and external factor similarities between Toronto Hydro and its Ontario LDC peers, please advise whether UMS Group agrees that these Ontario-specific factors could allow for a meaningful comparison of unit costs.
RESPONSE (PREPARED BY UMS GROUP):

a) The premise of this question is incorrect. Once Alectra Utilities systems and practices are fully integrated and operational, it might serve as a valid comparator. However, UMS Group does not view any other Ontario LDCs as scalable to the size and complexities of THESL’s business and operating environment. The factors that drive cost and performance for THESL are much more in line with those of mid and large size investor-owned and municipality-owned utilities in US than those in Ontario. Further, the issue of scalability dwarfs many of the factors that seem to support their inclusion (e.g.; regional costs, regulatory framework, weather, and environmental requirements), and does not lend itself to normalization.

b) For the reasons stated above, UMS Group does not concur with the notion that other Ontario LDCs would allow for a meaningful comparison of costs.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 7:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B, p. 12

a) Please explain how UMS Group solicited utilities for participation in the study (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 12).

RESPONSE (PREPARED BY UMS):

a) UMS Group leveraged its relationships across the industry to solicit utilities for participation in the study. UMG Group reached out to those utilities that have in past expressed their interest in improving work productivity and willingness to participate in benchmarking studies.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 8:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B, p. 17

Preamble:

Table IV-1 (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 17) highlights the results of the comparative analysis and demonstrates high levels of consistency between Toronto Hydro’s costs to comparator jurisdictions across all categories.

RESPONSE:

a) Please advise how Toronto Hydro would respond if procurements undertaken to solicit projects related to one of the investigated asset categories or maintenance programs result in forecast costs significantly higher than those presented in the UMS Group report.

RESPONSE:

a) Toronto Hydro cannot speculate as to how it would respond to the hypothetical scenario provided. The purpose of the UMS report was to show relative performance with other utilities and not to be a definitive basis against which all costs are measured. The utility always strives to secure the best possible external vendor pricing for its customers in accordance with the procedures set out in its Procurement Policy, provided at Exhibit 4A, Tab 3, Schedule 1, Appendix A.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 9:
Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B, p. 19

a) Please file the supporting materials on the record of this proceeding (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 19).

RESPONSE:

a) Please see Appendices A to O to this response. Please note that Appendices O and P have been filed confidentially.
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

ISSUE 2, INTERROGATORY 3:

REFERENCE(S): Exhibit 2

a) Please complete the attached spreadsheet (2-AMPCO-3) and provide the live excel version.

AMPCO included asset types under each segment that were identified in EB-2012-0064 & EB-2015-0173. If THESL believes that different asset types would be more reflective of the work forecasted and completed, please adjust the asset types in part a) accordingly.

RESPONSE:

Please see attachment (Appendix A to this response) for a best-efforts comparison of forecast versus actual assets installed by major asset class at the ICM segment level. For the reasons noted below, these units do not allow for a rigorous and detailed comparison of forecast versus actual unit accomplishments. However, the units are directionally comparable (i.e., at an order-of-magnitude level) and can be used to assess general alignment of asset-based accomplishments by segment during the ICM period.

Explanation of the Data Provided

Assets. Toronto Hydro has narrowed the list of assets requested to those that were originally filed in the Phase 1 and/or Phase 2 ICM Application evidence. Toronto Hydro did not establish forecasts for any other asset types in its ICM Application and is not in a position to retroactively do so now (see response to interrogatory 1-AMPCO-4). Furthermore, many of the specific asset types requested by AMPCO are not tracked at the
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

necessary level of granularity (or, in some cases, at all) in Toronto Hydro’s financial systems.

Actual Units Installed. As discussed in the “THESL Response re AMPCO Motion Settlement” (EB 2014-0116, Filed: January 21, 2015), Toronto Hydro can only provide actual units installed (as opposed to replaced or removed) for 2012 to 2014, based on data kept for financial tracking purposes. Toronto Hydro has provided these units for the relevant major asset classes at the maximum level of granularity facilitated by the financial tracking system.

Forecast Units Installed. Toronto Hydro derived the forecasted units installed by summing the unit counts that appeared in the original ICM segment narratives. For geographical or feeder based programs (e.g., Overhead Infrastructure), these asset counts were originally determined by reviewing maps of job areas and manually counting the major assets to be addressed. These forecasts were developed specifically for the filing in order to provide a sense of scale for the work forecasted in the application. As is generally the case at the high-level estimating stage, Toronto Hydro assumed a one-to-one relationship between units removed and units installed for programs that are like-for-like in nature (e.g., Underground Infrastructure). In practice, units installed will most often vary from the number of units replaced due to the application of updated standard design practices and consideration for site-specific design requirements.

1 The main exceptions to like-for-like replacement are the Rear Lot Construction segment, which even at the high-level must necessarily assume a new front-lot underground plan, and the Network Vaults & Roofs and ATS & RPBs segments, which may include work that is not like-for-like, such as decommissioned units.
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

1 Additional caveats related to both the forecast and actual units installed are provided in
2 footnotes to the attached table.
3
4 Toronto Hydro has excluded the Metering segment from the table as an activity-based
5 discussion of variances is already provided at Exhibit 2, Tab 12, Schedule 1 of this
6 Application.
<table>
<thead>
<tr>
<th>Segment</th>
<th>Assets</th>
<th>Unit of Measure</th>
<th>Non-Linear Units</th>
<th>Linear Units</th>
<th>Total Units</th>
<th>2012-2014 ISA Quantities (Forecasted Jobs)</th>
<th>2012-2014 ISA Quantities (Analogous Jobs)</th>
<th>2012-2014 ISA Quantities</th>
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</thead>
<tbody>
<tr>
<td><strong>B1</strong> Underground Infrastructure</td>
<td>Primary Cable</td>
<td>M</td>
<td>-</td>
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<td>601,275</td>
<td>447,045</td>
<td>112,861</td>
<td>559,906</td>
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<td></td>
<td>Submersible Transformers</td>
<td>EA</td>
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<td>-</td>
<td>976</td>
<td>473</td>
<td>78</td>
<td>551</td>
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<td></td>
<td>SFE-Insulated Pad-mounted Switchgear</td>
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<td>78</td>
<td>-</td>
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<td>84</td>
<td>45</td>
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<td></td>
<td>SFE-insulated Vault-installed Switchgear</td>
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<td>133</td>
<td>-</td>
<td>133</td>
<td>154</td>
<td>12</td>
<td>166</td>
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<tr>
<td><strong>B2</strong> PILC Cables</td>
<td>Piece Out and Leakers</td>
<td>EA</td>
<td>295</td>
<td>-</td>
<td>295</td>
<td>-</td>
<td>-</td>
<td>-</td>
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<td>-</td>
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<td>308</td>
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<tr>
<td></td>
<td>Porcelain Insulators</td>
<td>EA</td>
<td>3,403</td>
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<td>-</td>
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<td>567</td>
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<td>Switches</td>
<td>EA</td>
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<td>-</td>
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<td>-</td>
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<td></td>
<td>Transformers</td>
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<td>-</td>
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<td>340</td>
<td>17</td>
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<td>Underground Civil Work</td>
<td>M</td>
<td>-</td>
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<td>37,421</td>
<td>51,509</td>
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<td><strong>B6</strong> Rear Lot Construction</td>
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<td>EA</td>
<td>17</td>
<td>-</td>
<td>17</td>
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<td>51,509</td>
<td>4,199</td>
<td>55,708</td>
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<tr>
<td><strong>B9</strong> Network Vaults &amp; Roofs</td>
<td>Vaults - Decommissioned</td>
<td>EA</td>
<td>3</td>
<td>-</td>
<td>3</td>
<td>-</td>
<td>-</td>
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<tr>
<td></td>
<td>Vaults - Complete Rebuild</td>
<td>EA</td>
<td>19</td>
<td>-</td>
<td>19</td>
<td>17</td>
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<td>26</td>
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<td>Vaults - Roof Rebuild</td>
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<td>-</td>
<td>9</td>
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<tr>
<td><strong>B10</strong> Fibertop Network Units</td>
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<td>104</td>
<td>-</td>
<td>104</td>
<td>145</td>
<td>40</td>
<td>185</td>
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<tr>
<td><strong>B11</strong> Automatic Transfer Switches &amp; Reverse Power Breakers</td>
<td>Automatic Transfer Switches</td>
<td>EA</td>
<td>12</td>
<td>-</td>
<td>12</td>
<td>-</td>
<td>-</td>
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<tr>
<td><strong>B12</strong> Station Power Transformers</td>
<td>Transformers</td>
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<td>10</td>
<td>-</td>
<td>10</td>
<td>5</td>
<td>8</td>
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<tr>
<td><strong>B13</strong> Stations Switchgear</td>
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<td>-</td>
<td>10</td>
<td>-</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>TS Switchgear</td>
<td>EA</td>
<td>4</td>
<td>-</td>
<td>4</td>
<td>-</td>
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</tr>
</tbody>
</table>

**Note:**

1. Actuals data does not track this asset.
2. Forecast only includes amounts filed in Phase 2 as no forecasts were filed in Phase 1; actuals includes all 2012-2014 data.
3. Forecast only includes amounts filed in Phase 2 as no forecasts were filed in Phase 1; actuals includes all 2012-2014 data. Data in Actuals for financial statements was only tracked discretely starting from 2013.
### 2015-2019 Programs To Unit Cost Asset Category Mapping

<table>
<thead>
<tr>
<th>PROGRAM NAME</th>
<th>Unit cost Asset Categories</th>
<th>Activity Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>E6.1 Metering</td>
<td></td>
<td></td>
</tr>
<tr>
<td>E6.2 Customer Connections</td>
<td>O/H Pole Replacement</td>
<td>Pole replacement due to a new/modified customer connection</td>
</tr>
<tr>
<td></td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Cable and duct replacement due to a new/modified customer</td>
</tr>
<tr>
<td></td>
<td>U/G Transformers</td>
<td>O/H Transformer installation due to a new/modified customer</td>
</tr>
<tr>
<td></td>
<td>U/G Transformers</td>
<td>O/H Transformer replacement due to a new/modified customer</td>
</tr>
<tr>
<td></td>
<td>Station Breaker &amp; Switchgear Replacement</td>
<td>Station Breaker &amp; Switchgear replacement due to a new/modified customer</td>
</tr>
<tr>
<td>E6.3 Externally Initiated Plant Relocations &amp; Expansions</td>
<td>O/H Pole Replacement</td>
<td>This program includes work to maintain, upgrade, expand and improve existing public infrastructure. The replacement of any asset occurs when facilitating relocation projects. The existing facility is replaced on a like-for-like basis. In some cases, system expansion projects occur in conjunction with relocations to facilitate future plans in the area.</td>
</tr>
<tr>
<td></td>
<td>Station Breaker &amp; Switchgear Replacement</td>
<td>This program includes work to maintain, upgrade, expand and improve existing public infrastructure. The replacement of any asset occurs when facilitating relocation projects. The existing facility is replaced on a like-for-like basis. In some cases, system expansion projects occur in conjunction with relocations to facilitate future plans in the area.</td>
</tr>
<tr>
<td></td>
<td>U/G Transformers</td>
<td>This program includes work to maintain, upgrade, expand and improve existing public infrastructure. The replacement of any asset occurs when facilitating relocation projects. The existing facility is replaced on a like-for-like basis. In some cases, system expansion projects occur in conjunction with relocations to facilitate future plans in the area.</td>
</tr>
<tr>
<td></td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>This program includes work to maintain, upgrade, expand and improve existing public infrastructure. The replacement of any asset occurs when facilitating relocation projects. The existing facility is replaced on a like-for-like basis. In some cases, system expansion projects occur in conjunction with relocations to facilitate future plans in the area.</td>
</tr>
<tr>
<td>E6.4 Load Demand</td>
<td>O/H Pole Replacement</td>
<td>Replace poles where required to meet latest standards</td>
</tr>
<tr>
<td></td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Upgrade poles and rebuild duct banks to eliminate bottlenecks within the system</td>
</tr>
<tr>
<td></td>
<td>U/G Vault &amp; Equipment Inspections</td>
<td>Inspect vaults and equipment in the areas requiring upgrades</td>
</tr>
<tr>
<td></td>
<td>U/G Transformers</td>
<td>Replace U/G Transformers when the demand in the area requires additional capacity</td>
</tr>
<tr>
<td>E6.5 Generation Monitoring, Protection &amp; Control</td>
<td>O/H Pole Replacement</td>
<td>Replace poles where required to meet latest standards</td>
</tr>
<tr>
<td></td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Upgrade poles and rebuild duct banks to eliminate bottlenecks within the system</td>
</tr>
<tr>
<td></td>
<td>U/G Transformations</td>
<td>Replace U/G Transformers when the demand in the area requires additional capacity</td>
</tr>
<tr>
<td>E6.6 Underground Circuit Renewal</td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Upgrade and replace cables if modifying the distribution configuration away from URD. Replaces existing direct buried primary cable with cable in duct bank</td>
</tr>
<tr>
<td></td>
<td>U/G Vault &amp; Equipment Inspections</td>
<td>Replace/repair/replace existing vaults to install electrical equipment. Inspecting URD vaults.</td>
</tr>
<tr>
<td></td>
<td>U/G Transformers</td>
<td>Replace legacy URD transformers. Replaces assets due to condition, PCB content or at end of life.</td>
</tr>
<tr>
<td>E6.7 PILC Piece Outs &amp; Leakers</td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Repair/replace leaking PILC cables and piece out cable in congested U/G system</td>
</tr>
<tr>
<td></td>
<td>U/G Vault &amp; Equipment Inspections</td>
<td>Inspect cable chambers and vaults for PILC leaks</td>
</tr>
<tr>
<td>E6.8 Underground Legacy Infrastructure</td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Upgrade cables and ducts as required when removing underground</td>
</tr>
<tr>
<td></td>
<td>U/G Vault &amp; Equipment Inspections</td>
<td>Replace legacy infrastructure such as Saschenwerk switch and fuse</td>
</tr>
<tr>
<td></td>
<td>U/G Transformers</td>
<td>Replace vault step up transformers</td>
</tr>
<tr>
<td>E6.9 Overhead Circuit Renewal</td>
<td>O/H Pole Replacement</td>
<td>Program replaces old poles</td>
</tr>
<tr>
<td></td>
<td>O/H Transformers</td>
<td>Program replaces old TPs</td>
</tr>
<tr>
<td>E6.10 Overhead Infrastructure Relocation</td>
<td>O/H Pole Replacement</td>
<td>Program replaces and re-routes old and inaccessible pole lines</td>
</tr>
<tr>
<td></td>
<td>O/H Cable &amp; Duct Replacement</td>
<td>Program puts overhead existing OH lines to underground</td>
</tr>
<tr>
<td></td>
<td>O/H Transformers</td>
<td>Program replaces old and inaccessible transformers</td>
</tr>
<tr>
<td>E6.11 Rear Lot Conversion</td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Replace existing OH assets in rear lot with front lot UG system (cable in ducts)</td>
</tr>
<tr>
<td></td>
<td>U/G Transformers</td>
<td>Replace aging obsolete transformers with new UG Transformers</td>
</tr>
<tr>
<td></td>
<td>O/H Pole Replacement</td>
<td>Replace some of the poles on city street required for rearlot conversion</td>
</tr>
<tr>
<td>E6.12 Box Construction Conversion</td>
<td>O/H Pole Replacement</td>
<td>Replace legacy box construction poles with standard poles for conversion to 13.8kV</td>
</tr>
<tr>
<td></td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Upgrade cable and pull new cable to facilitate 13.8kV conversion</td>
</tr>
<tr>
<td></td>
<td>O/G Transformers</td>
<td>Replace 4kV O/H transformers</td>
</tr>
<tr>
<td>E6.13 SCADAMATE R1 Renewal</td>
<td>O/H Pole Replacement</td>
<td>Poles holding R1 switches are replaced due to age, condition or standard conformance.</td>
</tr>
<tr>
<td>E6.14 Network Vault Renewal</td>
<td>U/G Transformers</td>
<td>Replace and upgrade U/G transformers if required during civil</td>
</tr>
<tr>
<td></td>
<td>U/G Vault &amp; Equipment Inspections</td>
<td>More for vault civil rebuilds</td>
</tr>
<tr>
<td>E6.15 CTRL Infrastructure Relocation</td>
<td>U/G Transformers</td>
<td>Replace legacy ATS and RPR schemes with network units</td>
</tr>
<tr>
<td>E6.16 Network Circuit Reconfiguration</td>
<td>U/G Transformers</td>
<td>Upgrade network units if beneficial for the network</td>
</tr>
<tr>
<td></td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Upgrade secondary cabling if beneficial for the network</td>
</tr>
<tr>
<td>E6.17 Stations Switchgear Renewal</td>
<td>Station Breaker &amp; Switchgear Replacement</td>
<td>End of Life Replacement</td>
</tr>
<tr>
<td>E6.18 Stations Power Transformer Renewal</td>
<td>Station Breaker &amp; Switchgear Replacement</td>
<td>Obsolete and EOL replacement</td>
</tr>
<tr>
<td>E6.19 Stations Circuit Breaker Renewal</td>
<td>Station Breaker &amp; Switchgear Replacement</td>
<td>Obsolete and EOL replacement</td>
</tr>
<tr>
<td>PROGRAM NAME</td>
<td>Unit cost Asset Categories</td>
<td>Activity Description</td>
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<tr>
<td>E6.16 Stations Control &amp; Monitoring</td>
<td></td>
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<tr>
<td>E6.17 Stations Ancillary Systems</td>
<td></td>
<td></td>
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<tr>
<td>E6.18 Station Building Infrastructure</td>
<td></td>
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<tr>
<td>E6.19 Stations DC Battery Renewal</td>
<td></td>
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</tr>
<tr>
<td>E6.20 Reactive Capital</td>
<td>O/H Pole Replacement</td>
<td>Reactive - as required</td>
</tr>
<tr>
<td></td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Reactive - as required</td>
</tr>
<tr>
<td></td>
<td>O/H Transformers</td>
<td>Reactive - as required</td>
</tr>
<tr>
<td></td>
<td>U/G Transformers</td>
<td>Reactive - as required</td>
</tr>
<tr>
<td></td>
<td>Station Breaker &amp; Switchgear Replacement</td>
<td>Reactive - as required</td>
</tr>
<tr>
<td>E6.21 Worst Performing Feeder</td>
<td>O/H Pole Replacement</td>
<td>Asset age and/or condition</td>
</tr>
<tr>
<td></td>
<td>U/G Transformers</td>
<td>Asset age and/or condition</td>
</tr>
<tr>
<td></td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Asset age and/or condition. (No civil work is done under WPF program, remove ducts replacement)</td>
</tr>
<tr>
<td></td>
<td>Overhead Line Patrols</td>
<td>To determine feeder condition</td>
</tr>
<tr>
<td>E6.22 US Communications Infrastructure (USCI)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>E7.1 Contingency Enhancement</td>
<td>O/H Pole Replacement</td>
<td>For tie points and/or SCADAMate switch replacement</td>
</tr>
<tr>
<td></td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>For the creation and/or enhancement of tie points and contingency flexibility.</td>
</tr>
<tr>
<td>E7.2 Design Enhancement</td>
<td>O/H Pole Replacement</td>
<td>Pole replacements as needed to make fusing enhancements.</td>
</tr>
<tr>
<td>E7.3 Feeder Automation</td>
<td>O/H Pole Replacement</td>
<td>Poles holding OH switches are replaced due to age, condition or standard non-conformance.</td>
</tr>
<tr>
<td></td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Duct bank is required to install primary cables connected to OH riser switches. Install primary cables connected to OH riser switches</td>
</tr>
<tr>
<td>E7.4 Overhead Momentary Reduction</td>
<td>O/H Pole Replacement</td>
<td>Pole replacement/installation as needed to support the installation of reclosers.</td>
</tr>
<tr>
<td>E7.5 Handwell Upgrades</td>
<td></td>
<td></td>
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<tr>
<td>E7.6 Polymer SMD-20 Fuses</td>
<td>O/H Pole Replacement</td>
<td>Possible pole replacements when replacing polymer SMD-20 switches that have been identified as defective.</td>
</tr>
<tr>
<td>E7.7 Downtown Contingency</td>
<td>U/G Cable &amp; Duct Replacement</td>
<td>Add ties between station buses</td>
</tr>
<tr>
<td>E7.8 Customer Owned Station Protection</td>
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<td>E7.9 Stations Expansion</td>
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<td>E7.10 Local Demand Response</td>
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<td>E7.11 Energy Storage Systems</td>
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<tr>
<td>E8.1 Fleet and Equipment Services</td>
<td></td>
<td></td>
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<tr>
<td>E8.2 Facilities Management &amp; Security</td>
<td></td>
<td></td>
</tr>
<tr>
<td>E8.3 Facilities Consolidation</td>
<td></td>
<td></td>
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<tr>
<td>E8.4 IT Hardware Refresh</td>
<td></td>
<td></td>
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<tr>
<td>E8.5 IT Software</td>
<td></td>
<td></td>
</tr>
<tr>
<td>E8.6 ERP Implementation</td>
<td></td>
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<tr>
<td>E8.7 Voice Radio System Upgrade</td>
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</tr>
<tr>
<td>E8.8 Program Support</td>
<td></td>
<td></td>
</tr>
<tr>
<td>E8.9 Copeland Operational Readiness</td>
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<tr>
<td>E8.10 GEM Program</td>
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<tr>
<td>Executive Summary</td>
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<tr>
<td>Coordinated Planning</td>
<td></td>
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<tr>
<td>Performance Measurement</td>
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<tr>
<td>Asset Management Process</td>
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<td></td>
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<tr>
<td>CAPEX Planning Process</td>
<td></td>
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</tbody>
</table>
Preventative & Predictive Maintenance

<table>
<thead>
<tr>
<th>PROGRAM NAME</th>
<th>Unit cost Asset Categories</th>
<th>Activity Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pole Testing</td>
<td></td>
<td>Toronto Hydro conducts pole inspections and treatments on approximately 105,000 wood poles on a 10-year cycle. The inspections involve a visual assessment of each pole, and a sounding test using a hammer to check for internal cavities, which are an indication of an infected or internally decayed pole. Based on the results from the assessment, additional testing and treatment steps may be taken such as restorative testing to determine the presence and severity of decay in the pole, and using wood preservative treatments to extend the life of the pole and mitigate the risk of decay.</td>
</tr>
<tr>
<td>Overhead Line Patrols</td>
<td></td>
<td>Toronto Hydro conducts Overhead Line Patrols to inspect primary and secondary lines, along with any electrical equipment which exists in proximity to these circuits every 3 years. In addition, overhead infrared scans are performed annually on all primary lines and secondary lines in proximity. These inspections cover all overhead distribution equipment including pole-mounted transformers, conductor wire, lightning arresters, insulators, poles, switches, and other peripheral attachments, and are designed to identify deficiencies that are visible to the naked eye, such as leaking transformers, loose or broken attachments (e.g., cross-arms, insulator bracket), and damaged poles, as well as those that can be identified through infrared thermography. Overhead Line Patrols are mandated by the Ontario Energy Board’s (&quot;OEB&quot;) Distribution System Code’s Minimum Inspection Requirements (Appendix C).</td>
</tr>
<tr>
<td>O/H Switch Maintenance</td>
<td></td>
<td>Toronto Hydro Maintains 3 types of switches: 1. SCADA-Mate - Some SCADA-Mate switches are exposed to harsh environments near highways and high dust-prone areas, which may cause dirt buildup on the terminal. Salt along the moisture deposited on the switch may lead to corrosion on the terminals. Maintenance of this switch is conducted by System Controllers via remote close and open test of the device, as well as by Overhead Lineperson to perform local operation of the manual controls as well as visually inspect for deficiencies. 2. 3-phase Gang Operated - These switches may be exposed to harsh conditions near highways leading to dirt buildup on the contacts and terminals, resulting in seizure of the switch. Salt and moisture depositing on the switch may lead to corrosion of the terminals and contacts. Toronto Hydro has approximately 1,000 Gang-Operated switches in the system and their typical useful life of these switches is 50 years. Electrical maintenance involves verifying correct blade alignment, blade penetration, travel stops, and interrupter operation, and mechanical operation. The contacts are cleaned and greased and the switch is tested for correct operation. 3. Motorized Switch - Motorized Switches are similar to 3-Phase Gang Operated Switches. These switches are designed to open or close all three phases at the same time by automatic operation. The automatic operation is initiated by a button from the control panel. These units were a legacy standard from North York Hydro and have since been replaced with SCADA-Mate switches as of 2017.</td>
</tr>
<tr>
<td>U/G Vault &amp; Equipment Inspections</td>
<td></td>
<td>Underground Vault inspections are performed every 5 years and an electrical inspection is performed annually. Civil inspections include a visual inspection of the vault, proper sump pump operation, and cleaning of the vault floor. Electrical inspections include a visual inspection of the electrical equipment, thermograph of electrical components, and a partial discharge test for electrical connections. Network Protector - Routine overhauls are completed once every 5 years for low voltage protectors and once every 3 years for high voltage protectors. An overhaul includes visual inspection of the electrical components, vacuum the protector, replace mechanical relays with newly calibrated relays, repair or clean arcing and main contacts, and test operation functionality. Fibertop Network Protector - Protector top cleaning is performed annually to eliminate the dirt accumulation on the top of fibertop network protectors. The protector top cleaning includes a visual inspection of the outside of the arrester, travel stops, arc interrupter operation, and mechanical operation. The contacts are cleaned and greased and the switch is tested for correct operation. 3. Motorized Switch - Motorized Switches are similar to 3-Phase Gang Operated Switches. These switches are designed to open or close all three phases at the same time by automatic operation. The automatic operation is initiated by a button from the control panel. These units were a legacy standard from North York Hydro and have since been replaced with SCADA-Mate switches as of 2017. Inspection of the vault, proper sump pump operation, and cleaning of the vault floor. Electrical inspections include a visual inspection of the electrical equipment.</td>
</tr>
<tr>
<td>Vegetation Management</td>
<td></td>
<td>Each year, Toronto Hydro identifies the feeders that are in greatest need of tree pruning based on prioritization criteria that include feeder reliability history, the number of customers supplied by each feeder, and the amount of time that has elapsed since the trees surrounding the feeder were last pruned. The prioritization results in trees surrounding feeders being pruned once every two to five years, with the system average being approximately three years.</td>
</tr>
<tr>
<td>PROGRAM NAME</td>
<td>Unit cost Asset Categories</td>
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<td>Toronto Hydro conducts pole inspections and treatments on approximately 105,000 wood poles on a 10-year cycle. The inspections involve a visual assessment of each pole, and a sounding test using a hammer to check for internal cavities, which are an indication of an infested or internally decayed pole. Based upon the results from the assessment, additional testing and treatment steps may be taken such as resistograph testing to determine the presence and severity of decay in the pole, and using wood preservative treatments to extend the life of the pole and mitigate the risk of decay.</td>
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<tr>
<td>Corrective Maintenance</td>
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<td></td>
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<td>Overhead Line Patrols</td>
<td></td>
<td>Toronto Hydro conducts Overhead Line Patrols to inspect primary and secondary lines, along with any electrical equipment which exists in proximity to these circuits every 3 years. In addition, overhead infrared scans are performed annually on all primary lines and secondary lines in proximity. Th inspections cover all overhead distribution equipment including pole-mounted transformers, conductor wire, lightning arrestors, insulators, poles, switches, and other peripheral attachments, and are designed to identify deficiencies that are visible to the naked eye, such as leaking transformers, loose or broken attachments (e.g., cross-arms, insulator brackets), and damaged poles, as well as those that can be identified through infrared thermography. Overhead Line Patrols are mandated by the Ontario Energy Board’s (“OEB”) Distribution System Code’s Minimum Inspection Requirements (Appendix C).</td>
</tr>
<tr>
<td>O/H Switch Maintenance</td>
<td></td>
<td>Toronto Hydro Maintains 3 types of switches: 1. SCADA-Mate - Some SCADA-MATE switches are exposed to harsh environments near highways and high dust-prone areas, which may cause dirt buildup on the terminal. Salt along the moisture deposited on the switch may lead to corrosion on the terminals. Maintenance of this switch is conducted by System Controllers via remote close and open test of the device, as well as by Overhead Lineperson to perform local operation of the manual controls as well as visually inspect for deficiencies. 2. 3-phase Gang Operated - These switches may be exposed to harsh conditions near highways leading to dirt buildup on the contacts and terminals, resulting in seizure of the switch. Salt and moisture depositing on the switch may lead to corrosion of the terminals and contacts. Toronto Hydro has approximately 1,000 Gang-Operated switches in the system and their typical useful life of these switches is 50 years. Electrical maintenance involves verifying correct blade alignment, blade penetration, travel stops, arc interrupter operation, and mechanical operation. The contacts are cleaned and greased and the switch is tested for correct operation. 3. Motorized Switch - Motorized Switches are similar to 3-Phase Gang Operated Switches. These switches are designed to open or close all three phases at the same time by automatic operation. The automatic operation is initiated by a button from the control panel. These units were a legacy standard from North York Hydro and have since been replaced with SCADA-Mate switches as of 2017.</td>
</tr>
<tr>
<td>U/G Vault &amp; Equipment Inspections</td>
<td></td>
<td>Network Protector - Routine overhauls are completed once every 5 years for low voltage protectors and once every 3 years for high voltage protectors. An overhaul includes visual inspection of the electrical components, vacuum the protector, replace mechanical relays with newly calibrated relays, repair or clean arcing and main contacts, and test operation functionality. The protector top cleaning includes a visual inspection of the outside of the protector, travel stops, arc interrupter operation, and mechanical operation. The contacts are cleaned and greased and the switch is tested for correct operation. 3. Motorized Switch - Motorized Switches are similar to 3-Phase Gang Operated Switches. These switches are designed to open or close all three phases at the same time by automatic operation. The automatic operation is initiated by a button from the control panel. These units were a legacy standard from North York Hydro and have since been replaced with SCADA-Mate switches as of 2017. Overhauls of the vault, proper sump pump operation and cleaning of the vault floor. Electrical inspections include a visual inspection of the electrical equipment.</td>
</tr>
<tr>
<td>Vegetation Management</td>
<td></td>
<td>Each year, Toronto Hydro identifies the feeders that are in greatest need of tree pruning based on prioritization criteria that include feeder reliability history, the number of customers supplied by each feeder, and the amount of time that has elapsed since the trees surrounding the feeder were last pruned. The prioritization results in trees surrounding feeders being pruned once every two to five years, with the system average being approximately three years.</td>
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</tr>
<tr>
<td>Emergency Maintenance - Sandy Storm Restoration</td>
<td></td>
<td>This category involves efforts to restore power after major events (e.g. 2013 ice storm, floods, extended loss of transmission supply and damage). Severe weather and large events can necessitate a significant crew effort on a number of days each year. The effort is typically in response to widespread damage on the distribution system and power interruptions to customers. This category funds the necessary maintenance expenditure to return the distribution system to normal condition, in the shortest time possible, following these events. When major events and storm damage occurs, Toronto Hydro directs requisite resources to repair the damage and restore power. For events such as the 2013 Ice Storm, which caused tremendous and widespread damage, any and all available resources, including internal resources (e.g. crew on planned projects) or external resources (e.g., contractors, mutual aid crews from other utilities) are utilized and funded through the Storm and Major Event Damage category.</td>
</tr>
<tr>
<td>Emergency Maintenance - Ice Storm Restoration</td>
<td></td>
<td>This category involves efforts to restore power after major events (e.g. 2013 ice storm, floods, extended loss of transmission supply and damage). Severe weather and large events can necessitate a significant crew effort on a number of days each year. The effort is typically in response to widespread damage on the distribution system and power interruptions to customers. This category funds the necessary maintenance expenditure to return the distribution system to normal condition, in the shortest time possible, following these events. When major events and storm damage occurs, Toronto Hydro directs requisite resources to repair the damage and restore power. For events such as the 2013 Ice Storm, which caused tremendous and widespread damage, any and all available resources, including internal resources (e.g. crew on planned projects) or external resources (e.g., contractors, mutual aid crews from other utilities) are utilized and funded through the Storm and Major Event Damage category.</td>
</tr>
<tr>
<td>Emergency Maintenance - Other</td>
<td></td>
<td>The Emergency Maintenance program funds the 24/7 response to unplanned and urgent events involving Toronto Hydro’s distribution system assets. Toronto Hydro operates within a dynamic, dense, urban environment where emergency response is required for a wide variety of reasons including, but not limited to, equipment failure, severe weather, power quality issues, motor vehicle accidents, equipment isolations, and requests from Toronto emergency services (i.e., police, fire, and ambulance). The demands on the Emergency Response Program can vary considerably from one year to the next due to the volume and impacts of significant system events and extreme weather.</td>
</tr>
</tbody>
</table>
MEMO

date July 30, 2010

attention JS Couillard, Celine Arsenault-Smith, Asheef Jamal

copy Aida Cipolla, Ivan Yu, Wendy Cheah, Anne McGrath, Steve Lowden, Jessie Yip

from Andrea Davies and Yaniv Bitton

subject Property, Plant and Equipment – Engineering & Admin Reclass (“EAR”) – Version V5.7 – FINAL

EXHIBITS

- Exhibit 1 – Quantification - Summary of EAR Capitalized under IFRS
- Exhibit 2 – Tax Impact on Accounting Treatment for Property, Plant and Equipment – Engineering and Admin Reclass
1 Purpose

The purpose of this memo is to discuss the accounting treatment for EAR costs which are capitalized to items of PP&E. These considerations are made in accordance with IAS 16. This accounting memo does not consider IAS 16 in its entirety, and should be read in conjunction with the Corporation’s other memos on accounting for PP&E under IFRS. This memo is not intended to be a complete interpretation of the application of IAS 16, nor a complete memo on the treatment of PP&E under IFRS.

2 Executive Summary

Under IFRS, the process of capitalizing costs previously captured under CGAAP by the EAR will include labour costing (which translates into time-sheeting) differentiating between capital and operating activities, and allocating costs across projects based on identified cost drivers. These all represent process changes as compared to CGAAP. In the course of implementing these process changes, the key activities undertaken by the EAR employees have been analyzed to determine their nature: capital, operating or a blend (i.e., a combination of both operating and capital).

As a result of the exclusion of certain activities from the EAR labour cost calculation under IFRS, it is anticipated that the total value of employee burden capitalized will decrease by approximately $9.8 million to $13.3 million in 2010 compared to CGAAP, as supported in Exhibit 1 – Quantification: Decrease to EAR Capitalize under IFRS. The following is a summary of the conclusions for each of the respective groups captured by the EAR:

1. SM undertakes overall strategic and corporate initiatives. This group is focused on internal corporate initiatives. With the exception of the Project Management Services RC, which is primarily capital, the other RCs are primarily operating in nature and the costs will not be capitalized under the EAR Labour Costing under IFRS.

2. AM identifies and designs capital projects based on current and future capacity and load needs or requirements as well as asset conditions. AM is comprised of 4 RCs for which the following general conclusions regarding whether activities are operating, capital or a blend of both, were made:
   a. Administration – operating;
   b. System Reliability – primarily capital;
c. Capacity Planning – primarily capital; and

d. Policy and Standards – primarily capital; however, the subgroup relating to External Demand & Customer Relations is primarily operating in nature.

3. DG is concerned with the health of the grid, operation of the control room, the provision of emergency support through Trouble Dispatch, and is involved in the design and construction of municipal and/or transformer stations. DG is comprised of 4 RCs included in EAR for which the following general conclusions regarding whether activities are operating, capital or a blend of both, were made:

   a. Stations & Distribution Automation – primarily capital in nature, with activities relating to maintenance and administration being operating in nature;

   b. Distribution Grid Health – primarily operating;

   c. Systems Operations – with the exception of the subgroups relating to Operations Planning and Performance, and Trouble Dispatch which are primarily operating in nature, the remaining activities are either capital or a blend; and

   d. Distribution Grid Management – operating.

4. DS is involved in the construction of distribution stations, and the construction and management of customer connections and maintenance. DS is comprised of 4 EAR RCs for which the following general conclusions regarding whether activities are operating, capital or a blend of both, were made:

   a. Program Management – other than the key activities relating to Annual Budget Preparation, Program Planning (line development), Program Scheduling and Work Program Preparation which are a blend of capital and operating, the remaining activities are operating in nature;

   b. Distribution Projects – other than the activities relating to Maintenance Programs, Customer Enquiries and Administration which are operating in nature, the remaining activities are capital in nature;

   c. Customer Connections and Maintenance – same conclusion as Distribution Projects; and

   d. Distribution Systems Administration – operating.
5. CS deals with meter related services for commercial, residential and station meter installations.
   a. Smart Meter – there is a blend of operating and capital activities;
   b. Meter Operations – with the exception of the activities relating to Smart Meter Support / Maintenance and Administration which are operating in nature, the remaining activities are capital in nature; and
   c. Meter Technology – there is a blend of operating and capital activities.

See section 4.1.2.1 below for a detailed discussion regarding each of the RCs identified above, including a detailed analysis of the appropriate accounting treatment of activities as either operating, capital or a blend of both under IFRS.

3 Current Accounting Practice and Key Differences

A key difference between CGAAP and IFRS with respect to the calculation of the EAR, is the treatment of administration and other general overhead costs. Under CGAAP, administration and other general overhead costs are not specifically addressed, other than a statement that those costs directly attributable to bringing the asset to its intended use are eligible for capitalization. IFRS, on the other hand, specifically states that administration and other general overhead costs are not directly attributable, and thus cannot be capitalized as an item of PP&E.

Under CGAAP, the Corporation has adopted a “full-cost” approach to the capitalization of its PP&E, through the use of two methods of capitalized labour costs: (1) tracking labour costs for various employees and applying a standard labour rate to time recorded to various jobs (see memo on the Standard Labour Rates for a detailed discussion), and (2) allocating employee labour costs through the EAR, which is the focus of this paper. Labour costs for field crew are rolled up into capital intensive groups, outlined below. The field crew in these groups are supported, supervised and guided by those whose personnel costs are included in the EAR. There are approximately 300 individuals in the EAR including (but not limited to) program managers of capital build programs, call centre attendants, control room controllers, outage management staff, engineers working in the policy and standards group, engineers determining the current and future capacity needs of the network, and operational Vice Presidents, such as the Vice President of Grid Management and the Vice President of Distribution Services.

The following describes the process to allocate the EAR to capital projects under CGAAP:
1. Determine the number of employees in the EAR, namely employees other than field crew employed by the following groups:
   - SM;
   - AM;
   - DG;
   - DS; and
   - CS.

2. The total employee fully burdened labour cost is determined (budgeted to be approximately $40 million for 2010). The fully burdened labour cost is discussed in detail in the Standard Labour Rates memo.

3. The proportion of capital spending to total spending is determined as follows:
   \[
   \text{Portion of Capital} = \frac{\text{Budgeted capital spending}}{\text{(Budgeted capital spending + Budgeted operating and maintenance + Budgeted demand billable work)}}
   \]

   Historically, capital spending has represented approximately 80% of total spending.

4. This portion of capital spending is then applied to the total fully burdened labour cost calculated in Step 2 above, to determine the total dollar value of employee burden that should be allocated to capital projects during the year. This amount is known as the EAR, and was budgeted at approximately $33 million in 2010 ($40 million * 82.3% = $32.9 million).

5. The EAR allocation is booked through a monthly recurring journal entry as a debit to CWIP and credit to payroll costs (in EE9906 Engineering Admin Allocated) by each RC.

6. At year end, the “open” employee positions that were included in the budgeted EAR for the year are compared to the number of employee positions filled in the year. Any remaining unfilled employee positions are removed from the EAR balance in CWIP before the balance is allocated to capital assets. This activity is a true-up of the budgeted EAR to the actual EAR.

7. At the end of the year, the balance in CWIP is allocated on a pro rata basis primarily to the three main categories of distribution assets that have been energized in the year. The three main asset categories are: transformers, conductors and conduits, and poles.
The following diagram depicts the 2010 budgeted EAR amount to be capitalized:

4 Accounting Impacts

4.1 Application of IAS 16: Direct Attribution of EAR to an Item of PP&E

4.1.1 Accounting Principle

IAS 16 requires that “an item of property, plant and equipment that qualifies for recognition as an asset be measured at its cost” (paragraph 15).

Paragraph 16 defines the elements of the cost of an item of PP&E as:

(a) “its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates.

(b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

(c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligations for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.”
Paragraph 17 provides examples of directly attributable costs:

(a) “costs of employee benefits (as defined in IAS 19 Employee Benefits) arising directly from the construction or acquisition of the item of property, plant and equipment;

(b) costs of site preparation;

(c) initial delivery and handling costs;

(d) installation and assembly costs;

(e) costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition (such as samples produced when testing equipment); and

(f) professional fees.”

Paragraph 19 provides examples of costs that are not costs of an item of property, plant, and equipment:

(a) “costs of opening a new facility;

(b) costs of introducing a new product or service (including costs of advertising and promotional activities);

(c) costs of conducting business in a new location or with a new class of customer (including costs of staff training); and

(d) administration and other general overhead costs.”

This memo is focused on the costs permitted under paragraph 17(a) of IAS 16: the costs of employee benefits arising directly from the construction or acquisition of the item of PP&E.

Employee future benefits in IAS 19, paragraph 4, include:

(a) “short-term employee benefits, such as wages, salaries and social security contributions, paid annual leave and paid sick leave, profit-sharing bonuses (if payable within twelve months of the end of the period) and non-monetary benefits (such as medical care, housing, cars and free or subsidized goods or services) for current employees;

(b) post-employment benefits such as pensions, other retirement benefits, post-employment life insurance and other post-employment medical care;

(c) other long-term employee benefits, including long-service leave or sabbatical leave, jubilee or other long-service benefits, long-term disability benefits and, if they are not
payable wholly within twelve months after the end of the period, profit-sharing, bonuses, and deferred compensation; and

(d) termination benefits.”

Paragraph 3 of IAS 19 notes that employee benefits may arise from formal plans, legal obligations, or informal practices that give rise to constructive obligations. See the whitepaper on Employee Benefits for a detailed discussion and analysis.

4.1.2 Analysis

4.1.2.1 Analysis of Key Activities for Classification as Capital, Operating, or Blend

The allocation model associated with EAR under CGAAP will no longer be employed under IFRS. Finance completed a comprehensive analysis to support and provide documentation under IFRS for its determination of the nature of activities undertaken by EAR employees. Under the new process established, EAR employees will labour cost (i.e., timesheet) to the various activities outlined in sections 4.1.2.1.1 - 4.1.2.1.5 below. Once time sheeted hours are applied to these activities, the calculated cost will be allocated to capital expenditures, operating expenses, or a blend of both based on the nature of the activity. The Corporation believes that the key distinction between capital and operating work is the ultimate output of the effort undertaken. Whether or not the final product that this work supports is eligible for capitalization is the key driver in determining whether the underlying activity is capital or operating in nature. Costs associated to key activity work orders that are capital in nature will be mapped to CWIP and allocated to capital projects based on a cost driver. Costs associated to key activity work orders that are blended activities will be mapped first to CWIP then any portion determined to be operating will be allocated to an operating expense account. Costs related to key activity work orders that are operating will be mapped directly to the associated operating expense account. See discussion in 5.5 “Process Impacts” below for a full description of the process changes.

As illustrated in the diagram above, the EAR labour costed groups will be comprised of the following:

1. SM – refer to section 4.1.2.1.1;
2. AM – refer to section 4.1.2.1.2;
3. DG – refer to section 4.1.2.1.3;
4. DS – refer to 4.1.2.1.4; and
5. CS – refer to 4.1.2.1.5.
The discussion in sections 4.1.2.1.1 to 4.1.2.1.5, should be read with the following in mind:

1. The “Key Activities” and “Description” columns were identified based on discussions with managers in the respective RCs. The objectives being met are two-fold: IFRS compliance and increased information as requested by business units. Therefore, there may be more categories or activities than strictly necessary from an IFRS perspective.

2. The “Description” column is not intended to be an exhaustive list of the activities, and is only a sample of the tasks that the “Key Activities” column is meant to encompass.

3. Conclusions regarding whether the work is capital, operating, or a blend are based on the principles in IAS 16.

4.1.2.1.1 Strategic Management

The SM group has primary responsibility for assisting senior management with corporate goal setting and the implementation of corporate initiatives. The group helps to develop metrics for individual groups and RCs. The SM group consists of the following five RCs:

1. Strategic Management (RC 3800) represents the executive of the SM group.

2. Project Management Services (RC3810) is involved in identifying, developing and executing projects/initiatives to enable and achieve corporate goals by supporting Project sponsors.

3. Policy Administration (RC 3830) researches and develops corporate policies to align with the overall long-term and short-term strategy.

4. Enterprise Project Management (RC 3840) is responsible for project governance policies, scorecard reporting, and developing tools, templates, education and training needs.

5. Strategy and Enterprise Risk Management (RC 3850) is responsible for strategic planning, providing operational support and monitoring organization results.

Other than RC3810, the SM group works on corporate initiatives and projects that generally do not lead to capital projects or the acquisition/construction of PP&E, other than project management services (which may lead to capital work).
**RC 3800 Strategic Management**
This RC includes only the executive of the SM group who is responsible for the overall management of the SM group. As the role of the executive is broad in its nature and generally encompasses strategic planning for the group, including ensuring compliance with corporate goals and initiatives, it is difficult to prove the linkage of these activities to specific items of PP&E. As a result, these costs will not be capitalized under IFRS.

**RC 3810 Project Management Services**
This RC is involved in identifying, developing, executing projects/initiatives to enable and achieve corporate goals including research, planning, development of project KPIs, solution implementation, training and operationalizing projects/initiatives all to support Project sponsors. This RC includes project managers of large, cross-divisional initiatives that lead to the execution of capital projects and solution implementation which generally involve procurement and the implementation of IT solutions.

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C O B</th>
<th>Analysis and Support for Capital, Operating or Blend Classification.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Research</td>
<td>Staff charging time to this Research activity are performing and assisting the organization with the identification of methods and technologies to achieve corporate IT goals, including feasibility studies for certain technologies such as proof of concept or small scale deployments.</td>
<td>O</td>
<td>This activity results in research to support corporate initiatives and results for projects which may lead to capital projects through the acquisition and implementation of IT based systems. As the research undertaken will not necessarily generate probable future economic benefits, costs related to research should be expensed. Labour costed activities identified here are operating in nature and will not be capitalized.</td>
</tr>
</tbody>
</table>
| 2  | Planning       | Staff charging time to this activity may undertake the following:  
- Identifying business requirements or project specifications documents;  
- Assisting with the work program and WBS;  
- Designing requests for proposals (while this activity may be general or administrative in nature, the amount of | C    | This key activity work order relates to the planning of approved projects. These IT projects are capital in nature, and the planning work related to the project should also be capital in nature. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
<p>| | | |</p>
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<tbody>
<tr>
<td></td>
<td>time spent on it is immaterial in relation to the other activities); and - Other planning activities involved in the execution of approved projects</td>
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<tr>
<td>3</td>
<td>Development</td>
<td>Staff charging time to this activity may undertake the following: - Designing solutions including changes to the configuration of the systems; - Procuring solutions including vendor selections through a request for proposal (while this activity may be general or administrative in nature, the amount of time spent on it is immaterial in relation to the other activities); and - Executing plans for internal initiatives and projects.</td>
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<td>4</td>
<td>Implementation</td>
<td>Staff charging time to this activity may undertake the following: - Managing projects; - Implementing, building, testing and executing the identified plans, projects and initiatives.</td>
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<tr>
<td>5</td>
<td>Training Delivery</td>
<td>Staff charging time to this activity is typically delivering training to and educating staff involved in the initiatives. Training typically revolves around the new system.</td>
</tr>
</tbody>
</table>
| 6 | Operationalization | Staff charging time to this activity may undertake the following:  
- Providing assistance to departments in order to operationalize the IT system and transition from the project start to the end users (operations);  
- User acceptance testing of the solution;  
- Finalizing operational readiness reports; and  
- Closing the project. | C | The key activity work order supports the final implementation steps to close out the project and transfer it to the operations group. This is the final step in a capital project. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
| 7 | Administration | Staff charging time to this activity may undertake the following:  
- Performing clerical work that cannot be directly attributed to any predefined or provided WO;  
- Performing employee development activities (performance reviews, attendance, recruitment);  
- Scheduling or preparing facilities for appointments;  
- Managing employee training and administration activities (training, education, expenses, etc.); and  
- Performing community related activities. | O | The labour costed activities identified here are administrative, and therefore operating, in nature and will thus not be capitalized. |
The Policy Administration RC is involved with the research and development of corporate policies in order to align those policies with the overall long-term and short-term strategy.

<table>
<thead>
<tr>
<th>#</th>
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<th>Description</th>
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<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
</table>
| 8  | Policy Administration               | Staff charging time to this activity may undertake the following:  
- Developing programs and processes;  
- Designing programs and processes;  
- Planning work;  
- Managing execution of work program; and  
- Tracking and reporting. | O    | This key activity work order results in work to support internal corporate policies that do not result in capital projects or in the acquisition/construction of PP&E. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 9  | Health and Safety Management        | Staff charging time to this activity are likely to be engaged in performing work related to safety and wellness programs.                                                                                      | O    | The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 10 | Corporate Initiatives               | Staff charging time to this activity are likely to be engaged in performing work related to corporate initiatives.                                                                                           | O    | The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 11 | Department Administration           | Staff charging time to this activity may undertake the following:  
- Performing clerical work that cannot be directly attributed to any predefined or provided WO;  
- Performing employee development activities (performance reviews, attendance, recruitment);  
- Scheduling or preparing facilities for appointments;  
- Managing employee training and administration activities (training, education, expenses, | O    | The labour costed activities identified here are administrative, and therefore operating, in nature and will thus not be capitalized. |
etc.; and  
- Performing community related activities.

**RC 3840 Enterprise Project Management**

Enterprise Project Management is responsible for scorecard reporting, developing tools and templates, implementing project governance policies and performing audits on internal projects to measure compliance with corporate policies.

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C O B</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>12</td>
<td>Scorecards</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>O</td>
<td>Enterprise Project Management is responsible for internal project reporting and governance. This function and these activities benefit the organization as a whole, and are not directly attributable to items of PP&amp;E. The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
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<td></td>
<td></td>
<td>- Performing governance related activities;</td>
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<td></td>
<td></td>
<td>- Performing administration activities;</td>
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<td></td>
<td></td>
<td>- Reporting;</td>
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<td></td>
<td>- Analysing; and</td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td>- Communicating internally.</td>
<td></td>
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<tr>
<td>13</td>
<td>Project methodology</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>O</td>
<td>The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
</tr>
<tr>
<td></td>
<td>(development of methodology)</td>
<td>- Performing activities related to standards;</td>
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<td></td>
<td></td>
<td>- Performing development activities;</td>
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<td></td>
<td>- Providing training and education; and</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Reporting.</td>
<td></td>
<td></td>
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<tr>
<td>14</td>
<td>Project governance and</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>O</td>
<td>The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
</tr>
<tr>
<td></td>
<td>audits</td>
<td>- Performing activities related to project governance standards;</td>
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<td></td>
<td></td>
<td>- Performing development activities;</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Providing training and education; and</td>
<td></td>
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</tr>
</tbody>
</table>
| 15 | Master Production Plan / Investment and Operations Plan | Staff charging time to this activity may undertake the following:  
- Reporting;  
- Analyzing; and  
- Communicating to internal groups, management, and affected RCs. | B | Staff charging time to this activity work order work with program managers in the AM and DS/DG divisions to ensure the successful completion of capital and operating projects. Staff in this RC work with the divisions to prioritize projects and streamline resource requests so that optimal resources are applied to projects to ensure efficiency and effectiveness of projects. For example, staff will make suggestions regarding which projects should be undertaken due to interdependencies, and will make suggestions regarding allocation of labour resources between projects to maximize the success of all projects. Staff report and communicate their findings and decisions internally at IOP meetings. As staff undertake these activities for both capital and operating projects this key activity work order is a blend of operating and capital activities. Time attributed to capital activities will be capitalized, while time attributed to operating activities will not be capitalized, within the EAR labour costing allocation. See section 5.5 for further discussion as to how these will be allocated. |
| 16 | Department Administration | Staff charging time to this activity may undertake the following:  
- Performing clerical work that cannot be directly attributed to any predefined or provided WO;  
- Performing employee development activities (performance reviews, attendance, recruitment);  
- Scheduling or preparing facilities for appointments;  
- Managing employee training and administration activities (training, education, expenses, etc.); and  
- Performing | O | The labour costed activities identified here are administrative and operating in nature and will thus not be capitalized. |
Strategy & Enterprise Risk Management is responsible for strategic planning within the organization including identification of business requirements, designing a framework for processes to follow to ensure consistent application and identifying and assessing strategic initiatives. This RC is also responsible for monitoring and reporting and operational support including assessing risks, staffing and resourcing, and training and education.

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C O B</th>
</tr>
</thead>
</table>
| 17 | Strategic Planning / Strategic Planning Corporate Project | Staff charging time to this activity may undertake the following:  
- Identifying business requirements;  
- Designing framework;  
- Implementation;  
- Conducting post-implementation reviews; and  
- Assessing and analyzing strategic initiatives. | O Strategy & Enterprise Risk Management is involved with internal projects, and strategic development that benefits the organization as a whole. These initiatives are not directly attributable to items of PP&E. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 18 | Enterprise Risk Management / ERM Corporate Project | Staff charging time to this activity may undertake the following:  
- Identifying business requirements;  
- Identifying, assessing and monitoring enterprise risks;  
- Designing framework;  
- Implementing plans; and  
- Conducting post-implementation reviews. | O The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 19 | Department Administration | Staff charging time to this activity may undertake the following:  
- Performing clerical work that cannot be directly attributed to any predefined or provided WO;  
- Performing employee | O The labour costed activities identified here are administrative and operating in nature and will thus not be capitalized. |
4.1.2.1.2 Asset Management

Background

The AM group is responsible for managing assets over their life-cycles as a means of maximizing shareholder value while meeting the requirements of customer service and reliability. The AM group integrates technical considerations with the financial considerations of costs, benefits and overall risk management to support the strategy of maximizing value. The AM group consists of the following four RCs in EAR:

1. Asset Management Administration (RC 2000) consists of the executive of the AM group.

2. System Reliability (RC 2200), is involved in the monitoring of current distribution equipment assets (i.e., cables, towers, and fixtures) and the planning for future assets, including determining the priority of projects for the capital re-build program. The specific role of System Reliability is to ensure that the required load is moving through the system when required by the customer. System Reliability does this by first assessing the reliability and condition of the current grid assets. System Reliability is also responsible for developing the project design and working with the field crew in developing the planned work program.

3. Capacity Planning (RC 2700), similar to System Reliability, is involved in the monitoring of current station assets and the planning for future assets, including determining the priority of projects for the capital re-build program. The specific role of Capacity Planning is monitoring current availability, and ensuring future availability of electrical load (capacity) in the system. Capacity Planning is responsible for developing the project
design and planned work programs with the help of the designers and supervisors in DG/DS.

4. Standards & Policy Planning (RC2400) is involved in the design and implementation of technical specifications for all used assets. These specifications determine how assets within a project and within the distribution system interact. The Policy and Standards RC can be sub-divided into the following categories:
   - Standards and Materials;
   - External Demand and Customer Relations; and
   - Planning and Co-ordination.

**RC 2000 Asset Management Administration**

This RC includes only the executive of the AM group who is responsible for the overall management of the AM group. As the role of the executive is broad in its nature and generally encompasses strategic planning for the group, including ensuring compliance with corporate goals and initiatives, it is difficult to prove the linkage of these activities to specific items of PP&E. As a result, these costs will not be capitalized under IFRS.

**RC 2200 System Reliability**

The System Reliability RC is responsible for ensuring that the required load is moving through the system when required by the customer. The System Reliability RC designs capital build projects based on expected customer needs, asset condition and the 10 year re-build program (which focuses on rejuvenating the aging infrastructure). The System Reliability group focuses on distribution equipment, such as cables, poles and transformers. Similar to the Capacity Planning RC, the System Reliability RC will prepare high-level scope packages for projects which include conceptual designs and estimates. The designs in the scope packages are prepared based on a review or knowledge of the following: historical trends, load growth, customer requirements, defective equipment listing, and asset records in Ellipse.

The various projects are prioritized based on short- and long-term needs with a threshold of 3 years differentiating short- and long-term priorities. Short-term projects are expected to occur within a 3-year timeframe and are developed into Detailed Scope Packages with the help of the Distribution Projects group. A preliminary schedule is then completed with consideration given to any projects deferred from years past. The Detailed Scope Packages and preliminary schedules are submitted for approval. Once approved, the project is transferred to the DG and DS groups to be constructed (“Green Folder”). If the budget is not approved, the project is deferred to a later year. Budget approval is based on available dollars and hours for
a given year. A deferral of a project is a postponement only, with the project fully expected to go-ahead within the 3-year time frame. It should be noted that project delays typically are the result of prioritizing other projects ahead of that particular project and thus allocated funding will be spent as approved.

For short-term projects, it is not expected that a Detailed Scope Package will remain on the shelf indefinitely, as these projects are virtually certain to be built. For this reason, all design costs, from the high level scope package to the point where the project is given a “Green Folder”, are directly attributable to an item of PP&E and are thus capitalizable. The labour costs related to the design of short-term projects will be charged to key activity work orders # 1, 2 and 3 below.

Initial assessment work, such as determining whether the project will be completed within 3 years (short-term) or beyond 3 years (long-term), is part of key activity work order #4 below which is classified as operating in nature and is therefore expensed. The initial assessment work may include asset data collection, data analysis for research purposes, and the 10-year plan.

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>COB</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Underground Capital</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>C</td>
<td>This key activity work order is used for all underground related activities that are capital in nature (with respect to approved projects), as described to the left. All repairs, maintenance and operating related activities are outlined in key activity work order #4 below. Where the activity does not fall within this operating and maintenance list, the activity is considered capital in nature. Where the capital activity relates to underground capital, the time will be labour costed to this key activity work order. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Building the capital budget;</td>
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<tr>
<td></td>
<td></td>
<td>- Defining the project scope;</td>
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<tr>
<td></td>
<td></td>
<td>- Composing project justifications;</td>
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<td></td>
<td></td>
<td>- Composing project descriptions of work;</td>
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<td></td>
<td></td>
<td>- Analyzing project alternatives;</td>
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<tr>
<td></td>
<td></td>
<td>- Drafting high level project designs;</td>
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<td></td>
<td></td>
<td>- Undertaking project estimations</td>
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<td></td>
<td></td>
<td>- Undertaking project prioritizations; and</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Other capital activities related to underground assets that do not fall within the “operating and maintenance” listing in activity #4 below.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Overhead Capital</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>C</td>
<td>This key activity work order is used for all overhead related activities that are capital in nature (with respect to approved projects), as</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Building the capital budget;</td>
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</tr>
</tbody>
</table>
|   | - Building the capital budget;  
   | - Defining the project scope;  
   | - Composing project justifications;  
   | - Composing project descriptions of work;  
   | - Analyzing project alternatives;  
   | - Drafting high level project designs;  
   | - Undertaking project estimations  
   | - Undertaking project prioritizations; and  
   | - Other capital activities related to overhead assets that do not fall within the “operating and maintenance” listing in activity #4 below.  
|   | described to the left. All repairs, maintenance and operating related activities are outlined in key activity work order #4 below. Where the activity does not fall within this operating and maintenance list, the activity is considered capital in nature. Where the capital activity relates to overhead capital, the time will be labour costed to this key activity work order. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.  
| 3 | Stations Capital | Staff charging time to this activity may be engaged in capital activities related to stations assets that do not fall within the “operating and maintenance” listing in activity #4 below. Examples of activities include:  
|   | - Building the capital budget;  
   | - Defining the project scope;  
   | - Composing project justifications;  
   | - Composing project descriptions of work;  
   | - Analyzing project alternatives;  
   | - Drafting high level project designs;  
   | - Undertaking project estimations  
   | - Undertaking project prioritizations.  
|   | This key activity work order is used for all stations related activities that are capital in nature (with respect to approved projects). Hours labour costed to this key activity work order are not expected to be significant for System Reliability. All repairs, maintenance and operating related activities are outlined in key activity work order #4 below. Where the activity does not fall within this operating and maintenance list, the activity is considered to be capital in nature. Where the capital activity relates to Stations Capital, the time will be labour costed to this key activity work order. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.  
| 4 | Operating and maintenance | Staff charging time to this activity may undertake the following:  
|   | - Performing ACAs;  
   | - Completing EDR applications;  
   | - Investigating component  
|   | This key activity work order will be used for all operating and maintenance type work as described here. The labour costed activities identified here are operating in nature and will thus not be capitalized.  
|   |   |   |
failures;
- Investigating power quality;
- Performing maintenance activities;
- Inspecting;
- Investigating;
- Analyzing data for research purposes;
- Performing activities related to the 10-year plan;
- Budgeting;
- Conducting other research and development activities, including load flow forecasting;
- Conducting other development activities (performance reviews);
- Performing clerical work;
- Providing IT support (e.g., Ellipse, DMS/OMS, GEAR);
- Performing activities related to Corporate initiatives; and
- Performing community related activities.

5 Administration Staff charging time to this activity may undertake the following:
- Performing clerical work that cannot be directly attributed to any predefined or provided WO;
- Performing employee development activities (performance reviews, attendance, recruitment);
- Scheduling or preparing facilities for appointments;
- Managing employee training and administration activities (training, education, expenses, etc.); and
- Performing community related activities.

O The labour costed activities identified here are administrative and operating in nature and will thus not be capitalized.
RC 2700 Capacity Planning

The Capacity Planning RC designs capital-build projects based on assessments of future capacity or load requirements, and coordinates transmission and generation projects with Hydro One, the Independent Electricity System Operator and the Ontario Power Authority. The Capacity Planning group designs capital builds related to stations (sub-stations and transmission stations). The Capacity Planning group prepares high-level scope packages for projects which include conceptual designs and estimates. The designs in the scope packages are prepared based on a review or knowledge of the following: historical trends, load growth, known new customers (i.e., new developments), defective equipment listings, and asset records in Ellipse. Capacity Planning also manages the Record Services for Distribution Systems and Stations, and the Distribution Generation portfolio under the Green Energy Act, 2009.

The various projects are prioritized based on short- and long-term needs with a threshold of 3 years differentiating short- and long-term priorities. Short-term projects are expected to occur within a 3-year timeframe and are developed into detailed scope packages with the help of DG and DS (i.e., Stations & Distribution Automation, RC 3310 for station designs). A preliminary schedule is then completed with primary consideration given to any projects deferred from past years. The Detailed Scope Packages and preliminary schedules are submitted for approval. Once approved, responsibility for the project is transferred to DG or DS to be built (and to be given a “Green Folder”). If not approved, the project is deferred to a later year. Approval is based on available budget dollars and hours in a given year: deferral normally is a postponement only as deferred projects are fully expected to go-ahead within 3 years of preparation of the original detailed scope package.

For short term projects, it is expected that Detailed Scope Packages will be utilized within 3 years of their origination. For this reason, all design costs, from the high level scope package to the point where the project is given a “Green Folder” are considered to be directly attributable to an item of PP&E and are thus capitalizable.

Time related to the initial assessment work, namely determining whether the project will be completed within 3 years (short-term) or beyond 3 years (long-term), is part of key activity work order #12 below which is classified as operating in nature and therefore expensed. The initial assessment work may include asset data collection, data analysis for research purposes (i.e. activities that occur prior to obtaining approval for scope packages).
<table>
<thead>
<tr>
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<th>Description</th>
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</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>Stations Capital</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>This key activity work order is used for all stations related activities that are capital in nature, as described to the left. All repairs, maintenance and operating related activities are outlined in key activity work order #12 below. Where the activity does not fall within this operating and maintenance list, the activity is considered capital in nature. If this capital activity relates to stations, the time will be labour costed to this key activity work order. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. Documentation and narrative activities must be undertaken and are a necessary step prior to project commencement but after project approval. All documentation must be in order prior to “breaking ground” on any project.</td>
</tr>
<tr>
<td>7</td>
<td>Transmission</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>This key activity work order is used for all transmission related activities that are capital in nature, as described to the left. All repairs, maintenance and operating related activities are outlined in key activity work order #12 below. Where the activity does not fall within this operating and maintenance list, the activity is considered capital in nature. Where the capital activity relates to transmission, the time will be labour costed to this key activity work order. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
<tr>
<td>8</td>
<td>Distributed Generation</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>This key activity work order is used for all distributed generation related activities that are capital in nature, as described to the left. All repairs, maintenance and operating related activities are outlined in key activity work order #12 below. Where the activity does not fall within this operating and</td>
</tr>
</tbody>
</table>
related to the distributed generation FIT program;
- Performing activities related to the distributed generation smart grid;
- Performing activities related to the distributed generation major projects; and
- Performing activities related to the distributed generation development with non-renewable energy sources;
- Activities referred to above relate to similar activities as those listed for RC2200 related to stations, overhead, and underground capital; and
- Other capital activities related to transmission assets that do not fall within the “operating and maintenance” listing in activity #12 below.

9 Overhead Capital

Staff charging time to this activity may undertake the following:
- Performing work related to the SCADAMate projects;
- See further discussion on overhead capital related activities in RC2200 above; and
- Other capital activities related to overhead assets that do not fall within the “operating and maintenance” listing in activity #12 below.

| C | This key activity work order is used for all overhead related activities that are capital in nature, as described to the left. All repairs, maintenance and operating related activities are outlined in key activity work order #12 below. Where the activity does not fall within this operating and maintenance list, the activity is considered capital in nature. Where the capital activity relates to overhead capital, the time will be labour costed to this key activity work order. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |

10 Underground Capital

Staff charging time to this activity may undertake the following:
- Work on the TS contingency project;
- See further discussion on underground capital related to activities in RC

| C | This key activity work order is used for all underground related activities that are capital in nature, as described to the left. All repairs, maintenance and operating related activities are outlined in key activity work order #12 below. Where the activity does not fall within this operating and maintenance list, the |
| 11 | Records Management and update | Staff charging time to this activity may undertake the following:  
- Updating design records in Ellipse / GEAR;  
- Recording as built drawings capital;  
- Recording equipment changeout forms;  
- Recording Ellipse/GEAR data updates;  
- Recording Ellipse forms data updates;  
- Creating an asset registry in Ellipse for capital projects; and  
- Recording GEAR change request updates. | C  
This key activity work order relates to two separate functions: (1) all records management for stations capital and (2) updates to Ellipse and GEAR for “as built” designs for all distribution assets related to Toronto and East York districts of the City (refer to Operations Records in DG, activity #21 under DG section 4.1.2.1.3 of this memo for updates related to the remaining districts).  
1. Capacity planning is involved with designs of stations capital. Any designs and asset listings related to stations are found only in Ellipse. As there is only the one repository for station assets, Capacity planning must ensure that it is up to date for new designs, and change requests.  
2. In order to ensure the accuracy of both Ellipse and GEAR, the designs must be updated to reflect what was actually built in the field, known as “as built” designs. The “as built” records update is essential to the conclusion of the construction process and to future operations.  
Note that this is an update to the drawings in GEAR and the asset registry in Ellipse. This activity relates directly to designs for specific projects, is directly attributable to an item of PP&E. System updates are a necessary step prior to physical energization of assets (i.e. allowing current to flow through the assets) as records must be up-to-date from a safety perspective before assets can be used.  
The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |  

| 12 | Operating and maintenance | Staff charging time to this activity may undertake the following:  
- Performing activities related to the stations capital MS plan; | O  
This key activity work order will be used for all operating and maintenance type work as described. The labour costed activities identified here |
- Performing activities related to the stations maintenance plan;
- Providing stations contingency support;
- Providing stations engineering support;
- Performing activities related to Hydro One supply & relationship;
- Assisting the Records group with legal claims support;
- Assisting the Records group with locates support;
- Assisting the Records group with Nomenclature support;
- Records mapping customer owned transformers;
- Records feeder patrol & updates;
- Completing EDR filings;
- Completing EDR Applications;
- Performing stations ACAs;
- Investigating and inspecting component failures;
- Performing activities related to power quality;
- Collecting asset data;
- Analyzing data for research purposes;
- Performing activities related to the 10 year plan;
- Budgeting;
- Performing other research and development activities;
- Providing Ellipse IT support; and
- Providing GEAR IT support.

The labour costed activities identified here are operating in nature and will thus not be capitalized.

| 13 Administration | Staff charging time to this activity may undertake the following: | O |
- Performing clerical work that cannot be directly attributed to any predefined or provided WO;
- Performing employee development activities (performance reviews, attendance, recruitment);
- Scheduling or preparing facilities for appointments;
- Managing employee training and administration activities (training, education, expenses, etc.); and
- Performing community related activities.

and will thus not be capitalized.

<table>
<thead>
<tr>
<th>RC 2400 Standards &amp; Policy Planning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Policy and Standards is responsible for the design and implementation of technical specifications for all assets, and is made up of the following sub-groups:</td>
</tr>
<tr>
<td>- <strong>Standards and Materials</strong> is responsible for identifying and designing the specifications or standards for construction of specific combinations of assets;</td>
</tr>
<tr>
<td>- <strong>External Demand and Customer Relations</strong> works with customers to develop “Offers to Connect”, and organizes permits and leasing arrangements for attachments to poles; and</td>
</tr>
<tr>
<td>- <strong>Planning and Co-ordination</strong> assists construction crews with obtaining permits from the City, reviews designs for the City’s initiatives, and undertakes asset relocation projects.</td>
</tr>
</tbody>
</table>

Each sub-group, and the key activities to which each sub-group will labour cost, are described in detail below:

**Standards and Materials**

The Standards and Materials group is responsible for:

- Writing standards for products which are typically in support of capital projects identified by System Reliability or Capacity Planning;
- Operational support, including site visits, failure investigations and joint health and safety committee meetings;
- Updating the descriptions and part numbers in the WBS in Ellipse;
- Regulatory compliance, such as maintaining the relationship with the ESA;
- Developing capital projects from a standardization perspective; and
- Obtaining and providing professional engineering approval for specific projects or deviations from standards.
These responsibilities are classified into the following key activities for purposes of labour costing:

<table>
<thead>
<tr>
<th>#</th>
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</thead>
</table>
| 14 | New Standards or Specification Development               | Staff charging time to this activity may undertake the following:          | C    | This key activity work order is the development of standards for new assets.  
All components used in the electrical distribution system must be approved by the Standards & Materials group. Standards are developed to ensure sound design practices, to improve safety, to comply with legislation and to achieve a balance between design needs and reducing the complexity of purchased materials. Standards are created when the need arises and are almost always used in the construction of PP&E. Examples are the introduction of a new switch or the use of an existing switch in a non-traditional way (i.e., used in the Dufferin station contingency project).  
This key activity work order does not include updates to maintenance manuals, which are done by the System Reliability RC, see key activity work order #4.  
All hours labour costed to this key activity work order relate specifically to new standards for capital builds.  
The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
| 15 | Update of Standards or Development Specification          | Staff charging time to this activity may undertake the following:          | C    | This key activity work order involves the updating of existing standards and policies that will be used in approved capital builds.  
Updates to standards are made based on specific project requirements which are reflected in the approved capital program. The updated standards are required to start the project.  
The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
<p>| 16 | Professional Engineering                                 | Staff charging time to this activity may be engaged in reviewing and approving designs for planned | C    | This key activity work order works hand in hand with the development of new standards (key activity work order #14), and |</p>
<table>
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<tr>
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</thead>
<tbody>
<tr>
<td><strong>Support</strong></td>
<td>capital projects by a P. Eng.</td>
<td>encompasses the review and approval of standards or capital project designs. This activity is directly attributable to items of PP&amp;E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
<tr>
<td><strong>17</strong></td>
<td><strong>Change Request Administration</strong></td>
<td>Staff charging time to this activity may be engaged in administering change request forms.</td>
</tr>
<tr>
<td><strong>18</strong></td>
<td><strong>Ellipse Updating</strong></td>
<td>Staff charging time to this activity may undertake the following: - Updating Ellipse designs; - Updating Ellipse descriptions; and - Updating WBS descriptions.</td>
</tr>
</tbody>
</table>
Ellipse updating is not required for maintenance projects and only related to capital projects. As the updated design will be used in capital projects, the related labour cost is directly attributable to items of PP&E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.

| 19 | ESA Work (PSC, DDI, Audit) | Staff charging time to this activity are engaged in activities relating to compliance with ESA regulations. Examples of these activities include:  
- Conducting field inspections and site visits;  
- Responding to notifications of public safety concerns;  
- Working with ESA employees;  
- Managing the annual audit and closing audit gaps; and  
- Supporting the due diligence inspection audits, including responding to reports. | O The group is responsible for maintaining its relationship with the ESA and ensuring compliance with regulations. The group also has to respond to public requests regarding safety issues that are routed through the ESA. The response to public safety issues often includes site visits to verify the issue. This key activity work order deals with the safety of the existing network and not with capital builds. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
|---|---|---|
| 20 | Failure Investigations | Staff charging time to this activity may undertake the following:  
- Performing site visits;  
- Examining failed parts;  
- Writing reports; and  
- Providing remedial advice, if necessary. | O Failure investigations are references to failures of the existing network and not capital builds. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 21 | Operations Support | Staff charging time to this activity may undertake the following:  
- Performing site visits;  
- Attending joint health and safety committee meetings;  
- Assisting other staff to find standards; and  
- Understanding standards. | O Operations support refers to a variety of general activities to support the operations group. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
<table>
<thead>
<tr>
<th></th>
<th>Asset Management Projects</th>
<th>Staff charging time to this activity may be engaged internal AM projects, unless a specific project code is set up, in which case time will be charged to the specific code.</th>
<th>O Internal projects benefit the Corporation as a whole and are not attributable directly to items of PP&amp;E. The labour costed activities identified here are operating in nature and will thus not be capitalized.</th>
</tr>
</thead>
<tbody>
<tr>
<td>22</td>
<td>External Committee Support (CSA, CEA)</td>
<td>Staff charging time to this activity may be engaged in assisting, supporting or attending external committee meetings.</td>
<td>O Time spent on external meetings, such as the CEA, is not related directly to an item of PP&amp;E or to a capital build project. Some activities are also training related in their nature. These activities are not capitalized to an item of PP&amp;E. The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
</tr>
</tbody>
</table>

**External Demand and Customer Relations**

The External Demand and Customer Relations group is responsible for:

- Tracking lease payments on pole attachments (for example, leases with Bell and Rogers) and coordinating the sale of advertisements on the poles; and
- Offers to Connect, or requests from customers to connect and receive power at new development projects.

These responsibilities are classified into the following key activities for purposes of labour costing:

<table>
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<tbody>
<tr>
<td>24</td>
<td>Infrastructure Occupancy Permits</td>
<td>Staff charging time to this activity may undertake the following: - Reviewing occupancy permit applications; - Assessing technical specifications; - Calculating appropriate fees; - Obtaining signed contracts; and - Managing and administering day-to-day permits.</td>
<td>O</td>
<td>Occupancy permits result in rental income and do not result in new items of PP&amp;E. Also, expenditures on existing assets do not result in probable future economic benefit and therefore do not qualify for capitalization. The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
</tr>
<tr>
<td>25</td>
<td>Joint use Administration, Lease Payment</td>
<td>Staff charging time to this activity may be engaged in administering joint use projects and/or processing lease payments.</td>
<td>O</td>
<td>See Infrastructure Occupancy Permits above (key activity work order #24) for analysis. The labour costed activities identified here are operating in nature and will thus not be</td>
</tr>
<tr>
<td>Processing</td>
<td>capitalized.</td>
<td>26 Pole Transfers</td>
<td><strong>Staff charging time to this activity may be engaged in arranging pole transfers.</strong></td>
<td>O See Infrastructure Occupancy Permits above (key activity work order #24) for analysis. Pole transfers relate to time spent co-ordinating the attachments on poles (i.e., adding new attachments, removing old attachments or moving attachments from one pole to another). The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
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</tr>
<tr>
<td>27 Other Attachments, Banners</td>
<td><strong>Staff charging time to this activity may be engaged in performing any activities related to the attachments to poles, other than those identified above.</strong></td>
<td>O See Infrastructure Occupancy Permits above (key activity work order #24) for analysis. The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| 28 Policy Development | **Staff charging time to this activity may undertake the following:**  
- Defining the need / issue for a policy;  
- Researching alternatives;  
- Testing alternatives;  
- Developing policy framework; and  
- Implementing policy. | O This key activity work order relates to internal policies for the AM group, such as workflows, or policies on how to deal with other RCs. In addition, sample policies include the creation and maintenance of the Conditions of Service as required by the OEB. These activities are not related to capital projects and therefore are not directly attributable to an item of PP&E. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 29 Standard Practice Development | **Staff charging time to this activity may undertake the following:**  
- Drafting an initial document incorporating industry codes, standards, and legislation;  
- Consulting with subject matter experts or stakeholders across the company;  
- Holding meetings, collecting comments, and editing the document; and  
- Developing the standard practices for Capital Projects such as:  
  - SDS#001 Overhead | O This key activity work order relates to the documentation of construction standards and communicates the technical and business strategies for the design of overhead and underground distribution system projects. This document is similar to a training document identifying the activities to be considered in the design phase, design considerations to identify key design components and strategies, drawing guidelines etc. The completed document references standards, specifications and other standard practices or processes (i.e., Activity #14). The resulting document is a manual, similar to a training manual, to be used by design technicians when designing construction projects. The labour costed activities identified here |
<table>
<thead>
<tr>
<th>30 Offer to Connect Project</th>
<th>Staff charging time to this activity may undertake the following:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>- Reviewing the application form for an “offer to connect”;</td>
</tr>
<tr>
<td></td>
<td>- Reviewing the intended design;</td>
</tr>
<tr>
<td></td>
<td>- Ensuring facilities and connection assets meet specifications;</td>
</tr>
<tr>
<td></td>
<td>- Obtaining appropriate approvals;</td>
</tr>
<tr>
<td></td>
<td>- Preparing technical requirements, including metering connections, if required;</td>
</tr>
<tr>
<td></td>
<td>- Calculating appropriate fees;</td>
</tr>
<tr>
<td></td>
<td>- Calculating economic evaluation; and</td>
</tr>
<tr>
<td></td>
<td>- Obtaining signed Conditions of Service and approved contract from the customer.</td>
</tr>
</tbody>
</table>

C An "Offer to Connect" is an estimate of the cost to build the infrastructure necessary to connect the customer to the network. The customer is often a new commercial, industrial or residential developer. The "Offer to Connect" includes design plans, economic evaluations and an estimate of the amount the customer will have to contribute to the project, if any, as required by the DSC. The fees charged to the customer include a recovery of the time spent by this group. Whether customers choose to have the Corporation or another third party build the PP&E (refer to IFRC 18 whitepaper), once construction is complete, ownership of the asset resides with the Corporation. Therefore, the preliminary work, design and economic evaluation submitted in the "Offer to Connect" are ultimately directly attributable to an item of PP&E.

The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.
Planning and Co-ordination

The Planning and Co-ordination group is responsible for:

- Co-ordinating projects with the City of Toronto and other utilities;
- City Permit intervention for DS and CCM (both RCs reside in the DS group); and
- Planned relocation projects.

These responsibilities are classified into the following key activities for purposes of labour costing:

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>COB</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>31</td>
<td>City, Utility Circulations (mark-ups)</td>
<td>Staff charging time to this activity are engaged in reviewing City and utility circulations.</td>
<td>C</td>
<td>A circulation is the process of reviewing and providing comments for proposed capital projects. Comments by a utility are required as part of the submission criteria for a capital project permit. The City requires that all other utilities give the proposed project a “No Conflict” before a permit is granted to the applicant. For example, the City may build another subway line requiring digging and displacement of existing infrastructure. This activity covers the upfront review of the City's design plans. Based on experience, review of the City circulations related to maintenance work is infrequent and is not material. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
<tr>
<td>32</td>
<td>Pavement Restoration Invoice Processing</td>
<td>Staff charging time to this activity may be engaged in handling and processing pavement restoration invoices from the City.</td>
<td>C</td>
<td>Where a capital project results in a road cut, the City will perform the activity and invoice for the cost of repairing the pavement. Road cuts are only undertaken for capital projects related to underground infrastructure; they would not be undertaken for maintenance activities as the cost is prohibitive. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
<tr>
<td>33</td>
<td>Relocation Project</td>
<td>Staff charging time to this activity may be engaged in planning and/or co-ordinating activities that result in a relocation projects.</td>
<td>C</td>
<td>Relocation costs are not capitalizable under IFRS. However, in the case of the Corporation and other utilities, an asset cannot be removed, moved to a new location and re-installed without a loss in power. Therefore, to &quot;relocate&quot; an asset (pole, underground cable, duct), the new</td>
</tr>
<tr>
<td>Row</td>
<td>Activity Description</td>
<td>Staff Charging Time</td>
<td>O/B</td>
<td>Notes</td>
</tr>
<tr>
<td>-----</td>
<td>----------------------</td>
<td>---------------------</td>
<td>-----</td>
<td>-------</td>
</tr>
<tr>
<td>34</td>
<td>Toronto Public Utilities Coordinating Committee (“TPUCC”)</td>
<td>Staff charging time to this activity may be engaged in performing any activities required to resolve TPUCC issues.</td>
<td>O</td>
<td>This is for external meetings with the TPUCC. The TPUCC is concerned with the orderly, safe and efficient planning, design and construction and maintenance of transportation, telecommunication, energy, water and sewage services within the public road allowance. External meetings for this organization are not directly related to any capital build project. This key activity work order benefits the Corporation as a whole is not attributable to a specific item of PP&amp;E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
</tbody>
</table>
| 35  | City Permit Administration (Short Stream, Full Stream) | Staff charging time to this activity may undertake the following:  
- Assisting field crew in obtaining the correct work permits; and  
- Liaising between field staff and city hall staff. | B | In building and maintaining infrastructure, permits are required from the City. This activity involves facilitating the approval process, which includes reviewing the design with City administrators. As permits are required for any capital-build project, this activity is capitalizable. However, this labour costed key activity work order covers both short stream projects (generally maintenance) and full stream projects (capital projects). The labour costed activities identified here are a blend of operating and capital activities. Time attributed to capital activities will be capitalized, while time attributed to operating activities will not be capitalized, in the EAR labour costing allocation. See section 5.5 Process Impact for further discussion as to how these will be allocated. |
| 36  | Administration | Staff charging time to this activity may undertake the following:  
- Performing clerical work that cannot be directly attributed to | O | The labour costed activities identified here are administrative and operating in nature and will thus not be capitalized. |
Performing employee development activities (performance reviews, attendance, recruitment);
- Scheduling or preparing facilities for appointments;
- Managing employee training and administration activities (training, education, expenses, etc.); and
- Performing community related activities.

4.1.2.1.3 Distribution & Grids

The DG group is responsible for the health of the grid, supporting the build process, and ongoing operations of the network. DG is comprised of the following RCs:

1. Stations & Distribution Automation (RC 3310) works with the Capacity Planning RC (in AM) to design station related assets. This RC is responsible for the construction of these capital projects.

2. Distribution Grid Health (RC 3720) also works with the Capacity Planning RC (in AM) and is responsible for managing the performance and operations of distribution assets, including reactive repair and maintenance functions, and analysis of feeder reliability through FESI assessments.

3. System Operations: Planning and Control Room (RCs 4480 and 4481) manages the energization in the system, monitoring the system on a day-to-day basis, and de-energizing parts of the system when field crew require access. System Operations can be broken down into the following subgroups:
   - Schedulers;
   - Control Room;
   - Operations Records;
   - Operations Planning & Performance; and
   - Trouble Dispatch.

4. Distribution Grid Management (RC 3700) manages the operations of DG and may undertake some of the activities described in the other above-noted DG RCs.
RC 3310 Stations & Distribution Automation

Stations & Distribution Automation works with Capacity Planning on station related capital projects. This RC supervises both the design and construction of these capital projects and also supervises scheduled maintenance related to station capital. This RC is very similar to DS in that they are responsible for building planned capital projects. However this RC’s specific responsibilities are to stations capital, whereas DS is responsible for all other types of infrastructure. The following activities highlight the key activities of the RC.

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activity</th>
<th>Description</th>
<th>COB</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Detailed Design</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>C</td>
<td>Supervision activities follow the nature of the underlying work by design technicians. Design technicians currently labour cost directly to specific capital projects. This key activity work order represents the supervision of the design process. As the activity relates specifically to current capital projects, the cost is directly attributable to an item of PP&amp;E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Reviewing SCADA designs;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Reviewing facilities designs; and</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Reviewing telecommunication designs.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Capital build</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>C</td>
<td>Supervision activities follow the nature of the underlying work by field staff. Field crew currently labour cost directly to specific capital projects. This key activity work order represents the supervision of the capital build work. As the activity relates specifically to current capital projects, the cost is directly attributable to an item of PP&amp;E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Supervising construction activities;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Conducting site visits;</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Executing projects;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Supervising projects.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Scheduled maintenance</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>O</td>
<td>Supervision activities follow the nature of the underlying work performed. The underlying work is maintenance in nature and therefore this activity relates to the supervision of maintenance. The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Supervising staff on scheduled maintenance and repair activities;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Performing planned maintenance;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Performing reactive maintenance.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Reactive Replacement</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>C</td>
<td>The Reactive group works on unplanned projects, both capital and operating in nature. The type of work is segregated into Reactive Replacement (i.e., this key activity work order) and Reactive Repair (# 6 below).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Providing supervisory and support required in the completion of various</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| 5 Reactive Repair | Staff charging time to this activity may undertake the following: | O Reactive Replacement represents supervision for the replacement of equipment when it can no longer be repaired. The replacements undertaken by the staff are generally small capital projects (i.e., <$200k, and may include design work).

For utility and electrical infrastructure, a replacement first means putting in a new asset before the old asset can be removed. Since power cannot be halted, the new asset must first be installed and operational before the old asset can be removed from the network.

Replacements or relocations mean that a new asset is capitalized before the old one is derecognized, all costs of installing the new asset and removing the old asset (which are not separately identifiable from the installation costs) are directly attributable to the new item of PP&E.

The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.

| 6 Third Party Contracts | Staff charging time to this activity coordinate with and supervise third party contractors who provide the following types of services: | O This activity deals with the supervision of preventative and predictive maintenance programs such as tree pruning, insulator washing, vault cleaning, and infra-red thermographic inspections. The third party contract is related to maintenance of the existing infrastructure.

The labour costed activities identified here are operating in nature and will thus not be capitalized.

| 7 Administration | Staff charging time to this activity may undertake the following: | O The labour costed activities identified here are administrative and operating in nature and will thus not be capitalized.

- Providing supervisory support required in the completion of various corrective maintenance repair work;
- Assessing system/asset failures; and
- Preparing and dispatching job instructions to crew.

- Pruning trees;
- Washing insulators;
- Cleaning vaults;
- Conducting infra-red thermographic inspections; and
- Cleaning carbon dioxide from switchgear.

- Performing clerical work that cannot be directly
attributed to any predefined or provided WO;
- Performing employee development activities (performance reviews, attendance, recruitment);
- Scheduling or preparing facilities for appointments;
- Managing employee training and administration activities (training, education, expenses, etc.);
and
- Performing community related activities.

RC 3720 Distribution Grid Health

One of the key objectives of the group is to undertake more permanent repairs related to work performed by emergency crew. Unlike the work performed by emergency crews, these repairs or replacements are meant to be permanent and may extend the life of the asset. This RC supervises repair work and, where the equipment cannot be repaired, the group will replace the equipment. This RC is also responsible for third party maintenance contracts and undertakes feeder reliability analysis.

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activity</th>
<th>Description</th>
<th>C</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
</table>
| 8 | Reactive Replacement | Staff charging time to this activity may undertake the following:           | C   | The Reactive group works on unplanned projects, both capital and operating in nature. The type of work is segregated into reactive replacement (i.e., this key activity work order) and reactive repair (# 9 below). Reactive replacement represents supervision for the replacement of equipment when it can no longer be repaired. The replacements undertaken by the staff are generally small capital projects (i.e., <$200k, and may include design work).
For utility and electrical infrastructure, a replacement first means putting in a new asset before the old asset can be removed. Since power cannot be halted, the new asset must first be installed and operational before the old asset can be removed from the network.
Replacements or relocations mean that a new asset is capitalized before the old one is de- |
|   | Reactive Repair | Staff charging time to this activity may undertake the following:  
- Providing supervision and support required in the completion of various corrective maintenance repair work;  
- Assessing system/asset failures; and  
- Preparing and dispatching job instructions to crew. | O In contrast to reactive replacement (key activity work order #5 above), this activity represents the supervision of reactive repair activities, and does not include the replacement of equipment. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
|---|---|---|
| 10 | Third Party Contracts | Staff charging time to this activity may undertake the following:  
- Providing supervision and support required in the completion of various preventative and predictive maintenance programs;  
- Pruning trees;  
- Washing the insulator;  
- Cleaning the vault;  
- Conducting an infra-red thermographic inspection; and  
- Cleaning carbon dioxide from the switchgear. | O This activity supervises preventative and predictive maintenance programs such as tree pruning, insulator washing, vault cleaning, infra-red thermographic inspections. The third party contract is related to maintenance of the existing infrastructure. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 11 | FESI Analysis | Staff charging time to this activity may undertake the following:  
- Providing supervisory and support required in the completion of various FESI feeder reliability and customer complaint analyses. | O This key activity work order deals with analysis of feeder reliability indicators. Feeders are the link between stations and distribution systems and are related to underground capital. The analysis is an ongoing operational requirement and is not attributable to an item of PP&E. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 12 | FESI Design | Staff charging time to this activity may be engaged in providing supervisory and support required in the completion of various FESI | C Where FESI analysis (key activity work order #11 above) leads to the need for a solution to be designed, the design activity will be labour costed here. Projects are executed within the |
mitigation project designs. same year that the design is completed. Any problem that requires a solution to be designed would lead to a capital project, and often involve asset replacement in order to mitigate the cause(s) of the system failure. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.

13 Administration Staff charging time to this activity may undertake the following:
- Performing clerical work that cannot be directly attributed to any predefined or provided WO;
- Performing employee development activities (performance reviews, attendance, recruitment);
- Scheduling or preparing facilities for appointments;
- Managing employee training and administration activities (training, education, expenses, etc.); and
- Performing community related activities.

The labour costed activities identified here are administrative and operating in nature and will thus not be capitalized.

RC 4480 / 4481 Systems Operations: Planning and Control Room
System Operations manages energization in the system, monitors the system on a day-to-day basis, and de-energizes parts of the system when field crew require access. System Operations can be broken down into the following service lines:

- **Schedulers** co-ordinate with the construction crew, the control room and the public on the timing of interruptions due to capital or maintenance work;
- **Control Room** is responsible for the switching operations controlling the energization of the system;
- **Operations Records** is responsible for updates to GEAR, DMS, processing change requests and map update prints;
- **Operations Planning & Performance** monitors system performance and other reliability indices, reviews planned work and assists with customer enquiries;
- **Trouble Dispatch** co-ordinates requests from the call center to dispatch emergency crews to resolve emergency outages; and
- **System Analysis** performs real time system analysis for the control room, provides DGO feedback/requests for AM, coordinates AM/DGO engagement, validate proposed system loading connections, reviews capital planed work and manages SCADA asset.
Schedulers
Schedulers are responsible for scheduling planned work, including the OTO preparation and co-ordination with the control room to ensure that de-energization causes minimal disruption to customers. Schedulers also administer the design review process. These responsibilities are classified into the following key activity for purposes of labour costing:

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>14</td>
<td>Work scheduling</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>B</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Scheduling and planning switching operations to complete planned work;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Scheduling, arranging and notifying customers of power interruptions;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Tracking and processing interruption orders, accessing orders and requests related to customer maintenance and equipment repairs; and</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Liaising, consulting and co-ordinating with contractors, and internal and external customers.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Control Room
The Control Room is responsible for:

- Monitoring system status;
- Reviewing changes or additions to the system;
- Ensuring the correct sections of the system have been de-energized for the field crew; and
- Working with the emergency crew (see Trouble Dispatch below) to develop action plans to restore power during emergency outages.

These responsibilities are classified into the following key activities for purposes of labour costing:
<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C O B</th>
</tr>
</thead>
<tbody>
<tr>
<td>15</td>
<td>Order to Operate</td>
<td>Staff charging time to this activity may undertake the following:  - Preparing the OTO based on information provided once review of WO is completed; and  - Issuing the OTO to crew.</td>
<td>B</td>
</tr>
<tr>
<td></td>
<td></td>
<td>The OTO preparation is the listing of switching activities required to de-energize a line so that field crew can work in a specific area of the network. This activity is required for both maintenance and capital projects, as maintenance and construction cannot occur without the safety precaution of de-energizing the line. This necessary activity is applicable to both capital and operating activities. The labour costed activities identified here are a blend of operating and capital activities. Time attributed to capital activities will be capitalized, while time attributed to operating activities will not be capitalized, in the EAR labour costing allocation. See section 5.5 for further discussion as to how these will be allocated.</td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>WO Review</td>
<td>Staff charging time to this activity are typically engaged in reviewing any type of WO from field crew.</td>
<td>B</td>
</tr>
<tr>
<td></td>
<td></td>
<td>This key activity work order is the review of designs or work orders prior to construction, to ensure how the work can be safely integrated into the current network. This work is required for all capital and maintenance projects. The labour costed activities identified here are a blend of operating and capital activities. Time attributed to capital activities will be capitalized, while time attributed to operating activities will not be capitalized, in the EAR labour costing allocation. See section 5.5 for further discussion as to how these will be allocated.</td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>Execution (switching, work protection)</td>
<td>Staff charging time to this activity may undertake the following:  - Assisting with the implementation of the OTO, such as work protection and verbal communications and hold offs; and  - Switching and liaising with HO, TTC.</td>
<td>B</td>
</tr>
<tr>
<td></td>
<td></td>
<td>This Control Room key activity work order represents the actual switching work required to de-activate a line. While key activity work orders #15 and #16 are preparatory in nature, this activity represents the actual switching itself. Switching activities are required for all capital and maintenance projects. The labour costed activities identified here are a blend of operating and capital activities. Time attributed to capital activities will be capitalized, while time attributed to operating activities will not be capitalized, in the EAR labour costing allocation. See section 5.5 for further discussion as to how these will be allocated.</td>
<td></td>
</tr>
</tbody>
</table>
| 18 | Record keeping - interruption tracking information system and the defective equipment tracking system | Staff charging time to this activity may undertake the following:  
- Updating maps, feeder prints, and WOs;  
- Updating the interruption tracking information system and the defective equipment tracking system; and  
- Updating DMS and SCADA schematics. | C | Updates to these sources are necessary to the monitoring of asset connectivity.  
The Control Room is concerned with the connectivity (or the flow of power) between distribution assets in the network and supplements the use of GEAR with maps, feeder prints, ITIS, DETS, SCADA and other schematics. Updates to these schematics include drawing in the connectivity between assets in DMS/OMS. The records must reflect the assets and connections in the field to ensure the control room can properly monitor the grid and the safety of the field crew that work on the grid.  
As these updates relate specifically to new construction projects, it is attributable directly to items of PP&E. System updates are a necessary step prior to physical energization of assets (i.e. allowing current to flow through the assets) as records must be up-to-date from a safety perspective before assets can be used.  
Note that maintenance programs do not require new designs and thus updates to feeder prints or DMS are not necessary.  
The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
|---|---|---|---|---|
| 19 | Outage management | Staff charging time to this activity may undertake the following:  
- Perform power restorations;  
- Undertake feeder reconfigurations;  
- Communicate significant events; and  
- Undertake load shedding, voltage reductions. | O | The key activity work order identified as “outage management” refers to the operation of the existing grid and not the building of additional infrastructure.  
The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 20 | System monitoring | Staff charging time to this activity may undertake the following:  
- Monitor day-to-day system loading; and  
- Monitor day-to-day system alarms. | O | This key activity work order is for the general monitoring of the ongoing supply of power in the control room. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
The Operations Records group is responsible for updating GEAR/GIS, building DMS, ensuring that the nomenclature in the system is current and map products are current. These responsibilities are classified into the following key activities for purposes of labour costing:

<table>
<thead>
<tr>
<th>#</th>
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</thead>
<tbody>
<tr>
<td>21</td>
<td>DGO Process Change Requests</td>
<td>Staff charging time to this activity are likely to be engaged in processing change requests for approved projects.</td>
<td>B</td>
<td>This key activity work order is related to updating records as a result of change requests. Where a design requires an equipment addition, the digital records in GEAR must be updated. Equipment updates are accomplished by deleting the old design, and inserting a new one. This change request is related directly to a capital project, the portion related to new assets is capitalizable. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
</tbody>
</table>
| 22 | DMS Model Build         | Staff charging time to this activity may undertake the following:  
- Conducting model builds;  
- Undertaking production; and  
- Managing SYS07 (test environment).                                                                                                                                       | C   | A new software system is being built internally called DMS and its purpose is to align the pre-amalgamation systems. This time represents the engineers’ input to this system build. The IT project is capital in nature. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
| 23 | GEAR Update             | Staff charging time to this activity may undertake the following:  
Staff is involved in updating the GIS system may undertake the following:  
- Updating the GIS system;  
- Updating an NDS job;  
- Performing GEAR maintenance; and  
- Posting jobs (or project) to GEAR.                                                                                                                                 | C   | The Operations Records group must update all required records to ensure the “as built” infrastructure matches to initial designs in GEAR. This update is the same as the work performed by Capacity Planning in AM (activity # 11, section 4.1.2.1.2 Asset Management) but is undertaken for the remaining four regions of the City (i.e., Scarborough, Etobicoke, North York and York). This “as built” records update is essential to the conclusion of the construction process and to future operations. This key activity work order relates directly to designs for specific projects, is directly attributable to an item of PP&E. System updates are a necessary step prior to physical energization of assets (i.e. allowing current to
flow through the assets) as records must be up-to-date from a safety perspective before assets can be used.

The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.

<table>
<thead>
<tr>
<th>24</th>
<th>Nomenclature</th>
<th>Staff charging time to this activity may undertake the following:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>- Updating new nomenclature in GEAR; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Updating new nomenclature on maps, feeder prints, schematics.</td>
</tr>
</tbody>
</table>

When the 6 regions amalgamated in 1999, each had their own equipment naming conventions. However, since the naming convention and the system flags had different meanings (e.g. red light on a breaker in York means “off”, and the same red light on a breaker means “on” in Scarborough), a project was undertaken to ensure that all equipment was appropriately labeled to distinguish the meaning of all signals or flags used. Outside field crew involved in this project labour cost directly to a project code, which is capital under CGAAP. This key activity work order represents supervision of the project. Recognition as capital or expense of the supervisor’s time should be consistent with the recognition of the underlying field staff time.

System updates are a necessary step prior to physical energization of assets (i.e. allowing current to flow through the assets) as records must be up-to-date from a safety perspective before assets can be used.

The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.

Operations Planning & Performance
The Operations Planning & Performance group is responsible for collating and analyzing system data, which is required to monitor overall system performance. This group also deals with customer enquiries. These responsibilities are classified into the following key activities for purposes of labour costing:

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C O B</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>25</td>
<td>Planned Work (Review of customer drawings)</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Reviewing customer drawings;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Reviewing specifications;</td>
<td>C</td>
<td>Review of customer drawings relates to work with the AM group on offers to connect. At the time of DG involvement, the offer to connect has been accepted by the customer and work is intended to move forward. This</td>
</tr>
</tbody>
</table>
and
- Conducting site meetings.

activity is thus directly attributable to an item of PP&E.
The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.

| 26 | Customer Enquiries | Staff charging time to this activity may undertake the following:
- Addressing customer complaints;
- Providing details to legal for customer inquiries. | O | Customer enquiries and complaints are a function of the existing infrastructure and not related to capital builds.
The labour costed activities identified here are operating in nature and will thus not be capitalized. |

| 27 | Monitor System Performance | Staff charging time to this activity may undertake the following:
- Monitoring reliability indices such as SAIFI, SAIDI;
- Monitoring system loading;
- Investigating worst performance feeders. | O | This key activity work order is not related to monitoring in the control room, instead it covers system monitoring of key performance indicators to ensure the system is running effectively. This is a function of operating the existing infrastructure, and relates to maintenance.
The labour costed activities identified here are operating in nature and will thus not be capitalized. |

| 28 | SAIFI, SAIDI | Staff charging time to this activity may undertake the following:
Reliability indices SAIFI, SAIDI
- Reviewing and analyzing data relevant to power restoration;
- Performing system calculations for the utility to support the OEB indices;
- Providing actions and recommendations to stakeholders to support increases in reliability and performance. | O | This key activity work order relates to indices to measure outages. It does not result in capital projects.
The labour costed activities identified here are operating in nature and will thus not be capitalized. |

| 29 | Emergency Preparedness | Staff charging time to this activity may undertake the following:
- Providing direction and training for utility staff surrounding emergency power restoration;
- Supporting key initiatives as team members on the IESO working committees;
- Performing annual disaster recovery drills required by | O | Emergencies or outages refer to the maintaining of the current infrastructure and does not relate to capital builds.
The labour costed activities identified here are operating in nature and will thus not be capitalized. |
the IESO; and
- Maintaining, updating, and communicating changes related to the Power System Emergency Plan.

<table>
<thead>
<tr>
<th></th>
<th>Labour costing / Timekeeping</th>
<th>Staff charging time to this activity may undertake the following:</th>
<th>B</th>
</tr>
</thead>
<tbody>
<tr>
<td>30</td>
<td></td>
<td>- Entering labour costing information for capital project Work Orders;</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Entering labour costing information for operating and maintenance Work Orders;</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Entering, reporting and analyzing overtime exceptions to labour costing;</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Correcting errors;</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Validating pay;</td>
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<tr>
<td></td>
<td></td>
<td>- Entering holiday time;</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Entering sick time;</td>
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<td></td>
<td></td>
<td>- Entering medical appointments;</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Entering other time exceptions;</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Reporting and analyzing exceptions.</td>
<td></td>
</tr>
</tbody>
</table>

Labour costing is responsible for time-sheets and is administrative in nature. This key activity work order is required for both construction and maintenance projects. The labour costed activities identified here are a blend of operating and capital activities. Time attributed to capital activities will be capitalized, while time attributed to operating activities will not be capitalized, in the EAR labour costing allocation. See section 5.5 Process Impact for further discussion as to how these will be allocated.

### Trouble Dispatch

Trouble dispatch is a sub-group within grid operations. It co-ordinates the requests from the call center to dispatch the emergency crews to resolve emergency outages. The emergency crew will liaise with the control room to develop an action plan. Key activities for trouble dispatch are described below:

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C O B</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>31</td>
<td>Trouble Dispatching</td>
<td>Staff charging time to this activity may be engaged in receiving, assessing, dispatching and/or logging trouble calls, messages, or reports of accident.</td>
<td>O</td>
<td>Trouble dispatch is a key activity work order related to operating the existing infrastructure. The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
</tr>
<tr>
<td>32</td>
<td>Switching</td>
<td>Staff charging time to this activity may be engaged in receiving, dispatching and logging switching operation instructions.</td>
<td>O</td>
<td>This key activity work order involves switching operations for the trouble dispatch group. Like Trouble Dispatching the function is related to operating the existing infrastructure. The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
</tr>
</tbody>
</table>
### Mark-up, Confined Space

Staff charging time to this activity may be engaged in receiving, authorizing and recording mark ups for confined space entry.

O This key activity work order is part of the Trouble Dispatch process, and is related to operating the existing infrastructure. The labour costed activities identified here are operating in nature and will thus not be capitalized.

### Records Update

Staff charging time to this activity may undertake the following:
- Maintaining feeder maps and records;
- Reviewing overhead plant in field;
- Recording and reporting employee time and attendance, call outs, and field work when completed; and
- Receiving, satisfying, and updating data on inquiries/complaints by telephone, in person, or by correspondence.

O Records update is the end of the Trouble Dispatch process, and is likewise related to operating the existing infrastructure. The labour costed activities identified here are operating in nature and will thus not be capitalized.

### System Analysis

System analysis is a subgroup within grid operations and performs real time system analysis for the control room, provides DGO feedback/requests for AM, coordinates AM/DGO engagement, validates proposed system loading connections, reviews capital planed work and manages SCADA assets.

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C O B</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>35</td>
<td>Review Capital Planned Work</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>C</td>
<td>Review of designers’ drawings relates to planned work with the AM and DS groups and involves attending pre-construction meetings with all stakeholders. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Reviewing drawings from designers prior to construction; and</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Attending pre-construction meetings with designers and construction crews.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>36</td>
<td>Customer Enquiries</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>O</td>
<td>Customer enquiries and complaints are a function of the existing infrastructure and not related to capital builds. The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Addressing customer inquiries on technical issues such as loading, fault current level; and</td>
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<td></td>
</tr>
<tr>
<td><strong>37</strong></td>
<td><strong>Monitor System Performance</strong></td>
<td><strong>38</strong></td>
<td><strong>FESI 7, DETS Review</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Staff charging time to this activity may undertake the following:</strong></td>
<td><strong>Staff charging time to this activity may undertake the following:</strong></td>
<td><strong>Staff charging time to this activity may undertake the following:</strong></td>
<td><strong>Staff charging time to this activity may undertake the following:</strong></td>
<td></td>
</tr>
<tr>
<td>- Meeting with external agencies such as Hydro One and the TTC to coordinate their work, and addressing any supplying issues.</td>
<td>- Monitoring reliability indices such as SAIFI and SAIDI; - Monitoring system loading; and - Investigating worst performance feeders.</td>
<td>- Providing FESI-associated information related to the preliminary capital plan to AM so that they can update their long-term or short-term investment plan; - Reviewing and providing input to the reactive group with respect to their design plans and proposed changes to the distribution system; and - Attending weekly meetings with the AM and reactive groups regarding short-term and long-term action plans including implementation of changes.</td>
<td>- This key activity work order is not related to monitoring in the control room, instead it covers system monitoring of key performance indicators to ensure the system is running effectively. This is a function of operating the existing infrastructure and relates to maintenance. The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
<td></td>
</tr>
<tr>
<td><strong>O</strong></td>
<td><strong>B</strong></td>
<td><strong>B</strong></td>
<td><strong>B</strong></td>
<td></td>
</tr>
</tbody>
</table>

The control room is involved with the following FESI-related activities:

- The control room provides data to the AM group related to short and long-term projects. This part of the process is a blend of operating and capital work since AM’s long-term investment plan is operating in nature, while their short-term projects are capital in nature, as discussed in section 4.1.2.1.2 under AM.

- The AM group will eventually transfer the FESI-related designs to the reactive group (in distribution grid health RC 3720). The reactive group will further refine and finalize the designs and undertake the actual construction (key activity work order #9). During this time the reactive group will work with the control room to understand the impacts their plans will have on the system. The control room must understand any changes proposed to current asset connectivity to ensure they will be properly integrated into the system. This portion of the control room’s FESI activities is in the nature of capital as it relates specifically to design and construction of capital projects.

- Throughout this process, the control room attends weekly meetings with the AM and Reactive groups to discuss FESI related issues. These weekly meetings would also be a blend of capital and operating discussions and changes.

Overall, this key activity work order is a
blended activity which will be allocated across both capital and operating projects/codes. See section 5.5 Process Impact for further discussion as to how these will be allocated. Time attributed to capital activities will be capitalized, while time attributed to operating activities will not be capitalized.

| 39 | SCADA Detailed Design | Staff charging time to this activity may undertake the following:  
- Reviewing SCADA designs;  
- Reviewing designers’ drawing related to distribution automation;  
- Attending meetings with stakeholders;  
- Managing SCADA assets; and  
- Commissioning SCADA switches. | C | Supervision activities follow the nature of the underlying work by design technicians. Design technicians currently labour cost directly to specific capital projects. This key activity work order represents the supervision of the design process. As the activity relates specifically to current capital projects, the cost is directly attributable to an item of PP&E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
| 40 | SCADA Scheduled maintenance | Staff charging time to this activity may undertake the following:  
- Performing planned maintenance;  
- Performing Moscad radio maintenance;  
- Performing transit radio maintenance;  
- Performing XOS maintenance;  
- Performing PI maintenance;  
- Performing ICCP maintenance; and  
- Performing projection screen maintenance. | O | Supervision activities follow the nature of the underlying work performed. Maintenance, and therefore supervision of maintenance, is not directly attributable to an item of PP&E under IFRS. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 41 | Administration | Staff charging time to this activity may undertake the following:  
- Performing clerical work that cannot be directly attributed to any predefined or provided WO;  
- Performing employee development activities (performance reviews, attendance, recruitment);  
- Scheduling or preparing facilities for appointments; and  
- Managing employee | O | The labour costed activities identified here are administrative and operating in nature and will thus not be capitalized. |
training and administration activities (training, education, expenses, etc.); and
- Performing community related activities.

RC 3700 Distribution Grid Management

This RC includes the executive, a manager, a supervisor and an engineer. As the role of the executive is broad in its nature and generally encompasses strategic planning for the group, including ensuring compliance with corporate goals and initiatives, it is difficult to prove the linkage of these activities to specific items of PP&E. As a result, these costs will not be capitalized under IFRS. The manager’s work is viewed similarly and thus will not be capitalized under IFRS.

While the supervisor and engineer are part of this RC, their roles are not defined specifically to management activities. Where the supervisor and engineer undertake activities as described in the other DG RC above, their time will be labour costed based on the nature of those activities. For example, if the supervisor undertakes OTO prep activities, his time will be recorded with the associated activity and the related costs will be charged to that labour pool which will be allocated to capital and/or operating projects in the same fashion as the employees in RCs 4480/4481.

4.1.2.1.4 Distribution Projects / Distribution Systems

The DS group undertakes most of the construction activities and is broken down into the following RCs:

1. Program Management (RC3820) works directly with field crew in the DS and the DG groups. The RC is responsible for managing the overall planned work projects, which include planned capital builds and planned maintenance. Members of this RC are assigned to support DS and DG Managers and field crew supervisors and work directly with them on the initiation, progression and completion of a project. The group also works with AM to help ensure that adequate resources exist for the intended annual projects.

2. DS – East (RC 3110), West (RC 3160) and Centre (RC 3130) work directly with Program Management and System Reliability (in AM) to complete planned work. DS RCs have their own field crews for construction and maintenance projects, who can also support non-planned repairs and replacements on an as-needed basis. The activities described below apply to the supervisors of the field crews. Note that the field crews are labour
costed directly to the project work order, and the labour cost is not included in the EAR Labour Costing allocation discussed in this memo.

3. Program Support Office (RC3620) executes any overflow of projects, capital or operating, assigned to them from DS East, West or Centre, CCM and DG Health (such as planned capital work).

4. CCM – (RC 4330), focuses primarily on the construction and management of customer connections.

5. Distribution Systems Administration (RC 3600) manage the operations of DS and may undertake some of the activities described in the other above-noted DS RCs.

Note that DS East, West and Centre and CCM have similar functions such that the key activity work orders described below have been combined to avoid duplication.

### RC 3820 Program Management

Program Management works with construction supervisors on the projects to which they are assigned (generally 10-20 projects) and they are responsible for the following functions:

- Scheduling, generating the work plan schedule for the year and labour balancing (the right skill set for a project at the right time);
- Reviewing and developing work packages in conjunction with the AM group, including checking for overall completeness and assistance with budgeting; and
- Monthly project reporting, variance analysis (budget to actual) and progress reporting.

These responsibilities are classified into the following key activities for purposes of labour costing:

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C O B</th>
<th>Analysis and Support for Capital, Operating or Blend Classification.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Annual Budget Preparation (project specific by the individual Project Managers)</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Creating estimates;</td>
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<tr>
<td></td>
<td></td>
<td>- Creating version 3 of estimates (Stations);</td>
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<tr>
<td></td>
<td></td>
<td>- Validating all project estimates for programs that are SFW;</td>
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<td></td>
<td>- Validating Ellipse estimates to Hyperion;</td>
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<tr>
<td></td>
<td></td>
<td>- Managing standard estimates (WBS5);</td>
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<tr>
<td></td>
<td></td>
<td>- Balancing resource within the RC;</td>
<td></td>
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</tr>
<tr>
<td></td>
<td></td>
<td>- Balancing resources across RCs;</td>
<td></td>
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</tr>
</tbody>
</table>

This key activity work order includes the overall budget preparation for the year, including review of AM’s budgets for reasonability, and labour and resource balancing. All activities relate to projects that have already been approved. Budgeting is critical in order to demonstrate to the OEB that it is prudent in its expenditures, and is a necessary part of the construction process. The PM consultants (program managers) work with both operating and capital projects. The labour costed activities identified here are a blend of operating and capital activities. Time attributed to capital activities will be capitalized, while time
| **2** Project / Program Plan  
- Line Development | **Staff charging time to this activity may undertake the following:**  
- Performing calendarization by EE;  
- Performing calendarization by work type;  
- Performing calendarization by units;  
- Creating units summary sheet;  
- Developing planned work attainment sheets;  
- Developing maintenance work attainment sheets;  
- Developing design attainment sheets; and  
- Creating a calendarized civil plan. | **B** This key activity work order includes working with the AM group to develop work packages and to check its completeness. This activity is similar to scheduling however it is undertaken at a more granular level (i.e. work packaging) and these activities relate to approved projects.  
The PM Consultants work with both operating and capital projects.  
The labour costed activities identified here are a blend of operating and capital activities. Time attributed to capital activities will be capitalized, while time attributed to operating activities will not be capitalized, in the EAR labour costing allocation. See section 5.5 Process Impact for further discussion as to how these will be allocated. |
|  |  |  |
| **3** Project / Program Scheduling | **Staff charging time to this activity may undertake the following:**  
- Arranging the high-level design, construction, and civil schedules;  
- Managing importing/exporting of work between RC's;  
- Liaising with procurement RCs for material issues;  
- Consulting with design supervisors, procurement, and vendors regarding material management requirements for capital projects; | **B** Scheduling is a required key activity work order to ensure the right materials and labour are requisitioned for the project, and to ensure these necessary resources are available to the construction project when needed.  
The PM consultants work with both operating and capital projects.  
The labour costed activities identified here are a blend of operating and capital activities. Time attributed to capital activities will be capitalized, while time attributed to operating activities will not be capitalized, in the EAR labour costing allocation. See section 5.5 Process Impact for further discussion as to how these will be allocated. |
- Liaising with the control room on work execution;
- Directing/supporting OPM Schedulers;
- Developing MST matrix for work coordination;
- Facilitating creation/maintenance of the project construction plan;
- Co-ordinating schedules for interdependent projects across RCs;
- Attending pre-construction and mid-design meetings;
- Reporting on GEAR NDS compliance;
- Packaging projects;
- Picking materials for contractors/CCL’s;
- Tracking/validating completed MST inspections;
- Analyzing MST costs for anomalies;
- Analyzing capital costs by project and EE;
- Advising RCs of errors to correct cost charging;
- Correcting financial elements of projects/work orders;
- Attending various project review meetings (construction and maintenance);
- Attending RC OSR/OCM meetings;
- Facilitating BSC/PVA meetings;
- Consulting on IOP scope change order approval forms;
- Conducting CWIP analysis and closure;
- Identifying substantially complete Projects for capitalization;
- Closing projects and Work Orders for completed work;
- Reporting on CAPEX and OPEX costs, units completion, and project attainment;
- Consulting on work program
capitalized, in the EAR labour costing allocation. See section 5.5 Process Impact for further discussion as to how these will be allocated.
<table>
<thead>
<tr>
<th>Work Program</th>
<th>Staff charging time to this activity may undertake the following:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preparation / issuance / Tracking / Measurement / Reporting / Forecasting</td>
<td>- Committing MSTs to work order;</td>
</tr>
<tr>
<td></td>
<td>- Generating inspection forms;</td>
</tr>
<tr>
<td></td>
<td>- Generating check list of inspection forms;</td>
</tr>
<tr>
<td></td>
<td>- Reporting data error on MSTs to AM;</td>
</tr>
<tr>
<td></td>
<td>- Identifying MST printing errors to AM;</td>
</tr>
<tr>
<td></td>
<td>- Creating MST workarounds to generate forms;</td>
</tr>
<tr>
<td></td>
<td>- Following-up on MST inspection results;</td>
</tr>
<tr>
<td></td>
<td>- Re-issuing of MST inspection forms;</td>
</tr>
<tr>
<td></td>
<td>- Issuing of standing work orders for &quot;bucket&quot; programs;</td>
</tr>
<tr>
<td></td>
<td>- Closing of incorrectly packaged projects/work orders;</td>
</tr>
<tr>
<td></td>
<td>- Setting-up supervisor work program plan (design and construction);</td>
</tr>
<tr>
<td></td>
<td>- Issuing scope packages and creating corresponding design work orders; and</td>
</tr>
<tr>
<td></td>
<td>- Managing work-flow in ProjectWise.</td>
</tr>
</tbody>
</table>

| B | This key activity work order is the on-going tracking and reporting related to construction projects, and is a key function to ensure the project meets its targets and costs. The PM consultants work with both operating and capital projects. The labour costed activities identified here are a blend of operating and capital activities. Time attributed to capital activities will be capitalized, while time attributed to operating activities will not be capitalized, in the EAR labour costing allocation. See section 5.5 Process Impact for further discussion as to how these will be allocated. |
| 5 | Business and Process Analytics | Staff charging time to this activity may undertake the following:  
- Developing business processes within program management;  
- Developing system solutions within program management (liaison with IT);  
- Conducting data analysis within program management;  
- Conducting data analysis in support of PM consultants and operations RCs; and  
- Supporting clerical staff. | O | Time incurred here is for internal projects, i.e., internal budget to actual review, to help manage risk and improve efficiency. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 6 | Labour Costing / Time keeping | Staff charging time to this activity may undertake the following:  
- Entering labour costing information for capital project Work Orders;  
- Entering labour costing information for operating and maintenance Work Orders;  
- Entering, reporting and analyzing overtime exceptions to labour costing;  
- Correcting errors;  
- Validating pay;  
- Entering holiday time;  
- Entering sick time;  
- Entering medical appointments;  
- Entering other time exceptions; and  
- Reporting and analyzing exceptions. | B | This key activity work order is required for both construction and maintenance projects. The labour costed activities identified here are a blend of operating and capital activities. The Corporation acknowledges that certain time keeping activities are operating in nature. Project labour costing, however, provides real-time information regarding the costing status of the current project. The project labour costing is a necessary component and it is not simply a function of assessing performance against result. This information is critical in the assessment of current projects, which can translate to real-time decisions affecting how current projects are managed. Such information leads to decisions on resourcing (i.e. internal vs. external), management of project funding, and overall project completion. Time attributed to capital labour costing activities will be capitalized, while time attributed to time keeping operating activities will not be capitalized, in the EAR labour costing allocation. See section 5.5 Process Impact for further discussion as to how these will be allocated. |
| 7 | CCM | Staff charging time to this activity may undertake the following:  
- Arranging installation of new services for customers;  
- Arranging for disconnects and re-connects for building demolitions; | O | This work relates to energy service clerks, who take customer calls relating to new services, service disconnects and reconnects for building demolitions, temporary services to construction sites, and service upgrades for greater load. This key activity work order is |
<p>| | | |</p>
<table>
<thead>
<tr>
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</thead>
</table>
| 8 | Radio Room Support | Staff charging time to this activity may undertake the following:  
- Issuing, tracking and managing radios and confined space gas monitors used by field crews for carrying out capital projects and maintenance programs; and  
- Testing gas monitors to ensure accuracy and compliance to regulatory requirements.  
O This key activity work order deals with the management of radios and confined space gas monitors, both of which are distributed to field crew. This is an administrative activity.  
The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 9 | Claims Support | Staff charging time to this activity may undertake the following:  
- Assembling information related to claimable events;  
- Liaising with field supervisors to gather information; and  
- Liaising with the legal department to provide support to the claims effort.  
O This key activity work order is clerical in nature and relates to support given to the legal department for claims made against the public when damage is done to the assets, i.e., legal claims arising when a car hits a pole. This is an administrative activity.  
The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 10 | Administration | Staff charging time to this activity may undertake the following:  
- Performing clerical work that cannot be directly attributed to any predefined or provided WO;  
- Performing employee development activities (performance reviews, attendance, recruitment);  
- Scheduling or preparing facilities for appointments;  
- Managing employee training and administration activities (training, education, expenses, etc.); and  
- Performing community related activities.  
O The labour costed activities identified here are administrative and operating in nature and will thus not be capitalized. |
The DS and CCM groups are responsible for the planned capital work projects, whether scoped by the AM group or as a result of an Offer to Connect. As part of the capital re-build program, DS will work with the AM group to prepare the Detailed Design Package (detailed design scope and detailed estimates). The employees described in these RCs are responsible for the supervision of the field crew and therefore their activities will also include the following:

- Project status review;
- Management of staff;
- Workstation safety reviews ("crew visits" which are required by the SIS); and
- Logistics and operational issue resolution.

These responsibilities are classified into the following key activities for purposes of labour costing:

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C O B</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>11</td>
<td>Capital Project Designs</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>C</td>
<td>This specific key activity work order involves supervision of the more detailed design work performed by DS, including detailed estimates and site visits. By the time DS is involved, the project has been approved, and is capital in nature. Therefore, the supervision of the design work is directly attributable to an item of PP&amp;E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Creating MicroStation designs;</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Creating GEAR jobs;</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Creating Ellipse estimates;</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Developing material requirements;</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Validating account coding against estimates;</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Validating that all project estimates for program are SFW;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Analyzing data for PVA.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Capital Project Construction</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>C</td>
<td>This key activity work order is supervision of the physical construction of the capital project, is directly attributable to an item of PP&amp;E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Tactical scheduling of crew;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Tactical scheduling of units;</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Project resourcing;</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Monitoring and reporting of work progress against schedule;</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Monitoring and reporting of work completion against unit plan;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Monitoring and reporting of</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
|   |   | project expenditures against budget;  
|   |   | - Supervising crew work practice; and  
|   |   | - Reviewing of material usage, picking, and returns.  
| 13 | **Offers to Connect (CCM)** | Staff charging time to this activity may undertake the following:  
|   |   | - Preparing design estimates;  
|   |   | - Preparing offer documents;  
|   |   | - Performing calculations based on economic model;  
|   |   | - Supervising offer to connect project design and construction;  
|   |   | - Liaising with AM for contract details and economic model calculations; and  
|   |   | - Interacting with customers.  
| C |   | This key activity work order relates to preliminary assistance provided to AM in formulating the offer to connect and also relates to the supervision of all work performed once an offer has been accepted. An offer to connect project is managed by CCM once approved by the customer. This key activity work order is directly attributable to an item of PP&E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.  

| 14 | **Maintenance Programs** | Staff charging time to this activity may undertake the following:  
|   |   | - Tactical scheduling of crew;  
|   |   | - Tactical scheduling of units;  
|   |   | - Performing project resourcing;  
|   |   | - Monitoring and reporting of work progress against schedule;  
|   |   | - Monitoring and reporting of work completion against unit plan;  
|   |   | - Monitoring and reporting of Project expenditures against budget; and  
|   |   | - Supervising crew work practice.  
| O |   | This key activity work order is oversight of the maintenance programs. The labour costed activities identified here are operating in nature and will thus not be capitalized.  

| 15 | **Customer Enquiries** | Staff charging time to this activity may undertake the following:  
|   |   | - Investigating customer issues; and  
|   |   | - Meeting with customers/clients.  
| O |   | This key activity work order includes investigation of customer enquiries and issues related to existing infrastructure and not new capital builds. The labour costed activities identified here are operating in nature and will thus not be capitalized.  

| 16 | **Administration** | Staff charging time to this activity may undertake the following:  
|   |   | - Performing clerical work that cannot be directly attributed to any predefined or provided WO;  
| O |   | The labour costed activities identified here are administrative and operating in nature and will thus not be capitalized.  

- Performing employee development activities (performance reviews, attendance, recruitment);
- Scheduling or preparing facilities for appointments;
- Managing employee training and administration activities (training, education, expenses, etc.);
- and
- Performing community related activities.

**RC 3600 Distribution Systems Administration**

This RC includes both management (an executive, a manager, and an administrative assistant) and operational employees (supervisors, a professional engineer, and inside and outside union staff). As the role of the executive is broad in its nature and generally encompasses strategic planning for the group, including ensuring compliance with corporate goals and initiatives, it is difficult to prove the linkage of these activities to specific items of PP&E. As a result, these costs will not be capitalized under IFRS. The manager and administrative assistant are viewed similarly and their costs will also not be capitalized under IFRS.

While the operational employees are part of this RC, their roles are not limited to management activities. When the supervisor and engineer undertake activities as described in the other DS RCs above, their time will be allocable based on the nature of those activities. For example, if the engineer undertakes capital project construction activities, his time will be recorded and costs will be charged to that labour pool which will be allocated to capital projects in the same fashion as the employees in DS East or CCM.

### 4.1.2.1.5 Customer Services

The Customer Services group has the primary responsibility for meter installations and replacements, including the deployment of the smart metering program. The group is comprised of the following RCs:

1. Smart Meter (RC 5000) is responsible for technology selection, wholesale meter registration, data management, and smart meter installation and support.

2. Meter Services (RC 4100), like RC 5000, also manages aspects of the installation and support of smart meters. In addition, RC 4100 is responsible for meter replacements, including the replacement of meters, failed smart meters, and meters for the purpose of testing.
RC 5000 Smart Meter

The Smart Meter RC is responsible for the following functions:

- Technology selection to be used in smart meters;
- Deployment planning;
- Wholesale meter registration which deals with installation of wholesale meters at transfer stations; and
- Data management including collating and analyzing data from approximately 3,200 meters per day.

These responsibilities are classified into the following key activities for purposes of labour costing:

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>COB</th>
<th>Analysis and Support for Capital, Operating or Blend Classification.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Meter Registration (wholesale meters)</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>C</td>
<td>Meter registration is related to wholesale meters installed at stations, and their registration with the IESO. These meters measure energy transferred from Hydro One and used in distributing power to customers. The responsibility for these meters rests with the Corporation (i.e., monitoring, reporting, and maintenance). This key activity work order relates to the replacement of Hydro One's old meter with new wholesale meter technology as required by the IESO. The IESO also requires the Corporation to perform &quot;end to end&quot; tests to ensure meters are installed and functioning appropriately. These activities must be undertaken before the meter becomes operational. Once these activities are undertaken, the meter is registered and certain paperwork is filed with the IESO before it can be turned on. In addition to wholesale meter registration, RIMS retail accounts must also be set up before the meter can be turned on. A RIMS account is set up for large users whose peak monthly demand exceeds 200 kW and who pay for electricity based on the HOEP. By year-end 2011, all commercial customers will pay for electricity based on either TOU or HOEP</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Designing meter installations;</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Supporting meter installations;</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- Inspecting meters; and</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Creating wholesale RIMs accounts.</td>
<td></td>
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</tr>
</tbody>
</table>
rates, requiring some form of daily remote meter interrogation.
As meter registration relates to activities required to get the asset in the location and condition necessary for it to be capable of operating in the manner intended by management, the key activity work order is directly attributable to an item of PP&E.
The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.

| 2 | Program Deployment | Staff charging time to this activity may undertake the following:  
- Budgeting for deployment;  
- Planning for conversion;  
and  
- Managing contractors (installers). | C | This key activity work order relates to the strategies around prioritizing where smart meters will next be deployed (e.g., commercial vs. residential meter installations, or which locations require more complex meter functionality). The key activity work order is ultimately related to the installation of meters and therefore it is attributable to an item of PP&E. Very little residential and commercial work is expected in this work order beyond 2010, and 2011 respectively, when the Smart Meter Program is expected to be completed. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |

| 3 | Data Management | Staff charging time to this activity may undertake the following:  
- Analyzing and collating data;  
- Reporting;  
- Reviewing data; and  
- Liaising with the billing department. | O | This activity supports billing efforts and refers to the back office function to collate and analyze data gathered from the meters. The labour costed activities identified here are operating in nature and will thus not be capitalized. |

| 4 | Technology selection | Staff charging time to this activity may undertake the following:  
- Assisting in the selection of new technologies;  
- Ensuring technology satisfies program requirements for smart grid and grid modernization activities; and  
- Working with IT to ensure the technology can be integrated with the current | C | The main goals of technology selection to date have been to ensure purchased products comply with all regulatory requirements and deliver the required functionality for billing, including working with the IT department to ensure the technology has the necessary application support for high volume meter communications and data gathering, to deliver complex calculations to the billing system, and build a secure, reliable and high speed billing infrastructure. This work |
billing infrastructure where additional calculations or volume requirements are needed.

is capital in nature. Going forward, technology selection will be aimed at satisfying additional program requirements, such as satisfying smart grid and grid modernization activities. This key activity work order relates to selecting new technology to ensure it meets with additional program requirements and as such the activity will result in an item of PP&E. However, this activity does not involve investigating whether the meter technology is feasible (i.e., can be integrated into the Corporation’s systems), but is more of a cost analysis of different technologies. While an item of PP&E will result from this activity and there is an element of capital in this activity, any time related to technologies that are not eventually chosen should be expensed. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.

| 5 | Smart Meter Installations | Staff charging time to this activity may undertake the following:  
- Planning for installations;  
- Supervising installations;  
- Installation verification testing;  
- Pre-installation meter testing; and  
- Updating the CIS for installation purposes. | C | In addition to the planning, supervision and testing of smart meter installations, this key activity work order involves the necessary updates to the information system used by the CS group. As this key activity work order relates to the steps required to get the asset (i.e., smart meter) in the location and condition necessary for it to be capable of operating in the manner intended by management, the key activity work order is directly attributable to an item of PP&E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |

| 6 | Smart Meter Support / Maintenance | Staff charging time to this activity may undertake the following:  
- Supervising the meter refurbishment;  
- Performing meter maintenance / repair;  
- Updating CIS for non-installations;  
- Performing meter post-installation trouble shooting; and  
- Performing activities in the | O | This key activity work order supports meter maintenance and refurbishments of existing infrastructure. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
<table>
<thead>
<tr>
<th>Activity</th>
<th>Description</th>
<th>Classification</th>
</tr>
</thead>
</table>
| 7 Meter Audits | Staff charging time to this activity may undertake the following:  
- Assisting with the audits performed by IESO on wholesale meters; and  
- Performing troubleshooting activities related to audits. | O This key activity work order relates to assisting the IESO with the audits of wholesale metering and related functions. These audits are performed on operational wholesale meters (i.e. existing assets and not newly constructed assets). The labour costed activities identified here are operating in nature and will thus not be capitalized. |
| 8 Meter Installations (Wholesale, Suite and Distribution meters) | Staff charging time to this activity may undertake the following:  
- Planning for the meter installation;  
- Providing meter installation support;  
- Performing meter installation troubleshooting;  
- Updating CIS for installations;  
- Selecting and ordering meters;  
- Installing meter replacements; and  
- Performing pre-installation meter testing. | C This key activity work order represents the supervision of the crew installing or replacing the meters. The underlying field crew labour cost to capital projects and therefore, the supervisory time should be consistent. There is also considerable third party resource management for suite meter installations. At the time, very little suite meter installing is done in-house, and current resources probably don’t support transitioning the work internally until 2012. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
| 9 CCM – New Meter Installations (all meters) | Staff charging time to this activity may undertake the following:  
- Planning for meter installations;  
- Updating CIS for installations; and  
- Performing pre-installation meter testing. | C This key activity work order relates to the planning of meter installations. While this RC plans the meter installations, it is CCM that installs them. Planning includes the deployment and design of meters. As the eventual installation is capital in nature, the planning should also be capital in nature. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
| 10 Administration | Staff charging time to this activity may undertake the following:  
- Performing clerical work that cannot be directly attributed to any predefined or provided WO;  
- Performing employee development activities (performance reviews, attendance, recruitment); | O The labour costed activities identified here are administrative and operating in nature and will thus not be capitalized. |
- Scheduling or preparing facilities for appointments;
- Managing employee training and administration activities (training, education, expenses, etc.); and
- Performing community related activities.

**RC 4100 Meter Operations**

Meter Operations is responsible for the following functions:

- Ensuring compliance with Measurement Canada requirements for the meter quality management program applicable to all electricity meters used for billing purposes;
- Ensuring compliance with Ontario Wholesale Electricity Market Rules for all grid supply point (wholesale) meter installations;
- Ensuring the efficient and accurate replacement of existing conventional meters in accordance with the Smart Meter program;
- Ensuring the timely, accurate and efficient installation and/or removal of metering equipment for new, revised, or decommissioned customer services;
- Testing different types of electricity meters for metering accuracy and automated reporting functions;
- Identifying, investigating and resolving suspected metering errors and customer metering disputes; and
- Assisting with storm response triage functions during major system emergencies.

These responsibilities are classified into the following key activities for purposes of labour costing:

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C O B</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
</table>
| 11 | Meter Installations (Wholesale, Suite and Distribution meters) | Staff charging time to this activity may undertake the following:  
- Planning for the meter installation;  
- Providing meter installation support;  
- Performing meter installation troubleshooting;  
- Updating CIS for installations;  
- Selecting and ordering meters;  
- Installing meter replacements; and  
- Performing pre-installation meter testing and on-site verification testing. | C    | This key activity work order represents the work planning and supervision of the crews installing or replacing the meters. The underlying field crews labour cost to capital projects, and therefore the supervisory time is also capital in its nature. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
| 12 | CCM – New                                          | Staff charging time to this activity                                      | C    | This key activity work order relates to the                       |
| Meter Installations (any meters) | May undertake the following:  
- Planning for meter installations;  
- Ordering meters and associated materials;  
- Updating CIS for installations; and  
- Performing pre-installation meter testing and on-site verification testing. | Planning of meter installations. CCM staff coordinate the design and installation of the customer services, including advising the customers of the metering requirements. RC 4100 plans and installs the metering equipment. The planning and installation of metering equipment is directly attributable to an item of PP&E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
|---|---|---|
| 13 Smart Meter Installation | Staff charging time to this activity may undertake the following:  
- Planning for the installations;  
- Supervising the installations;  
- Performing installation verification testing;  
- Performing pre-installation meter testing and on-site verification testing; and  
- Updating CIS for installation purposes. | In addition to the planning, supervision and testing of smart meter installations, this key activity work order involves the necessary updates to the Customer Information System. As this key activity work order relates to the steps required to get the asset (i.e. smart meter) in the location and condition necessary for it to be capable of operating in the manner intended by management, the key activity work order is directly attributable to an item of PP&E. The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation. |
| 14 Meter Support / Maintenance | Staff charging time to this activity may undertake the following:  
- Supervising meter refurbishment;  
- Performing meter maintenance / repair and verification testing;  
- Updating CIS with meter status records;  
- Performing meter post-installation trouble shooting;  
- Performing maintenance activities in the meter test shop; and  
- Assisting with storm response triage functions during major system emergencies. | This key activity work order supports meter maintenance and refurbishments of existing infrastructure. The labour costed activities identified here are operating in nature and will thus not be capitalized. |
Staff charging time to this activity may undertake the following:
- Designing meter installations;
- Supporting meter installations;
- Performing meter inspections; and
- Creating wholesale RIMs accounts.

RC 4150 Meter Technology

RC4150 is responsible for:

- The data management function associated with smart meters and billing activities;
- New additions to the advanced metering infrastructures over the next few years; and
- The remaining manual meter reading systems.

These responsibilities are classified into the following key activities for purposes of labour costing:

<table>
<thead>
<tr>
<th>#</th>
<th>Key Activities</th>
<th>Description</th>
<th>C O B</th>
<th>Analysis and Support for Capital, Operating or Blend Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>16</td>
<td>Meter Registration (wholesale meters)</td>
<td>Staff charging time to this activity may undertake the following:</td>
<td>C</td>
<td>Meter registration is related to wholesale meters installed at stations, and their registration with the IESO. These meters measure energy transferred from Hydro One and used in distributing power to customers. The responsibility for these meters rests with the Corporation (i.e. monitoring, reporting, and maintenance). This key activity work order relates to the replacement of Hydro One’s old meter with new wholesale meter technology as required by the IESO. The IESO also requires the Corporation to perform “end to end” tests to ensure meters are installed and functioning appropriately. These activities must be undertaken before the meter becomes</td>
</tr>
</tbody>
</table>
operational. Once these activities are undertaken, the meter is registered and certain paperwork is filed with the IESO before it can be turned on.

In addition to wholesale meter registration RIMS retail accounts must also be set up before the meter can be turned on. A RIMS account is set up for large users whose peak monthly demand exceeds 200 kW and who pay for electricity based on the HOEP. By year-end 2011, all commercial customers will pay for electricity based on either TOU or HOEP rates, requiring some form of daily remote meter interrogation.

As meter registration relates to activities required to get the asset in the location and condition necessary for it to be capable of operating in the manner intended by management, the key activity work order is directly attributable to an item of PP&E.

The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.

<table>
<thead>
<tr>
<th></th>
<th>17 Data Management</th>
<th>Staff charging time to this activity may undertake the following:</th>
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</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>- Analyzing and collating data;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Reporting;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Reviewing data; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Liaising with the billing department.</td>
</tr>
<tr>
<td></td>
<td>O</td>
<td>This activity supports billing efforts and refers to the back office function to collate and analyze data gathered from the meters. The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
</tr>
</tbody>
</table>

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<thead>
<tr>
<th></th>
<th>18 Meter Audits</th>
<th>Staff charging time to this activity may undertake the following:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>- Assisting with the audits performed by IESO on wholesale meters; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Performing troubleshooting activities related to audits.</td>
</tr>
<tr>
<td></td>
<td>O</td>
<td>This key activity work order relates to assisting the IESO with the audits of wholesale metering and related functions. These audits are performed on operational wholesale meters (i.e., existing assets and not newly constructed assets). The labour costed activities identified here are operating in nature and will thus not be capitalized.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>19 Meter Installations (Wholesale, Suite and Distribution meters)</th>
<th>Staff charging time to this activity may undertake the following:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>- Planning for meter installations;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Providing meter installation support;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Performing meter</td>
</tr>
<tr>
<td></td>
<td>C</td>
<td>This key activity work order represents the supervision of the crew that is installing or replacing meters. The underlying field crew labour cost to capital projects, and therefore the supervisory time should also be capital.</td>
</tr>
</tbody>
</table>
installation troubleshooting;
- Updating CIS for installations;
- Selecting and ordering meters;
- Installing meter replacements; and
- Performing pre-installation meter testing.

The labour costed activities identified here are capital in nature and will be capitalized within the EAR labour costing allocation.

20 Administration Staff charging time to this activity may undertake the following:
- Performing clerical work that cannot be directly attributed to any predefined or provided WO;
- Performing employee development activities (performance reviews, attendance, recruitment);
- Scheduling or preparing facilities for appointments;
- Managing employee training and administration activities (training, education, expenses, etc.); and
- Performing community related activities.

O The labour costed activities identified here are administrative and operating in nature and will thus not be capitalized.

4.1.2.1.6 Quantification of Change Impact

The new process, as described in Section 5.5 Process Impacts, will represent a significant change from the current process for capitalizing engineering and other time. Additionally, this new method of labour costing is expected to result in various employees’ burdens being capitalized at different rates. Historically, all EAR employees’ salaries have been capitalized at a rate of approximately 82.3%. Capitalization under IFRS will be reflective of the actual time that employees spend on capital projects, as discussed above.

Although it is not possible to definitively determine the effect of this change, prior to employees actually beginning to labour cost, an estimate of the expected result has been quantified in Exhibit 1. Based on this quantification, it is expected that the total value of employee burden to be capitalized under IFRS will decrease by approximately $9.8 million to $13.3 million in 2010 compared to CGAAP. Capitalized EAR is expected to be between $19.6 million and $23.1 million in a year.
5 Additional Implementation Issues

5.1 PILS Impact
Refer to Exhibit 2 – Tax Impact on Accounting Treatment for Property, Plant and Equipment – Engineering & Admin Reclass.

5.2 Rate Base Impact
As stated in a letter issued by the OEB on February 24, 2010, entitled “Accounting for Overhead Costs Associated with Capital Work”, the OEB “is requiring full compliance with IFRS requirements (e.g., IAS 16) as applicable to non-regulated enterprises and only where the [OEB] authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable.” As such, it is expected that the capitalization principles in IAS 16 will apply to EAR Labour Costing. Based on the conclusions reached above, there will be a negative impact to rate base arising from PP&E additions that reflect reduced capitalized costs. Overall, the EAR Labour Costing will decrease due to the removal of items that are not directly attributable under IFRS as discussed in section 4 above. Lower capitalization results in a future negative impact to the rate base, thereby reducing the amount on which THESL will earn a rate of return. It is worthy of mention that although these amounts will not earn a rate of return, as would have been the case under CGAAP, they are still expected to be fully recovered through the 1:1 recovery of O&M spending.

5.3 Debt Covenants Impact
A reduction in the Corporation’s EAR Labour Costing amount will result in decreased capitalization each year (between $9.8 million and $13.3 million), with the debit recorded as a current period expense in the Statement of Comprehensive Income each year.

Currently, the Corporation has a financial covenant relating to the debt to capitalization ratio, where the ratio cannot exceed 0.75:1.00. Debt is defined as total debt (current and non-current liabilities are considered in aggregate) and capitalization is defined as debt plus shareholders’ equity. As a result of the EAR Labour Costing adjustment, the debt to capitalization ratio will be negatively impacted. However, the Corporation is currently well on-side of this ratio (0.55:1.00 at the end of Q4, 2009) and the adjustment resulting from the EAR Labour Costing change of $9.8 million to $13.3 million, in isolation of other IFRS adjustments, is not expected to result in the Corporation being offside with respect to this covenant. A decrease in the amount of the denominator by $13.3 million increased the ratio from 0.55:1.00 to 0.56:1.00.
In addition to its debt covenants, the Corporation is bound to pay an annual dividend to its shareholder, the City of Toronto. This dividend must be the greater of $25 million or half of the Corporation’s consolidated net income. Considered in isolation, the impact of the EAR Labour Costing adjustment will be to reduce the Corporation’s consolidated net income and, therefore, is likely to marginally reduce the dividend paid to the shareholder.

5.4 IT Impact

The impact to the Corporation’s IT systems includes the following:

1. Creation of new work orders;
2. Mapping of the work orders to CWIP and expense elements; and
3. Creating algorithms to allocate EAR for a capital project to specific assets within that project. See section 5.5 below for further discussion.

Note that the related process impacts are done manually at this time (see section 5.5. Process Impacts for further details). The Corporation will explore automation of certain reports at a later time.

5.5 Process Impacts

The process to provide support and documentation for the determination of the nature of activities undertaken by EAR employees has changed. The current method of allocating EAR will be replaced with the following process:

1. Finance will calculate SLRs for all employees, which will be averaged to obtain an SLR for each class of employee. Employee SLRs will be calculated using the same methodology as described in the memo on Cost Capitalization – Standard Labour Rates. The SLR is an hourly rate that will be applied to labour costed activities.

2. EAR personnel will labour cost to specific activities, not to specific capital projects. These key activities are described in sections 4.1.2.1 to 4.1.2.5 above, and will be classified as Capital, Operating or Blend activities. It is expected that the following will be adhered to cover labour costing.
   a. Labour costing is not expected for managers, executives and administrative assistants.
b. It is expected that personnel identified to labour cost will labour cost the full number of hours in their day (100% of their time), which is specific to their position, i.e. time-shifters work 12-hour days.

3. The employee or labour costs for each activity, namely the time booked by the employee and multiplied by the SLR, will be calculated for each activity. For example, if design tech labour costs 5 hours to key activity work order #4 in AM and his SLR is $15/hr, the labour cost is $75 (i.e., $15/hr x 5 hr = $75).

4. Costs identified as Capital or Blend will be mapped to CWIP while costs identified as Operating will be mapped to OPEX. This mapping occurs on a monthly basis. This process is further explained below:

   a. Capital activities will be mapped to CWIP. Total costs in CWIP related to capital projects will be allocated on a pro rata basis across projects that have been energized in the reporting period (in the three months representing the current quarter). The allocation of costs to projects, as opposed to all open projects, allows EAR labour costed amounts to be cleared out in the same reporting period as they are incurred. As the nature of the utility industry is perpetual, the three-month lag will offset continuously on a year-over-year basis such that the financial impact of allocating EAR costs only to those projects that have been closed in the period (as opposed to all open projects) is immaterial from both a balance sheet and profit or loss statement perspective.

   b. Blended activities are first mapped to CWIP. The percentage of capital to total hours of non-EAR labour costed employees will be determined (i.e., field crew) and applied to total blended hours in CWIP to determine the split of activities between capital and operating projects. The costs related to capital projects are allocated to individual projects as outlined in above. Costs related to operating projects are then journalized out of CWIP and into an OPEX expense account (see discussion in 4c below). For example: an activity has $500 in total labour cost and is related to switching activities in the control room. Where field crew labour cost 60% of their time to capital projects, the $500 total labour cost will be split $300 capital and $200 operating. The $300 will then be allocated across capital projects energized in the reporting period as described above and the $200 will be journalized to an expense account.
c. For operating activities, the labour costs will be mapped directly to an operating expense account and will not be further allocated to operating projects.

5. Once costs are allocated to projects, the capitalization team will work to allocate costs to individual assets. Refer to the memo on Componentization for a discussion of the methodology of allocating costs to asset components.

**5.5.1 Illustrative Example**

For example, using the steps described above:

1. Finance calculates a supervisor’s SLR as $85/hour.

2. A supervisor in DS labour costs 7 hours to Capital Project Designs, which is classified as a capital activity. The supervision of the capital designs relates to 4 different capital projects.

3. The Capital Project Designs labour cost pool is $595 (e.g., $85/hour x 7 hours).

4. Of the four capital projects only 3 are energized in the current reporting period, the EAR labour costs attributed to these projects would be calculated as follows:

<table>
<thead>
<tr>
<th>Project</th>
<th>Dollars</th>
<th>% of Total</th>
<th>Calculation</th>
<th>EAR allocated to each project</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project X</td>
<td>$200</td>
<td>20%</td>
<td>$595 x 20%</td>
<td>$119.00</td>
</tr>
<tr>
<td>Project Y</td>
<td>$500</td>
<td>50%</td>
<td>$595 x 50%</td>
<td>$297.50</td>
</tr>
<tr>
<td>Project Z</td>
<td>$300</td>
<td>30%</td>
<td>$595 x 30%</td>
<td>$178.50</td>
</tr>
<tr>
<td>Total</td>
<td>$1,000</td>
<td>100%</td>
<td>$595.00</td>
<td>$595.00</td>
</tr>
</tbody>
</table>

This process change will have the following impact:

1. EAR employees will have to labour cost as described above, thus increasing their administrative activities.

2. Finance will have to undertake detailed calculations to support the allocation of labour costs pools to the respective capital projects and to re-class a portion of labour costs for blended activities to an OPEX expense.
Exhibit 1

Quantification – Summary of EAR Capitalized under IFRS
### Exhibit 1
Quantification - Summary of EAR Capitalized under IFRS

| Average Employee Burden (fully burdened amount) | A | 135,000 |
| Number of EAR employees (based on the 2010 budget) | B | 296 |
| Total EAR Employee Burden | C = A*B | 39,960,000 |

Not Attributable under IFRS therefore exclude:

| Category | F |
| Executives | 750,000 |
| Administrative Assistants | 200,000 |
| Managers (not time-sheeting) | 2,720,000 |
| Strategic Management Division (half the division) | 700,000 |

| sum(F) | 4,370,000 |

Full payroll burden of employees in EAR eligible for capitalization under IFRS: 35,590,000

### Note
The nature work undertaken by the supervisors and other EAR functions, should reflect the nature of the work of the underlying field crew. Therefore, the percentage of capital hours undertaken by the field crew (based on 2009 budgeted capital hours to total available hours) is applied to the full EAR payroll burden eligible for capitalization (i.e. G above) to determine the expected amount capitalized under IFRS. Historically, field crew have time-sheeted between 55-65% of their time to capital projects. Therefore, expected amounts capitalized under IFRS for 2010 should also fall within this range:

<table>
<thead>
<tr>
<th>H</th>
<th>55%</th>
<th>60%</th>
<th>65%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected amount capitalized under IFRS</td>
<td>I = G*H</td>
<td>19,574,500</td>
<td>21,354,000</td>
</tr>
<tr>
<td>Decreased capex</td>
<td>J = I - E</td>
<td>(13,312,580)</td>
<td>(11,533,080)</td>
</tr>
</tbody>
</table>

Amount Capitalized under CGAAP: 32,887,080
Exhibit 2

Tax Impact on Accounting Treatment for Property, Plant and Equipment – Engineering and Admin Reclass
1. Purpose

The purpose of this memo is to discuss the tax impact in response to the accounting memo dated July 30, 2010 with respect to the accounting treatment of engineering and administration costs which are capitalized to items of PP&E in accordance with IFRS – IAS 16 Property, Plant and Equipment.

Although the Corporation is exempt from income tax under the Act and the TA, it is a municipal electricity utility for purposes of the payment of PILs as required by Section 93 of the EA. The amount of PILS to be paid is equal to the income tax that it would be liable to pay under the Act and TA if it were not exempt from income tax.

2. Facts

Refer to the accounting memo for the relevant facts.
3. Canada Revenue Agency’s Views

CRA has confirmed that the Act does not mandate that financial statements be prepared according to a particular accounting framework and that it is currently undertaking a review of the key differences between CGAAP and IFRS to assess the income tax consequences, if any. CRA has stated that “financial statements prepared in accordance with IFRS will be considered an acceptable starting point to compute taxable income”. CRA has also stated that all references to CGAAP in CRA documents or tax legislation can be interpreted as IFRS for those entities that report under IFRS.

The other relevant statutory provisions, judicial history and CRA’s views are discussed in detail below.

4. Analysis and Recommendation

Under CGAAP, the Corporation uses a “full-cost” methodology for the capitalization of costs to PP&E. Labour costs are capitalized using information from the time-sheets of field crew based on a SLR and the allocation of employee costs through the EAR. Historically, the salaries of all EAR employees have been capitalized at a rate of approximately 82.3%.

Under IFRS, the Corporation’s process of capitalizing engineering and administration costs will change to include the time-sheeting of labour, differentiating between capital and operating activities and allocating costs to projects based on identified cost drivers. EAR employees will use time-sheets to record the time spent on defined activities within strategic management, asset management, distribution and grids, distribution projects and customer service. A SLR will be applied to the hours recorded on time-sheets and the calculated amount will be allocated based on the nature of the activity. The portion of the calculated amount that relates to capital activities will be mapped to CWIP and allocated to capital projects based on a cost driver. The portion of the calculated amount that relates to blended activities, including both capital and operating projects, will first be mapped to CWIP and then an identified cost driver will be used to determine the split of the calculated amount between capital and operating projects. The portion of the calculated amount that relates to operating activities will be mapped directly to operating expenses. Capitalization under IFRS will be reflective of the actual time employees spend on capital projects.

Under IFRS, it is expected that the total value of employee burden that will be capitalized will decrease by approximately $9.8 to $13.3 million annually. Operating expenses will increase by the same amount.

4.1 Income Taxes

4.1.1 Tax treatment

Section 9 of the Act provides that a taxpayer's income from a business or property is the taxpayer’s profit from that business or property for the year. The computation of profit is subject to six “guiding principles” set out by the Supreme Court of Canada in the Canderel (98 DTC 6100 (S.C.C.)) decision. According to these principles, a taxpayer is “free to adopt any method which is not inconsistent with” the provisions of the Act, legal principles and well accepted business principles (including CGAAP), although the method must also provide an accurate picture of the taxpayer’s profit for the given year.

Amounts for future post-employment benefits and sick leave are included in the SLR. For income tax purposes, these amounts are considered a reserve or contingent liability and are not deductible pursuant to paragraph 18(1)(e) of the Act. A deduction for tax purposes will be permitted for all amounts that are in respect of a legal liability where the events that give rise to the liability have occurred and the amount of the liability is determinable.

CRA has issued an interpretation\(^2\) in respect of the capitalization of expenses in the regulated natural gas transmission and distribution industry. CRA confirmed that overhead expenses, such as the engineering department, incurred to bring capital assets into existence would be capital costs of the taxpayers.

4.1.2 Analysis and Recommendation

A portion of the SLR includes an amount for future post-employment benefits and accrued sick leave. The SLR is applied to the hours of activities undertaken by EAR personnel in respect of capital projects to determine an amount that is capitalized to PP&E. The amount of future post-employment benefit expense and accrued sick leave pay that is capitalized to PP&E as part of the SLR must be excluded from the cost of fixed asset additions for income tax purposes. The impact of the amount debited to PP&E should also be removed from the

\(^2\) CRA Document 9812566, Capitalized Expenses in Regulated Industry, September 24, 1998
taxable income adjustment for the increase or decrease in the accounting liability for POEB and sick leave since this amount is not included in the computation of income for accounting purposes.

With the exception of future post-employment benefits and sick leave as described above, the remaining balance of costs included in the SLR will be included in the cost of PP&E for both accounting and tax purposes.

Reference should be made to the PILs memo incorporated within the whitepaper regarding Accounting for Employee Benefits for the discussion of the tax treatment for the post-employment benefits and accrued sick leave pay.

Reference should also be made to the PILs memo incorporated within the accounting memo regarding PP&E - SLR.

**4.2 Deferred taxes**

The PILs return to be filed for 2010 will be based on financial statements prepared in accordance with CGAAP. The tax basis of items of PP&E recognized for income tax purposes during 2010 will be based on CGAAP. Consequently, for 2010 only, there will be a temporary difference for amounts capitalized through the EAR due to the difference between the amount capitalized for accounting purposes under IFRS and the amount capitalized for tax purposes.

For 2011 and years thereafter, the PILs returns will be filed based on financial statements prepared in accordance with IFRS, as noted above in Section 3. Subject to the exception explained below, the accounting treatment and the tax treatment for the amount capitalized through the EAR is generally expected to be the same and therefore no new temporary differences will be created.

The one exception is the difference between the accounting treatment and tax treatment for the amount of future post-employment benefits and accrued sick leave. These amounts will be capitalized for accounting purposes on an accrual basis and will be deducted for tax purposes as paid, creating a temporary difference that results in a deferred tax asset or liability. Refer to the PILs Memo issued in respect of the Accounting treatment for Property, Plant and Equipment – Standard Labour Rates.
Under CGAAP for rate-regulated entities, the deferred tax asset or liability is grossed-up and is offset by a regulatory liability or regulatory asset to the extent that the future tax will be included in future rates, i.e., to the extent that the temporary difference is included in setting the PILs proxy. If the cost or benefit of the future taxes is not recovered from or rebated to ratepayers, i.e., the temporary difference is not included in setting the PILs proxy, the change in the deferred tax amount is charged to tax expense.

IFRS does not provide guidance on rate-regulated accounting. In particular, no requirement exists for an entity to record a regulatory liability or asset for deferred tax assets or liabilities of a rate-regulated enterprise that are expected to be rebated to or recovered from its ratepayers.

The exposure draft on rate-regulated activities provides for a regulatory liability or asset to be recorded in circumstances where the deferred tax asset is expected to be repaid or the deferred tax liability is expected to be recovered from ratepayers. A probability factor would be applied to the regulatory liability or asset and the amount would be discounted for the expected timing of future cash flows.

The Corporation is currently evaluating the impact on regulatory assets and liabilities in the event a final standard is not in place at the time of transition to IFRS and if, as a consequence, it is not permitted to recognize regulatory assets or liabilities.

As noted above, the amount to be capitalized through the EAR for 2010 under IFRS will be approximately $9.8 million to $13.3 million less than the amount to be recorded under CGAAP for tax purposes. As a consequence, the deferred tax asset directly related to the amount of EAR capitalized to PP&E will be $2.5 million to $3.3 million higher under IFRS than under CGAAP as at December 31, 2010 because the Corporation will be using financial statements prepared under CGAAP for income tax filing purposes. Because the future tax reductions that are reported as a deferred tax asset must be rebated to customers in a future period, a liability to customers is recognized. That liability to customers in turn gives rise to an additional deferred tax asset. In this situation, the additional impact resulting from the direct increase to

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3 Based on an enacted income tax rate of 25% for 2013 and taxation years thereafter when the temporary differences are expected to reverse. A gross-up factor of 1.33 is used to determine the pretax amount that is expected to be rebated to customers since the tax saving from the rebate will be calculated at 25%.
the deferred tax asset of $2.5 million to $3.3 million will be a further increase to the deferred
tax asset of $0.8 million to $1.1 million. The total impact on deferred tax assets will be an
increase of $3.3 million to $4.4 million. Assuming that the revised temporary difference
resulting from the change in the SLR factor under IFRS will cause an increase in the deferred
tax asset from an amount of $2.5 million plus a consequential gross-up amount of $0.8 million
to an amount of $3.3 million plus a consequential gross-up amount of $1.1 million as
compared to CGAAP in 2010, the liability will be increased by $3.3 to $4.4 million in total.
These amounts do not include the impact of discounting the regulatory liability for income
taxes as would be required by the exposure draft. These amounts do not include the impact of
future post-employment benefits and accrued sick leave that will be capitalized to items of
PP&E under IFRS which will be lower than the amount capitalized under CGAAP.

4.3 Information that the Tax Department requires from Finance Department

- The details of the future post-employment benefit expense and accrued sick leave
  recognized for the year, details of these amounts capitalized to PP&E and amounts
  charged to operations for the year, as well as transfers of future post-employment
  benefit expenditures and accrued sick leave to other districts, and transfers of these
  amounts previously capitalized to expenses for accounting purposes. This is the same
  information requirement as noted in the PILs memo on PP&E-SLR.
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 3:

REFERENCE(S): Exhibit 1, Tab 2, Schedule 2, page 23

Preamble:
THESL indicates that high level estimates are based on standardized costs for installing various types of assets.

a) Please provide the standardized costs for each type of asset.
b) Please list the job segments with high level estimates determined using standardized asset costs.

RESPONSE:

a) For the reasons set out below, Toronto Hydro believes that providing the detailed list of standardized units referenced in the preamble would not be relevant or useful in assessing variances for the purposes of this Application.

Standardized labour and material units are elements of (1) high-level estimates created for electrical jobs and (2) detailed estimates created for electrical jobs executed by internal resources. These units are not equivalent to average unit costs for major asset classes and are not relevant if assessing performance on a cost per installed asset basis. This is because many variations of material and labour units exist for the same major asset class. This level of granularity is necessary to accommodate the many different applications of major assets in the system. Therefore, no particular standardized unit represents the average installation cost for a major asset class.
Similarly, Toronto Hydro creates all civil construction estimates, which are executed by external resources, and any detailed estimates for electrical jobs that are to be executed by external resources, using thousands of detailed contractor unit prices. Again, no particular unit price represents the average installed cost for a major asset class.

Toronto Hydro has provided, on a best efforts basis, the forecast versus actual units by major asset class at the ICM Segment level in response to Interrogatory 2-AMPCO-3.

b) Please see Toronto Hydro’s response to interrogatory 1-AMPCO-4.
Maintenance Practices

Policy summary for maintenance and inspection cycles / frequencies for relevant asset classes

The planned inspections and maintenance tasks are typically conducted on a fixed cycle which is determined either as per Ontario Energy Board’s (“OEB”) Distribution System Code’s Minimum Inspection Requirements (Appendix C) or through the Reliability Centered Maintenance (RCM) approach based on the mean time between failures of a given equipment class. The below table summarizes the fixed cycles for the maintenance and inspection programs.
## Maintenance Practices

<table>
<thead>
<tr>
<th>Major or Substantial Distribution Facility</th>
<th>Asset Type</th>
<th>Program Description</th>
<th>Appendix C Max Interval (Urban)</th>
<th>TH Interval</th>
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</thead>
<tbody>
<tr>
<td>Distribution Transformers</td>
<td>Pad Mounted</td>
<td>Padmounted Transformer Inspection</td>
<td>3 Years</td>
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<td></td>
<td>Submersible</td>
<td>Submersible Vault Inspection</td>
<td>3 Years</td>
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<td>Vault</td>
<td>Compact Radial Vault Inspection - Electrical</td>
<td>1 Year</td>
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<td>Network Vault Inspection - Electrical</td>
<td>1 Year</td>
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<td>Transformer Vault Inspection</td>
<td>3 Years</td>
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<td></td>
<td>URD Vault Inspection - Electrical</td>
<td>1 Year</td>
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<td></td>
<td></td>
<td>Reverse Power Breaker Overhaul</td>
<td>3 Years</td>
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<td>Protector Top Cleaning</td>
<td>1 Year</td>
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<td>Network Protector Overhaul - HV</td>
<td>3 Years</td>
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<td>Network Protector Overhaul - LV</td>
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<td>Switching and Protective Devices; Conductors; Poles; Vegetation; Overhead TX</td>
<td>Line Patrol</td>
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<td>OH IR Scan</td>
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<td>Civil Infrastructure</td>
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<td>Network Vault Inspection - Civil</td>
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<td>URD Vault Inspection - Civil</td>
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<td>Padmounted Switch Inspection</td>
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<td>Submersible Switch Inspection</td>
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<td>Overhead Scada-Mate Switch</td>
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<td>Overhead Gang-Operated Switches</td>
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<td>Motorized Switch Maintenance</td>
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<td>Poles</td>
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<td>Wood Poles Inspection and Treatment</td>
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<td></td>
<td>Tree Trimming</td>
<td>2-5 Years</td>
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<td>Vegetable</td>
<td>Cable Chamber Inspection and IR Scan</td>
<td>10 Years</td>
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<td>Civil Infrastructure; Underground Conductor</td>
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<td>Customer Specific Substation</td>
<td>Customer Owned Substation Maintenance</td>
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<td>Spring Inspection with Oil Sampling</td>
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<td>TTC Bus Maintenance</td>
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<td>TTC CB Maintenance</td>
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<td>Stations</td>
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<td>Distribution Station; Transformer Station</td>
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<td></td>
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<td>Equipment Maintenance 2+ TX in Horseshoe</td>
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<td>Equipment Maintenance 3+ TX in Downtown</td>
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<td>Pilot Wire Protection</td>
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<td>Station Compressed Air System Maintenance</td>
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<td>Switchgear Maintenance 1-6 Circuits</td>
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<td>Alarm Testing Downtown</td>
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<td>Equipment Maintenance 1 TX in Horseshoe</td>
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<td></td>
<td>Seasonal Detailed Inspection</td>
<td>6 Months</td>
<td></td>
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</tbody>
</table>
Maintenance Practices

Vegetation management program / policy - Any document you may have describing your VM strategy and plan, (for example: what cycles, what kind of trim, clearances established by voltage, use of chemicals if any, differentiation if any between Feeder and Lateral trimming standards applied, etc.).

Toronto Hydro’s distribution system contains over 800 primary feeders that require periodic trimming. These feeders co-exist with the City of Toronto’s mature and abundant tree canopy, which includes approximately 600,000 City-owned “street trees” and thousands of trees located on customer properties. (In total, there are approximately 10.2 million trees in the City of Toronto.) Over 125,000 of these street trees are immediately adjacent to primary overhead feeders, and can potentially interfere with the safe and reliable distribution of electricity. Each year, Toronto Hydro identifies the feeders that are in greatest need of tree pruning based on prioritization criteria that include feeder reliability history, the number of customers supplied by each feeder, and the amount of time that has elapsed since the trees surrounding the feeder were last pruned. The prioritization results in trees surrounding feeders being pruned once every two to five years, with the system average being approximately three years.

Vegetation Management is also a widely accepted means of effectively “storm-hardening” a system and thus proactively mitigating storm damage and system reliability risks. Storm hardening involves selectively removing portions of the tree canopy to reduce the “sail effect” of branches during high winds and to reduce the likelihood that broken branches will contact lines. More frequent tree pruning further reduces risks posed by severe weather.

Below is the Toronto Hydro standard for minimum clearances between conductors and trees.
Maintenance Practices

Overhead - Minimum Clearances
Between Conductors and Trees

1) General

Consideration shall always be given to the aesthetic impact on trees when routing distribution lines. In all cases, the routes chosen shall minimize the extent of tree pruning. All tree pruning must comply with the City of Toronto Urban Forestry cycle pruning guidelines developed by the City of Toronto. All clearances must be relative to the estimated position of maximum sag and swing of the nearest conductor.

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<tr>
<th>VOLTAGES</th>
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<td>300 mm (1'-0&quot;) from nearest conductor</td>
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<td>16/27.6 kV - Tree-proof Conductors*</td>
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*If conductor is exposed on Tree-proof cable, treat it as bare conductor

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<tr>
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2) New Construction

The initial tree clearance will set the pattern for future line clearing practices. Therefore, the following should be taken into consideration:

a) Avoid indiscriminate cutting of branches;

b) Install poles of proper height to match field conditions;

c) Plan for some separation of pole and tree alignments;

d) Where permissible use special offset brackets to obtain maximum clearances;

e) Line construction shall be designed to avoid central tree trunks and large limbs.

DISTRIBUTION CONSTRUCTION STANDARD CLEARANCES

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OVERHEAD - MINIMUM CLEARANCES BETWEEN CONDUCTORS AND TREES

| ORIGINAL ISSUE: L.G. 2000-03-28 |
| SCALE: N.T.S. |
| REV. 03-2450 1/1 |
Maintenance Practices

Procedures / process description for Work scheduling, planning, and execution
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## IFRS Componentization Spreadsheet

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## STREETLIGHTING ASSETS

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January 16, 2015

RESS, EMAIL & COURIER
Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited (“Toronto Hydro”) Custom Incentive Rate Application (EB-2014-0116)

We are counsel to the applicant, Toronto Hydro, in the above referenced proceeding. On January 13, 2015 Toronto Hydro filed its responding submission on the December 31, 2014 motion filed by the Association of Major Power Consumers in Ontario (“AMPCO”). Subsequent to the responding submission being filed, Toronto Hydro continued to make further inquiries in an effort to determine whether AMPCO’s information requests could be satisfied, in whole or in part, through any methods other than those explained in the Responding Submission. The enclosed Affidavit of Ms. Angela Rouse, Toronto Hydro’s Supervisor of Capital Planning and Reporting, is provided in connection with those continued efforts.

Yours truly,

Jonathan Myers

cc: A. Klein and D. Coban, THESL
C. Kelzer and C. Smith, TORYS LLP
All Parties
ONTARIO ENERGY BOARD


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 and for each following year effective January 1 through to December 31, 2019.

AFFIDAVIT

I, Angela Rouse, of the City of Toronto, in the Province of Ontario, MAKE AN OATH AND SAY:

1. I am the Supervisor of Capital Planning & Reporting for Toronto Hydro Electric System Limited ("Toronto Hydro") and, as such, have knowledge of the matters to which I herein depose.

2. As the Supervisor of Capital Planning & Reporting, my responsibilities include capital planning, compliance reporting and centralized capital management reporting. In connection with these areas of responsibility, I was asked to determine whether any of the information requested in the December 31, 2014 Notice of Motion from the Association of Major Power Consumers in Ontario ("AMPCO") could be obtained through Toronto Hydro’s financial reporting system.

3. I have determined that although some information could be obtained from Toronto Hydro’s financial reporting system for the years 2012 and 2013 within a reasonable period of time, the information for these years cannot be provided for all specific assets requested by AMPCO because the assets are not necessarily represented in Toronto Hydro’s financial reporting system in the same manner that AMPCO is requesting. In addition, AMPCO’s request refers to assets forecasted to be replaced or taken out of service in a particular year, whereas the information that could be obtained from the financial system within a reasonable period of time refers to assets placed into service in a given year. If the assets placed into service are not like-for-like with the assets taken out of service, the information in the financial reporting
system cannot be reconciled back to the information that AMPCO is requesting. As such, the data that can be provided for 2012 and 2013 would not be exactly as per AMPCO’s request.

4. In addition, as further explained below, the requested information for the years 2010, 2011 and 2014 is not available in the same manner as 2012 and 2013 and could instead only be ascertained through the manual mapping process described in the January 14, 2015 affidavit of Mike Walker. The requested forecast information for the years 2015-2019 is also not available in the same manner through Toronto Hydro’s financial reporting system, as described below.

Treatment of Capital Projects in Toronto Hydro’s Financial Reporting System

5. Once a project is completed in the field, Toronto Hydro’s practice is to extract the relevant transactional details from Toronto Hydro’s Enterprise Resource Planning (“ERP”) system, Ellipse. The extracted project information will include labour hours, vehicle hours, material or equipment quantities and associated costs. Supplementary detail for externally contracted costs booked to the completed project are obtained from other internal, customized systems. The labour costs within the project are spread across the work orders associated with the construction of the assets based on timesheets prepared by internal crews or based on the billing sheets from external contractors. Toronto Hydro will then undertake a manual process to identify the major asset categories, as defined in accordance with Toronto Hydro’s capitalization policy and the Ontario Energy Board’s Accounting Procedures Handbook, to which the material or equipment used in the project corresponds.

6. Once the material and equipment is associated with the relevant major asset categories, Toronto Hydro will apply a methodology to attribute related design costs, engineering capital, allowance for funds used during construction, as well as other costs, to the corresponding major assets. The material and equipment quantities that are associated with the major asset categories are then used to represent the asset quantity and an upload sheet is prepared to record the total costs and quantities by asset class in the financial assets sub-ledger.

7. The process described above is an ongoing one in that it involves daily activity, carried out manually throughout the year, by a dedicated team. Through this process, the actual costs associated with all in-service additions since 2010 are represented in Toronto Hydro’s financial asset sub-ledger. Moreover, the quantities of in-service assets since 2010 can be extracted from the financial asset sub-ledger using the corresponding project number.
However, as described below, only the information relating to assets that went into service during 2012 and 2013 has been mapped to specific programs.

**Availability of Information Requested by AMPCO**

8. Each of Toronto Hydro’s 2012 and 2013 capital projects has been manually mapped to the corresponding program, as such programs are defined in its Distribution System Plan (“DSP”). This mapping exercise was carried out for purposes of preparing the rate application and involved a labour-intensive process that took several months. As a result of that effort, Toronto Hydro now has the capability to extract from its financial reporting system listings of specific projects that have been carried out in connection with specific DSP programs. Using such listings, Toronto Hydro can extract from the financial asset sub-ledger the total costs and quantities of materials and equipment that were placed into service as a result of the completion of each particular project for each DSP program. However, there are several important limitations on the cost and material/equipment quantity information that is available through Toronto Hydro’s financial reporting system. These are described below.

9. First, because the manual mapping exercise described above has not been undertaken for 2010 and 2011 capital projects, the corresponding information is not able to be extracted from the financial asset sub-ledger to align with the DSP programs. While Toronto Hydro did map the historical project spending for those years at a program level, this does not provide the capability to extract the necessary listings of specific projects carried out in connection with particular DSP programs. As such, the requested information for 2010 and 2011 can, instead, only be determined through the challenging and labour-intensive mapping exercise that is described in the January 14, 2015 Affidavit of Mike Walker.

10. Second, not all capital expenditures in the years 2012 and 2013 would have gone into service in those same years. As a result, the information that Toronto Hydro is able to extract from the financial asset sub-ledger for 2012 and 2013 will not represent the total capital expenditures in those years. Consequently, the information will not match the capital spending tables that are presented in the relevant DSP program descriptions.

11. Third, the cost information that can be extracted from the financial reporting system includes costs for the particular project that has been placed into service, regardless of the year in which funds were spent. As such, a project that was placed into service in 2012 and for which information would therefore be available in the financial asset sub-ledger may include
expenditures from prior years, which would have been presented as construction work-in-progress. Similarly, a project which was placed into service in 2012 may have lagging costs that are reflected in the 2013 in-service additions. For these reasons, the data that Toronto Hydro is able to extract from the financial reporting system is not representative of unit costs.

12. Fourth, the assets reflected in Toronto Hydro’s financial reporting system are not necessarily grouped or represented in the same level of detail as the assets that are reflected in the DSP programs which AMPCO’s motion request relates to. As an example, transformers in the rear lot conversion program could be mapped to one of the following two asset categories in the financial reporting system: underground transformer or pole mount transformers. In addition, the information that could be obtained from the financial system relates to assets that are placed into service in a given year, whereas AMPCO’s request refers to assets that Toronto Hydro has forecasted to be replace (i.e. take out of service) in a particular year. If the assets placed into service are not like-for-like with the assets taken out of service, the information in the financial reporting system cannot be reconciled back to the information that AMPCO is requesting. Consequently, to provide the information in a manner that is aligned with the presentation of assets in the DSP program descriptions would require the challenging and labour-intensive mapping exercise that is described in the January 14, 2015 Affidavit of Mike Walker.

13. Fifth, the process of mapping projects that went into service during 2014 to specific DSP programs has not been completed. Moreover, the 2014 financial year has not yet been closed out or audited. As such, the information that AMPCO has requested in respect of 2014 cannot be extracted from Toronto Hydro’s financial reporting system on a DSP program by program basis and, instead, would need to be determined through the mapping exercise that is described in the January 14, 2015 Affidavit of Mike Walker.

14. Sixth, because 2015 is a forecast year, actual costs and in-service additions for 2015 (i.e. the type of information that is available for 2012 and 2013) cannot be extracted from Toronto Hydro’s financial reporting system. The 2015 forecast was determined in a different manner, through a process whereby the estimates were developed using the labour and material/equipment costs allocated to work orders. For the 2015 forecast, the estimated labour hours and material/equipment units would have been inputted into Ellipse, but when this information was extracted and loaded into the financial planning system, it would have been done using costing information for each work order to allocate the costs to the assets.
and the material or equipment quantity information would consequently not be available in the financial planning system. In addition, design and engineering capital estimates are created separate from the construction project and the amounts would not be reflected in the project by project breakout of assets.

15. Finally, as no actual cost or in-service information is available for the 2016-19 forecast years, the type of information that is available for 2012 and 2013 is not available from Toronto Hydro’s financial reporting system in respect of the 2016-19 forecast years. Rather, for 2016-2019 the forecast in-service additions is based on the historical percentage of the total DSP program capital expenditures coming into service or the latest program projections, not on detailed project level information. As such, the information requested for those years is not available.

SWORN BEFORE ME at the City of Toronto, in the Province of Ontario, this 16th day of January, 2015

[Signature]

Commissioner for Taking Affidavits

[Signature]

Angela Rouse

[Signature]

Daliana Coban

62139A
January 13, 2015

RESS, EMAIL & COURIER
Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited (“THESL”) Custom Incentive Rate Application (EB-2014-0116)

We are counsel to the applicant, THESL, in the above noted matter. Filed with this letter are THESL’s responses to motions filed by Energy Probe and AMPCO on December 22 and 31, 2014, respectively. Paper copies of these documents will follow by courier.

Also filed is a native excel version of the spreadsheet attached to THESL’s response to Energy Probe’s motion.

Yours truly,

Jonathan Myers

cc: A. Klein and D. Coban, THESL
C. Keizer and C. Smith, Torys LLP
All Parties
ONTARIO ENERGY BOARD


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 and for each following year effective January 1 through to December 31, 2019.

RESPONDING SUBMISSIONS OF TORONTO HYDRO
(on motions by Energy Probe and AMPCO returnable January 19)

Torys LLP
79 Wellington St. W., Suite 3000
Box 270, TD Centre
Toronto, Ontario
M5K 1N2

Charles Keizer
Crawford Smith
Jonathan Myers
Myriam Seers

Lawyers for Toronto Hydro-Electric System Limited
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<th>Tab</th>
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<td>1.</td>
<td>Responding submission of Toronto Hydro (on motion by Energy Probe returnable January 19, 2015)</td>
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<tr>
<td>A</td>
<td>Excel spreadsheet in response to Energy Probe motion</td>
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<td>2.</td>
<td>Responding submission of Toronto Hydro (on motion by AMPCO returnable January 19, 2015)</td>
</tr>
<tr>
<td>A</td>
<td>Affidavit of Mike Walker sworn January 13, 2015</td>
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2. Toronto Hydro remains of the view that J1.2 Energy Probe-49 seeks information that is not relevant to this proceeding. As set out in Toronto Hydro’s initial response, the premise underlying Energy Probe’s request is that Toronto Hydro is that has filed a five-year cost of service application, and accordingly possesses detailed forecasts of all the elements comprising the utility’s revenue requirement beyond the 2015 rebasing year. This is not Toronto Hydro’s proposal.

3. As discussed in Exhibit 1B, Tab 2, Schedule 3, Toronto Hydro proposes to set rates for 2016-2019 on the basis of a custom Price Cap Index that incorporates the Ontario Energy Board’s (“OEB”) inflation and productivity values, utilizes a custom stretch factor, and
includes a capital factor to fund Toronto Hydro’s necessary investments. Toronto Hydro
has not forecasted its Operations, Maintenance and Administration (“OM&A”) and
revenue offsets for 2016 to 2019.

4. Nevertheless, without admitting the relevance of Energy Probe’s request, in the attached
document, Toronto Hydro has verified the data provided by Energy Probe, corrected for
errors (noted by entries in green), and populated those other aspects of the table where
the requested information was available. Where a cell has been left blank, Toronto
Hydro does not possess the requested information. These areas include the forecasted
breakdown of the utility’s OM&A expenditures by category beyond the 2015 Test Year,
and categorization of the utility’s past and future In-Service Additions by major
Distribution System Plan (“DSP”) investment type. In any event, in both instances the
requested information is not required by the OEB’s Filing Requirements for Electricity
Distribution Rate Applications, nor would it provide probative value, incremental to the
evidence already adduced by Toronto Hydro or provided through the discovery process.

5. Toronto Hydro is further unable to populate the column entitled “2014 Forecast,” as
distinct from the “2014 Estimate” column, which contains the information provided to
the OEB in the course of Toronto Hydro’s September 2014 application update. Since the
utility does not currently possess the audited year-end financial information for 2014, the
data contained in the “2014 Estimate” column continues to represent the utility’s latest
estimate for its 2014 financial performance.

6. Toronto Hydro also submits the following specific comments with respect to the
information included into the table by Energy Probe.

**2016-2019 OM&A Projections**

7. The 2016-2019 OM&A projections (rows 8 and 57) reflect the application of Toronto
Hydro’s proposed incentive framework (Exhibit 1B, Tab 2, Schedule 3). Toronto Hydro
has not forecast its OM&A expenditures beyond the application of this framework. The OM&A projections provided are consistent with the information in the utility Business Plan filed with the OEB as an Appendix A to interrogatory 1A-CCC-01.

**Revenues and Rates Revenue Requirement: 2016-2019**

8. Toronto Hydro’s proposal does not entail five separate revenue requirements over the 2015-2019 timeframe, as depicted in Energy Probe’s Draft Consolidated Financial Summary (rows 19 – 21). Toronto Hydro’s understand that this information reflects the sum of the OM&A forecast described above in paragraph 8 and the capital cost components of the Custom Capital Factor outlined in Exhibit 1B, Tab 2, Schedule 3. Toronto Hydro maintains the position that calculating the revenue requirements for the outer years of the plan is not consistent with the utility’s proposal to set rates for 2016-2019 based on a Custom Price Index mechanism.

**Rates Revenue Requirement: 2012-2014**

9. Toronto Hydro also notes that the utility’s 2012-2014 rates were not set on the basis of a revenue requirement for those years, as suggested by Energy Probe in row 21 of Draft Consolidated Financial Summary. Over this timeframe, rates were determined by applying the OEB’s 3rd Generation IRM Price Cap Index to the utility’s 2011 base rates, and the incremental OEB-approved rate riders.

**Operating Revenues: 2012-2014**

10. Toronto Hydro’s operating revenues for years 2012 and 2013 and the 2014 estimate (row 4 of the Draft Consolidated Financial Summary) are based on the methodology prescribed in the OEB’s Reporting and Record Keeping Requirements.

**Past ISA Variation**

11. Toronto Hydro removed the Past ISA variances provided by Energy Probe in row 45 of the Draft Consolidated Financial Summary, as these values no longer correspond with the
updated In-Service Addition values in row 44. In addition, Toronto Hydro submits that these values are inconsistent with the utility proposal to defer to the true-up the 2012-2014 Incremental Capital Module to a separate phase of this proceeding (Exhibit 2A, Tab 9, Schedule 1).

All of which is respectfully submitted this 13th day of January, 2015.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

By its Counsel

Torys LLP

[Signature]

Crawford Smith
### Consolidated Financial Summary 2013 (Sic) - 2019

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#### Capital Expenditures

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#### CAPEX and In Service Asset Additions

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#### Footnotes

- **15.** **Return on Equity (ROE)**
- **21.** **Gross Requirement**
- **22.** **Rate Base**
- **23.** **Depreciation & Amortization**
- **24.** **Interest Expense**
- **25.** **Common Equity**
- **26.** **Total Rate Base**
- **27.** **CAPLEX and In Service Asset Additions**
- **28.** **Other ISAs**
- **29.** **Total**

---

**References**

- 2015-2019: E1B_T02_S03
- 2012-2014: Toronto Hydro RR
- Filings and Supporting Materials
- See Cover Letter Para 11
- See Cover Letter Para 8
- Past/Test Year data: E4A_T01_S01; *2012 amount is net of 27.7 restructuring costs
- Information underlying E1B_T02_S03
- Information underlying E1B_T02_S03
TAB 2
ONTOARIO ENERGY BOARD


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 and for each following year effective January 1 through to December 31, 2019.

RESPONDING SUBMISSION OF TORONTO HYDRO

(on Motion by AMPCO returnable January 19, 2015)

1. On December 31, 2014 the Association of Major Power Consumers in Ontario (“AMPCO”) filed a Notice of Motion seeking an order requiring Toronto Hydro-Electric System Limited (“Toronto Hydro”) to provide full and adequate responses to those questions posed by AMPCO at the Technical Conference in which it requested that Toronto Hydro provide historical information for the period 2010 to 2014 of the quantities of particular asset units replaced (e.g., switches, transformers, poles, etc.) and the spending for those particular units for a number of asset replacement programs.

2. This information is apparently required by AMPCO to derive an estimate of unit cost (e.g., $/pole).

3. The specific information requested by AMPCO is not relevant because it would not properly permit the comparison of unit costs. In addition, the information sought cannot be extracted from the project information in an accurate manner in a reasonable time frame, even with significant effort and resources. Accordingly, it is Toronto Hydro’s submission that AMPCO’s motion should be dismissed.
Resulting Data Would Not be Relevant

4. Even if the data sought could be obtained in a reasonable time frame (which it cannot), the unit cost information requested by AMPCO would not permit the meaningful comparison of unit costs over time since the data would not provide insights with respect to what happens on a particular project design or execution of a particular project (Technical Conference Transcript, Vol. 1, p. 101). As the requested information would not properly permit the comparison of unit costs, it is not relevant to the proceeding and its production should not be required.

5. By way of example, during the Technical Conference AMPCO suggested that Toronto Hydro could take the total number of poles to be installed over a period of time, break them out into wood and concrete and calculate the relevant unit cost. In response, Toronto Hydro’s General Manager of Engineering and Investment Planning, Mr. Walker, indicated that while mathematically such a calculation was possible, the result would be a number that does not actually represent a standard unit cost (Technical Conference Transcript, Vol. 1, p. 97). This is because the associated costs relate to circumstances unique to that particular project in which the asset unit was used. Varying circumstances (such as an asset replacement in a suburban area versus the downtown core) will present different cost results even through the same asset is replaced. The asset and work undertaken each time an asset is employed or replaced are not uniform as in a manufacturing process where unit costs are more appropriately measured (Affidavit of Mike Walker, attached hereto as Schedule “A”, at para. 11).

6. By way of further example, when counsel for AMPCO asked about the possibility of calculating the dollars per kilometer of PILC cable replacement and whether the resulting information would be valuable in assessing the reasonableness of the proposed spending, Mr. Walker similarly indicated that while this would produce an average cost it would not produce a consistent cost or a cost that would be comparable as between prior completed jobs and planned future jobs. For example, Mr. Walker noted that while some work involves patching a small segment of cable length, in other jobs entire sections would be replaced, thereby rendering the proposed calculation meaningless (Technical
Conference Transcript Vol. 1, pp. 99-100). Similarly, when asked whether an historical average compared to the average of the planned future spending period would provide a meaningful number, Mr. Walker responded that an average would not be meaningful because the mix of work within a program or portfolio in a given year would differ year over year and so such numbers would be misleading (Technical Conference Transcript Vol. 1, p. 100; Affidavit, para. 9).

7. Toronto Hydro’s approach to tracking project costs recognizes the diverse range of work environments and circumstances that are encountered by Toronto Hydro across its system. Given this approach and that the circumstances of each job varies greatly, it would be very challenging to reconcile the unit costs of particular assets as between different jobs (Technical Conference Transcript, Vol. 1, p. 94).

8. As described at para. 12 in the Affidavit of Mr. Walker, the range of variables that would be encountered, for example on a typical pole installation project, is broad and would include such aspects as the relevant ground conditions, location, number of circuits, voltage of those circuits, whether the poles will carry circuits with a single or multiple voltages, whether there will be a need for underground risers, transformer type, guying, work time restrictions, etc. Toronto Hydro can encounter any one or more of these variables in the field, which would affect the cost of the project. For example, a pole installation in concrete could cost more than a pole installation in soil, a pole installation outside of business hours could cost more than during regular business hours, and pole installation in the downtown core could cost more than in a suburban area of the city.

9. It is also important to note that approximately 81% of Toronto Hydro’s distribution system capital costs (i.e. all electrical material costs, all civil construction costs, and a portion of electrical design and construction work) are subject to market driven pricing, and are therefore outside of Toronto Hydro’s direct control (Affidavit, para. 7). In addition, the method by which a contractor accounts for costs or values assets to be replaced will vary between contractors and will be adapted to facilitate responses to Toronto Hydro’s rigorous competitive procurement processes. As a result, the value to the Board of the data sought is further diminished.
Costs are Accounted for on a Project Basis

10. As explained by Mr. Walker, Toronto Hydro measures, tracks and manages its project costs by comparing its actual costs for specific jobs within a project to its design estimate for each specific job within a project (Technical Conference Transcript, Vol. 1, p. 98). Following high-level project planning, Toronto Hydro’s designers prepare a design estimate for each particular job or activity that forms part of the project. That estimate will take into account the specific requirements for that job or activity, having regard to the circumstances unique to that job or activity. These include factors such as its location, the number of circuits involved, parking or timing of work restrictions and other relevant circumstances that are specific to the planned job or activity. During and post-completion, Toronto Hydro measures its performance against the design estimate for the particular job or activity. If a significant variance is found, Toronto Hydro then conducts a project variance analysis to determine the cause(s) of the variance and any lessons learned that may be helpful for future projects.

11. Toronto Hydro experiences significant diversity in its project activities over time. It has been Toronto Hydro’s experience that the mix of work within a program or portfolio in a given year may not be consistent from year to year (Affidavit, para. 9). Because of this diversity Toronto’s practice is to measure, track and manage its project costs relative to the design estimates that are prepared on a project by project basis or job by job basis rather than by comparison of unit costs between programs or from year to year.

12. As further explained by Mr. Walker, Toronto Hydro does not consider costs on a per-asset basis (Technical Conference Transcript, Vol. 1, pp. 96-97). With respect to projects or jobs that are bid on by and awarded to outside contractors, the bid costs reflect logical groupings of assets, as well as associated material, labour, overhead and other costs that contractor will charge, regardless of their actual cost to construct. With respect to work that is performed using internal resources, Toronto Hydro instead tracks actual project costs through a detailed work order process (Affidavit, para. 6).

13. As a result of the foregoing, it would be extremely complex and time-consuming for Toronto Hydro to review each designed and completed job for the purpose of extracting
the asset units and related costs. In effect, the costs and asset units are woven into the project accounting.

14. This problem is further complicated by the functionality of Toronto Hydro’s IT framework for managing project information. In particular, through Toronto Hydro’s custom applications and existing enterprise resource planning (“ERP” or “Ellipse”) system project information is transformed at various stages of a project’s lifecycle. These transformations can involve changes in scope, the splitting or combining or phasing of scopes, advancing or deferring scopes between years, etc. Each transformation represents a new stage in the project lifecycle, which is not automatically reconciled to previous stages (Affidavit, para. 18).

15. This process of reconciling executed work and costs against the initially planned work and costs requires a labour-intensive and extensive mapping exercise so as to account for each of the transformational steps back to the original project scope that informed the underlying regulatory filing (Affidavit, para. 17-18).

The Requested Information Can Only be Provided with Significant Time and Resources

16. Having regard to the manner in which Toronto Hydro measures and tracks its project costs, as well as the limitations of its Ellipse system, the information requested by AMPCO could only be ascertained and provided if Toronto Hydro were to dedicate and divert considerable resources over a significant period of time.

17. As described in para. 18 of the Affidavit, it is estimated that this effort would require three full time resources and would take approximately one full year to complete. This level of resources and time commitment is required because, as explained in para. 16 of the Affidavit, the unit cost for installing or replacing a particular piece of equipment will not be apparent from any particular work order but must instead be derived from a labour-intensive process of manually allocating costs from numerous work orders to the relevant assets associated with a project, and repeating this for each project within a given program.
18. It is Toronto Hydro’s submission that the level of resources and time needed to provide this information is unreasonable as it would require Toronto Hydro to divert significant resources away from normal business activities - including the execution of its capital program - and has real potential to cause delay in the proceeding. Given the relevance and usefulness of the data, and the foregoing complication with extracting the data, the production of such information should not be required.

All of which is respectfully submitted this 13th day of January, 2015.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

By its Counsel
Torys LLP

[Signature]

Charles Keizer
TAB 2A
ONTARIO ENERGY BOARD


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 and for each following year effective January 1 through to December 31, 2019.

AFFIDAVIT

I, Mike Walker, of the City of Toronto, in the Province of Ontario, MAKE AN OATH AND SAY:

1. I am the General Manager, Engineering and Investment Planning, Toronto Hydro Electric System Limited ("Toronto Hydro") and, as such, have knowledge of the matters to which I herein depose.

2. As the General Manager, Engineering and Investment Planning, my responsibilities include capacity and generation planning, as well as asset lifecycle planning for all assets within Toronto Hydro's distribution system; annual capital investment planning; annual maintenance investment planning; design, material and equipment standards development and maintenance; and engineering policy development and maintenance.

3. In evidence filed on July 31, 2014 in support of its application in EB-2014-0116 (the "Pre-filed Evidence"), Toronto Hydro describes a number of discrete capital investment programs which together comprise Toronto Hydro's 2015-2019 Distribution System Plan ("DSP"). Toronto Hydro filed detailed business case evidence in support of each of these programs (Exhibit 2B, Sections E5.1 to E8.8).

4. For some of the capital investment programs,1 Toronto Hydro provided forecast estimates of the quantities of certain asset units that it expected to replace, install or remove (depending on the nature of the program) in each year of the DSP. While Toronto Hydro was able to

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provide these estimated asset quantities on a forecast basis at the program level, as a component of forecasting its cost estimates in the business cases, it did not provide the corresponding costs for the particular assets. In addition, its ability to provide estimated asset quantities does not speak to Toronto Hydro’s ability to provide historical information on the quantities of particular asset units installed, removed or replaced, or the corresponding costs on a per-unit basis.

Measurement and Tracking of Project Costs

5. Capital investment programs are implemented through the completion of specific projects. Toronto Hydro designs and executes its capital work on a project basis. A project consists of all of the activities that are involved in removing, replacing or installing a group of assets within a particular geographic location. A project’s cost consists of the blended costs of the various activities that together comprise the project.

6. Project costs are measured and tracked differently, depending on whether the work is being performed internally or externally. If the work, or a portion of it, has been contracted, the costs reflect the contractor’s bid price for the civil materials, labour, overhead and other costs necessary to execute the work (with the exception of electrical equipment that is provided by Toronto Hydro). The contractor is bound to their bid price even if their actual costs of completing the project differ. If the work is being performed using internal resources, the costs represent the actual material, labour and equipment costs incurred by Toronto Hydro to execute the work, which are tracked through a detailed work order process.

7. Approximately 81 percent of Toronto Hydro’s capital costs in its electrical work program are subject to competitive market forces. This includes the costs of all electrical equipment, which Toronto Hydro procures for use on its system (whether or not such equipment is installed by internal resources or outside contractors), all civil construction related costs, and costs related to electrical design and construction work provided by outside contractors, all of which are sourced through competitive processes. The remaining 19 percent of Toronto Hydro’s capital costs in its electrical work program are attributable to the internal labour and vehicle costs in connection with the relevant projects. As a consequence of there being a high proportion of Toronto Hydro’s capital costs subject to competitive market forces, the level of those costs on a per unit basis is largely outside of Toronto Hydro’s control. Competitive
market pressures already ensure that Toronto Hydro is able to obtain the lowest cost per unit that the market can bear, for the majority of its project spending.

8. Project costs are influenced by the variety of circumstances and factors that Toronto Hydro encounters across its large and diverse system. For example, pole installations as part of an Overhead Circuit Renewal project can be subject to variables such as the following: installation in soil or in concrete; location of the pole (i.e. downtown, suburban, road with or without parking); type and number of connected circuits (i.e. single phase, three-phase, 27.6 kV, 13.8 kV, 4.16 kV, or combination of these); type and number of other equipment installed on the pole (i.e. switches, risers, transformer, etc.); and the loading conditions and switching requirements applicable to the pole. These variables can change from project to project, or from pole to pole within a project. The unique combination of variables encountered on a particular project will affect the cost of that project. For example, on a pole installation project the cost of the project will be affected by such factors as whether the poles need to be installed in concrete as compared to soil, or whether the poles can be installed during regular business hours or must be installed outside of regular business hours.

9. Because of the diverse conditions and circumstances encountered across Toronto Hydro’s system, the mix of work within a project and the mix of projects within a program vary considerably from year to year. As an example, the majority of projects in the Overhead Circuit Renewal program in a given year may be executed in the suburbs where crews generally encounter fewer restrictions and complexities when installing poles. The next year, the bulk of the work within the program may shift to the downtown core, where pole installations are typically more complex and time consuming. As a result of these geographical differences, the number of pole installations would likely be significantly higher but with much lower costs in the first year as compared to the second year. A comparison of the cost per pole installed in these years would not reflect the diverse conditions and circumstances encountered and, as a result, would not be meaningful.

10. Given the complexities described above, Toronto Hydro plans, designs and tracks work on a project by project basis, rather than on an asset by asset basis. As such, rather than considering the unit cost of a particular asset on one project or in one period relative to the unit cost of the same type of asset on another project or in another period, Toronto Hydro instead considers the actual costs of a project relative to the estimated costs for that particular
project, where the estimate will have taken into account the known circumstances and conditions unique to the particular project.

11. Unit costing is a common consideration in manufacturing, where the output is the production of consistent, uniform and repeatable units. In that context, unit costing enables the manufacturer to track the unit costs by standardizing production through an assembly line manufacturing process, with the objective of every product off the line being identical in form and quality, and every step in production being consistent and optimized.

12. Toronto Hydro is subject to many variables outside of its control in meeting its service requirements and managing its large and complex system. A unique combination of variables is encountered on each project and that unique combination of variables gives rise to a cost profile that is unique to the particular project. These include variables such as system configuration, system voltage, construction standards, number of circuits/phases, switching requirements, system loading, location within the City, type of street, site access restrictions, soil/ground conditions, seasonal/weather impacts, timing of work execution, condition of associated assets, third party coordination requirements, and presence of other utility plant.

Project Accounting Processes

13. Toronto Hydro’s capital projects begin as “scopes” of work that are created in a custom scoping application by planning engineers who have experience identifying, prioritizing and planning investments within one or more discrete capital programs. Using the utility’s suite of planning tools and databases, these engineers exercise professional judgement to create project scopes that address discrete assets (e.g. stations circuit breakers), arrays of like assets (e.g. polymer SMD-20s), or geographic/feeder based investment needs (e.g. Overhead Circuit Renewal).

14. Once the investment needs within a particular project scope are fully specified, the engineer produces a “high-level estimate” of the project cost using the utility’s Enterprise Resource Planning (“ERP”) system (currently Ellipse). The engineer then delivers the scope package to a program management consultant, who reviews the scope and determines the resources and scheduling of the work. At this stage, the scope may be split, combined, phased, advanced or deferred based on the project management consultant’s recommendations.
15. The project then moves to detailed design where a designer is tasked with assessing site-specific construction needs through field visits, the Geographic Information System (GIS) and other available records. The scope of the project could be modified at this point in the process. Using this information and their professional experience, designers produce construction drawings and an accompanying detailed design estimate in Ellipse. When the design is complete, the designer “packages” the estimate in Ellipse, which results in the creation of new identifiers called “Projects” and “Work Orders”. It is not until the estimate is packaged that Ellipse establishes a transactional record for the project.

16. As a result of the process described above, the “unit cost” for installing or replacing a particular piece of equipment, such as a pole installation, will not be apparent from any particular work order. Rather, the cost of each installed or replaced asset unit will be made up of costs that would be found in multiple work orders, each of which addresses a discrete set of tasks that contributes to that installation or replacement (i.e. one work order for setting the poles, another for framing them, etc.). As such, deriving the unit cost for the installation or replacement of a particular asset will involve allocating the costs of those multiple work orders to the relevant assets, which on account of the diverse conditions and circumstances encountered in the field may require certain estimates or assumptions to be made. It is not uncommon for there to be dozens of work orders associated with a particular project. As such, the process would be expected to be very labour-intensive, given that a program is made up of a number of individual projects.

17. Toronto Hydro’s ERP system does not provide the capability to create or manage a master record for a capital project throughout its entire lifecycle. Toronto Hydro can track project execution costs against Ellipse projects and work orders, and can be compared to packaged design estimates. However, in order to report project variances or historical unit costs on a program basis, the utility must manually map this transactional record back to the original project scopes. As mentioned previously, these scopes are created in a custom application with no linkage to Ellipse. Scopes are subsequently managed in different custom tools as the project information is transformed at various stages in its lifecycle. The reconciliation of each of the previous steps in the lifecycle of the project requires significant manual effort, which is further compounded by the process described in paragraph 16 above.

Feasibility of Providing the Information Requested by AMPCO
18. To provide the information requested by AMPCO, Toronto Hydro would have to manually reconcile the costs of executed projects against the scope of work initially developed for each corresponding project. Through such a process, Toronto Hydro would need to determine the quantities and costs for the assets in question and aggregate those asset quantities and costs back to the specific projects and programs where they originated, while taking into account any scope changes that may have occurred over the lifecycle of the project. Toronto Hydro would also have to manually derive the unit costs for each of the assets in question for each project by way of analyzing each work order for a project to allocate costs. This data is not readily available within Ellipse. This process would be very labour-intensive. Toronto Hydro estimates that if it were to dedicate three staff from the System Planning and Project Management functions on a full-time basis, it would take a duration of approximately one year to manually derive all of the unit cost information requested by AMPCO.

SWORN BEFORE ME at the City of Toronto, in the Province of Ontario, this 13 day of January, 2015

[Signature]
Commissioner for Taking Affidavits

Elias Lyberogiannis
(LSVC #: 64499C)
January 21, 2015

RESS, EMAIL & COURIER
Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro") Custom Incentive Rate Application (EB-2014-0116)

We are counsel to the applicant, Toronto Hydro, in the above referenced proceeding. On January 19, 2015 Toronto Hydro and the Association of Major Power Consumers in Ontario (AMPCO) reached a settlement on AMPCO’s motion of December 31, 2014. As part of the settlement, Toronto Hydro agreed to provide certain information in response to AMPCO’s information requests, as detailed before the Board on January 19, 2015. Enclosed, please find Toronto Hydro’s responses.

Yours truly,

Jonathan Myers

cc: A. Klein and D. Coban, THESL
    C. Keizer and C. Smith, TORYS LLP
    All Parties
AMPCO Motion Settlement: Toronto Hydro Response

A. Background

For purposes of settling and the withdrawal of the motion brought by the Association of Major Power Consumers in Ontario ("AMPCO") dated December 31, 2014, Toronto Hydro agreed to provide the information set out below. This information is provided without prejudice to Toronto Hydro’s position that unit and cost information obtained for the purpose of calculating a unit cost is irrelevant and Toronto Hydro is free to make submissions in this regard in the future.

1. For the Distribution System Plan ("DSP") programs that AMPCO identified in its motion (i.e. E6.1, E6.2, E6.4, E6.5, E6.6, E6.7, E6.8 and E6.9), and for the specific asset types identified for each program in the same motion, Toronto Hydro agreed to provide, on a best efforts basis, numbers of assets and the dollar values associated with those assets for the years 2012 and 2013, and for the period of January to June, 2014. This information is only available on an in-service additions basis, as opposed to a capital expenditures basis.

2. Toronto Hydro agreed to provide the same information, on a best efforts basis, for the major asset types identified in programs E6.10, E6.13, E6.14 and E6.15, which were not included in AMPCO’s motion or original request.

3. For the subset of capital programs listed in points 1 and 2 above, Toronto Hydro agreed to provide the number of units to be replaced in 2015 for programs that are planned on a discrete asset basis (as opposed to programs that are planned on a geographical basis), and the associated program spending for 2015.

B. Discrete Investment Programs

Further to item 3, above, the following table lists the programs within the designated subset of DSP capital programs requested by AMPCO that address discrete asset replacements, as opposed to
geographically planned rebuilds or refurbishments. While these programs are driven by the replacement of a specific major asset type, the expenditures can also include a number of other related assets, depending on the nature of each individual project. As such, a simple division of planned program expenditures by the number of units for the corresponding major asset type will not yield an asset-specific average cost that is directly comparable to the historical data provided for 2012-2014.

Table 1: Discrete Investment Programs

<table>
<thead>
<tr>
<th>DSP Program</th>
<th>Major Asset Type (Installed)</th>
<th>Examples of other major assets in a project</th>
</tr>
</thead>
<tbody>
<tr>
<td>E6.8 SCADA-Mate R1 Switch Renewal</td>
<td>Overhead Switch</td>
<td>RTU, Wooden Poles</td>
</tr>
<tr>
<td>E6.9 Network Vault Renewal</td>
<td>Network Vault</td>
<td>Network Units, Underground Cable</td>
</tr>
<tr>
<td>E6.10 Network Unit Renewal</td>
<td>Network Units (Transformers &amp; Protectors)</td>
<td>Underground Cable</td>
</tr>
<tr>
<td>E6.13 Switchgear Renewal</td>
<td>Stations Switchgear (TS &amp; MS)</td>
<td>Station Battery, Circuit Breakers</td>
</tr>
<tr>
<td>E6.14 Power Transformer Renewal</td>
<td>Stations Power Transformer</td>
<td>Bus Structure</td>
</tr>
<tr>
<td>E6.15 Circuit Breaker Renewal</td>
<td>Stations Circuit Breaker</td>
<td>Relays</td>
</tr>
</tbody>
</table>

C. Description of Data Provided

*Historical Data*

As explained in Ms. Rouse’s affidavit dated January 16, 2015 (the “Rouse Affidavit”), Toronto Hydro is able to provide historical data for the years 2012 and 2013 using the utility’s financial reporting system and by leveraging the detailed program mapping exercise that was carried out in preparing the DSP, specifically for the Incremental Capital Module (“ICM”) program years (2012-2013). Historical data for 2014 (up to June) has been provided using the same sources. Data beyond June 2014 is unavailable as the year-end has not yet been closed-out or audited and the relevant program mapping exercise has not been completed.
The historical data provided is available only on an in-service basis. As explained in the Rouse Affidavit, not all capital expenditures in the years 2012 and 2013 (as well as 2014) would have gone into service in those same years. Similarly, in-service amounts associated with assets that came into service in any given year may include expenditures from prior years. Therefore, the costs and associated units provided in the tables in Section D below will not bear a direct relationship to the overall historical annual capital expenditure amounts provided in the spending summary tables in each of the identified programs.

It is also possible that a project that was placed into service in a given year could have lagging costs that appear separately as in-service additions in the following year. Therefore, the data that Toronto Hydro has been able to provide in Section D is not a true representation of average costs per unit.

As explained in the Rouse Affidavit, the financial asset classes that Toronto Hydro used to report historical actual units and costs in this response can include multiple different asset types with significantly different average costs. For example, the Overhead Switches asset class in Table 4, below, could include assets ranging from large three-phase gang-operated switches to single-phase manual cut-out switches. The financial asset sub-ledger cannot report at this lower level of detail.

It should also be noted that because this historical data is provided on an in-service basis, the units and costs necessarily represent the number of assets installed. This is distinct from the forecast information provided in the referenced DSP programs. The units provided in the DSP forecast tables for System Renewal programs represent the number of units to be replaced, removed, or otherwise intervened upon by that program. This is a particularly important distinction for programs that are not “like-for-like” in nature. For example, Toronto Hydro is planning to remove rear lot plant that may be situated either overhead or underground, depending on the area. However, regardless of the current rear lot configuration, Toronto Hydro replaces existing rear lot plant with front lot, underground plant. Therefore, the historical information provided will be based on the new front lot plant installed, whereas the forecast
information will be based on the quantity of existing rear lot plant to be replaced. This means that the historical unit counts provided in Section D below are not directly comparable to the forecasted unit counts summarized in the DSP evidence.

Moreover, while some programs may on the surface appear to be “like-for-like”, it is likely that the rebuilt plant will nevertheless differ on an asset unit count basis from the existing plant due to changes in design and construction standards, field conditions, feeder loading and other considerations over time. For example, Toronto Hydro may replace a larger number of existing low kVA rated transformers with a smaller number of higher kVA rated transformers in order to improve cost efficiency in the renewed feeder design.

**Forecast Data**

The forecast unit count and program cost information that Toronto Hydro has summarized in Section E is taken directly from the original DSP program evidence. As explained in Section B above, this information cannot be used to derive an average asset unit cost for the referenced asset types because overall program costs may include expenditures related to other types of assets.

The forecast information provided in Section E is total capital expenditures by program. The historical actual information for 2012-2014 is provided on an in-service basis. Accordingly, the data will not be directly comparable.

**D. Historical Units and Costs (2012 to June 2014)**

The tables provided in this section summarize the historical number of units and the in-service dollar amounts associated with those units for each of the programs and asset types requested by AMPCO. As explained in Mr. Walker’s affidavit dated January 13, 2015 and filed by Toronto Hydro (the “Walker Affidavit”), the information provided below does not permit the meaningful comparison of unit costs over
time since the data does not provide insights with respect to what happens on a particular project design or execution of a particular project.

Project costs are influenced by the variety of circumstances and factors that Toronto Hydro encounters across its large and diverse system. For example, pole installations as part of an Overhead Circuit Renewal project can be subject to the following variables: installation in soil or in concrete; location of the pole (i.e. downtown, suburban, road with or without parking); type and number of connected circuits (i.e. single phase, three-phase, 27.6 kV, 13.8 kV, 4.16 kV, or a combination of these); type and number of other equipment installed on the pole (i.e. switches, risers, transformers, etc.); and the loading conditions and switching requirements applicable to the pole. These variables can change from project to project, from pole to pole within a project, or from time to time. The unique combination of variables encountered on a particular project will affect the cost of that project. For example, on a pole installation project the cost of the project will be affected by such factors as whether the poles need to be installed in concrete as compared to soil, or whether the poles can be installed during regular business hours or must be installed outside of regular business hours.

Because of the diverse conditions and circumstances encountered across Toronto Hydro’s system, the mix of work within a project and the mix of projects within a program vary considerably from year to year. As an example, the majority of projects in the Overhead Circuit Renewal program in a given year may be executed in the suburbs where crews generally encounter fewer restrictions and complexities when installing poles. The next year, the bulk of the work within the program may shift to the downtown core, where pole installations are typically more complex and time consuming. As a result of these geographical differences, the number of pole installations would likely be significantly higher but with much lower costs in the first year as compared to the second year. A comparison of the cost per pole installed in these years would not reflect the diverse conditions and circumstances encountered and, as a result, would not be meaningful.
Please note that in most cases the 2012 ISA unit counts and dollar amounts in the following tables are significantly lower than in 2013 and 2014, and in some cases are zeros. This is due to the ramp-down of Toronto Hydro’s capital program that occurred following the decision in the utility’s 2012-2014 Cost of Service application, and pending the Phase 1 IRM/ICM decision.
Table 2: E6.1 Underground Circuit Renewal

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Underground Cable</td>
<td>Underground Primary Induct-XLPE</td>
<td>M</td>
<td>106,291</td>
<td>$6,715,307</td>
<td>283,719</td>
<td>$15,431,361</td>
<td>31,033</td>
<td>$1,524,924</td>
</tr>
<tr>
<td>Underground Switches</td>
<td>Underground Switch Installation</td>
<td>EA</td>
<td>36</td>
<td>$2,695,127</td>
<td>40</td>
<td>$3,115,838</td>
<td>3</td>
<td>$289,065</td>
</tr>
<tr>
<td>Underground Transformer</td>
<td>Underground Distribution Transformer</td>
<td>EA</td>
<td>85</td>
<td>$1,052,331</td>
<td>270</td>
<td>$4,747,080</td>
<td>122</td>
<td>$2,222,103</td>
</tr>
</tbody>
</table>

- Please note that Underground Cable is reported in terms of meters of cable in the above table. For the forecasted units that appear in the DSP program evidence, the amount of cable is represented in terms of circuit kilometres, which does not take into account the number of phases in a section of feeder. As such, these measures are not directly comparable.

Table 3: E6.2 Paper-Insulated Lead-Covered Leakers and Cable Piece-Outs

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Underground Cable</td>
<td>Underground Primary PILC</td>
<td>M</td>
<td>-</td>
<td>$-</td>
<td>525</td>
<td>$111,443</td>
<td>579</td>
<td>$253,474</td>
</tr>
</tbody>
</table>
Table 4: E6.4 Overhead Circuit Renewal

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wood Poles</td>
<td>Wooden Poles</td>
<td>EA</td>
<td>147</td>
<td>$1,047,156</td>
<td>2,672</td>
<td>$15,205,774</td>
<td>804</td>
<td>$4,051,829</td>
</tr>
<tr>
<td>Concrete Poles</td>
<td>Concrete Poles</td>
<td>EA</td>
<td>3</td>
<td>$16,505</td>
<td>39</td>
<td>$432,769</td>
<td>5</td>
<td>$68,159</td>
</tr>
<tr>
<td>Overhead Switches</td>
<td>Overhead Switches, Overhead SMD-20 Switches</td>
<td>EA</td>
<td>47</td>
<td>$849,687</td>
<td>569</td>
<td>$4,422,034</td>
<td>68</td>
<td>$286,201</td>
</tr>
<tr>
<td>Overhead Transformers</td>
<td>Overhead Polemount Transformers</td>
<td>EA</td>
<td>113</td>
<td>$1,320,316</td>
<td>730</td>
<td>$7,332,735</td>
<td>205</td>
<td>$2,203,596</td>
</tr>
</tbody>
</table>

Table 5: E6.5 Overhead Infrastructure Relocation

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poles</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OH Conductor (mts)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OH Switches</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OH Transformers</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Underground Cable</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Not Applicable - New Program in 2015
Table 6: E6.6 Rear Lot Conversion

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poles</td>
<td>Wooden Poles</td>
<td>EA</td>
<td>2</td>
<td>$ 8,323</td>
<td>131</td>
<td>$ 1,219,236</td>
<td>-</td>
<td>$ -</td>
</tr>
<tr>
<td>Transformers</td>
<td>Underground Distribution Transformer, Overhead Polemount Transformers</td>
<td>EA</td>
<td>-</td>
<td>$ -</td>
<td>158</td>
<td>$ 2,547,017</td>
<td>47</td>
<td>$ 555,704</td>
</tr>
<tr>
<td>Fuse</td>
<td>Not Applicable - Not tracked in financial asset sub-ledger</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Riser</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Conductor (m)</td>
<td>Overhead Lines</td>
<td>M</td>
<td>-</td>
<td>$ -</td>
<td>2,581</td>
<td>$ 197,148</td>
<td>-</td>
<td>$ -</td>
</tr>
<tr>
<td>Cable (m)</td>
<td>Underground Primary In-duct-XLPE</td>
<td>M</td>
<td>-</td>
<td>$ -</td>
<td>40,937</td>
<td>$ 4,164,428</td>
<td>8,782</td>
<td>$ 715,142</td>
</tr>
</tbody>
</table>
Table 7: E6.7 Box Construction Conversion

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>OH Transformer</td>
<td>Overhead Polemount Transformers</td>
<td>EA</td>
<td>$ -</td>
<td>120</td>
<td>$ 904,168</td>
<td>11</td>
<td>$ 7,330</td>
<td></td>
</tr>
<tr>
<td>OH Switch</td>
<td>Overhead Switches, Overhead SMD-20 Switches</td>
<td>EA</td>
<td>$ -</td>
<td>61</td>
<td>$ 326,611</td>
<td>3</td>
<td>$ 421</td>
<td></td>
</tr>
<tr>
<td>Poles</td>
<td>Wooden Poles, Concrete Poles</td>
<td>EA</td>
<td>$ -</td>
<td>257</td>
<td>$ 1,409,059</td>
<td>208</td>
<td>$ 722,496</td>
<td></td>
</tr>
<tr>
<td>UG Switch</td>
<td>Underground Switch Installation</td>
<td>M</td>
<td>$ -</td>
<td>-</td>
<td>$ -</td>
<td>-</td>
<td>$ -</td>
<td></td>
</tr>
<tr>
<td>UG Transformer</td>
<td>Underground Distribution Transformer</td>
<td>EA</td>
<td>$ -</td>
<td>12</td>
<td>$ 162,685</td>
<td>-</td>
<td>$ -</td>
<td></td>
</tr>
<tr>
<td>OH Conductor (km)</td>
<td>Overhead Lines</td>
<td>M</td>
<td>$ -</td>
<td>28,914</td>
<td>$ 644,636</td>
<td>5,173</td>
<td>$ 8,874</td>
<td></td>
</tr>
<tr>
<td>UG Cable (km)</td>
<td>Underground Primary Induct-XLPE</td>
<td>M</td>
<td>$ -</td>
<td>4,272</td>
<td>$ 577,285</td>
<td>-</td>
<td>$ -</td>
<td></td>
</tr>
</tbody>
</table>

Table 8: E6.8 SCADA-Mate R1 Switch Renewal

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>R1 Switch</td>
<td>Overhead Switches</td>
<td>EA</td>
<td>$ -</td>
<td>31</td>
<td>$ 957,343</td>
<td>-</td>
<td>$ -</td>
<td></td>
</tr>
<tr>
<td>RTU</td>
<td>System Supervisory Scada RTU</td>
<td>EA</td>
<td>$ -</td>
<td>25</td>
<td>$ 732,206</td>
<td>-</td>
<td>$ -</td>
<td></td>
</tr>
</tbody>
</table>
### Table 9: E6.9 Network Vault Renewal

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vaults</td>
<td>Underground Vault</td>
<td>EA</td>
<td>-</td>
<td>-</td>
<td>15</td>
<td>$ 3,888,327</td>
<td>-</td>
<td>$ -</td>
</tr>
<tr>
<td>Roofs</td>
<td>Underground Vault Roof</td>
<td>EA</td>
<td>2</td>
<td>$ 113,203</td>
<td>5</td>
<td>$ 497,433</td>
<td>2</td>
<td>$ 315,172</td>
</tr>
<tr>
<td>UG Network Units</td>
<td>Underground Network Transformers</td>
<td>EA</td>
<td>-</td>
<td>-</td>
<td>36</td>
<td>$ 2,998,417</td>
<td>4</td>
<td>$ 323,468</td>
</tr>
</tbody>
</table>

### Table 10: E6.10 Network Unit Renewal

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Unit (Transformer &amp; Protector)</td>
<td>Underground Network Transformers</td>
<td>EA</td>
<td>43</td>
<td>$ 2,226,623</td>
<td>90</td>
<td>$ 6,191,413</td>
<td>8</td>
<td>$ 587,140</td>
</tr>
</tbody>
</table>

### Table 11: E6.13 Station Switchgear Renewal

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>TS Switchgear</td>
<td>HONI Contributions</td>
<td>N/A</td>
<td>$ 5,475,623</td>
<td>N/A</td>
<td>$ 2,597,670</td>
<td>N/A</td>
<td>$ -</td>
<td>$ -</td>
</tr>
<tr>
<td>MS Switchgear</td>
<td>Substation Equipment Air Insulated Switch</td>
<td>EA</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>2</td>
<td>$ 3,426,968</td>
</tr>
</tbody>
</table>
- Note that no TS switchgear were put into service in the time period covered by the table above. The ISA dollars shown for TS switchgear represent lagging HONI contribution expenditures related to previously installed switchgear assets.

Table 12: E6.14 Power Transformer Renewal

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stations Power Transformer</td>
<td>Substation Transformer</td>
<td>EA</td>
<td>7</td>
<td>$3,849,895</td>
<td>1</td>
<td>$529,308</td>
<td>4</td>
<td>$1,391,540</td>
</tr>
</tbody>
</table>

Table 13: E6.15 Circuit Breaker Renewal

<table>
<thead>
<tr>
<th>AMPCO Requested Assets</th>
<th>THESL Financial Assets Installed</th>
<th>Unit of Measure</th>
<th>2012 ISA Quantities</th>
<th>2012 ISA Dollars</th>
<th>2013 ISA Quantities</th>
<th>2013 ISA Dollars</th>
<th>As at June 2014 ISA Quantities</th>
<th>As at June 2014 ISA Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>KSO Oil Circuit Breakers</td>
<td>Substation Equipment - Outdoor Breaker</td>
<td>EA</td>
<td>3</td>
<td>$487,266</td>
<td>5</td>
<td>$857,882</td>
<td>1</td>
<td>$162,730</td>
</tr>
</tbody>
</table>
E. 2015 Discrete Asset Program Forecasts

Table 14: E6.8 SCADA-Mate R1 Switch Renewal (2015 forecast)

<table>
<thead>
<tr>
<th>Major Asset Type (Replaced)</th>
<th>2015 Estimated Units</th>
<th>2015 Total Estimated Program Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCADA-Mate R1 Switch</td>
<td>72</td>
<td>$6.16 M</td>
</tr>
</tbody>
</table>

- Note that if an obsolete RTU exists at an R1 switch location, the RTU may also be replaced, which will affect the total cost of the R1 replacement. Toronto Hydro estimates that 52 RTUs will be replaced in 2015.

Table 15: E6.9 Network Vault Renewal (2015 forecast)

<table>
<thead>
<tr>
<th>Major Asset Type (Project Type)</th>
<th>2015 Estimated Units</th>
<th>2015 Total Estimated Program Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Vault Rebuild</td>
<td>4</td>
<td>$2.95 M</td>
</tr>
<tr>
<td>Network Vault Roof Rebuild</td>
<td>4</td>
<td>$0.70 M</td>
</tr>
<tr>
<td>Network Vault Decommissioning</td>
<td>2</td>
<td>$0.30 M</td>
</tr>
</tbody>
</table>

- Note that while the Network Vault Renewal program deals with discrete assets, the intervention on those assets will vary depending on requirements. Intervention can include a full vault rebuild, a roof rebuild only, or vault decommissioning. Each planned 2015 project in this program (summarized in Exhibit 2B, Section E6.9, Table 9) corresponds to a particular project type for a discrete unit; as such, Toronto Hydro is able to provide the estimated costs related each type of network vault project in 2015, as shown in the table above.

Table 16: E6.10 Network Unit Renewal (2015 forecast)

<table>
<thead>
<tr>
<th>Major Asset Type (Replaced)</th>
<th>2015 Estimated Units</th>
<th>2015 Total Estimated Program Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Units (Transformer &amp; Protector)</td>
<td>40</td>
<td>$3.95 M</td>
</tr>
</tbody>
</table>
Table 17: E6.13 Switchgear Renewal (2015 forecast)

<table>
<thead>
<tr>
<th>Major Asset Type (Replaced)</th>
<th>2015 Estimated Units</th>
<th>2015 Total Estimated Program Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>MS Switchgear</td>
<td>3</td>
<td>$ 11.9 M</td>
</tr>
<tr>
<td>TS Switchgear</td>
<td>0</td>
<td></td>
</tr>
</tbody>
</table>

Table 18: E6.14 Power Transformer Renewal (2015 forecast)

<table>
<thead>
<tr>
<th>Major Asset Type (Replaced)</th>
<th>2015 Estimated Units</th>
<th>2015 Total Estimated Program Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Transformer</td>
<td>4</td>
<td>$ 1.68 M</td>
</tr>
</tbody>
</table>

- Please note that the total cost in the table above includes one project for the installation of an oil containment unit at an existing power transformer location. This project is estimated to cost $161 K and will not result in the replacement of a power transformer.

Table 19: E6.15 Circuit Breaker Renewal (2015 forecast)

<table>
<thead>
<tr>
<th>Major Asset Type (Replaced)</th>
<th>2015 Estimated Units</th>
<th>2015 Total Estimated Program Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>KSO Oil Circuit Breaker</td>
<td>10</td>
<td>$ 1.66 M</td>
</tr>
</tbody>
</table>
There is work expected to be done under that, of the same type as what's in the '15 program. It is not down at a job level, but it is expected to be the same kind of work. 182

191. The evidence contained in the DSP clearly substantiates the need, both at a system level (i.e. one-third of assets will be past their useful life by 2020) and on a program-basis, to invest in the renewal of the distribution system over the next five years. The utility went beyond the Chapter 5 Filing Requirements and provided project level details for 2015 to illustrate the type of work that it plans to execute and provide as part of each program. As Ms. Klein noted,

… we have provided very detailed business cases with respect to what we intend to do in our capital program for the years 2015 to 2019. And in the first year, we actually went beyond the DSP requirements and provided an additional level of detail, dropping down into something that probably would resemble more closely the ICM level of detail, to provide the Board and parties some continuity between the two regulatory views of the application and the continuation of the capital plan.

....

And so we have, as best as possible and at quite a granular level of detail, provided an indication of the types of work we intend to do. I believe there is something like 46 DSP programs, most of which span all five years and a number of which span several of the years. Beyond that, providing more detailed plans is not our intention and, at this point, for the later years is not possible. 183

192. Toronto Hydro would have had to expend significant costs and resources to prepare detailed project designs for the outer years of the plan in a format that would be useful to the OEB, in addition to the increased regulatory costs associated with reviewing, evaluating and defending the capital proposals. AMPCO and CCC argue that 2016-2019 project details are necessary to evaluate the reasonableness and appropriates of the DSP, but do not explain how the information would actually be useful for this assessment. More importantly, the parties do not consider the benefits relative to the costs, or the potential inefficiency implicit in their argument.

193. **Unit Costs:** As discussed above, Toronto Hydro’s program forecasts are based on the identified needs of the system and the application of experienced engineering judgment to

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183 OH Transcript Volume 8 (February 27, 2015), at page 47, line 12-23 and pages 48-49, lines 17-7.
estimate, at a high-level, the costs of accomplishing work in the identified areas. For the reasons
detailed above, Toronto Hydro does not forecast capital expenditures on the basis of detailed
design estimates, which would be required to derive accurate unit costs.

194. AMPCO and SEC assert that they expected Toronto Hydro to be able to provide unit cost
information. In his affidavit to the AMPCO Motion, Mr. Walker explained why this information
is not readily available:

To provide the information requested by AMPCO, Toronto Hydro would have to
manually reconcile the costs of executed projects against the scope of work
initially developed for each corresponding project. Through such a process,
Toronto Hydro would need to determine the quantities and costs for the assets in
question and aggregate those asset quantities and costs back to the specific
projects and programs where they originated, while taking into account any scope
changes that may have occurred over the lifecycle of the project. Toronto Hydro
would also have to manually derive the unit costs for each of the assets in
question for each project by way of analyzing each work order for a project to
allocate costs. This data is not readily available within Ellipse [Toronto Hydro’s
legacy ERP system]. This process would be very labour-intensive. Toronto
Hydro estimates that if it were to dedicate three staff from the System Planning
and Project Management functions on a full-time basis, it would take a duration of
approximately one year to manually derive all of the unit cost information
requested by AMPCO. 184

184 Toronto Hydro Response to AMPCO Motion, M. Walker Affidavit (January 13, 2015) at page 18.

195. Ultimately, unit costs do not provide a meaningful assessment of costs or efficiency
because the costs of doing work can vary significantly on the circumstances of each particular
job. 185 Again, this was explained by Mr. Walker: 186

If we try to compare past cost to future cost, projected cost, we’re not necessarily
comparing the same kind of unit. Installing a pole in, you know, the downtown
core of Toronto is a completely different costing structure than installing it in a
subdivision in the north of Scarborough, as an example.

Some poles have a single-phase single circuit on. And some have a three-phase
circuit. Some have two three-phase circuits. Some have transformers hung on
them and some do not, and so on. So the variability in units is huge, and the
variability in the programs year over year can be huge as well. In one year, if we
are doing more projects in the downtown core than we are in the Horseshoe, our

185 Toronto Hydro Response to AMPCO Motion, M. Walker Affidavit (January 13, 2015) at paras. 9-10.
unit costing -- should we calculate one -- is going to be significantly higher than it would be if we were doing more in Scarborough than we were in downtown Toronto.

If we're doing those poles in an area where there's parking restrictions in this job and there's another job where there are no parking restrictions, our costs are going to be different, and so on and so on.

So when we try to apply average unit costing, we find it meaningless. And especially as an efficiency measure, it provides no value.

196. In addition, because a significant portion of Toronto Hydro’s capital work is performed by external contractors, there is also an issue of comparability with respect to unit costs. If the work, or a portion of it, has been contracted, the costs reflect the contractor's bid price for the civil materials, labour, overhead and other costs necessary to execute the work (with the exception of electrical materials that are provided by Toronto Hydro). The contractor is bound to its bid price even if its actual costs of completing the project differ. If the work is being performed using internal resources, the costs represent the actual material, labour and equipment costs incurred by Toronto Hydro to execute the work, which are tracked through a detailed work order process. To better understand the difference between internal and external construction costs going forward, Toronto Hydro has developed the Contractor Cost Efficiency metric, which is discussed in more detail below.

197. **Asset Assemblies Metric.** Recognizing the OEB and parties’ interest in unit costs, over the 2015-2019 Toronto Hydro also proposes to develop a metric which will enable the utility to effectively track and evaluate the internal labour inputs of completing specific types of assets in a manner that recognizes the complexity and diversity of the utility’s service territory. This measure will enable Toronto Hydro’s engineers and designers to prepare better estimates to account for specific engineering, topographic or other related circumstances applicable to each individual project. It will also allow Toronto Hydro to analyze the costs structure of

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188 Exhibit 2B, Section C3.5.
189 Exhibit 2B, Section C3.5, at page 26, lines 9-12.
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Wooden Pole Replacement</td>
<td>Each</td>
<td>3,040</td>
<td>3,858</td>
<td>4,127</td>
<td>3,882</td>
<td>3,142</td>
<td>$7,148</td>
<td>$7,530</td>
<td>$7,848</td>
<td>$7,344</td>
<td>$7,104</td>
<td>$7,122</td>
<td>Unit costs submitted to OEB in 2015 CIR, unit costs are determined from DDPs Maintenance Inspections contract.</td>
</tr>
<tr>
<td>UG XLPF Replacement</td>
<td>U-G Pri Cable - XLPF (In-Duct)</td>
<td>Meter</td>
<td>272.14</td>
<td>94</td>
<td>260.17</td>
<td>99</td>
<td>311.61</td>
<td>96</td>
<td>96</td>
<td>Assumed to be in duct (PVC) by Major Asset Definition for SA purposes.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vegetation Management - Time Limiting</td>
<td>Kilometer</td>
<td>$2,080.00</td>
<td>$2,131.00</td>
<td>$2,131.00</td>
<td>$2,137.00</td>
<td>$2,137.00</td>
<td>$2,137.00</td>
<td>$2,137.00</td>
<td>$2,137.00</td>
<td>$2,137.00</td>
<td>$2,137.00</td>
<td>$2,137.00</td>
<td>Unit costs submitted to OEB in 2015 CIR, unit costs are determined from DDPs Maintenance Inspections contract.</td>
</tr>
<tr>
<td>Pole Test and Treat</td>
<td>Each</td>
<td>10,360</td>
<td>10.76</td>
<td>12,231</td>
<td>18.33</td>
<td>15,986</td>
<td>21.75</td>
<td>18</td>
<td>22</td>
<td>Unit costs submitted to OEB in 2015 CIR (way may have been provided during inspections), unit costs are determined by dividing total actual spend with total poles inspected.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overhead Use Factual &amp; R-I-Can</td>
<td>Kilometer</td>
<td>7,465</td>
<td>46.00</td>
<td>7,147</td>
<td>46.00</td>
<td>7,497</td>
<td>44.00</td>
<td>44</td>
<td>44</td>
<td>Unit costs submitted to OEB in 2015 CIR (way may have been provided during inspections), unit costs are determined by dividing total actual spend with total poles inspected.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Network Vault Inspection</td>
<td>Each</td>
<td>2,881</td>
<td>325.00</td>
<td>2,844</td>
<td>335.00</td>
<td>3,089</td>
<td>346.00</td>
<td>335</td>
<td>335</td>
<td>Unit costs submitted to OEB in 2015 CIR, unit costs are determined from DDPs Maintenance Inspections contract.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Submersible Vault Inspection</td>
<td>Each</td>
<td>3,229</td>
<td>139.00</td>
<td>2,469</td>
<td>195.00</td>
<td>2,739</td>
<td>149.00</td>
<td>140</td>
<td>140</td>
<td>Unit costs submitted to OEB in 2015 CIR, unit costs are determined from DDPs Maintenance Inspections contract.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Building Vault Inspection</td>
<td>Each</td>
<td>1,855</td>
<td>300.00</td>
<td>1,565</td>
<td>330.00</td>
<td>1,490</td>
<td>320.00</td>
<td>309</td>
<td>309</td>
<td>Unit costs submitted to OEB in 2015 CIR, unit costs are determined from DDPs Maintenance Inspections contract.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OH Cross Arm Operated Switches</td>
<td>OH Switches</td>
<td>Each</td>
<td>20</td>
<td>11,024</td>
<td>109</td>
<td>11,084</td>
<td>112</td>
<td>11,222</td>
<td>11,222</td>
<td>11,222</td>
<td>11,222</td>
<td>11,222</td>
<td>No breakdown by asset type available in ISA data.</td>
</tr>
<tr>
<td>OH Pole Top Transformer Replacement</td>
<td>OH Transformers</td>
<td>Each</td>
<td>800</td>
<td>11,024</td>
<td>109</td>
<td>11,084</td>
<td>112</td>
<td>11,222</td>
<td>11,222</td>
<td>11,222</td>
<td>11,222</td>
<td>11,222</td>
<td>No breakdown by asset type available in ISA data.</td>
</tr>
<tr>
<td>Underground (submersible and sub) Transformer Replacement</td>
<td>U-G Transformers</td>
<td>Each</td>
<td>500</td>
<td>18,473</td>
<td>442</td>
<td>22,497</td>
<td>573</td>
<td>23,091</td>
<td>25,471</td>
<td>25,471</td>
<td>25,471</td>
<td>25,471</td>
<td>No breakdown by asset type available in ISA data.</td>
</tr>
<tr>
<td>Network Transformer Replacement</td>
<td>Network Unit (T &amp; Protector)</td>
<td>Each</td>
<td>46</td>
<td>70,650</td>
<td>46</td>
<td>84,580</td>
<td>63</td>
<td>106,034</td>
<td>88,000</td>
<td>88,000</td>
<td>88,000</td>
<td>Network data is combined in ISA as Network Unit and Network Unit data are combined in ISA as Network Unit (limited unit counts). Combined with Transformer in OEB submittal</td>
<td>Network Vault Renewal and Network Unit Renewal</td>
</tr>
<tr>
<td>OH Breaker Replacement</td>
<td>Subj Eq Indv Brk</td>
<td>Each</td>
<td>4</td>
<td>78,270</td>
<td>4</td>
<td>84,580</td>
<td>63</td>
<td>106,034</td>
<td>88,000</td>
<td>88,000</td>
<td>88,000</td>
<td>No breakdown by asset type available in ISA data.</td>
<td></td>
</tr>
<tr>
<td>OH Circuit Breaker Replacement</td>
<td>Subj Eq Switch Avr</td>
<td>Each</td>
<td>2</td>
<td>1,714,839</td>
<td>2</td>
<td>1,715,015</td>
<td>2</td>
<td>1,706,806</td>
<td>1,720,626</td>
<td>1,720,626</td>
<td>1,720,626</td>
<td>No breakdown by asset type available in ISA data.</td>
<td></td>
</tr>
<tr>
<td>Underground Duct</td>
<td>U-G Duct Bank</td>
<td>Meter</td>
<td>1203.00</td>
<td>719</td>
<td>848.54</td>
<td>764</td>
<td>727.14</td>
<td>894</td>
<td>894</td>
<td>894</td>
<td>894</td>
<td>894</td>
<td>894</td>
</tr>
</tbody>
</table>

General Assumption: Reactive Capital, Worst Performing Feeder, and PILC Spot Replacement (Piece-out and Leakers) are not included out of renewal programs.

General Assumption: Costs are in "year-of" dollars and are not normalized to 2017 dollars.
<table>
<thead>
<tr>
<th>Local Factors</th>
<th>&quot;X&quot; to those that apply</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Excessive travel time (over 30 mins.)</td>
<td>x</td>
<td>Most contractor jobs would require travel time greater than 30 minutes (building/ work center locations outside Toronto)</td>
</tr>
<tr>
<td>Road restrictions which limit working hours (Permits, time of day and overnight parking)</td>
<td>x</td>
<td>All projects on arterial roads are limited to non rush hours work time 9:30 AM to 3:30 PM. Work in sub divisions cannot start prior to 7:30 AM. Total daytime restrictions on some roadways.</td>
</tr>
<tr>
<td>High water table (results in transportation of water and cost of disposal along with environmental issues)</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>Working next to energized lines (requiring dedicated observer, gloves, etc.) - Live line work</td>
<td>x</td>
<td>Almost all overhead work is performed in this manner. Very few projects where there is no adjacent live conductor</td>
</tr>
<tr>
<td>Requirements to perform work off hours (i.e., night/weekend). Road restrictions i.e. Bay St, City coordinated construction work zones - Customer requirements for off hour work</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>Changed standards requiring rebuilds rather than like-for-like (i.e., clearances i.e. taller poles and new ESA requirements)</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>Excessive switching requirements (i.e., to isolate on dual radial construction, network)</td>
<td>x</td>
<td>switching charges to PSO CSS projects by internal crews?</td>
</tr>
<tr>
<td>Shoring requirements for UG work Need to use vac truck due to congested landbase (no spot for equipment setup/ excavated material - too close to building)</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>Limitations on tree trimming (e.g.; unusually tight clearances)</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>Box Construction/shielded primary</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>Prior use of lead cables</td>
<td>x</td>
<td>Can get dollars paid for Paid duty by contractors annually</td>
</tr>
<tr>
<td>High fault currents (impacting equipment sourcing)</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>Paid duty for police presence on public roads (direct people and traffic)</td>
<td>x</td>
<td>Can get dollars paid for Paid duty by contractors annually</td>
</tr>
<tr>
<td>Extensive use of submersible transformers (High Civil cost)</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>Environmental regulations</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>City consent requirements (i.e., customer notification, restoration, progressive clean-up, etc.)</td>
<td>x</td>
<td></td>
</tr>
</tbody>
</table>
| Other (please specify in Comments)                                          | x                      | 1) Cable chamber pump and wash, additional review, permits and approvals, not sufficient ROW to construct (have to construct under sidewalk or on roadway), clearance to zero lot line building construction (underpinning of building foundation)  
2) Bio-waste (spent needles), other regulatory permits such as Metrolinx, Toronto Region Conservation Authority, Business Improvement Associations, 3rd party utilities i.e. gas, telecom, TV cables, Accessibility for Ontarians with Disability Act, Zero lot line construction  
3) Delays caused by customer inquiries  
4) Delays caused by unforeseen field conditions (e.g. abandoned gas service)  
5) Defective customer owned infrastructure (have to issue Customer Action Form)  
6) Access to legacy equipment                                                                                                                                 |
Capital Unit Costs
Methodology

- The Capital Unit costs are derived from actual project costs based on information from the In-Service Additions (ISA) of capital projects

- In Service Additions include information on both units and total costs allocated to each major asset type as captured by the Capital Finance team

- The data spans from 2012-2016 for this analysis

- The process involves cleansing the ISA data, parsing the data, and calculating the unit cost per asset in each project and aggregating this information up to the system level for every major asset type
### Methodology - Outline

**Data Cleanse**

1. **Input in service addition (ISA) Data**
   - Inputs may require analyst to organize them manually to the acceptable format.

2. **Isolate for Cap. Year**
   - Change Cap Date to Cap Year. Remove any records with NULL Cap Year.

3. **Summarize: Group Asset Class Under each Parent Project. Sum up Cost for each asset within project**
   - Organize data by Parent Project and their Class.

4. **Filter Out: NULL DSP Program, Asset Quantity = 0, and NULL Cap. Year**
   - Isolates out data which are not mapped to individual programs

5. **Output the Cleansed Data**
Methodology - Outline

Data Parse

The Output Data from Data Cleanse is used.

Input Cleansed Data

Filters out all DSP Programs that are not in the interest of this exercise.

Filter Out Out-of-Scope DSP Programs

For multiple Cap Year under the same Parent Project, the year with the greatest Annual Cost is set to be the Cap Year for the entire Parent Project.

Address Multiple Cap Year Issue

Filters out all Asset Classes that are not in the interest of this exercise.

Filter Out Out-of-Scope Asset Class

Asset Classes may have multiple Asset Numbers. The Quantity of asset under each Class is aligned with the maximum Quantity of assets under each Asset Number.

Multiple Asset Quantities per Project
Continuation from the end of Data Parse. The Unit Cost of each Class under each Parent Project is Calculated by taking its Cost/Quantity.

Outlier Removal. Currently, the records below the 10th Percentile and records above the 90th Percentile are removed.

All Unit Costs are grouped by their Class. Then the average is taken in each asset Class.

Data Output

Calculate Unit Cost Using Cost/Quantity → Remove Outliers Based on Percentiles → Calculate System-Wide Average Unit Cost → Output Data
## Capital Unit Costs

<table>
<thead>
<tr>
<th>CLASS</th>
<th>COST</th>
<th>UNIT</th>
</tr>
</thead>
<tbody>
<tr>
<td>WOOD POLES</td>
<td>$7,653.71</td>
<td>EACH</td>
</tr>
<tr>
<td>CONCRETE POLES</td>
<td>$10,702.23</td>
<td>EACH</td>
</tr>
<tr>
<td>UNDERGROUND CABLE PRIMARY (XLPE IN DUCT)</td>
<td>$108.44</td>
<td>PER METRE</td>
</tr>
<tr>
<td>OVERHEAD TRANSFORMERS</td>
<td>$11,842.68</td>
<td>EACH</td>
</tr>
<tr>
<td>UNDERGROUND TRANSFORMERS</td>
<td>$22,044.16</td>
<td>EACH</td>
</tr>
</tbody>
</table>
Please note that Appendix O to this response has been filed confidentially.

(2 pages)
Please note that Appendix P to this response has been filed confidentially.

(3 pages)
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 10:

Reference(s):  Exhibit 1B, Tab 2, Schedule 1, Appendix B, p. 23

a) Please explain how the list of cost impact categories was developed.

b) Please provide definitions for each cost impact category and explain how UMS Group determined whether a utility encountered that specific challenge.

c) Based on Table B-2 (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 23) is it correct to conclude that Toronto Hydro encounters more of the cost impacts than any other peer included in the study?

RESPONSE (PREPARED BY UMS):

a) The cost impact categories originated from the interviews with THESL personnel as UMG Group delved into the factors that could affect work productivity (and as such unit costs). UMS Group then vetted the resulting list with its internal subject-matter experts to identify similar non-THESL specific items. This exercise yielded the addition of the following cost impact categories: “Insufficient IT Enablement” and “Union Work Rules” as external factors that pose challenges to the utility industry.

b) In responding to the request to provide definitions for each cost impact category listed in Table B-2 of Exhibit 1B, it is UMS Group view that the descriptions themselves offer sufficient context to understand the issue. Furthermore, Table 1 below provides additional insight as to how these items actually affect unit costs.
Table 1: External Factors Impact Summary

<table>
<thead>
<tr>
<th>Cost Impact Category</th>
<th>Time</th>
<th>Workload</th>
<th>Coordination</th>
<th>Premium Pay</th>
</tr>
</thead>
<tbody>
<tr>
<td>Excessive Travel Time</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Road restrictions which limit working hours</td>
<td></td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>High Water Table</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Working next to energized lines (requiring dedicated observer, gloves, etc.)</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Requirements to perform work off hours (i.e., night/weekend)</td>
<td></td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Changed standards requiring rebuilds rather than like-for-like (i.e., clearances)</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Excessive switching requirements (i.e., to isolate on dual radial construction)</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Shoring requirements for UG work</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Limitations on tree trimming (e.g.; unusually tight clearances)</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Prior use of lead cables</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>High fault currents (impacting equipment sourcing)</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Paid duty for police presence on public roads</td>
<td></td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Extensive use of submersible transformers</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Environmental Regulations</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Insufficient IT Enablement</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Union Work Rules</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>City consent requirements (i.e., customer notification, restoration, progressive clean up, etc.)</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
</tr>
</tbody>
</table>

UMS Group included the above cost impact categories in the survey form (refer to Appendix F - Local Factors Tab of the UMS Group Benchmarking Study) where UMS Group requested each utility to select those factors that are applicable to their working environment.
c) If one were to count the number of items that apply to each utility, one might conclude that Toronto Hydro encounters more of the cost impacts than any other study participant. However, in applying adjustments based on this criterion, UMS Group grouped eight other utilities in the “high impact” category, and thus treated them similarly. Therefore, it would be more accurate to say that Toronto Hydro was among the top 50 percent in dealing with external factors that affect work productivity / unit costs.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 11:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B, p. 24

Preamble:

UMS Group states that a primary differentiator between Toronto Hydro and all other Ontario LDCs is population density. Review of Table B-3 (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 24) demonstrates that Seattle Light and Power is the only utility included in the peer group with similar population density. The second closest utility has a population density 35% lower than Toronto Hydro.

(a) Please explain the limitations to the study’s findings resulting from including only one utility in the peer group that has a population density similar to Toronto Hydro (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 24).

RESPONSE (PREPARED BY UMS GROUP):

(a) The premise of this question is incorrect. Population density is one of the primary differentiators when comparing THESL to other Ontario LDCs, but UMS Group considered several other factors that it views as more significant in the initial formation of a peer group panel. As explained in Appendix B of the UMS Group Benchmarking Study, “the sheer magnitude and scope of the differences in customer density, system configuration, and number of installed assets, combined with the external factors that are typically intensified in large urban areas, presents THESL as an outlier relative to all the other Ontario LDCs. Furthermore, UMS Group explained in its response to 1B-SEC-15 (c ii) that, with the exception of the recently formed

Panel: General Plant, Operations, and Administration
Alectra Utilities, UMS Group did not consider the other Ontario LDCs because it did not view them as scalable to the dimensionality and complexities of THESL’s business and operating environment. It is possible to normalize for population density; however, the same cannot be said for the scalability issue.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 12:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B, p. 27-33

a) UMS Group normalization for regional cost differences seems to include only wages (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 27). Please confirm whether this is correct and explain why other regional costs differences (e.g. input costs) were not considered for normalization purposes.

b) Please advise to what degree UMS Group applied the same unit cost benchmarking normalization methodology described in Appendix C in previous studies (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / pp. 27-33). If applicable, please explain how the normalization approach applied in the Toronto Hydro study differs from other studies completed by UMS Group.

c) Beyond those described in Appendix C, please advise whether other normalization factors exist that UMS Group considered but were not included in the study (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / pp. 27-33). If applicable, please provide these factors and explain why they were not included in the study.

d) Please advise whether UMS group believes that the normalization process would have benefited from Ontario LDC data (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / pp. 27-33).
e) Please identify the source(s) of the data used to populate Table B-2 (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 23) and Tables C-1 to C-10 (Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / pp. 29-33).

RESPONSE (PREPARED BY UMS):

a) In applying its normalization routines, UMS Group always starts with wages, as it constitutes the most basic differentiator when comparing costs across regions and other jurisdictional boundaries. The other grouping of normalizers (referred to in the study as “Difficulty Factors”) include other cost-related, regionally driven variables (particularly within those items categorized as “External Factors”), which include the following, but not limited to:

- Excessive Travel Time
- Road Restrictions
- Requirements to Work during Off Hours
- Limitations on Tree Trimming
- Environmental Regulations
- Union Work Rules
- City Consent Requirements

b) Conceptually, the normalization methodology adopted for this study coincides with that used in other studies, tailored to assure proper adjustments to those elements that affect unit cost comparisons. The following discussion summarizes this point:

- **Regional Cost Differences:** UMS Group used the same methodology as in the majority of its benchmarking efforts.
- **Accounting Practices:** Applied to efforts where UMS Group compares unit costs. Depending on the scope, higher level benchmarking studies (which
comprise the majority of our work) may look only at differences in policies around capitalizing vs. expensing costs.

- **Population Density**: Also factored in studies that assess service restoration during major storm events.

- **Underground Utility Congestion**: Considered when assessing the cost and performance levels at the asset level.

- **External Factors**: The level of detail for this study was commensurate with the task of looking at individual asset classes and specific maintenance programs. Higher-level studies may apply a “correction factor,” usually focused on the influence of the bargaining unit in driving overtime and work rules and the existence of unusual city ordinances.

- **Weather**: Applicability determined by the composition of the peer group (i.e.; the extent to which they experience similar weather), and the scope of the study.

- **Vegetation**: Particularly relevant when comparing overall O&M spending levels and programs where accessibility to the assets may be an issue.

The framework remains constant, but depending on the level of detail called for in a study and the specifics regarding the benchmarked utility, the level of rigor applied within these categories will vary.

Due to the scope and focus of the study, the uniqueness of an “Investor Owned Utility sized” municipality in a heavily populated area, and the composition of the peer group, UMS Group did not consciously omit any normalizing factors, and applied a level of detail beyond that of more typical UMS Group’s studies.
c) Please refer to UMS Group’s response to 1B-SEC-15 (c ii) for rationale in excluding Ontario utilities from the peer group. With respect to the question at hand, our criteria in selecting the peer group (outlined in UMS Group’s response to interrogatory 1B-SEC-15 (c i)) did not include benefiting the normalizing process. UMS Group apply normalizers to increase the likelihood of an “apples-to-apples” comparison when assessing dissimilar utilities (which is always the case). That said, had we selected an Ontario utility, there are a few factors that would have been the same (i.e.; regional costs, weather and vegetation), but nearly 30 percent of the utilities that comprised the peer group were evenly matched in weather and vegetation.

d) The completed survey forms formed the bases for the majority of data contained in Exhibit 1B, Tables B-2 and C-3 through C-10. Specific to each table:

- **Table B-2:** UMS Group assigned a level of difficulty (high, medium, or low) based on the number of external factors indicated as relevant by each utility.

- **Table C-1:** UMS Group applied regional cost adjustors based on a comparison of regional average wages provided by the Board of US Labor Statistics for the US utilities and municipalities and individual governmental provincial websites in Canada.

- **Table C-2:** UMS Group based the split between labor and non-labor costs on information contained within the UMS Group proprietary data bases used to store cost and service level performance data for our Global Learning Consortia.

- **Table C-3:** UMS Group assigned an adjustment factor based on the number of categories included in the unit cost calculation.

- **Table C-4:** The source for each column is included in the table in red font.
Table C-5: UMS Group applied the weightings and ranking scales based on similar approaches used in our Global Learning Consortia.

Table C-6: UMS Group assessed the applicability of asset categories and maintenance programs of the five factors that defined the level of difficulty in performing work.

Table C-7: Reflects an accumulation of the factors in preparation for our three-phased approach to normalization across the seven asset categories and four maintenance programs.

Tables C-8 through C-10: The unit cost information reflects that provided by each of the utilities via the survey form. Each table reflects the incremental application of normalization starting with Phase 1 (Raw Comparisons: Metric and Dollar Conversion), continuing with Phase 2 (Applying Regional Cost and Accounting Adjustments), and ending with Phase 3 (Applying Full-Scale Normalization).

Please refer to the actual worksheets in UMS Group’s response to interrogatory 1B-SEC-15 (f).
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 13:
Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 3

RESPONSE:

a) In 2017, following the submission of the 2016 DSP Implementation Progress measure results to the OEB, as part of the Electricity Distributor Scorecard submission, Toronto Hydro identified an error in its calculation of the 2016 reported result. The correction resulted in a change to the previously reported 2016 result – from 113 percent to 100 percent. This change has been reflected in the pre-filed evidence, see Exhibit 1B, Tab 2, Schedule 2, Page 3, Table 1, and was communicated to the OEB as part of the 2017 Electricity Distributor Scorecard submission process.

b) The decline in liquidity, as measured by the current ratio, between 2013 and 2014 was primarily due to greater utilization of short-term borrowings (revolving credit facility
and commercial paper program) in 2014 to finance capital and operating requirements. Between 2014 and 2017, liquidity remained relatively steady.

c) Please refer to Toronto Hydro’s response to interrogatory 1B-CCC-22.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 14:

Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 17-21

a) Please provide a list of the DSP measures that are being replaced and provide rationale for removing these measures (Exhibit 1B / Tab 2 / Schedule 2 / p. 17 / footnote 15).

b) Please advise whether the trend for planning efficiency (engineering and support costs) is expected to continue going forward (Exhibit 1B / Tab 2 / Schedule 2 / p. 21).

RESPONSE:

a) Please see Table 1 below for a list of the measures being replaced along with summary notes outlining Toronto Hydro’s reason for replacing each measure. As an overview, Toronto Hydro’s rationale for replacing the measures includes aligning measures with customer preferences and outcomes, and eliminating lower value or redundant.

Table 1: List of DSP measures being replaced

<table>
<thead>
<tr>
<th>Measure</th>
<th>Summary Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>MAIFI</td>
<td>As discussed in EB-2014-0116 (Exhibit 2B, Section C2.3.2), Toronto Hydro’s ability to measure MAIFI is limited and restricted by manual processes and incomplete SCADA coverage. Given the limitations, Toronto Hydro has removed this measure.</td>
</tr>
</tbody>
</table>
### Measure | Summary Notes
--- | ---
**CAIDI** | In light of the inclusion of SAIDI and SAIFI, Toronto Hydro’s position is that including CAIDI as a third measure would be redundant given that CAIDI is derived by dividing SAIDI by SAIFI. Utilities typically choose to report one of CAIDI or SAIDI.

**Outages Caused by Defective Equipment** | Given the inclusion of SAIDI and SAIFI Defective Equipment measures, this measure was replaced as it is less sophisticated (i.e. only tracks raw numbers of interruptions) and does not capture the customer experience (e.g. customer interruptions or customer minutes of interruption).

**Stations Connection Capacity Availability** | Given the inclusion of System Capacity Measure, which considers both station capacity and the availability of feeder breaker positions, this measure was replaced as it is less sophisticated. Stations with capacity may still be constrained by a lack of feeder positions, which will challenge large customer connections.

**Planning Efficiency** | The four efficiency measures were replaced as Toronto Hydro works towards developing a broad unit cost framework for measuring efficiency, productivity, and costs. Toronto Hydro is proposing to monitor unit costs for poles and vegetation management during the 2020-2024 period. Given that the unit cost framework contemplated naturally includes planning, supply chain, and construction elements, the continued inclusion of more granular measures is redundant.

Furthermore, Toronto Hydro’s experience with each of the measures was that each had substantial weakness such as considerable volatility for **Construction Efficiency**.

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1. *b)* Toronto Hydro expects the Planning Efficiency trend to continue in 2018 and 2019.

2. The reasons for the increase of approximately 2% over the four years between 2013 and 2017 are outlined in Exhibit 1B, Tab 2, Schedule 2, page 21 of 23.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 15:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, p. 7, 9

a) Please advise whether Toronto Hydro is aware if the same customers that provided their input in Phase 1 of the customer engagement process also provided their input in Phase 2 of the process (Exhibit 1B / Tab 3 / Schedule 1 / p. 7).

b) Please advise whether the costs associated with additional functionality of Toronto Hydro’s web offerings (e.g. MyTorontoHydro) are included in the costs proposed in the current application (Exhibit 1B / Tab 3 / Schedule 1 / p. 9).

RESPONSE:

a) Customers who participated in Phase 1 of the engagement were removed from customer lists and were not eligible to participate in the random-sampling element of Phase 2 of the engagement, including the workbook testing focus groups and telephone surveys. The primary objective of Phase 2 of this engagement was to gather feedback from the average customer in relation to Toronto Hydro’s proposed plan.

The online Customer Feedback Portal, however, created an open voluntary process that allowed all customers who wanted to be heard, including those who may have participated in Phase 1, an opportunity to express themselves. As such, the 10,346 customers who completed the Customer Feedback Portal could have participated in any other element of either Phase 1 or 2 of the customer
engagement. Because of the voluntary nature of this element of the engagement, it is not possible to identify participants who also participated in the randomly-recruited, representative elements, including the telephone surveys and focus groups.

b) The costs associated with additional functionalities of Toronto Hydro’s web offerings are not included in the costs proposed in this application.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 16:
Reference(s): Exhibit 1B, Tab 3, Schedule 1, Appendix A, p. 1, 13
Exhibit 1B, Tab 3, Schedule 1, Appendix 2.1 to Appendix A

a) Please confirm that Appendix 2.1 to Exhibit 1B / Tab 3 / Schedule 1 / Appendix A is what Toronto Hydro has termed the “workbook” throughout its customer engagement evidence.

b) Please provide the number of key account customers that participated in the Phase 2 customer engagement process (Exhibit 1B / Tab 3 / Schedule 1 / Appendix A / p. 13).

RESPONSE:

a) No. Appendix 3.1 of the referenced schedule is the “workbook,” and is synonymous with “Online Customer Feedback Portal.” Appendix 2.1 of the referenced schedule contains the results of the engagement that leveraged the workbook.

b) Please see Page 2 of Appendix 2.5 of the Innovative Report at Exhibit 1B, Tab 3, Schedule 1, Appendix A. All Key Account customers were invited to participate. 37 completed the survey.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 17:

Reference(s): Exhibit 1B, Tab 3, Schedule 5

a) Please file a response to any letters of comment currently on the public record for this proceeding.

b) Going forward, please ensure that responses are filed to any subsequent letters that may be submitted in this proceeding. All responses must be filed before the argument phase of this proceeding.

RESPONSE:

As part of this interrogatory response, Toronto Hydro has provided responses to all public letters of comment currently on the record. As part of its evidence update, it will also include the letters and its replies at Exhibit 1B, Tab 3, Schedule 5, and once again update that section with any additional letters and replies prior to the argument phase of the proceeding.

Toronto Hydro notes that a number of the letters of comment received to-date were submitted either before or after the community meetings for this application (November 22 through December 6). Toronto Hydro did not have access to the list of attendees for those meetings, so unless they have self-identified as a community meeting attendee, it is not possible for Toronto Hydro to identify which of these individuals attended the community meeting, and may or may not be responding to what they heard from the utility, the OEB, or others at the community meetings. For that reason, unless the
commenter has self-identified as a community meeting attendee, Toronto Hydro has responded to each letter assuming that the writers were not in attendance at the community meetings. Toronto Hydro apologizes to the authors of the letters if it is repeating something that they may have already heard from the utility or others during the community meetings, and encourages any and all customers to contact Toronto Hydro at any time should they have questions, comments or concerns.

https://www.torontohydro.com/sites/electricsystem/Pages/ContactUs.aspx

Please also see the process and results for Toronto Hydro’s customer engagement activities, including those related to this application: Exhibit 1B, Tab 2, Schedule 1.

Letter of Comment: Dean Lancaster: October 4, 2018

I do not believe Toronto Hydro has sufficiently informed the public on why rates are increasing. Rates should be decreasing assuming Toronto Hydro is operating in the interest of the people of Toronto, and any rate increase should be carefully considered along with supporting data to provide evidence as to the reasoning behind rate increases. Toronto Hydro should be requested to justify its rates vs. other similar jurisdictions with a similar power distribution model (i.e. benchmarking against other Hydro-power majority source providers) along with exploring any opportunities for cost reduction through modernization etc. I believe careful regulation and transparent accounting practices are vital to ensuring a "good deal" for the people of Ontario within our current energy operating model - and with today's data-driven accounting platforms, this should be very easy to implement whilst balancing regulatory burden on Toronto Hydro.

Toronto Hydro Reply

Dear Mr. Lancaster,
Thank you for your letter of comment. Toronto Hydro recognizes your frustration in lacking access to information about how we have informed the public on why rates are increasing, and your interest in us supporting the proposed increase with data and evidence.

Toronto Hydro has taken a number of steps to not only inform, but also engage the public about the amount of the proposed rate increase, and why we believe this plan achieves the appropriate balance between factors such as price, safety, reliability, and service. In addition to our ongoing customer engagement activities, as part of developing our plan and having that plan tested by the Ontario Energy Board in an open public process, Toronto Hydro heard from over 10,000 customers, through channels that include:

- Phase 1 customer engagement (2016/17): we asked for input and feedback from customers about their needs, priorities and outcomes they value – we used the results to help develop our business plan
- Phase 2 customer engagement (2018): before we filed our business plan with the Ontario Energy Board, we went back to customers to confirm that we correctly understood their input from phase 1, and then asked for additional customer input and feedback on the plan itself (including costs of the plan). Approximately 2/3 of customers supported Toronto Hydro’s plan, or one that does even more to improve services.
- Community Meetings (2018): after we filed our business plan with the Ontario Energy Board, we attended six community meetings between November 22 and December 6, 2018 to make a presentation on our plan (including the costs), receive feedback from customers and others in attendance, and answer questions.

Toronto Hydro’s costs take up approximately one third of the average residential customer’s bill. As a result of Toronto Hydro’s five year plan for 2020-2024, a typical
residential customer can expect an average annual increase of 1.7% on the Delivery line of the bill, and less than half of one percent on the total electricity bill. We have supported our request for this increase with approximately 4,300 pages of data and evidence filed with the Ontario Energy Board, including many details about our accounting assumptions and practices.

Toronto Hydro believes that the proposed rate increase is necessary to keep the lights on, maintain a grid that provides a safe source of electricity, and ensure that we are a steward of long-term service and value for our customers. Factors driving this rate increase include deteriorating infrastructure, a growing city, more extreme weather, workforce retirements and renewal, and technology advancements including protecting against cyber threats.

We’re always looking for ways to minimize cost and rate increases through finding productivity and efficiencies in our plans and work. For example, as part of reducing our facilities footprint in Toronto, we consolidated from 7 operating centers down into 4. As part of this consolidation, we sold properties, and are returning proceeds of close to $140M to customers to help reduce bills.

As part of our business plan, Toronto Hydro asked external experts to assess our performance, including benchmarking with respect to productivity, reliability, and unit/cost efficiency. The results of those studies (which are publicly filed with our plan) demonstrate that Toronto Hydro’s performance is similar or better than peer utilities.

Finally, Toronto Hydro took what it heard from customers about their priorities, and used this to create a customer-focused outcomes framework to measure its performance during the plan. As part of this plan, we propose to publicly report annually on how we’re
performing against over 40 unique measures that relate to our goals and objectives –
measures such as how frequently you lose power, and when you do lose power, how long
it takes us to get it back on.

If you are interested in learning more about Toronto Hydro’s proposed plan, the
executive summary of Toronto Hydro’s application to the Ontario Energy Board may be a
helpful document to begin with, and is available at Exhibit 1B, Tab 1, Schedule 1.

Letter of Comment: Lilly McIsaac: November 20, 2018
I object to rate changes and believe that ratepayers deserve to have more options
regarding electricity use and billing. As a homeowner, I do not require a smart meter to
tell me when to use my electricity and I never consented to time of use rates or to having
a smart meter (RF) emitting device installed on my property. I have developed a disability
called microwave sickness which prevents me from being in areas where there are
wireless and radio frequencies. It has gotten to the point where I cannot even live
comfortably in my own home because I have: headaches (particularly tension headaches
along the sides of the head and temple area, heart palpitations and a pressure in the
chest (a feeling that the heart wants to jump out of the chest while at the same time the
chest is being stepped upon), skin burning, redness, rashes and tingling (particularly on
the face and arms), difficulties sleeping (sleep is interrupted, light, dreamless and leaves
the person feeling tired in the morning), Tinnitus (ringing in the ears), fatigue and
tiredness during the day (even after many hours of sleep, tiredness pervades the day),
and cognitive decline (memory and concentration difficulties – a “brain fog”. All of these
symptoms either disappear or get better when I am in an environment without wireless
and radio frequencies, but they return when I am home. People who have symptoms
form microwave radiation exposure need accommodation and the ability to opt out of
the smart meter / time of use billing without additional costs to do so. I would like
Toronto Hydro to offer an opt out for people with disabilities due to radio frequency and microwave (EMF) exposure such as myself. We deserve to live in a safe home without being penalized for asking that the meter be an analogue meter and one which does not emit harmful emissions. The public has not seen any benefits to having a smart meter and in fact, the smart meter program increased costs for consumers, yet no one has seen any benefit, except for the electricity providers who saved on the cost of employing meter readers. That savings has not been passed on to consumers, not have consumers seen a decrease in electricity bills due to having a smart meter. Our smart meter is "on" all of the time - even when we turn off our electricity inside our home. The signals wake us up every hour at night and prevents us from getting proper sleep. We have tracked this and it happens at approximately the same time every night. We would like the OMB to change the billing to allow for an opt out of the smart meter program and not agree to more rate increases. Thank you.

Toronto Hydro Reply

Dear Ms. McIsaac,

Thank you for your letter of comment. Toronto Hydro is sorry to hear about your experience, which we understand must be difficult.

Toronto Hydro uses a smart meter system that uses wireless technology to deliver the data from each meter to our billing system. Each smart meter has a low power transmitter that communicates with a device known as a gatekeeper, which in turn delivers the meter reading data to our billing system.

Toronto Hydro’s customers have identified safe operation of the distribution system as one of their top three priorities. Toronto Hydro will only install smart meter models that have been extensively tested by the manufacturer and clearly demonstrate Radio
Frequency ("RF") emissions that are below the City of Toronto precautionary recommendations and the Health Canada Safety Code 6 guideline.

These meters are valuable tools in maintaining the safety and reliability of the grid, as they assist distributors in identifying outages, including during major weather events.

Toronto Hydro is not able to offer you the ability to opt-out of Time of Use rates or using a smart meter, as they are required by provincial law and regulation. Although Toronto Hydro is able install a non-RF transmitting smart meter equipped with a regular telephone connection for you. There is however a cost associated with the installation of the telephone connection and its monthly operation, currently $201.77 and $23.13/month respectively.

Regarding rate increases and our plan to invest in the grid, you may also be interested in our reply to Mr. Lancaster’s letter of October 4, 2018.

Letter of Comment: Beverly Brooks: November 22, 2018

This session was extremely disappointing. Neither the OEB or Toronto Hydro has any answers to questions. The first gentleman who gave a presentation had some excellent questions – the same questions that he had in a previous occasion. No answers were provided and he commented that he had never received answers to his previous questions. I strongly oppose the rate increases – nothing I heard tonight justifies the increases.

Toronto Hydro Reply

Dear Ms. Brooks,
Thank you for your letter of comment. Toronto Hydro is sorry that you were disappointed with the community meeting presentations and responses to questions by OEB and Toronto Hydro staff. Recognizing the value of your time, if you have any specific feedback on how we in particular can do better, we would appreciate receiving that.

Regarding the gentleman who provided the presentation and asked questions, we believe you are speaking about Mr. Hann. We did not have the information readily available to answer those questions at the community meeting, and even if we had, providing the answers would have taken a number of hours and eliminated the time for other customers to provide their feedback and ask questions at the meeting. As you may recall, during the community meeting, we committed to providing written answers to Mr. Hann’s questions on the public record as part of our application process before the Ontario Energy Board. As the OEB has since granted Mr. Hann intervenor status in this proceeding, he has now filed those and other questions in writing and Toronto Hydro is responding to them as part of the public record at the same time as filing this reply to your letter of comment.

Regarding rate increases and our plan to invest in the grid, you may also be interested in our reply to Mr. Lancaster’s letter of October 4, 2018.

Letter of Comment: Christine Douglas: November 22, 2018

Please see the attached. I prepared a chart which is attached. The charges are in addition to my usage. As a single individual I am paying as much as a neighbour who is using hydro electricity – air conditioner, washer dryer, heat & I am paying as much as she and her family of 4 people.

Attachment:

Toronto Hydro Charges
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</table>
Dear Ms. Douglas,

Thank you for your letter of comment. Toronto Hydro apologizes that you are finding it difficult to understand your charges compared with those of a neighbour, and we recognize that it is complicated to do so. As you may know, the methodology and

Panel: General Plant, Operations, and Administration
presentation of the electricity bill in Ontario is largely set by provincial law and regulation, and there are a lot of complex charges and credits that go into your bill each month.

Thank you for preparing a table setting out your charges over several years, however without additional information about your and your neighbour’s households, plus her consent for privacy purposes, we cannot give you a precise explanation of what is happening with your bill versus hers. Nevertheless, Toronto Hydro’s experience is that there are a few common drivers for questions such as yours, relating to the different types of charges on the bill.

The Delivery Line:
Your column labelled charges represents the delivery line on the bill, which represents the cost of getting power from generators to your home, and ensuring electricity is available when you need it. The delivery line is made up of a number of costs (some ours and some related to others), such as:

- Toronto Hydro costs: this is your distribution charge, which is invested into the local distribution grid to maintain safety and reliability of our infrastructure, help support a growing city, and enable us to plan for and respond to extreme weather. This part of your bill may also include certain credits or charges related to temporary, unpredictable, or deferred costs for delivering electricity and services to customers.

- Non-Toronto Hydro costs:
  - Transmission rates which we collect on behalf of companies such as Hydro One
  - Pass-through charges in the form of rate riders that credit customers or collect from customers historic over-charges or under-charges on parts of
the bill related to transmission, generation and other commodity costs, 
and other provincially-administered charges.

Your Overall Bill

Provincial and OEB law and regulation mean that your delivery line and overall bill is partially based on your overall consumption. This means it includes both charges that do change depending on how much electricity you use (called variable charges) and those which don’t change depending how much electricity you use (called fixed charges). The fixed portion of the charge helps cover the costs of the poles and wires that are available 24/7 to deliver electricity to your home, on demand. Because of this, changes in the amount you pay on your delivery line often do not move by the same amount, or even in the same direction, as changes in how much electricity you use (called kilowatt hours or kWh).

Some of the common factors you may wish to consider in addition to those mentioned in your letter that influence the amount of energy usage and contribute to differences in charges between households include:

- Size and type of home
- Upgraded insulation or windows
- Heating and cooling factors such as gas or electric heating or air conditioning systems, baseboard or portable heaters, thermostat settings, heated floors, heated driveways, pool pumps, etc.
- Gas or electric water heating
- Types and frequency of appliances in use, and their energy efficiency ratings

We hope this information provides some additional insight into what may be driving the difference in charges. For further background on rates, please visit Toronto Hydro’s website at [www.torontohydro.com/rates](http://www.torontohydro.com/rates), or for additional tips on managing energy usage, please visit [http://www.torontohydro.com/saveonenergy](http://www.torontohydro.com/saveonenergy).
Letter of Comment: Weston Trott: November 22, 2018

More transparency on Rates – How are distribution rates calculated? Show fixed and variable cost on the bill – Bill is not transparent.

Is the system working to allow utilities to ask and then reduce after the ask? It seems it does not work to have the utilities ask for the sky why not keep them honest from the beginning? The stats for reducing by 38% shows it does not work the current ask system.

Toronto Hydro Reply

Dear. Mr. Trott,

Thank you for your letter of comment. Toronto Hydro recognizes that the bill is complicated, and that you are frustrated by the way that the charges are calculated. As you may know, the methodology and presentation of the electricity bill in Ontario is largely set by provincial law and regulation, and there are a lot of complex charges and credits that go into your bill each month.

On the Toronto Hydro website we try to break down the bill and explain it as best as we can:


Please see our reply to Ms. Douglas’ letter of November 22, 2018 for your questions regarding distribution rates and the way charges are calculated.

Regarding your interest in how our plan has been developed and how the OEB will test it and ensure it strikes the right balance, we have supported our plan with 4,300 pages of evidence and data, and that plan is now before the regulator in a public process where
the OEB, customer advocacy groups and other experts are scrutinizing and challenging it. Please also see our reply to Mr. Lancaster’s letter of October 4, 2018.

Letter of Comment: An Ge: November 26, 2018

I’m very concerned and confused about your Delivery Charge. Delivery Charge should not be a fixed rate. It should be determined by the actual usage. The higher usage, the higher the delivery charge; the lower usage, the lower the delivery charge should be. Not on some fixed nonsense charge, IF someone is away from home for, say 6 mnths, barely have usage on the energy, only incur fixed cost of delivery charge. So re-define the delivery charge.

Toronto Hydro Reply

Dear Mr. Ge,

Thank you for your letter of comment. Toronto Hydro recognizes that the bill is complicated, and that you are frustrated by the fixed charges in the Delivery line. Provincial and OEB law, regulation and methodology for charges mean that your delivery line and overall bill is partially based on your overall consumption and partially based on fixed charges. This means it includes both charges that do change depending on how much electricity you use (called variable charges) and those which don’t change depending how much electricity you use (called fixed charges). The fixed portion of the charge helps cover the costs of the poles and wires that are available 24/7 to deliver electricity to your home, on demand.

Please see our reply to Ms. Douglas’ letter of November 22, 2018 regarding the specific concerns that you raise in your letter regarding the delivery charge.
Letter of Comment: Caleb Kouahou: November 26, 2018
I’m concerned by the transmission poles (high tension) crossing residential area (like South Etobicoke) with risk of cancer.
Also the risk related to 50+ old nuclear plant and the safety gap for example populations not sensibilised or distributed the RADBLOCK pills.

Toronto Hydro Reply
Dear Mr. Kouahou,
Thank you for your letter. Toronto Hydro is the local distributor of electricity in Toronto, and owns and operates the poles and wires that bring electricity to your home. The transmission lines and nuclear plants are owned and operated by others such as Hydro One and Ontario Power Generation.

For more information about your local grid and our plan to invest it in, please see our reply to Mr. Lancaster’s letter of October 4, 2018.

Letter of Comment: Sijing Liu: November 26, 2018
The Delivery Charge on a typical Residential Bill should NOT be set as a fixed rate. It should be billed based on the actual usage of energy. It’s not fair to set delivery charge a set rate. We use only <$20 energy bill, but our delivery charge is always around >$35. Is this Normal for a typical bill?
Anyways, delivery charge needs restructured however it’s determined.

Toronto Hydro Reply
Dear Ms. Liu,
Thank you for your letter of comment. Toronto Hydro recognizes that the bill is complicated, and that you are frustrated by the fixed charges in the Delivery line.
Provincial and OEB law, regulation and methodology for charges mean that your delivery line and overall bill is partially based on your overall consumption and partially based on fixed charges. This means it includes both charges that do change depending on how much electricity you use (called variable charges) and those which don’t change depending how much electricity you use (called fixed charges). The fixed portion of the charge helps cover the costs of the poles and wires that are available 24/7 to deliver electricity to your home, on demand.

Please see our reply to Ms. Douglas’ letter of November 22, 2018 regarding your comments regarding delivery charges. For more information about your local grid and our plan to invest it in, please see our reply to Mr. Lancaster’s letter of October 4, 2018.

Letter of Comment: Slobodan and Dobrila Vujnovic: November 26, 2018

I participated in TIME OF USE for many years being probably among the first to apply. Now my husband Slobodan age 86 and myself Dobrila age 83 are not able to adjust our use no more. It puts in need to use electricity when it is the most expensive increasing our financial burden as well as time of use schedule loosing any purpose. We are not only old but old timers as well and know and participate in all possible means to save electricity not only for people of Ontario but for our own budget.

Please assist.

Toronto Hydro Reply

Dear Mr and Mrs. Vujnovic,

Thank you for your letter of comment. While Toronto Hydro recognizes that not all customers favour Time of Use rates, Toronto Hydro is required by provincial law and regulation to bill customers in accordance with that pricing structure. To help customers
better manage their energy costs, please visit Toronto Hydro’s website for additional information and tips.

http://www.torontohydro.com/saveonenergy

Please see our reply to Ms. Douglas’ letter of November 22, 2018 regarding delivery charges. For more information about your local grid and our plan to invest in it, please see our reply to Mr. Lancaster’s letter of October 4, 2018.

Letter of Comment: Bill Gaw: November 29, 2018

Thank you for the opportunity to hear about and question Toronto Hydro's Rate Application for 2020-2024 at the Scarborough CivicCentre Community Meeting on November 26.

I have no issue with the proposed cost recovery rates, but I notice a couple of elements in the application that seem odd and might bear close examination by the Board. "approximately a quarter of the utility's asset base continues to operate beyond useful life..." and "continued investment is required to ensure there is no deterioration in recently stabilized system performance" do not suggest a strong plan to eliminate the "beyond" part, but simply to maintain the current level of stuff "past their useful life" and accept whatever level of outages that implies.

I think it would be more appropriate to declare an ambition to reduce the "population of assets beyond their useful life" to less than 1% by 2024, and plan to drive it down from that level going forward until we bump into the structural minimum.

In section D 3.1.2 Asset Replacement Policy, "Toronto Hydro does not have a dedicated proactive renewal strategy for overhead conductors. Where appropriate conductors are replaced as part of a planned area rebuild or reactively upon failure due to age..."

Given the illustrated property damage, and potential personal injury risk due to "porcelain pothead failure" plus the know-how to replace "legacy porcelain insulators
with new polymeric equivalents”, a "dedicated proactive renewal strategy" could be a
good thing - perhaps it would even reduce the maintenance expense of "washing the
porcelain insulators every six months."
Similarly, if we recognize "below ground rotted poles" and "car accidents" as known risks
of catastrophic pole failures, replacement of old wooden poles with new wooden poles
rather than composite, concrete, or steel poles, and leaving the new poles unprotected
by concrete-steel guard posts, are questionable practices. Those new wooden poles are
subject to Toronto’s belligerent woodpeckers, unnecessarily reduce our forest carbon
absorption somewhere in Canada, and maintain a continuing risk of pole fires.
I did not see a compelling justification for choosing wooden poles going forward.
The argument that "removed assets are typically refurbished and kept as spares due to
the scarcity of these obsolete asset types" seems seriously dubious. It might make at
least as much sense to chuck the obsolete stuff and invest the savings from refurbishment
expenses into fixing the next repair with current standard equipment. That might also
conveniently drive down the inventory of obsolete assets that will need continued
investment in the future.

Toronto Hydro Reply

Dear Mr. Gaw,
Thank you for your letter, and for your support of the proposed rate increase. We
acknowledge your preference for a plan that would:

- do more to reduce the population of assets beyond useful life to less than 1% by
  2024 (compared with Toronto Hydro’s current age profile at approximately a
  quarter of assets past end of useful life);
- eliminate the practice of using refurbished assets removed from service for spare
  parts and instead redirect the expenses of refurbishment (and inventory) to
  additional investment;
• create a dedicated proactive renewal strategy for areas such as overhead
  conductors (e.g. porcelain insulators); and
• eliminate wooden poles as a replacement option.

Toronto Hydro has developed and refined its plan taking into account customer feedback
that limiting price increases was a paramount concern, to the degree that doing so would
not adversely affect service performance, and that performance would improve in certain
areas. This means that our plan does not include all the reasonable funding requests that
it assesses are appropriate given the needs of the system. We constrained our capital
plan, even though a higher level is preferable from an asset management perspective to
better manage certain elevated asset risks.

For more information about your local grid and our plan to invest it in, please see our
reply to Mr. Lancaster’s letter of October 4, 2018.

Letter of Comment: Bruce Bryden: December 4, 2018
Allow me to get all the information on my bill as on my Micro fit Meter Credit, and not
have to use a computer to gain this information.

Toronto Hydro Reply
Dear Mr. Bryden,
Thank you for your letter of comment. Toronto Hydro recognizes that the bill is
complicated, and that you are frustrated by the way that the information is presented. As
you may know, the methodology and presentation of the electricity bill in Ontario is
largely set by provincial law and regulation, and there are a lot of complex charges and
credits that go into your bill each month. As a MicroFIT customer, we appreciate that you
may want additional billing information and as you may be aware, MicroFIT generation
detail is available on Toronto Hydro’s PowerLens web portal. Accessing the portal may be
an added step, however, it does provide a wealth of account specific information useful
for validating your charges and managing your electricity usage. To reduce this effort, we
are planning an enhancement that will enable customers to enroll in auto receipt of
regular emails providing information specific to their needs.

For more information about your local grid and our plan to invest it in, please see our
reply to Mr. Lancaster’s letter of October 4, 2018.

Letter of Comment: Joe Gudinskas: December 4, 2018
In the light of how Hydro is going wild, these meetings are very useful.

Toronto Hydro Reply
Dear Mr. Gudinskas,
Thank you for your letter, and we appreciate that you found the community meeting
useful.
For more information about your local grid and our plan to invest it in, please see our
reply to Mr. Lancaster’s letter of October 4, 2018.

Letter of Comment: Josephine Ng: December 4, 2018
The changes I experienced are fine
1. Monthly bills
2. Summer deals
   etc.
I did climate change research for a project and I knew nothing about the OEB. By coming
to this meeting I can clarify the things that matter. I feel better about consuming
electricity and conserving energy. I’m a new Toronto Hydro customer, but it was really important to make me be at the meeting. I feel appreciated to be someone that was here. So all I can think about now is that I pay hydro and get it at home and that’s great! Thank you.

Toronto Hydro Reply
Dear Ms. Ng,
Thank you for your letter, and we appreciate that you found the community meeting to be a positive experience, and that your experience with your bill, conservation and incentives has also been positive.

For more information about your local grid and our plan to invest it in, please see our reply to Mr. Lancaster’s letter of October 4, 2018.

Letter of Comment: Paul Stuewe: December 4, 2018
The proposed changes will have no impact on my family. However, I am very concerned about how people on fixed incomes, and people who are just getting by, will be affected. I hoped that this would be addressed during this meeting; it was certainly raised, but I wasn’t impressed by the somewhat vague response of the OEB chairman.

Toronto Hydro Reply
Dear Mr. Stuewe,
Thank you for your letter and your interest in help for those needing assistance paying their bills. A number of assistance programs are available with different types of support ranging from helping customers reduce their electricity usage to on-bill credits to help offset monthly charges. The following are programs available for eligible customers:
- The Independent Electricity System Operator’s Home Assistance Program provides energy-efficient upgrades from free light bulbs to appliances;

- The Ontario Energy Board’s Low-Income Energy Assistance Program (LEAP) provides a one-time emergency grant to help pay your electricity bill;

- The Ontario Energy Board’s Ontario Electricity Support Program (OESP) provides an on-bill credit each month to qualifying households. In 2017, this program was expanded to include more eligible households, and;

- The provincial Affordability Fund provides free upgrades to help lower electricity costs.

Toronto Hydro uses a number of communication channels to make customers aware of these programs. Additional information is available at [www.torontohydro.com/help](http://www.torontohydro.com/help) or through the Customer Care team at 416-542-8000.

**Letter of Comment: Greg Pimento: December 10, 2018**

I attended the public meeting in Etobicoke on Dec 6th and would like to go on record as not supporting Toronto Hydro’s application for a rate increase.

When compared against our natural gas supplier Toronto Hydro does not do well. This is from both a cost and level of service perspective. Both services are regulated but the differences in their structures make for the differences we’ve experienced as consumers, to my judgement. I pick natural gas over hydro every time.

Given the growth in Toronto I do not understand the need for the increased rate, unless the existing rate payers are subsidizing the capital costs of new connections. I also find the inflexibility with the acceptance of micro-grids bothersome and poorly justified by Toronto Hydro.
I know it is not under Toronto Hydro’s or the OEB’s control but I want to also go on record that the level of Global Adjustment is totally unacceptable. Incremental power production rates are close to 3 cents whereas the GA is three time that amount. Poorly managed is the only conclusion I can determine.

I would be interested in helping in any way feasible knowing that the task at hand is massive at best.

Thanks for the opportunity to attend and see the presentations.

Best Regards,
Greg Pimento

Toronto Hydro Reply
Dear Mr. Pimento,
Thank you for your letter, and we appreciate that you found the community meeting to be a positive experience.

With respect to your concern about the differences in electricity and natural gas pricing, there are significant differences between the costs of generation and distribution of these fuel types, which leads to differences between costs, prices and services. For more information about the drivers of Toronto Hydro’s costs, our plan to invest in the grid, and our performance and efforts to mitigate your rate increases, please see our reply to Mr. Lancaster’s letter of October 4, 2018.

Regarding your questions about whether ratepayers are subsidizing developers and new customers, the Ontario Energy Board has regulations designed so that each type of
customer pays their own way and cross-subsidization is avoided. This includes calculations around capital costs and a complete economic evaluation designed to ensure developers pay their fair share. Toronto Hydro has a responsibility to connect customers to the grid and make sure enough capacity exists so that those new customers can receive a safe and reliable source of power.

Regarding your comments about the unacceptability of the global adjustment, we appreciate your recognition that this is not included in our part of the bill and we do not control it.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 18:
Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 5

Preamble:
Toronto Hydro states:

“The OEB decided on a new methodology for the I-factor. The I-factor is based on a 30/70 weighting of labour and non-labour sub-indices and is updated annually. The labour sub-index is determined by changes in the average weekly earnings of Ontario workers, and the non-labour sub-index is determined by changes in the Canada Gross Domestic Product Implicit Price Index for final domestic demand.

Toronto Hydro proposes to use the OEB’s I-factor in its [Custom Price Cap Index] CPCI. As the value for the I-factor is updated annually, Toronto Hydro will incorporate the updated value into its CPCI to appropriately adjust base distribution rates for the following year” (Exhibit 1B / Tab 4 / Schedule 1 / p. 5).

The current electricity distribution price cap plan has been in place for five years (2014 to 2018), and 2019 will be the sixth year. The OEB may review and update the plan at some point in the future. Changes to parameters such as inflation could be considered in such a review.

a) In the event that the OEB were to change its inflation measure, please provide Toronto Hydro’s views as to whether it considers it appropriate to continue with the 2-factor inflation factor for its Custom IR plan.
RESPONSE:

a) In the event that the OEB were to change the inflation measure used for the I-factor in IRM plans, Toronto Hydro would need to assess at the time the applicability of that inflation measure for inclusion in its CPCI. The utility has proposed its CPCI taking into account the conditions, including variable methodologies and values, as are detailed throughout its evidence in this application. Toronto Hydro does not know the nature of any changes the OEB may make, which would be necessary to assess whether those changes would be appropriate in the context of the utility’s CPCI rate mechanism and the need for funding its underlying capital and operational plans.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 19:

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

Preamble:

Toronto Hydro notes that the OEB adopted a base X-factor of 0% (excluding any stretch factor based on the annual cost benchmarking commissioned by the OEB for all electricity distributors).

Toronto Hydro states that it: “… proposes to embed the OEB’s productivity with its implicit incremental stretch factor unchanged within the proposed CPCI, fixed throughout the term of the ratemaking period” (Exhibit 1B / Tab 4 / Schedule 1 / p. 6).

a) Please advise whether Toronto Hydro’s proposal is to fix the X plus stretch factor in its PCI formula at 0% + 0.3%, or that, if the OEB were to adopt a different base X-factor due to a generic review, Toronto Hydro would adopt the updated base X-factor? Please explain your response.

RESPONSE:

a) Please refer to Toronto Hydro’s response to interrogatory 1B-Staff-18.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 20:

Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 6-7
OEB Handbook for Utility Rate Applications, p. 26
Empirical Research in Support of Incentive Rate-Setting: 2017
Benchmarking Update, August 2018, Pacific Economics Group LLC

Preamble:

Toronto Hydro proposes to use a custom stretch factor of 0.3%, based on the total cost benchmarking study of Power Systems Engineering (PSE).

Pacific Economics Group LLC (PEG) annually conducts a total cost benchmarking on behalf of the OEB, which is used to determine the cohort and stretch factor for all Ontario LDCs for Price Cap Incentive Rate-setting (IR) and similar rate adjustment mechanisms.

PEG’s most recent analysis, for 2019 rate adjustment applications, was issued by the OEB on August 23, 2018. In Table 4 on page 21 of that report, Toronto Hydro is assigned a stretch factor of 0.6% (cohort 5) based on 2015-2017 actual data. Toronto Hydro has also typically been assigned cohort 5 in PEG’s analyses in the past.

With respect to Custom IR proposals, the OEB’s Handbook for Utility Rate Applications (the Rate Handbook), issued October 13, 2016 states on page 26, with respect to the OEB’s expectations for Custom IR plan proposals, that:

It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility’s ability to customize the approach
to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.

Toronto Hydro’s proposal for the Price Cap Index (PCI), net of the capital and growth factors, is $0\% + 0.3\%$. Under the standard Price Cap IR option, Toronto Hydro’s IPI would be $0\% + 0.6\%$ based on the estimated stretch factor for 2019 and earlier years.

a) Please explain how Toronto Hydro’s proposed 2020-2024 Custom IR plan satisfies the OEB’s expectation in the Rate Handbook quoted above.

**RESPONSE:**

a) The alternative total cost benchmarking model prepared by PSE for Toronto Hydro was undertaken to provide an approach that is econometric in nature (similar to PEG’s model), statistically significant, and includes an expanded data set intended to help inform the OEB’s analysis of Toronto Hydro’s performance. The PSE work and corresponding report was also undertaken to address the comments about Toronto Hydro’s cost benchmarking set out in the OEB’s Decision in Toronto Hydro’s 2015-2019 Rate Application (EB-2014-0116). While PSE’s benchmarking results put Toronto Hydro in the median cohort - which results in a lower stretch factor than the stretch factor that the OEB has established for electricity distribution IRM applications - Toronto Hydro respectfully concludes this is appropriately driven by the data and analysis detailed in PSE’s report, will provide a revenue requirement necessary to fund the utility’s proposed plan, and contributes to Toronto Hydro’s productivity incentives. Please also see Section 3.2 of Exhibit 1B, Tab 4, Schedule 1.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 21:
Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 8-9

a) Please provide detailed calculations for the approved 2016-2019 capital factors (C-factors) similar to what is provided in Table 2 (Exhibit 1B / Tab 4 / Schedule 1 / p. 9).

b) Please provide the original applied for 2016-2019 C-factors from the 2015-2019 Custom IR proceeding. Please provide the detailed calculations as requested in part (a) of this question.

c) Please provide the C-factors that would have been in place during the 2016-2019 period if cost of capital had been updated in each year as follows:

   i. Updated only for the OEB-approved ROE;

   ii. Updated for OEB-approved ROE and an updated weighted average cost of debt in each year.

RESPONSE:

a) See Table 1 below for the calculation of Cn-factor approved for the period 2016-2019.
Table 1: Calculation of Cn 2016-2019 (approved version) ($ Millions)

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ratebase</td>
<td>3,232.0</td>
<td>3,575.2</td>
<td>3,890.2</td>
<td>4,075.3</td>
<td>4,253.8</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>79.2</td>
<td>87.7</td>
<td>95.4</td>
<td>99.9</td>
<td>104.3</td>
</tr>
<tr>
<td>Return on Equity</td>
<td>120.2</td>
<td>133.0</td>
<td>144.7</td>
<td>151.6</td>
<td>158.2</td>
</tr>
<tr>
<td>Depreciation</td>
<td>206.02</td>
<td>218.8</td>
<td>242.2</td>
<td>257.7</td>
<td>275.0</td>
</tr>
<tr>
<td>PILs/Taxes</td>
<td>25.0</td>
<td>16.9</td>
<td>24.3</td>
<td>40.2</td>
<td>45.7</td>
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<tr>
<td>Capital-related RR (A)</td>
<td>430.5</td>
<td>456.3</td>
<td>506.6</td>
<td>549.5</td>
<td>583.2</td>
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<tr>
<td>OM&amp;A</td>
<td>243.9</td>
<td>247.6</td>
<td>251.3</td>
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<tr>
<td>Revenue Offsets</td>
<td>-41.3</td>
<td>-41.9</td>
<td>-42.5</td>
<td>-43.2</td>
<td>-43.8</td>
</tr>
<tr>
<td>Total RR (B)</td>
<td>633.1</td>
<td>662.0</td>
<td>715.4</td>
<td>761.4</td>
<td>798.3</td>
</tr>
<tr>
<td>Cn = (Ayx - Ay_{(x-1)}) / B_y(x-1)</td>
<td>4.07%</td>
<td>7.60%</td>
<td>5.99%</td>
<td>4.43%</td>
<td></td>
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</tbody>
</table>

b) See Table 2 for the calculation of Cn-factor from application version for the period 2016-2019.

c) i) See Table 3 below for the calculation of Cn-factor if ROE is based on OEB approved annually instead of 9.3% which is approved ROE for the period 2016-2019 of Toronto Hydro’s CIR.
### Table 3: Calculation of Cn 2016-2019 (if ROE is OEB approved) ($ Millions)

<table>
<thead>
<tr>
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<td>95.4</td>
<td>99.9</td>
<td>104.3</td>
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<tr>
<td>Return on Equity</td>
<td>120.2</td>
<td>131.4</td>
<td>136.6</td>
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<td>152.8</td>
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<td>Depreciation</td>
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<tr>
<td>PILs/Taxes</td>
<td>25.0</td>
<td>16.3</td>
<td>21.4</td>
<td>38.5</td>
<td>43.8</td>
</tr>
<tr>
<td>Capital-related RR (A)</td>
<td>430.5</td>
<td>454.2</td>
<td>495.6</td>
<td>542.8</td>
<td>575.8</td>
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<tr>
<td>OM&amp;A</td>
<td>243.9</td>
<td>247.6</td>
<td>251.3</td>
<td>255.1</td>
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<td>Revenue Offsets</td>
<td>-41.3</td>
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<td>-43.2</td>
<td>-43.8</td>
</tr>
<tr>
<td>Total RR (B)</td>
<td>633.1</td>
<td>659.9</td>
<td>704.4</td>
<td>754.7</td>
<td>790.9</td>
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<tr>
<td>Cn = (Ay(x) - Ay(x-1)) / By(x-1)</td>
<td>3.74%</td>
<td>6.28%</td>
<td>6.70%</td>
<td>4.37%</td>
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ROE

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<tr>
<td>ROE</td>
<td>9.30%</td>
<td>9.19%</td>
<td>8.78%</td>
<td>9.00%</td>
<td>8.98%</td>
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ii) See Table 4 below for the calculation of Cn-factor if ROE and debt rates are based on OEB approved and deemed for the period 2016-2019.
Table 4: Calculation of Cn 2016-2019 if ROE and Debt Rates are based on OEB approved values

<table>
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<tr>
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<td>789.8</td>
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<td>Cn = (A_yx - A_y(x-1)) / B_y(x-1)</td>
<td>4.62%</td>
<td>3.65%</td>
<td>8.32%</td>
<td>4.40%</td>
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ROE

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Long-Term Debt

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</thead>
<tbody>
<tr>
<td>Long-Term Debt</td>
<td>n/a</td>
<td>4.54%</td>
<td>3.72%</td>
<td>4.16%</td>
<td>4.13%</td>
</tr>
</tbody>
</table>

Short-Term Debt

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Short-Term Debt</td>
<td>n/a</td>
<td>1.65%</td>
<td>1.76%</td>
<td>2.29%</td>
<td>2.82%</td>
</tr>
</tbody>
</table>

Weighted Average Debt

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weighted Average Debt</td>
<td>n/a</td>
<td>4.35%</td>
<td>3.59%</td>
<td>4.04%</td>
<td>4.04%</td>
</tr>
</tbody>
</table>
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 22:

Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 9

Chapter 2 Appendices, Appendix 2-BA

a) Please confirm that the rate base amounts for the 2021-2024 period which underpin the C-factor calculations are based on detailed forecasts of capital additions and depreciation for each of those years (Exhibit 1B / Tab 4 / Schedule 1 / p. 9). If not, please explain.

b) Please provide fixed asset continuity schedules (in the same format as Appendix 2-BA) for the years 2021-2024 that support the proposed rate base amounts used in the calculation of the C-factors. Please also show the rate base calculation (including the calculation of the working capital allowance amounts). If Toronto Hydro believes that such evidence is not integral to this application, please explain why.

c) Please provide the calculations supporting each aspect of the capital-related revenue requirement (interest, ROE, depreciation and PILs) for each year 2021-2024 (Exhibit 1B / Tab 4 / Schedule 1 / p. 9).

d) Please confirm that the OM&A and revenue offset amounts for 2021-2024 used in the C-factor calculation are calculated by inflating the starting amount in each year by I-X (Exhibit 1B / Tab 4 / Schedule 1 / p. 9).
RESPONSE:

a) Please refer to Toronto Hydro’s responses to parts (b) and (c) of this interrogatory for the rate base amounts and calculations for the 2021-2024 period which underpin the C-factor calculations.

Please refer to the following interrogatory responses for Toronto Hydro’s forecasting approaches to determine amounts underlying the C-factor calculations: 2A-SEC-31 for in-service additions; 2A-Staff-52 (b) for depreciation; and 4B-Staff-141 for derecognition.

b) Please see attached Appendix A for the Fixed Asset Continuity Schedules from 2021-2024. Please refer to part (c) below for the rate base calculation (including the calculation of the working capital allowance amounts).

c) Table 1 below provides details for each aspect of capital-related revenue requirement in Exhibit 1B, Tab 4, Schedule 1, Table 2.

Table 1: Revenue Requirement ($ Millions)

<table>
<thead>
<tr>
<th>Rate Base and Debt</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>Calculations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Opening Balance</td>
<td>4,270.4</td>
<td>4,489.8</td>
<td>4,689.9</td>
<td>4,986.1</td>
<td>5,266.5</td>
<td>C</td>
</tr>
<tr>
<td>Closing Balance</td>
<td>4,489.8</td>
<td>4,689.9</td>
<td>4,986.1</td>
<td>5,266.5</td>
<td>5,525.5</td>
<td>D</td>
</tr>
<tr>
<td>Average Fixed Assets</td>
<td>4,380.1</td>
<td>4,589.9</td>
<td>4,838.0</td>
<td>5,126.3</td>
<td>5,396.0</td>
<td>E = (C+D)/2</td>
</tr>
<tr>
<td>Working Capital Allowance</td>
<td>235.2</td>
<td>239.1</td>
<td>243.6</td>
<td>248.2</td>
<td>254.0</td>
<td>F</td>
</tr>
<tr>
<td>Rate Base</td>
<td>4,615.3</td>
<td>4,829.0</td>
<td>5,081.6</td>
<td>5,374.5</td>
<td>5,650.0</td>
<td>G = E+F</td>
</tr>
<tr>
<td>Return on Equity (%)</td>
<td>8.82%</td>
<td>8.82%</td>
<td>8.82%</td>
<td>8.82%</td>
<td>8.82%</td>
<td>H</td>
</tr>
<tr>
<td>Long-term Debt (%)</td>
<td>3.71%</td>
<td>3.71%</td>
<td>3.71%</td>
<td>3.71%</td>
<td>3.71%</td>
<td>I</td>
</tr>
<tr>
<td>Short-term Debt (%)</td>
<td>2.61%</td>
<td>2.61%</td>
<td>2.61%</td>
<td>2.61%</td>
<td>2.61%</td>
<td>J</td>
</tr>
<tr>
<td>Total Debt</td>
<td>3.64%</td>
<td>3.64%</td>
<td>3.64%</td>
<td>3.64%</td>
<td>3.64%</td>
<td>K</td>
</tr>
<tr>
<td>Revenue Requirement</td>
<td>2020</td>
<td>2021</td>
<td>2022</td>
<td>2023</td>
<td>2024</td>
<td>Calculations</td>
</tr>
<tr>
<td>---------------------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
<td>--------------</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>100.8</td>
<td>105.5</td>
<td>111.0</td>
<td>117.4</td>
<td>123.4</td>
<td>( L = (56% \times G \times I) + (4% \times G \times J) )</td>
</tr>
<tr>
<td>Return on Equity</td>
<td>162.8</td>
<td>170.4</td>
<td>179.3</td>
<td>189.6</td>
<td>199.3</td>
<td>( M = 40% \times G \times H )</td>
</tr>
<tr>
<td>Depreciation</td>
<td>268.7</td>
<td>281.9</td>
<td>293.1</td>
<td>310.9</td>
<td>325.4</td>
<td>N</td>
</tr>
<tr>
<td>PILs/Taxes</td>
<td>34.7</td>
<td>36.5</td>
<td>32.7</td>
<td>35.7</td>
<td>42.2</td>
<td>O</td>
</tr>
<tr>
<td>Capital-related RR (A)</td>
<td>567.0</td>
<td>594.3</td>
<td>616.0</td>
<td>653.6</td>
<td>690.3</td>
<td>( A = L + M + N + O )</td>
</tr>
<tr>
<td>OM&amp;A</td>
<td>277.5</td>
<td>280.0</td>
<td>282.5</td>
<td>285.1</td>
<td>287.6</td>
<td>P</td>
</tr>
<tr>
<td>Revenue Offsets</td>
<td>-47.7</td>
<td>-48.1</td>
<td>-48.5</td>
<td>-49.0</td>
<td>-49.4</td>
<td>Q</td>
</tr>
<tr>
<td>Total Revenue Requirement (B)</td>
<td>796.8</td>
<td>826.2</td>
<td>850.0</td>
<td>889.6</td>
<td>928.5</td>
<td>( B = A + P + Q )</td>
</tr>
</tbody>
</table>

\[ Cn = \frac{A_y - A_{y(x-1)}}{B_{y(x-1)}} \]

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>( Cn )</td>
<td>3.43%</td>
<td>2.63%</td>
<td>4.42%</td>
<td>4.12%</td>
<td></td>
</tr>
</tbody>
</table>

Rounding variances may exist.

d) Confirmed.
### OEB Appendix 2-BA
#### Fixed Asset Continuity Schedule - MiFRS

**Year 2021**

<table>
<thead>
<tr>
<th>Description</th>
<th>Opening Balance</th>
<th>Additions</th>
<th>Disposals</th>
<th>Closing Balance</th>
<th>Net Book Value</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total PP&amp;E</strong></td>
<td>$483,816,517</td>
<td>$46,953,586</td>
<td>$9,339,034</td>
<td>$474,451,073</td>
<td>$46,953,586</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CCA Class</td>
<td>OEC Account</td>
<td>Description</td>
<td>Opening Balance</td>
<td>Additions</td>
<td>Disposals</td>
</tr>
<tr>
<td>-----------</td>
<td>-------------</td>
<td>-------------</td>
<td>----------------</td>
<td>----------</td>
<td>-----------</td>
</tr>
<tr>
<td>12</td>
<td>1611</td>
<td>Computer Software (Purchased at Account 1558)</td>
<td>$335,770,046</td>
<td>$54,288,180</td>
<td>-</td>
</tr>
<tr>
<td>12</td>
<td>1213</td>
<td>Property, Plant &amp; Equipment</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>N/A</td>
<td>1803</td>
<td>Land</td>
<td>$7,001,827</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>N/A</td>
<td>1805</td>
<td>Buildings</td>
<td>$111,385,985</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>1411</td>
<td>Transformer Station Equipment - 11/23kV</td>
<td>$90,958,965</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>1420</td>
<td>Distribution Station Equipment - 11kV</td>
<td>$322,866,286</td>
<td>$29,135,018</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>1610</td>
<td>Power Transformers &amp; Transformers</td>
<td>$603,506,081</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>1620</td>
<td>Switchyard Lines &amp; Transformers</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>1631</td>
<td>Overhead Conductors &amp; Devices</td>
<td>$59,159,584</td>
<td>$45,723,000</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>1632</td>
<td>Underground Conductors &amp; Devices</td>
<td>$1,247,093,916</td>
<td>$104,221,949</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>1633</td>
<td>Services (Overhead &amp; Underground)</td>
<td>$6,765,165</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>1670</td>
<td>Distribution Station Equipment - 50 kV</td>
<td>$198,465,602</td>
<td>$22,117,752</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>1680</td>
<td>Service (Overhead &amp; Underground)</td>
<td>$195,457,059</td>
<td>$20,290,191</td>
<td>-</td>
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<tr>
<td>47</td>
<td>1700</td>
<td>Waters</td>
<td>$149,282,260</td>
<td>$17,137,058</td>
<td>-</td>
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<td>1710</td>
<td>Transmission Lines &amp; Conduits</td>
<td>$389,900,868</td>
<td>$9,479,000</td>
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<tr>
<td>N/A</td>
<td>1911</td>
<td>Stores Equipment</td>
<td>$17,396,067</td>
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<td>-</td>
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<tr>
<td>N/A</td>
<td>1941</td>
<td>Office Furniture &amp; Equipment</td>
<td>$246,804,032</td>
<td>$21,654,357</td>
<td>-</td>
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<tr>
<td>47</td>
<td>1950</td>
<td>Buildings &amp; Fixtures</td>
<td>$753,845</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>1960</td>
<td>Office Furniture &amp; Equipment</td>
<td>$10,085,700</td>
<td>$7,157,398</td>
<td>-</td>
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<tr>
<td>47</td>
<td>1970</td>
<td>Computer Equipment - Device</td>
<td>$90,362,052</td>
<td>$15,555,836</td>
<td>-</td>
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<tr>
<td>47</td>
<td>1980</td>
<td>Transportation Equipment</td>
<td>$54,284,421</td>
<td>$7,707,722</td>
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<tr>
<td>47</td>
<td>1990</td>
<td>Power Equipment</td>
<td>$7,508</td>
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<td>-</td>
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<td>47</td>
<td>2411</td>
<td>Tools, Shop &amp; Garage Equipment</td>
<td>$83,351,799</td>
<td>$20,506,707</td>
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<td>47</td>
<td>2421</td>
<td>Maintenance &amp; Repairing Equipment</td>
<td>$87,671</td>
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<td>2510</td>
<td>Service Equipment</td>
<td>$1,083,461</td>
<td>$48,499</td>
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<tr>
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<td>2590</td>
<td>Communications Equipment</td>
<td>$2,618,719</td>
<td>$1,818,508</td>
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<tr>
<td>47</td>
<td>2600</td>
<td>Business Equipment</td>
<td>$275,724</td>
<td>$1,173,957</td>
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<td>47</td>
<td>2700</td>
<td>Land Management Control Customer Premium</td>
<td>$3,022,834</td>
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</tr>
<tr>
<td>47</td>
<td>2710</td>
<td>Land Management Control Utilities Premium</td>
<td>-</td>
<td>-</td>
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</tr>
<tr>
<td>47</td>
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<td>Rail Station Equipment</td>
<td>$39,094,885</td>
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<tr>
<td>47</td>
<td>2760</td>
<td>Rail Station Equipment</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>2770</td>
<td>Rail Station Equipment</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>2780</td>
<td>Rail Station Equipment</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>2790</td>
<td>Rail Station Equipment</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>N/A</td>
<td>2001</td>
<td>Property Under Capital Lease</td>
<td>$18,170,894</td>
<td>-</td>
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</tr>
<tr>
<td>47</td>
<td>3000</td>
<td>Sub-Total</td>
<td>$6,148,357,059</td>
<td>$615,303,972</td>
<td>$39,047,421</td>
</tr>
<tr>
<td>47</td>
<td>3010</td>
<td>Less Socialized Renewable Energy Generation Investments (input as negative)</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3020</td>
<td>Contributions &amp; Grants (Formally known as Account 1991)</td>
<td>$374,083,973</td>
<td>$46,206,880</td>
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</tr>
<tr>
<td>47</td>
<td>3030</td>
<td>Capital Expenditure Reserve</td>
<td>$494,918,544</td>
<td>$3,561,917</td>
<td>-</td>
</tr>
<tr>
<td>N/A</td>
<td>3050</td>
<td>Property Under Capital Lease</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>N/A</td>
<td>3060</td>
<td>Sub-Total</td>
<td>$18,170,894</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3100</td>
<td>Less Other Non-Rated Utility Assets (input as negative)</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3110</td>
<td>Less Socialized Renewable Energy Generation Investments (input as negative)</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3120</td>
<td>Less Other Non-Rated Utility Assets (input as negative)</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3130</td>
<td>Less Other Non-Rated Utility Assets (input as negative)</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3140</td>
<td>Less Other Non-Rated Utility Assets (input as negative)</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3150</td>
<td>Less Other Non-Rated Utility Assets (input as negative)</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3200</td>
<td>Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)</td>
<td>$1,594,849</td>
<td>$761,800</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3210</td>
<td>Sub-Total</td>
<td>$4,398,079,020</td>
<td>$207,043,602</td>
<td>$35,047,421</td>
</tr>
<tr>
<td>47</td>
<td>3300</td>
<td>Less Fully Allocated Depreciation</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3310</td>
<td>Transportation</td>
<td>$1,799,523</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3320</td>
<td>Divestiture</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>47</td>
<td>3330</td>
<td>Net Depreciation</td>
<td>$287,045,069</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
Toronto Hydro-Electric System Limited
EB-2018-0165
Interrogatotry Responses
1B-STAFF-22
Appendix A
FILED: January 21, 2019
Page 3 of 4

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS
2023

Year

Cost (Forecast)
CCA Class

OEB Account

12

1611

N/A
N/A
1
47
47
47
47
47
47
47
47
47
47
N/A
1
13
8
50
10
8
8
8
8
8

1612
1805
1808
1815
1820
1830
1835
1840
1845
1850
1855
1860
1860
1905
1908
1910
1915
1920
1930
1935
1940
1945
1950
1955

8

1960

47

1970

Description
Computer Software (Formally known as
Account 1925)
Land Rights

Land
Buildings
Transformer Station Equipment >50 kV
Distribution Station Equipment <50 kV

Poles, Towers & Fixtures
Overhead Conductors & Devices
Underground Conduit
Underground Conductors & Devices
Line Transformers
Services (Overhead & Underground)
Meters
Meters (Smart Meters)
Land
Buildings & Fixtures
Leasehold Improvements
Office Furniture & Equipment
Computer Equipment - Hardware
Transportation Equipment
Stores Equipment
Tools, Shop & Garage Equipment
Measurement & Testing Equipment
Service Equipment
Communications Equipment
Miscellaneous Equipment
Load Management Controls Customer
Premises

47

1975

Load Management Controls Utility Premises

47

1980

47

2440

N/A
N/A

1609
2005

System Supervisor Equipment
Contributions & Grants (Formally known as
Account 1995)
Capital Contributions Paid
Property Under Capital Leases
Sub-Total
Less Socialized Renewable Energy
Generation Investments (input as negative)

Opening Balance

Additions

$
$
$
$
$
$
$
$
$
$
$
$
$
$
$
$
$
$
$
$
$
$
$
$
$
$

399,859,228
7,001,832
189,251,466
43,278,622
331,468,271
491,614,608
602,132,394
1,654,224,750
1,243,019,681
857,521,776
215,282,831
165,416,836
157,348,645
17,356,057
268,269,188
753,840
30,458,843
112,607,729
61,974,533
7,066
92,212,456
487,612
1,347,960
52,001,825
1,855,203

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3,022,834

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89,075,205

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419,653,509) ($
245,925,566 $
18,170,834 $

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6,933,294,181

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53,264,769) $

Accumulated Depreciation (Forecast)
Disposals

41,936,722
24,862,013
4,663,767
30,034,149
36,474,413
47,002,240
117,197,293
113,889,863
87,904,740
21,002,880
21,096,001
9,675,324
5,387,713
1,931,444
13,760,863
8,291,568
2,195,808
234
90,900
1,961,339
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3,022,834

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3,022,834) $

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10,387,589 ($

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712,351) $

98,750,443

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28,515,224) ($

45,072,071) $
40,711,097 $
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643,931 ($
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464,081,648)
286,636,663
18,170,834

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($
($

595,385,892 ($

32,375,518) $

-

$

Less Other Non Rate-Regulated Utility
Assets (input as negative)
($
20,299,432) ($
2,364,569) $
Total PP&E
$
6,859,729,980 $
593,021,323 ($
Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)
Total

-

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-

($

32,375,518) $

7,496,304,556

53,264,769)
22,664,001)
7,420,375,785

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247,852,326)
28,493,829)
8,532,794)
83,715,532)
90,913,809)
94,142,780)
406,320,519)
221,522,897)
211,650,905)
27,820,723)
44,253,831)
95,645,430)
83,207,747)
753,840)
16,429,445)
86,709,989)
39,401,456)
7,066)
26,267,076)
481,584)
933,232)
29,139,802)
281,671)

Additions

441,795,950
7,001,832
214,113,478
47,942,389
361,143,970
520,319,953
646,174,960
1,770,677,732
1,350,220,319
933,192,608
235,831,075
185,531,295
166,907,685
17,356,057
273,656,901
753,840
32,390,288
126,368,592
70,266,101
7,066
94,408,264
487,847
1,438,860
53,963,164
1,855,203

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358,450)
7,769,068)
2,959,674)
744,311)
6,689,225)
12,233,907)
454,636)
981,543)
116,284)
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Opening Balance

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Closing Balance

42,323,474)
5,886,992)
1,543,305)
13,787,587)
13,387,282)
14,977,861)
58,697,608)
36,586,924)
35,274,498)
5,146,705)
9,044,328)
8,975,671)
12,134,798)
2,084,719)
11,597,216)
5,261,264)
6,299,506)
700)
88,888)
3,066,257)
124,277)

65,053,038

53,687,583 $
47,582,829) ($
11,784,550) ($

13,106,556 ($
10,223,081) $
89,423) $

32,825) $
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($

66,761,314 ($
57,805,910) $
11,873,973) $

397,320,334)
228,830,753
6,296,861

($

1,881,696,137) ($

288,754,972) $

4,120,617 ($

2,166,330,492) $

$

5,327,133

$

$

2,706,482

$

($

1,873,662,522) ($

Stores Equipment
Net Depreciation

2-BA 2023 MIFRS

151,620,150
7,001,832
179,732,657
37,866,290
263,746,056
417,039,203
537,369,192
1,305,766,964
1,092,742,974
687,975,648
202,889,874
132,368,185
62,313,072
17,356,057
178,314,356
13,876,124
28,061,388
25,603,382
61,841,682
5,562
416,740
21,757,105
1,449,255

$
33,697,405) $

Transportation

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage
program
Other Non Rate-Regulated Utility Assets includes Generation Protection,
Monitoring and Control program

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76,983 ($

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Transportation
Stores Equipment

290,175,800)
34,380,822)
10,076,099)
97,397,914)
103,280,750)
108,805,769)
464,910,769)
257,477,345)
245,216,960)
32,941,201)
53,163,110)
104,594,614)
95,342,545)
753,840)
18,514,164)
98,307,205)
44,662,719)
7,066)
32,566,582)
482,284)
1,022,120)
32,206,059)
405,948)

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5,259,164) $

3,550,985

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845,403

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284,358,584) $

284,358,584)

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1,759,521)
282,599,064)

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3,022,834) $

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105,205
1,020,341
314,872
107,359
632,475
1,708,443
26,227
135,049
26,487
-

Net Book Value

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Less: Fully Allocated Depreciation

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Closing Balance

-

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8,878,118 ($

-

$

3,551,885 ($

4,120,617 ($

2,153,900,489) $

-

5,329,974,064

44,386,651)
19,112,116)
5,266,475,297


# OEB Appendix 2-B

## Fixed Asset Continuity Schedule - MFRRS

### Year 2024

<table>
<thead>
<tr>
<th>CCA Class</th>
<th>OEB Account</th>
<th>Description</th>
<th>Cost (Forecast)</th>
<th>Accumulated Depreciation (Forecast)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>12</td>
<td>Computer Software (formerly known as Account 1055)</td>
<td>Opening Balance: $441,795,650</td>
<td>Opening Balance: $290,157,800</td>
</tr>
<tr>
<td>N/A</td>
<td>1901</td>
<td>Land</td>
<td>Additions: $42,240,621</td>
<td>Additions: $44,166,800</td>
</tr>
<tr>
<td>N/A</td>
<td>1809</td>
<td>Buildings</td>
<td>Disposals: $4,057,988</td>
<td>Disposals: $3,946,200</td>
</tr>
<tr>
<td>49</td>
<td>1811</td>
<td>Transformer Station Equipment: 10kV &amp; 34.5 kV</td>
<td>Closing Balance: $406,006,571</td>
<td>Closing Balance: $234,342,605</td>
</tr>
<tr>
<td>47</td>
<td>1820</td>
<td>Distribution Station Equipment: 11 kV</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1830</td>
<td>Index, Towers &amp; Towers</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1840</td>
<td>Overhead Conductor &amp; Devices</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1850</td>
<td>Underground Conduit &amp; Cable</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1860</td>
<td>Transformer Station Equipment: &gt;50 kV</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1870</td>
<td>Distribution Station Equipment: 11 kV</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1880</td>
<td>Index, Towers &amp; Towers</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1890</td>
<td>Overhead Conductor &amp; Devices</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1900</td>
<td>Underground Conduit &amp; Cable</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1910</td>
<td>Transformer Station Equipment: 10kV &amp; 34.5 kV</td>
<td></td>
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<tr>
<td>47</td>
<td>1920</td>
<td>Distribution Station Equipment: 11 kV</td>
<td></td>
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<tr>
<td>47</td>
<td>1930</td>
<td>Index, Towers &amp; Towers</td>
<td></td>
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<tr>
<td>47</td>
<td>1940</td>
<td>Overhead Conductor &amp; Devices</td>
<td></td>
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<tr>
<td>47</td>
<td>1950</td>
<td>Underground Conduit &amp; Cable</td>
<td></td>
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<tr>
<td>47</td>
<td>1960</td>
<td>Transformer Station Equipment: &gt;50 kV</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1970</td>
<td>Distribution Station Equipment: 11 kV</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1980</td>
<td>Index, Towers &amp; Towers</td>
<td></td>
<td></td>
</tr>
<tr>
<td>47</td>
<td>1990</td>
<td>Overhead Conductor &amp; Devices</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**

- Fixed Asset Continuity Schedule includes monthly billing.
- Socialized Renewable Energy Generation Investments include Energy Storage program.
- Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program.

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**2024 MFRRS**
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 23:

Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 13

a) Please provide a comparison for each year 2021-2024 (and in total for the 2020-2024 period) of the revenue requirement resulting from Toronto Hydro’s proposed CPCI and resulting from a standard IRM formula (I-X). For the standard I-X calculation, use the proposals and assumptions made in the current application.

b) Please provide a comparison for each year 2016-2019 (and in total for the 2015-2019 period) of the revenue requirement resulting from Toronto Hydro’s approved CPCI and resulting from a standard IRM formula (I-X). For the standard I-X calculation, use the approved I-X factors from each year.

RESPONSE:

a) Please see Table 1 below.

Table 1: Annual Revenue ($ Millions)

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>Total 2020-2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenue based on proposed CPCI</td>
<td>796.8</td>
<td>822.8</td>
<td>843.0</td>
<td>878.8</td>
<td>913.3</td>
<td>4,254.6</td>
</tr>
<tr>
<td>Revenue based on I-X (where I=1.2% and X=0.3%)</td>
<td>796.8</td>
<td>804.0</td>
<td>811.2</td>
<td>818.5</td>
<td>825.9</td>
<td>4,056.4</td>
</tr>
</tbody>
</table>

b) Please see Table 2 below.
## Table 2: Annual Revenue ($ Millions)

<table>
<thead>
<tr>
<th></th>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenue based on OEB approved CPCI 1</td>
<td>633.1</td>
<td>657.3</td>
<td>705.1</td>
<td>743.3</td>
<td>772.5</td>
<td>3,511.3</td>
</tr>
<tr>
<td>Revenue based on OEB approved I-X 2</td>
<td>633.1</td>
<td>642.6</td>
<td>651.0</td>
<td>654.9</td>
<td>660.7</td>
<td>3,242.3</td>
</tr>
</tbody>
</table>

1. OEB approved values for CPCI: 2016 = 3.83%, 2017 = 7.26%, 2018 = 5.42%, 2019 = 3.93%
2. OEB approved values for I: 2016 = 2.1%, 2017 = 1.9%, 2018 = 1.2%, 2019 = 1.5%.
   OEB approved value for X = 0.6% (Productivity = 0.0% + Stretch = 0.6%).
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 24:

Reference(s): EB-2017-0077, Decision and Rate Order, p. 7
Updated Exhibit 1B, Tab 4, Schedule 1, p. 14-15

Preamble:
In its Decision and Order, dated December 14, 2017, in Toronto Hydro’s 2018 rates proceeding, the OEB states that it “encourages Toronto Hydro to review the methodology for calculating the earnings sharing with OEB staff in advance of the filing of the next Custom IR or rebasing application at which time the variance account will be reviewed for disposition” (EB-2017-0077 / Decision and Rate Order / p. 7).

a) Please advise whether Toronto Hydro reviewed its methodology for calculating earnings sharing with OEB staff in advance of its current filing. If not, please explain.

RESPONSE:

a) In 2017 and 2018, Toronto Hydro followed the OEB-established process for rates update proceedings and believes it satisfactorily responded to the interrogatories from OEB staff regarding earnings sharing. As a result, Toronto Hydro did not further engage OEB staff to review the earnings sharing calculation. All information provided to, or discussed with, OEB staff is available in Exhibit 1B, Tab 4, Schedule 1 starting on page 14.


Panel: Rates and CIR Framework
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 25:
Reference(s): Updated Exhibit 1B, Tab 4, Schedule 1, pp. 14-15

Preamble:
Toronto Hydro provided the methodology it uses for calculating earnings sharing during the 2015-2019 period as follows.

(Actual non-capital revenue requirement) – (Funded non-capital revenue requirement)
Actual equity on a deemed basis

a) Please provide the earnings sharing calculations based on Toronto Hydro’s methodology for each year 2015-2017. Please provide and explain in detail all adjustments that are made in the calculation (Exhibit 1B / Tab 4 / Schedule 1 / p. 15 / Footnote 19).

b) Please advise whether actual equity on a deemed basis means the deemed equity portion of actual rate base.

c) Please advise whether Toronto Hydro agrees that the methodology it uses for calculating the earnings sharing amount is essentially a true-up of OM&A costs and revenue offsets between the amounts approved in rates and actual (subject to a ROE-related threshold to determine whether earnings sharing is required). Specifically, please confirm that actual revenues are not considered as part of the earnings sharing calculation.
d) Please provide Toronto Hydro’s understanding of the operation of the earnings sharing mechanism in terms of the following:

i) Is earnings sharing symmetrical (e.g. if Toronto Hydro overspends OM&A on an actual basis relative to the amount approved for recovery in rates, and the earnings sharing threshold is met, does Toronto Hydro collect that amount from ratepayers)?

ii) Is earnings sharing cumulative (i.e. do the over and under-earning amounts net against each other over the entire 2015-2019 period)?

e) As part of the current proceeding, is it Toronto Hydro’s intent to seek final approval of the earning sharing amounts for 2015-2018 (with the 2019 balance subject to review in the 2021 rates proceeding)? Alternatively, does Toronto Hydro believe that it already has final approval of the 2015-2017 earnings sharing amounts? Please discuss what requests Toronto Hydro is making as part of the current proceeding.

f) Please provide alternative earnings sharing calculations for 2015-2017 based on the following methodology and provide Toronto Hydro’s position on the suggested approach.

\[(\text{Actual non-capital revenue}) - (\text{Funded non-capital revenue requirement})\]

Actual equity on a deemed basis

For calculating the actual non-capital revenue amount,

i) apply the approved $S_{\text{cap}}$ in the relevant year to total base distribution revenues (with any adjustments that Toronto Hydro believes are necessary);
i) subtract the amount from part (i) from the total base distribution revenues;

ii) add the residual amount (which OEB staff believes could be considered a reasonable proxy for the actual non-capital base distribution revenues) from part (ii) to the revenue offset amount.

The remainder of the calculation is unchanged from Toronto Hydro’s proposed approach.

g) Please provide alternative earnings sharing calculations for 2015-2017 based on a methodology that compares the utility net income amount to the deemed equity portion of actual rate base. Please make any necessary adjustments to back-out amounts that are non-utility or are otherwise encumbered in deferral and variance accounts (DVAs) (which are subject to separate dispositions) in order to avoid double counting.

RESPONSE:

a) Toronto Hydro’s calculation of the earnings sharing mechanism (“ESM”) for 2015-2017 follows.
Table 1: 2015-2017 ESM Calculations\(^1\) ($ Millions)

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>OM&amp;A (^a)</td>
<td>244.0</td>
<td>246.6</td>
<td>250.6</td>
</tr>
<tr>
<td>Revenue Offsets (^a)</td>
<td>-39.9</td>
<td>-50.2</td>
<td>-51.7</td>
</tr>
<tr>
<td>Unadjusted non-capital revenue requirement (&quot;Non-CRRR&quot;) (^c)</td>
<td>204.1</td>
<td>196.4</td>
<td>198.9</td>
</tr>
<tr>
<td>RRR Adjustments (^b)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation expense related to non-regulated assets (renewable energy investment) (^b)</td>
<td>-0.4</td>
<td>-0.4</td>
<td>-0.6</td>
</tr>
<tr>
<td>Subtotal (^f)</td>
<td>203.7</td>
<td>196.1</td>
<td>198.2</td>
</tr>
<tr>
<td>Adjustments for items not included in rates (^e)</td>
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<td></td>
</tr>
<tr>
<td>Amortization of 2014 balance in DVA account 1575 – IFRS USGAAP Transitional PP&amp;E Amounts (^c)</td>
<td>-</td>
<td>5.2</td>
<td>6.6</td>
</tr>
<tr>
<td>Amortization of capital contributions (deferred revenue) (^d)</td>
<td>2.2</td>
<td>3.8</td>
<td>4.7</td>
</tr>
<tr>
<td>Actual non-CRRR items for ESM purposes (^f)</td>
<td>206.0</td>
<td>205.1</td>
<td>209.5</td>
</tr>
<tr>
<td>Less: non-CRRR embedded in rates (^e,f)</td>
<td>202.7</td>
<td>205.7</td>
<td>208.3</td>
</tr>
<tr>
<td>Non-CRRR difference (^f)</td>
<td>3.3</td>
<td>-0.6</td>
<td>1.2</td>
</tr>
<tr>
<td>Deemed equity portion of actual rate base (^e)</td>
<td>1,285.2</td>
<td>1,420.1</td>
<td>1,540.4</td>
</tr>
<tr>
<td>ESM threshold (^e)</td>
<td>1.00%</td>
<td>1.00%</td>
<td>1.00%</td>
</tr>
<tr>
<td>ESM test result (^f)</td>
<td>1.00%</td>
<td>1.00%</td>
<td>1.00%</td>
</tr>
</tbody>
</table>

*Rounding variances may exist.*

\(^a\) Source: RRR 2.1.7 - trial balance.

\(^b\) Source: RRR 2.1.5.6 - Appendices 1 and 2.

\(^c\) Source: RRR 2.1.7 - trial balance account 4310, reported as revenue offsets.

\(^d\) Source: RRR 2.1.7 - trial balance account 4245, reported as revenue offsets.

\(^e\) EB-2014-0116, Decision and Order (29\(^{th}\) Dec, 2015), page 49

\(^f\) 2015 non-CRRR is from EB-2014-0116, Draft Rate Order Update (29\(^{th}\) Feb, 2016), Table 2, Page 6. To determine 2016 and 2017 amount, I (2.1% and 1.9%) and X (0.6% and 0.6%) was applied to the previous year amount.

\(^1\) Source: Toronto Hydro’s annual RRR submissions.
c) Toronto Hydro’s earnings sharing methodology (as described in part a) is essentially a true-up of OM&A costs and revenue offsets between the: (i) amounts approved in base rates; and (ii) comparable actuals. Actual amounts from Toronto Hydro’s RRR submissions are adjusted for items which do not form approved base rates. The resulting difference is subject to the ROE-related threshold to determine whether earnings sharing is required.

Actual distribution revenue, as reported in the RRR, is not considered in Toronto Hydro’s earnings sharing calculation, although actual reported OM&A and revenue offsets are.

d) Toronto Hydro’s understanding of the operation of the ESM follows.

i) The account is symmetrical. ²

ii) The account is not cumulative. ³

e) In each of Toronto Hydro’s annual rate updates during the 2015-2019 rate cycle, the ESM has been a live issue. In each proceeding, Toronto Hydro has produced the annual ESM calculation. It has been Toronto Hydro’s expectation that if the ESM threshold had been surpassed in any given year, that the OEB would order the resulting ESM disposition at that time.

In the event that the 2018 ESM threshold is surpassed, those financial results and the resulting disposition are subject to review in this proceeding (following finalization and filing of Toronto Hydro’s 2018 financial results). In the event that the 2019 ESM

_____________________________________

² EB-2014-0116 Decision and Order dated December 29, 2015, section 3.2, page 49.
³ Handbook to Electricity Distributor and Transmitter Consolidations, Section - Earning Sharing Mechanism (ESM), page 16 of the handbook.
threshold is surpassed (following finalization and filing of Toronto Hydro’s 2019 financial results in its first rate updates thereafter, namely the 2021 rate update proceeding), Toronto Hydro expects that the OEB would order disposition in relation to 2019.

f) The 2015-2017 calculations, based on Toronto Hydro’s understanding of the alternative approach, are provided below in Table 2.

Toronto Hydro believes that reported distribution revenue should not form part of Toronto Hydro’s earning sharing calculation since it (i) results from approved rates which are based on forecasted OM&A and revenue offsets, (ii) includes items not embedded in approved rates for the 2015-2019 CIR term and is not comparable to non-CRRR embedded in rates, and (iii) has errors in logic.

- The approach entails double-counting of revenue offsets;
- The alternative approach uses projected S_{cap} (not actual S_{cap}) applied to actual revenues to determine a proxy for actual OM&A and revenue offsets, rather than actual amounts which are available from RRR filings;
- Reported distribution revenue includes accounting recognition of revenues in the CIR term for DVA balances prior to the CIR term (i.e. “out-of-period” amounts) and amounts excluded for determining base distribution rates (e.g. donations); and
- Reported revenue includes effects of unplanned weather and other forecasting differences, which are already considered as part of the ROE threshold test.
Table 2: ESM calculation based on the alternative methodology ($ Millions)

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution revenue *</td>
<td>A</td>
<td>612.4</td>
<td>696.5</td>
</tr>
<tr>
<td>Adjustments for rate rider revenues and out of period items (See Table 3)</td>
<td>B</td>
<td>- 14.1</td>
<td>- 38.8</td>
</tr>
<tr>
<td>Distribution revenue, adjusted (base revenue)</td>
<td>C=A+B</td>
<td>598.3</td>
<td>657.7</td>
</tr>
<tr>
<td>Projected S&lt;sub&gt;cap&lt;/sub&gt; b</td>
<td>D</td>
<td>68.9%</td>
<td>70.8%</td>
</tr>
<tr>
<td>Derived capital related revenue</td>
<td>E=C*D</td>
<td>412.2</td>
<td>465.7</td>
</tr>
<tr>
<td>Distribution revenue, adjusted (base revenue)</td>
<td>F=C</td>
<td>598.3</td>
<td>657.7</td>
</tr>
<tr>
<td>Less: derived capital related revenue</td>
<td>G=E</td>
<td>412.2</td>
<td>465.7</td>
</tr>
<tr>
<td>Derived non-CRRR</td>
<td>H=F-G</td>
<td>186.1</td>
<td>192.0</td>
</tr>
<tr>
<td>Add: revenue offsets per RRR</td>
<td>I</td>
<td>39.9</td>
<td>50.2</td>
</tr>
<tr>
<td>Derived non-CRRR plus revenue offsets</td>
<td>J=H+I</td>
<td>226.0</td>
<td>242.2</td>
</tr>
<tr>
<td>Less: funded non-CRRR</td>
<td>K</td>
<td>202.7</td>
<td>205.7</td>
</tr>
<tr>
<td>Non-CRRR approved vs Non-CRRR actual</td>
<td>L=J-K</td>
<td>23.3</td>
<td>36.5</td>
</tr>
<tr>
<td>Deemed equity portion of actual rate base</td>
<td>M</td>
<td>1,285.2</td>
<td>1,420.1</td>
</tr>
<tr>
<td>Non-CRRR difference</td>
<td>N=L/M</td>
<td>-1.82%</td>
<td>-2.57%</td>
</tr>
<tr>
<td>ESM threshold</td>
<td>O</td>
<td>1.00%</td>
<td>1.00%</td>
</tr>
<tr>
<td>ESM test result</td>
<td>N compared to O</td>
<td>Not within threshold</td>
<td>Not within threshold</td>
</tr>
<tr>
<td>$ Impact (Recovery/(Credit) from/to the customers)</td>
<td>P=[M*(N-O)]/2</td>
<td>5.2</td>
<td>11.2</td>
</tr>
</tbody>
</table>

Rounding variances may exist.

* RRR 2.1.7 - trial balance account 4080 (distribution revenue).

b EB-2014-0116, Draft Rate Order Update, Filed 2016, Feb 29, Page 6, Table 3. Toronto Hydro notes that these values are based on values projected in 2014, not actual S<sub>cap</sub>.
### Table 3: Adjustments to distribution revenue a ($ Millions):

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Rate Rider Revenue</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Smart Meter</td>
<td>-10.9</td>
<td>-7.9</td>
<td>-2.4</td>
</tr>
<tr>
<td>Smart Grid Funding Adder</td>
<td></td>
<td></td>
<td>-0.1</td>
</tr>
<tr>
<td>OCCP: Operation Centres</td>
<td></td>
<td>5.2</td>
<td>6.6</td>
</tr>
<tr>
<td>Consolidation Program</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Amortization of 1575 (IFRS</td>
<td></td>
<td>-0.9</td>
<td>-1.2</td>
</tr>
<tr>
<td>transition cost (return)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HONI Contribution</td>
<td>-1.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Named Properties</td>
<td>-5.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Out of Period Items</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Incremental Capital Module</td>
<td></td>
<td>-41.2</td>
<td></td>
</tr>
<tr>
<td>Harmonized Sales Tax</td>
<td></td>
<td>1.1</td>
<td></td>
</tr>
<tr>
<td>Lost Revenue Adjustment</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mechanism</td>
<td>-9.0</td>
<td>-4.5</td>
<td>-10.9</td>
</tr>
<tr>
<td><strong>Others</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CRRRVA, External Initiated</td>
<td>12.6</td>
<td>9.0</td>
<td>20.2</td>
</tr>
<tr>
<td>Projects (EIP) and Derogation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tax on gain on sale of</td>
<td></td>
<td></td>
<td>-1.2</td>
</tr>
<tr>
<td>properties (50/60 Eglinton)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Monthly billing</td>
<td></td>
<td>0.4</td>
<td>1.8</td>
</tr>
<tr>
<td>POEB tax</td>
<td>0.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Adjustments</td>
<td>-14.1</td>
<td>-38.8</td>
<td>12.8</td>
</tr>
<tr>
<td><strong>A RRR 2.1.7 – Trial balance</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1 There is insufficient information in this question for Toronto Hydro to produce the requested calculation.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 26:

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

Preamble:
Toronto Hydro retained PSE to apply econometric modelling to benchmark its historical and projected cost and reliability.

a) Please confirm that the main purpose of the study is to support Toronto Hydro’s proposed stretch factor.

RESPONSE:

a) The main purpose of the PSE econometric study is to provide the OEB the necessary benchmarking study it states is a requirement in its Handbook for Utility Rate Applications.1 Toronto Hydro retained PSE to inform its Custom IR application on the appropriate Productivity Factor and Stretch Factor. PSE’s is recommending that Toronto Hydro receive a Productivity Factor of zero and Stretch Factor of 0.3%.

b) Confirmed. In addition, the PSE Report addresses the feedback provided by the OEB in Toronto Hydro’s 2015-2019 rate decision with respect to benchmarking, and provides Toronto Hydro’s total cost and reliability performance results based on an expanded data set, with due consideration for the utility’s operating conditions.

______________________________

1 OEB Handbook for Utility Rate Applications, October 13, 2016

Panel: Expert Witnesses
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 27:

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

OEB Handbook for Utility Rate Applications

a) Please confirm that the PSE cost benchmarking study addresses the level of Toronto Hydro’s costs but not the appropriate rate of cost escalation. Please explain whether this is consistent with the Rate Handbook.

b) Please explain why the weights on the OM&A input price index are fixed for all utilities when the weights for U.S. utilities are readily available.

c) Please advise what alternatives, if any, were considered for measuring the trend in Ontario construction cost other than the Handy-Whitman index.

d) Please explain why a 1988 benchmark year adjustment was used for all utilities when a much earlier benchmark year is possible for the U.S. utilities in the sample.

e) Please advise whether the parameters used to calculate Toronto Hydro’s cost performance come from a version of the cost model that includes Toronto Hydro in the sample.

RESPONSE (PREPARED BY TORONTO HYDRO):

a) Toronto Hydro believes that the PSE study demonstrates an appropriate and thorough analysis of both the level of costs and the rate of cost escalation. PSE conducted an
econometric benchmarking study in a manner consistent with the Rate Handbook guidance on areas to benchmark.\(^1\) PSE’s econometric modelling evaluated historical and forecasted costs to determine that Toronto Hydro’s costs are below the benchmark which supported their recommendation of a Productivity Factor of zero and Stretch Factor of 0.3%.

**RESPONSE (PREPARED BY PSE):**

b) The weights used for the OM&A input price index are identical to the weights used for the OEB 4th Generation IR benchmarking research. These are 70 percent for the labour weight and 30 percent for the non-labour weight. The labour/non-labour breakdowns are not available for the seven Ontario distributors in the sample and, thus, varying the weights for those distributors was not possible. Using the fixed weights employed by the OEB benchmarking methodology provides consistent treatment to all the distributors in the sample. We would not expect this assumption to have a significant impact on the study results.

c) Other alternatives were not considered. The Handy-Whitman index provides construction cost inflation measures that are specific to the electric distribution industry. The Handy-Whitman index is widely used in rate applications and benchmarking research, including in Ontario. For example, the Board Staff’s benchmarking consultant (Pacific Economics Group) used it in their research in Ontario Power Generation’s incentive regulation application (EB-2016-0152) and has regularly used it in their U.S. benchmarking and productivity research.

\(^1\) Ontario Energy Board, Handbook for Utility Rate Applications (October 13, 2016)
PSE used the Handy-Whitman index during the 2015 Toronto Hydro CIR application, in the Hydro One Distribution benchmarking for their CIR application (EB-2017-0049), and in PSE’s Hydro One SSM Transmission benchmarking study for their CIR application (EB-2018-0218). The reason PSE uses the Handy-Whitman index is because it is important to use a construction cost inflation measure that tracks the industry sector it is being applied to. In electric distribution, commodities like copper are used far more frequently than in a sector like gas distribution. Since 2005, copper prices have annually increased by over four percent. If a more general inflation factor (like one that applies to all utilities rather than specifically to electric distribution) were used, the proper asset inflation for the electric distribution sector would not be captured.

The upside of using the Handy-Whitman indexes is that they are widely used and are specific to electric distribution construction costs. To address the fact that the measure is for specific U.S. regions, PSE took the Handy-Whitman indexes for electric distribution for the U.S. North Atlantic region, and then converted them using the Canadian purchasing price parities (PPPs). This treatment was the same for all seven Ontario distributors in the sample.

d) To clarify, a 2002 benchmark year adjustment for the capital stock was used for all of the Ontario distributors, and a 1989 benchmark year adjustment for the capital stock was used for the U.S. utilities. The benchmark year adjustment essentially measures the quantity of capital present in an early year; with that year as a baseline, we can calculate capital quantity from all subsequent plant additions. Capital costs are then calculated based on this capital quantity multiplied by a capital service price.
We used 2002 for the Ontario distributors because this is the earliest year of available distribution net plant data where no imputations need to be made on the subsequent plant additions. Data prior to 2002 for Ontario requires assumptions on the plant additions, and is not consistent for each Ontario distributor. Starting in 2002 treats all Ontario distributors consistently.

As for the U.S. utilities, the capital benchmark year was set at 1989. This is the first year of readily available distribution net plant data and all subsequent plant additions data from PSE’s data vendor, SNL Energy. This goes back nearly 30 years, and in our opinion there would be little value in going back further, as the results would not likely change. This aligns with the 4th Generation OEB benchmarking study where the capital benchmark is set at either 1989 or 2002. At the time, the year 1989 was 23 years younger than the last year in the sample. In the current PSE research, it is now 27 years younger than the last year in the sample.

In an interrogatory response in the Hydro One Distribution CIR application (EB-2017-0049) directed to the Board Staff’s benchmarking consultant, Pacific Economics Group (PEG), PEG mentioned they have data from 1964, which is “confidential data,” but PEG did not provide that data.

In the EB-2017-0049 Hydro One Distribution proceeding, PEG put forth a total cost model of its own but in that research also did not use an older capital benchmark year. Rather they used the more recent year used by PSE.

Here was the IR and response:
Given that the benchmark year is already nearly 30 years ago, PSE is of the opinion that changing the benchmark year to 1964 would have a negligible impact on Toronto Hydro’s results.

e) Toronto Hydro observations are excluded from the cost model used to calculate Toronto Hydro’s cost benchmarks and performance. This makes the benchmarks external to Toronto Hydro.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 28:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 2

a) In order to facilitate an alternate analysis please provide the following data for Toronto Hydro for the years covered by the PSE study:
   i) Route-km and circuit-km of the distribution system. Please indicate if this includes the length associated with services.
   ii) Salaries and wages included in OM&A expenses exclusive of pensions, benefits and taxes.
   iii) Ratio of accumulated depreciation to the gross value of plant in service.

RESPONSE:

a)
   i) Toronto Hydro is not aware of the OEB definition for route km. Toronto Hydro tracks and reports linear asset information in a manner consistent with the OEB’s RRR definition(s).\(^1\) Please refer to Table 1 below for the annual circuit km of line of linear assets available to Toronto Hydro that includes both primary and secondary service lengths.

\(^1\) RRR Filing Guide, 2.1.5.5 (e) Total Circuit Kilometers of Line.
Table 1: Circuit-km of Line

<table>
<thead>
<tr>
<th>Year</th>
<th>Total (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>16,533</td>
</tr>
<tr>
<td>2006</td>
<td>17,561</td>
</tr>
<tr>
<td>2007</td>
<td>19,541</td>
</tr>
<tr>
<td>2008</td>
<td>21,520</td>
</tr>
<tr>
<td>2009</td>
<td>23,500</td>
</tr>
<tr>
<td>2010</td>
<td>25,517</td>
</tr>
<tr>
<td>2011</td>
<td>25,982</td>
</tr>
<tr>
<td>2012</td>
<td>25,881</td>
</tr>
<tr>
<td>2013</td>
<td>27,750</td>
</tr>
<tr>
<td>2014</td>
<td>28,480</td>
</tr>
<tr>
<td>2015</td>
<td>28,605</td>
</tr>
<tr>
<td>2016</td>
<td>28,605</td>
</tr>
<tr>
<td>2017</td>
<td>28,763</td>
</tr>
<tr>
<td>2018</td>
<td>28,922</td>
</tr>
<tr>
<td>2019</td>
<td>29,082</td>
</tr>
<tr>
<td>2020</td>
<td>29,242</td>
</tr>
<tr>
<td>2021</td>
<td>29,404</td>
</tr>
<tr>
<td>2022</td>
<td>29,566</td>
</tr>
<tr>
<td>2023</td>
<td>29,729</td>
</tr>
<tr>
<td>2024</td>
<td>29,894</td>
</tr>
</tbody>
</table>

ii) Please see Table 2, below, for the salaries and wages included in OM&A expenses exclusive of pensions, benefits, and taxes for 2005-2020. Toronto Hydro’s approach to OM&A for 2021-2024 is its Custom Price Cap Index.

---

2 Values for the period 2018-2024 is based on forecast.
3 This is different than the RRR filing values filed by Toronto Hydro since Toronto Hydro reported primary circuit kilometers of line in the RRR filing for 2005-2015.
4 Year 2007 and 2008 is based on estimate.
### Table 2: Salaries and Wages Included in OM&A ($ Millions)

<table>
<thead>
<tr>
<th>Year</th>
<th>Salary and Wages</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>$55.2</td>
</tr>
<tr>
<td>2006</td>
<td>$56.9</td>
</tr>
<tr>
<td>2007</td>
<td>$75.5</td>
</tr>
<tr>
<td>2008</td>
<td>$69.8</td>
</tr>
<tr>
<td>2009</td>
<td>$74.6</td>
</tr>
<tr>
<td>2010</td>
<td>$84.3</td>
</tr>
<tr>
<td>2011</td>
<td>$103.1</td>
</tr>
<tr>
<td>2012</td>
<td>$97.9</td>
</tr>
<tr>
<td>2013</td>
<td>$93.0</td>
</tr>
<tr>
<td>2014</td>
<td>$96.3</td>
</tr>
<tr>
<td>2015</td>
<td>$83.9</td>
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<tr>
<td>2016</td>
<td>$87.1</td>
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<tr>
<td>2017</td>
<td>$84.4</td>
</tr>
<tr>
<td>2018</td>
<td>$89.6</td>
</tr>
<tr>
<td>2019</td>
<td>$93.0</td>
</tr>
<tr>
<td>2020</td>
<td>$95.0</td>
</tr>
</tbody>
</table>

Note: Amounts are exclusive of pensions, benefits and taxes.

iii) Please see the table below for the ratio of accumulated depreciation to the gross value of plant in service.

### Table 3: Gross Assets/Accumulated Dep

<table>
<thead>
<tr>
<th>Gross Assets/Acc Dep</th>
<th>Ratio %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>52%</td>
</tr>
<tr>
<td>2006</td>
<td>53%</td>
</tr>
<tr>
<td>2007</td>
<td>53%</td>
</tr>
<tr>
<td>2008</td>
<td>53%</td>
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<tr>
<td>2009</td>
<td>54%</td>
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<td>2010</td>
<td>55%</td>
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<td>2011</td>
<td>53%</td>
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<tr>
<td>2012</td>
<td>53%</td>
</tr>
<tr>
<td>2013</td>
<td>53%</td>
</tr>
<tr>
<td>2014</td>
<td>53%</td>
</tr>
<tr>
<td>Year</td>
<td>Ratio %</td>
</tr>
<tr>
<td>------</td>
<td>---------</td>
</tr>
<tr>
<td>2015</td>
<td>9%</td>
</tr>
<tr>
<td>2016</td>
<td>13%</td>
</tr>
<tr>
<td>2017</td>
<td>15%</td>
</tr>
<tr>
<td>2018</td>
<td>18%</td>
</tr>
<tr>
<td>2019</td>
<td>21%</td>
</tr>
<tr>
<td>2020</td>
<td>23%</td>
</tr>
<tr>
<td>2021</td>
<td>26%</td>
</tr>
<tr>
<td>2022</td>
<td>27%</td>
</tr>
<tr>
<td>2023</td>
<td>29%</td>
</tr>
<tr>
<td>2024</td>
<td>31%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Ratio %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>52%</td>
</tr>
<tr>
<td>2006</td>
<td>53%</td>
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<td>53%</td>
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<td>2011</td>
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<tr>
<td>2012</td>
<td>53%</td>
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<td>2013</td>
<td>53%</td>
</tr>
<tr>
<td>2014</td>
<td>53%</td>
</tr>
<tr>
<td>2015(^5)</td>
<td>9%</td>
</tr>
<tr>
<td>2016</td>
<td>13%</td>
</tr>
<tr>
<td>2017</td>
<td>15%</td>
</tr>
<tr>
<td>2018</td>
<td>18%</td>
</tr>
<tr>
<td>2019</td>
<td>21%</td>
</tr>
<tr>
<td>2020</td>
<td>23%</td>
</tr>
<tr>
<td>2021</td>
<td>26%</td>
</tr>
<tr>
<td>2022</td>
<td>27%</td>
</tr>
<tr>
<td>2023</td>
<td>29%</td>
</tr>
<tr>
<td>2024</td>
<td>31%</td>
</tr>
</tbody>
</table>

\(^5\) Toronto Hydro notes that, in 2015, it adopted and prepared its first financial statements in accordance with IFRS. For additional information, please refer to Toronto Hydro’s financial statements (Exhibit 1C, Tab 3, Schedule 3, Appendix A, page 11).
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 29:

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

Preamble:

Toronto Hydro was found to be a good total cost performer in the early years of the decade, and that its performance has declined significantly under its 2015-2019 Custom IR plan and will continue to decline under the proposed 2020-2024 Custom IR plan.

(Exhibit 1B / Tab 4 / Schedule 2 / p. 6 / Table 1).

a) Please provide a summary table that compares Toronto Hydro’s actual and target rate of return on equity for each year since the beginning of the first generation IR.

b) Please provide Toronto Hydro’s gross plant additions for each year since 2002.

RESPONSE:

Toronto Hydro does not agree with the conclusions asserted in the preamble of this question. The information requested is below.

a) Please see Table 1 below for Toronto Hydro’s actual (i.e. achieved) and deemed annual rate of return on equity since 2005. Please also see Toronto Hydro’s response to 1B-CCC-22.
Table 1: Rate of return on equity (on a deemed basis)

<table>
<thead>
<tr>
<th>Year</th>
<th>Deemed</th>
<th>Achieved</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>9.88%</td>
<td>9.63%</td>
</tr>
<tr>
<td>2006</td>
<td>9.00%</td>
<td>13.44%</td>
</tr>
<tr>
<td>2007</td>
<td>9.00%</td>
<td>10.64%</td>
</tr>
<tr>
<td>2008</td>
<td>8.57%</td>
<td>10.90%</td>
</tr>
<tr>
<td>2009</td>
<td>8.01%</td>
<td>7.23%</td>
</tr>
<tr>
<td>2010</td>
<td>9.85%</td>
<td>8.14%</td>
</tr>
<tr>
<td>2011</td>
<td>9.58%</td>
<td>9.73%</td>
</tr>
<tr>
<td>2012</td>
<td>9.58%</td>
<td>7.62%</td>
</tr>
<tr>
<td>2013</td>
<td>9.58%</td>
<td>7.10%</td>
</tr>
<tr>
<td>2014</td>
<td>9.58%</td>
<td>7.41%</td>
</tr>
<tr>
<td>2015</td>
<td>9.30%</td>
<td>10.71%</td>
</tr>
<tr>
<td>2016</td>
<td>9.30%</td>
<td>12.18%</td>
</tr>
<tr>
<td>2017</td>
<td>9.30%</td>
<td>9.08%</td>
</tr>
</tbody>
</table>

b) Refer to table 2 for Gross Plant Additions.

Table 2: Gross Plant Additions ($ Millions)

<table>
<thead>
<tr>
<th>Year</th>
<th>Gross Plant Additions</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>48.3</td>
</tr>
<tr>
<td>2003</td>
<td>137.4</td>
</tr>
<tr>
<td>2004</td>
<td>97.7</td>
</tr>
<tr>
<td>2005</td>
<td>155.8</td>
</tr>
<tr>
<td>2006</td>
<td>198.1</td>
</tr>
<tr>
<td>2007</td>
<td>303.6</td>
</tr>
<tr>
<td>2008</td>
<td>227.9</td>
</tr>
<tr>
<td>2009</td>
<td>261.1</td>
</tr>
<tr>
<td>2010</td>
<td>421.2</td>
</tr>
<tr>
<td>2011</td>
<td>470.7</td>
</tr>
<tr>
<td>2012</td>
<td>304.6</td>
</tr>
<tr>
<td>2013</td>
<td>381.3</td>
</tr>
<tr>
<td>2014</td>
<td>468.7</td>
</tr>
<tr>
<td>2015</td>
<td>465.4</td>
</tr>
<tr>
<td>2016</td>
<td>617.1</td>
</tr>
<tr>
<td>2017</td>
<td>548.9</td>
</tr>
</tbody>
</table>
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 30:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 16

Preamble:
PSE notes that pension and benefit expenses are included in its cost benchmarking study because “these costs appear not to be accurately disaggregated for the Ontario distributors” (Exhibit 1B / Tab 4 / Schedule 2 / p. 16).

PSE also notes that high voltage expenses have been included in Toronto Hydro’s costs (Exhibit 1B / Tab 4 / Schedule 2 / p. 16).

a) Please confirm that pension and benefit expenses tend to be larger for U.S. electric utilities than for Ontario utilities because health care expenses are privately funded in the U.S. Please advise how this discrepancy has been accounted for in the model. For example, is it accounted for in the O&M price patch?

b) Please advise whether high voltage expenses were added to the costs of all of the other sampled Ontario utilities.

c) Please provide detailed information on Toronto Hydro’s substation and substation line capacity.
RESPONSE (PREPARED BY PSE):

a) PSE has not examined this issue empirically. No adjustment for pensions and benefits was made, but the impacts on the study of any change would be small. If pensions and benefits are subtracted from the cost definition rather than included, Toronto Hydro’s benchmarking score moves to -19.5% for the 2015-2017 average and -6.7% for the 2020-2024 average. This compares to the PSE reported results of -18.6% and -6.0% for 2015-2017 and 2020-2024 averages, respectively.

b) Yes, the high voltage expenses were added to the costs of all seven of the Ontario distributors. Please see the response to 1B-SEC-26 for a breakdown of the high voltage expenses of the Ontario distributors.

RESPONSE (PREPARED BY TORONTO HYDRO):

c) Please refer to Exhibit 2B, Section D2.3, System Utilization for information on Toronto Hydro’s substation loading. For more information, please also refer to Exhibit 2B, Section E7.4, Table 7 and Table 9.
INTERROGATORY 31:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 17

a) Please provide the maximum peak demand variable used in the study (Exhibit 1B / Tab 4 / Schedule 2 / p. 17). Please advise whether the data has been adjusted for known differences between U.S. and Ontario reporting.

RESPONSE (PREPARED BY PSE):

a) The maximum peak demand data can be found in the working papers provided by PSE. It can be found in the file labeled, “Modeling Dataset.xls” in column U. Yes, the data has already been adjusted for the fact that required “sales for resale” demand is included in the reported peak demand data for the U.S. utilities. This inclusion of sales for resale demand in the U.S. data is the only known difference between the two.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 32:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 18

EB-2017-0049, Exhibit A, Tab 3, Schedule 2, Attachment 2

Preamble:

PSE states, “there are eight business condition variables aside from input prices, plus a
time trend variable” (Exhibit 1B / Tab 4 / Schedule 2 / p. 18).

a) Some of the most cost-challenged distributors in Ontario are rural. The cost model
that PSE used in its recent Hydro One Networks Inc. (Hydro One) distribution
benchmarking study (EB-2017-0049 / Exhibit A / Tab 3 / Schedule 2 / Attachment
2) includes an area variable. Please explain whether PSE’s cost and reliability
model specifications provide balanced attention to rural and urban challenges. If
not, please explain why.

b) Please explain why there is an interaction term for urban congestion and
undergrounding but not one for urban congestion and forestation or
undergrounding and forestation. Are each of these pairs not equally reasonable?

c) Please identify any other measures of density considered besides the congestion
variable constructed by PSE.

d) Please advise whether the age of plant is a driver of cost. If so, please describe
how the model accounts for the effect of system age on cost. Please discuss any
age variables considered in the research.
e) Please provide the source of data for the Advanced Metering Infrastructure (AMI) variable for U.S. companies. If the EIA-861 was used, please explain whether any distinction was made between AMI vs. Automatic Meter Reading (AMR) when constructing this variable.

RESPONSE (PREPARED BY PSE):

a) PSE did include the same density variable (square KM of service territory divided by the number of customers) used in PSE’s Hydro One distribution benchmarking study. The variable was correctly signed, but barely missed the border of statistical significance with a p-value of 0.11 rather than the required p-value of 0.10. The congested urban provides an accurate depiction of Toronto Hydro’s benchmark since the utility has basically no rural service territory.

While it would not align with benchmarking principles to include the variable (due to it not meeting the 90% confidence level threshold), if the density variable is included in the model, the results show only a small change. Toronto Hydro’s 2015-2017 average becomes -19.9% (versus the reported -18.6%) and the 2020-2024 average becomes -7.1% (versus the reported -6.0%).

The reliability models do include the density variable. The CAIDI model also includes the congested urban variable, whereas that variable was not statistically significant in the SAIFI model.

b) No, they are not equally reasonable in PSE’s opinion. We began the research with the engineering underpinnings that undergrounding in urban areas is an important cost driver. Undergrounding power lines in urban settings is a drastically different process.
than undergrounding in rural or suburban settings. The cost differences between
undergrounding power lines in congested urban settings versus rural settings are also
dramatic. In rural or suburban settings, underground power lines can be direct
buried. Undergrounding does not require poles, and protects lines from climatic
elements. Therefore, undergrounding power lines in rural and suburban areas could
reduce costs relative to constructing overhead lines.

However, in congested urban settings, the civil infrastructure prohibits directly
burying the power lines. In putting in new lines or maintaining existing lines, the
utility must go through or around all the existing civil infrastructure (sidewalks, roads,
buildings). Traffic needs to be re-routed or delayed, and crews oftentimes need to
work on off-hours. Furthermore, the power lines and transformers themselves must
be protected and oftentimes encased in concrete and in vaults. All of this drastically
increases the capital and maintenance costs of underground power lines in congested
urban settings versus undergrounding in non-urban settings.

From both an engineering perspective and an empirical one, there are no other
differences that are so stark in terms of driving costs. While other interactions could
be considered from an engineering theoretical basis, including the undergrounding
and congested urban interaction to allow the model to disaggregate these dramatic
cost differences is important to accurately benchmarking Toronto Hydro, or any utility
with a congested urban core. Beyond just the engineering theory, which predicts
undergrounding in urban areas will cost significantly more, the total cost model itself
provides the empirical confirmation. The variable has a p-value of 0.0000, which
essentially means there is a 0% chance this variable is insignificant. None of the other
possible interactions has the engineering cost realities that urban undergrounding
possesses.
c) Please see the response to part (a) of this interrogatory. No other density variable was considered. PSE opted to exclude a density variable constructed with KM of line length. It is PSE’s experience that the data source used for the KM of line length (Platt’s UDI Directories) does not provide a consistent definition, and the differences in how utilities measure and report this variable can be large. Some utilities appear to report primary distribution lines only, whereas others report primary plus secondary lines that go all the way to the customer transformers or into the structure. The differences in these two measurements can be large.

d) There are two primary obstacles to including the age of plant into the benchmarking model. The first is that the age of plant is not entirely external to the management of the utility. Utilities make decisions on how much capital spending is required and how long asset lives can be prolonged. When evaluating cost performance, how the utility manages its capital infrastructure is not something that should be adjusted for. In fact, how a utility manages its infrastructure is one of the key items that flow into a utility’s cost performance. Performance benchmarking should not include variables that adjust for the management of capital infrastructure rather that is the very thing we are attempting to measure. Only external conditions that are primarily outside the control of utility management should be included in the total cost model. It is not obvious to PSE that the age of plant would qualify as an external business condition.

A system age variable is likely not an appropriate one for a cost performance benchmarking study. One issue is mentioned above (age of plant is not an external business condition). The second issue is that even if the researcher believed that the age of plant was primarily out of the control of the utility, there does not exist consistent data on accounting items like accumulated depreciation to formulate the variable. Utilities will have varying depreciation rates and investment patterns, both
across utilities and across a specified time period. Given that many assets will have
service lives in excess of 40 or 50 years, in order to create such a variable, the data
used would need to be consistent across those years and across utilities. In PSE’s
experience, that is not the case.

e) The EIA-861 form was the data source for the U.S. utilities. The variable was
formulated using the Advanced Metering Infrastructure (AMI) meters and does not
include Automated Meter Reading (AMR) meters. The AMI or smart meters typically
enable two-way communications and rate structures such as time-of-use (TOU)
pricing.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 33:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 21

Preamble:
PSE notes that its projection for Toronto Hydro’s capital cost is based on the Conference Board of Canada’s projections for Engineering Structures, Electric Power Generation, Transmission, and Distribution.

PSE notes that its projection for Toronto Hydro’s OM&A cost is based on Toronto Hydro’s projections for 2018, 2019, and 2020 and then the inflation factor formula proposed by Toronto Hydro. (Exhibit 1B / Tab 4 / Schedule 2 / p. 21).

a) Please advise whether the Conference Board of Canada’s projections for Engineering Structures, Electric Power Generation, Transmission, and Distribution is a Statistics Canada variable. If so, please provide the ID number.

b) Please compare Toronto Hydro’s OM&A projections for 2018, 2019, and 2020 to the inflation factor formula for those years.

RESPONSE (PREPARED BY PSE):

a) PSE gathered the variable from the Conference Board of Canada’s website. The ID for the variable is PIBOWNSE.
b) The table below provides the OM&A levels and growth rates and compares them to the projected inflation factor given the Canadian Board of Canada (CBoC) projections used in the benchmarking study. These were the projections as of April 2018. We provided the projected inflation factor, which uses a 70% weight on the GDP-IPI and a 30% weight on Average Weekly Earnings (AWE), and the OM&A-specific weights used in the study for inflation. The OM&A weights used put a 70% weight on the AWE and a 30% weight on the GDP-IPI. In comparing the growth rates, recall that OM&A expenses would be expected to grow at inflation minus productivity plus the growth in outputs (customers are projected to grow by 0.8%).

Table 1: Toronto Hydro OM&A Growth Compared to Inflation Measures

<table>
<thead>
<tr>
<th>Year</th>
<th>THESL OM&amp;A Growth Rate</th>
<th>Projections from CBoC Used in Benchmarking Study (April 2018)</th>
<th>Inflation Factor (70 GDP-IPI/30 AWE)</th>
<th>OM&amp;A Inflation Weights Used in Study (30 GDP-IPI/70 AWE)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>202,359</td>
<td>2.3% 2.3% 3.7% 2.8% 3.3%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>207,074</td>
<td>3.5% 1.8% 2.8% 2.1% 2.5%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td>214,419</td>
<td>5.0% 2.0% 2.5% 2.1% 2.3%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td>225,362</td>
<td>3.6% 2.3% 2.7% 2.1% 2.3%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Growth</td>
<td>3.6%</td>
<td>2.3%</td>
<td>2.7%</td>
<td></td>
</tr>
</tbody>
</table>
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 34:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 24

Preamble:

PSE states, “we determine the relative levels of utility plant asset prices for 2012 by using the City Cost Indexes for electrical work in RSMeans’ Heavy Construction Cost Data” (Exhibit 1B / Tab 4 / Schedule 2 / p. 24).

a) Please advise whether a weighted average of RSMeans values for cities in each service territory was considered when assigning a value for a given company.

b) If cost in higher population cities tends to exceed that in less populous cities, does it follow that a simple average will be lower than a weighted average for distributors that are assigned multiple cities?

c) Assuming Toronto Hydro was only assigned the RSMeans value for Toronto, does it follow that Toronto Hydro will be assigned a higher relative price level when compared to a simple average for others than it would if weighted averages were taken?

RESPONSE (PREPARED BY PSE):

a) No. PSE mapped the RSMeans values for the capital price levelization to the headquarter city of each utility. We did not use a simple average or a weighted
average for the levelization but rather used the headquarter city to set the RSMeans capital price levelization.

This compares to the 4th Generation IR OEB benchmarking study where no capital price levelization was implemented. The OEB benchmarking study is essentially assuming that capital prices are identical across Ontario. This is likely to disadvantage a utility serving a higher cost city like Toronto. In our benchmarking study, PSE corrects for this oversight. We made the assumption that uses the headquarter city for every utility as the basis for the levelization. We then use the city cost index for that city found in the 2012 RSMeans Heavy Construction Cost book. This will tend to be a conservative estimate as it pertains to Toronto Hydro relative to a weighted or a simple average approach.

b) To clarify, PSE did not use a simple average of multiple cities, but rather mapped the values for each utility to the headquarter city for that utility. Rather than a simple average, this likely gave full weight to the higher population city in the service territory, which is likely to correspond to the headquarter city. Given the assumption that cost in higher population cities tends to exceed cost in less populous cities, then if a simple average had been used (it was not), then the logic would follow. The approach PSE took will tend to be somewhat disadvantageous to Toronto Hydro relative to either a simple or a weighted average. However, the PSE approach does correct for an oversight in the OEB Study that does not levelized the capital price at all. The OEB Study assumes that construction costs are the same across all of Ontario and will be far more disadvantageous to utilities serving large Ontario cities, such as Toronto Hydro.
c) See the responses to part (a) and part (b) of this interrogatory. Toronto Hydro was assigned a relatively lower price level in the PSE Study relative to either a simple average or a weighted average. Despite this being somewhat disadvantageous to Toronto Hydro, the PSE assumption is fairer and more reasonable than the OEB Study assumption of having no capital price levelization.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 35:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 25

Preamble:
PSE states, “there are 90 utilities included in the total cost sample (this number includes Toronto Hydro)” (Exhibit 1B / Tab 4 / Schedule 2 / p. 25).

a) Please advise whether the sample selection process takes into account large transfers of utility plant from transmission to distribution and vice-versa. Would the perpetual inventory method include plant formerly classified as transmission? If so, please explain.

b) Please explain how the model controls for differing amounts of sub-transmission work done by the companies in the sample.

c) Please explain the logic of including only Ontario distributors that are classified as urban.

RESPONSE (PREPARED BY PSE):

a) PSE uses the classification of capital (transmission or distribution) that was designated in the year the plant went into service. We did not create a sample exclusion criterion for subsequent transfers of plant classifications. PSE believes this would unnecessarily make the sample smaller and would be an arbitrary exclusion. Further, the Board Staff’s consultant, PEG, did not exclude utilities for these transfers in their U.S. total
cost benchmarking sample and model put forth during Toronto Hydro’s 2015 CIR application.

It is unlikely that the perpetual inventory method includes plant formerly classified as transmission. The perpetual inventory method uses the classification of plant as it is designated in the year it goes into service. If the plant is designated as transmission in the year it goes into service, it is classified as transmission plant and not included in the definition of distribution costs. The only possible exception to our answer is if the plant was originally classified as distribution, re-classified as transmission, and then reverted back to distribution. However, this is an unlikely scenario, and would likely be such a small portion of capital as to have an insignificant impact.

b) All the high voltage expenses for the Ontario distributors, including Toronto Hydro, have been included in the cost definition. High voltage in Ontario is defined as assets above 50 kV. This generally aligns with the demarcation of distribution and transmission in the U.S. There are no other necessary model controls for the differences in the definition of distribution versus transmission. During Toronto Hydro’s 2015 CIR application (EB-2014-0116), the Board Staff’s consultant, PEG, put forth their revised model that included a variable intended to control for any differences. The variable was found to have no statistical impact on total cost, with a p-value of 0.6522, which is a strong indicator that the variable essentially has no impact on total cost.

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1 This variable is defined as the MVA of capacity with primary voltage above or equal to 50kV. The model can be found on p. 32 of PEG’s report in EB-2014-0116 entitled, “Toronto Hydro Electric System Limited Custom IR Application and PSE Report, Econometric Benchmarking of Toronto Hydro’s Historical and Projected Total Cost and Reliability Levels, Assessment and Recommendations.” December 2014.

Panel: Expert Witnesses
c) Please see Chapter 7, p. 48, of PSE’s report where the dataset is discussed. During Toronto Hydro’s 2015 CIR application (EB-2014-0116) the total cost benchmarking discussion primarily revolved around PSE’s U.S.-only dataset. In that proceeding, PSE put forth an Ontario plus U.S. dataset and model results that included a total of 156 utilities (71 Ontario distributors) and a U.S.-only dataset and model results. The Board Staff’s consultant, PEG, revised PSE’s U.S.-only dataset and model and presented those results in their report. Most of the discussions, therefore, focused on the U.S.-only results of both PSE and PEG and this was not raised as a point of concern in the Board Decision.

Based on that experience, PSE began the benchmarking research focused on the U.S.-only dataset. However, we have always contended that more data and observations are helpful to the precision of the model results, provided the additional observations are somewhat comparable and useful to the study. For this reason, we added the six Ontario distributors to the U.S. dataset. We selected the six because they had some portion of their service territory designated as congested urban, and this is one of the key variables in the study as it pertains to evaluating Toronto Hydro.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 36:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 36-37

Preamble:
PSE states:

“The estimates from the total cost model are presented in the following table. The results in the table show that the cost function parameter estimates have plausible signs and magnitudes. The output variables are fully interacted based on the translog cost function specification” (Exhibit 1B / Tab 4 / Schedule 2 / p. 36).

a) Please explain why the sign on the %UG coefficient is negative. How is this consistent with the hypothesis that subterranean work is a major factor in higher cost?

RESPONSE (PREPARED BY PSE):
Please see the response to 1B-Staff-32, part (b). While the hypothesis that undergrounding will increase costs is certainly true in urban settings, it is not necessarily true in non-urban settings. The costs of undergrounding power lines are dramatically different in different land use environments. In non-urban settings, being able to direct bury power lines, thus having them protected from climatic conditions, may actually reduce total costs. This is why the inclusion of the interaction term on undergrounding and the congested urban variable (%UG*%CU) is important: so the model can distinguish empirically between the urban and non-urban costs of undergrounding.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 37:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, pp. 37, 40-43, 45

Preamble:

PSE provides a summary of its approach to the reliability benchmarking of system average interruption frequency index (SAIFI) and customer average interruption duration index (CAIDI) for Toronto Hydro. PSE states that the approach was similar to the regression-based approach used for total cost benchmarking, but includes some different variables and different model specifications.

PSE provides summary tables of the estimated explanatory variable coefficients and associated t-statistics for, respectively, the SAIFI and CAIDI models (Exhibit 1B / Tab 4 / Schedule 2 / p. 43 / Tables 9 and 10).

a) Please provide Toronto Hydro’s system average interruption duration index (SAIDI) and SAIFI values for all historic and projected years (2005-2024) in the following forms:

i) All events
ii) Excluding events relating to loss of supply (LOS)
iii) Excluding events relating to major event days (MEDs)
iv) Excluding MEDs and LOS
v) Excluding MEDs, LOS, and scheduled outages

b) Please advise whether it is possible to derive performance on SAIDI from benchmarking only SAIFI and CAIDI.
c) Toronto Hydro reported its reliability using a sustained outage definition of five minutes, which matches what most of the sample uses as a sustained outage definition (Exhibit 1B / Tab 4 / Schedule 2 / p. 40).
   
i) Please provide the source of information on the definition of a sustained outage.
   
ii) Please provide the number of companies in the sample that define a sustained outage to be five minutes.
   
iii) Please provide the range of sustained outage definitions.
   
iv) Please advise which companies in the sample include LOS.
   
v) Please advise which companies in the sample include planned outages.
   
vi) Please advise whether Toronto Hydro’s metrics include LOS.
   
vi) Please advise whether Toronto Hydro’s metrics include planned distribution system outages.


d) Please advise whether the six other Ontario urban distributors included in the total cost benchmarking dataset were included in the reliability benchmarking dataset. Please explain your response.


e) Please provide detailed regression summary tables similar to Table 6 (Exhibit 1B / Tab 4 / Schedule 2 / p. 37) for the SAIFI and CAIDI regression models summarized in Tables 9 and 10 (Exhibit 1B / Tab 4 / Schedule 2 / p. 43).

f) PSE included “number of customers” as an explanatory variable in both the SAIFI and CAIDI models. In the SAIFI model, the estimated coefficient for this variable is -0.011 with a t-statistic of -1.565; it would be statistically insignificant at a 5% significance level given the number of observations. For the CAIDI model, the estimated coefficient is 0.024 with a t-statistic of 5.399, and would be statistically
significant at a 5% level (Exhibit 1B / Tab 4 / Schedule 2 / p. 43). Please explain why PSE considers “number of customers” to be a relevant explanatory variable for estimating SAIFI and CAIDI, which are normalized to be on a per customer basis.

g) In the CAIDI model, PSE includes both “sq. km. per customer” and “% congested urban” as explanatory variables. The “sq. km. per customer” variable has an estimated coefficient of 0.064 and a $t$-statistic of 5.999. The “% congested urban” variable has an estimated coefficient of 6.688 and a $t$-statistic of 2.709. Therefore, both variables are statistically significant at the 5% level (Exhibit 1B / Tab 4 / Schedule 2 / p. 43).

The positive coefficient value for “sq. km. per customer” is expected, as this corresponds with a utility serving a less dense, and probably larger service territory, and a utility may take longer on average to restore customers more geographically remote to operations centres, compared to utilities serving smaller developed communities.

It is less certain what the coefficient of the “% congested urban” variable should be. In addition to shorter travel distances (i.e. shorter times to have teams on site to respond to service interruptions), utilities serving major urban centres and with key industries (e.g., finance), government and other (e.g., hospital, education) sectors served may have invested in and manage infrastructures with increased redundancy and resiliency to avoid or recover from interruptions. At the same time, when interruptions do occur, recovery may take longer as evidenced by some underground vault incidents in Toronto in 2018. For Toronto Hydro, it has a
higher “% congested urban” variable level but a lower sq. km. per customer than is the case for most of the utilities in the benchmark dataset.

i) Given the diversity of characteristics for the utilities, please explain why PSE considers that the dataset of U.S. utilities is suitable for comparing Toronto Hydro’s reliability performance.

ii) With specific reference to Toronto Hydro, which of “sq. km. per customer” or “% congested urban” has a bigger impact on the residual difference of actual CAIDI less expected CAIDI.

h) PSE shows that Toronto Hydro’s SAIFI performance has historically been poor and will continue to be poor during the 2020-2024 Custom IR period (Exhibit 1B / Tab 4 / Schedule 2 / p. 45). Please explain why poor SAIFI performance is acceptable.

RESPONSE (PREPARED BY TORONTO HYDRO):

a) Please refer to Appendix A to this interrogatory.

Toronto Hydro notes that the SAIFI and SAIDI values provided are based on the five minute threshold for momentary interruptions and these values were used as part of the PSE study. Toronto Hydro provides these results on a best efforts basis as Toronto Hydro does not specifically track statistics based on a five minute threshold for momentary interruptions. Projections for items i) and ii) cannot be reasonably determined due to the variability and unpredictability of MEDs.

Following the submission of its pre-filed evidence, Toronto Hydro refined its approach underlying the results presented in Appendix A (and CAIDI) to more accurately reflect Toronto Hydro’s reliability performance under a five minute threshold for momentary
interruptions. The revised results are slightly different than the information Toronto Hydro provided to PSE (and as used by PSE in its benchmarking study).

**RESPONSE (PREPARED BY PSE):**

b) SAIDI is equal to SAIFI multiplied by CAIDI. Using this equation, the benchmarks could be multiplied to derive the SAIDI benchmark.

c) For reliability information for years prior to 2013, PSE gathered the information by searching regulatory filings. Most of the filings that specified a definition used a threshold of five minutes to define an outage. Since 2013 the reliability data has been gathered from the U.S. government form EIA-861, which does not provide the definition.

The table below provides the latest known sustained outage definition of each utility in the sample. For the utilities where the sustained outage definition is known, over 85% use a 5-minute definition, with the remainder using a 1-minute definition. The average sustained outage definition for the known sample is 4.42 minutes.
Loss of supply (LoS) amounts are not disaggregated from major event day outages on the EIA-861 form, and are typically not provided in the regulatory filings. On the EIA-861 form, utilities are not asked to exclude LoS outages from the metrics PSE used and we assume most of the utilities in the sample include LoS outages in the study metrics. For this reason, Toronto Hydro metrics include LoS outages. To the extent that some of the sampled utilities exclude LoS outages in the reliability metrics this would tend to disadvantage Toronto Hydro’s reliability benchmarking results.

<table>
<thead>
<tr>
<th>Utility</th>
<th>Last Known Sustained Definition</th>
<th>Utility</th>
<th>Last Known Sustained Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama Power Company</td>
<td>unknown</td>
<td>Metropolitan Edison Company</td>
<td>5</td>
</tr>
<tr>
<td>ALLETE (Minnesota Power)</td>
<td>5</td>
<td>Monongahela Power Company</td>
<td>unknown</td>
</tr>
<tr>
<td>Appalachian Power Company</td>
<td>unknown</td>
<td>Nevada Power Company</td>
<td>unknown</td>
</tr>
<tr>
<td>Arizona Public Service Company</td>
<td>unknown</td>
<td>New York State Electric &amp; Gas Corp.</td>
<td>5</td>
</tr>
<tr>
<td>Atlantic City Electric Company</td>
<td>unknown</td>
<td>Niagara Mohawk Power Corporation</td>
<td>5</td>
</tr>
<tr>
<td>Avista Corporation</td>
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<td>Northern States Power Co. - WI</td>
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<td>Consolidated Edison Co.</td>
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<td>Pennsylvania Electric Co.</td>
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<tr>
<td>Consumers Energy Co.</td>
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<td>Potomac Electric Power Co.</td>
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<td>Toledo Edison Co.</td>
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<td>Indiana Michigan Power Co.</td>
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<td>Wisconsin Electric Power Co.</td>
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<tr>
<td>Madison Gas and Electric Co.</td>
<td>5</td>
<td>Wisconsin Public Service Co.</td>
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</tbody>
</table>
It is PSE’s understanding that the reported reliability metrics include planned outages as these outages are not asked to be excluded on the EIA-861 form. To the extent that some of the sampled utilities exclude planned outages in the reliability metrics this would tend to disadvantage Toronto Hydro’s reliability benchmarking results.

Yes, Toronto Hydro’s study metrics include LoS outages.

Yes, Toronto Hydro’s study metrics include planned outages.

d) The six other Ontario distributors were not included, due to comparable data not being readily available for all of the sampled years.

e) Please see the following tables.

<table>
<thead>
<tr>
<th>EXPLANATORY VARIABLE</th>
<th>ESTIMATED COEFFICIENT</th>
<th>T STATISTIC</th>
<th>EXPLANATORY VARIABLE</th>
<th>ESTIMATED COEFFICIENT</th>
<th>T STATISTIC</th>
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</thead>
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<tr>
<td>N</td>
<td>-0.011</td>
<td>-1.565</td>
<td>IEEE</td>
<td>0.168</td>
<td>10.147</td>
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<tr>
<td>F</td>
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<td>1.936</td>
<td>Constant</td>
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<td>-3.800</td>
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<td>%UG</td>
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<td>-24.433</td>
<td>Adjusted R-Squared</td>
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<td></td>
</tr>
<tr>
<td>D</td>
<td>0.020</td>
<td>1.675</td>
<td>Sample Period:</td>
<td>2010-2016</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>Number of Observations</td>
<td>420</td>
<td></td>
</tr>
</tbody>
</table>

SAIFI Model Estimates

VARIABLE KEY
N = Number of Retail Customers
%F = Percent forestation
%UG = Percent underground distribution plant
D = Square KM divided by customers
IEEE = Binary variable for Ontario distributor

Adjusted R-Squared 0.681
f) The number of customers is a variable that adjusts for the size of the utility and how that may impact SAIFI or CAIDI metrics. It is true that the indexes are already reported on a per customer basis. PSE views the “number of customers” variable as basically a quadratic variable that provides the model the flexibility to adjust for the impact on reliability as the size of the utility changes.

g) The strength of the econometric benchmarking method is that diversity in the characteristics of the utilities can be accommodated and adjusted for through the econometric process. Toronto Hydro has a lower sq. km per customer and a higher congested urban value than most of the utilities in the sample; the econometric method uses the diversity of the dataset to determine how sq. km per customer and the percentage of congested urban impacts the expected CAIDI of the specific utility being studied.
The sq. km per customer term in the model equation equals the natural log of sq. km per customer multiplied by the coefficient on the term. This equals -0.456. The congested urban term in the equation equals 0.125. On an absolute basis, the sq. km per customer term has a larger impact on Toronto Hydro’s benchmark.

RESPONSE (PREPARED BY TORONTO HYDRO):

h) Please refer to Exhibit 2B, Section E2 for a description of Toronto Hydro’s balanced approach to: address customer preferences on rates and on reliability; achieve the utility’s service and public policy obligations; and sustainably manage asset risk over the long-term while mitigating material safety and environmental risks.
# Interrogatory Responses

Toronto Hydro-Electric System Limited

EB-2018-0165

1B-STAFF-37

Appendix A

FILED: January 21, 2019

Page 1 of 1

## Table 1: SAIFI

<table>
<thead>
<tr>
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<td>1.12</td>
<td>1.15</td>
<td>1.19</td>
<td>1.07</td>
<td>1.03</td>
<td>2.17</td>
<td>1.24</td>
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<td>0.95</td>
<td>0.95</td>
<td>1.01</td>
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<td>1.01</td>
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<td>0.85</td>
<td>0.96</td>
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## Table 2: SAIDI

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Notes: Results above were determined using a custom analysis to exclude interruptions that were less than 5 minutes for use in the PSE Econometric Benchmarking Report. Rounding differences may exist.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 38:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, pp. 18-19, 41

Preamble:

PSE provided a list of variables in Section 5.2 (which include percent forestation and square kilometres of territory per customer) (Exhibit 1B / Tab 4 / Schedule 2 / p. 41).

PSE noted that, “the reliability dataset is comprised of 74 distributors (this number includes Toronto Hydro)” (Exhibit 1B / Tab 4 / Schedule 2 / p. 41).

a) Similar to the information provided in Section 2.3.4 (Exhibit 1B / Tab 4 / Schedule 2 / pp. 18-19), please discuss the reason that each variable is included in the model. If a variable only appears in one model, please state why that variable was excluded from the other model.

b) Please provide the source of the data for square kilometres of territory per customer.

c) Please discuss the development of the forestation variable from the data sources.

d) Please advise if weather variables (e.g. precipitation) were considered.

e) Please advise whether there are groupings of reporting standards used in the U.S. similar enough to merit their own binary variable (similar to the IEEE binary variable).
f) Please advise whether Toronto Hydro was included in the estimation of the parameters used to benchmark Toronto Hydro. If so, please explain why.

RESPONSE (PREPARED BY PSE):

a) Number of customers: This variable measures how the size of the utility impacts the measured reliability metric. It essentially acts as a quadratic variable, providing the model flexibility to adjust for the impact of the number of customers on SAIFI or CAIDI.

Percent forestation: This variable measures the percentage of the service territory that is classified as forested. The more forestation, the higher the chances that trees or wildlife will cause outages. A higher chance for tree or wildlife outages will tend to increase the frequency of outages (SAIFI) and increase the outage restoration times when outages occur (CAIDI).

Percent underground (in SAIFI model only): Undergrounding power lines protects the lines from most weather events. This will tend to decrease the frequency of outages (SAIFI). The variable is not included in the CAIDI model because it has a negative coefficient value. This is contrary to PSE’s understanding that while undergrounding power lines will reduce the frequency of outages, it will increase the restoration time when outages do occur. Since the parameter estimate had a sign that did not align with our a priori theory we did not include it in the CAIDI model.

Standard deviation of the elevation changes in the service territory (in CAIDI model only): If the service territory has un-level terrain, it will tend to create longer drive
times and increase the complexity of restoring outages due to the hilly or
mountainous terrain. We did not include elevation standard deviation in the SAIFI
model, because we did not have a theoretical basis for why the standard deviation of
elevation would create more outages.

**Square kilometers of territory per customer:** This variable measures the density of
the service territory of each utility. The more square KM that a utility needs to cover
per customer, the higher the chances of an outage occurring, due to the longer line
lengths and chances for an outage-causing event. Drive times will increase when an
outage occurs as the square KM of territory per customer increases, thus increasing
CAIDI values.

**Percent smart meters (in CAIDI model only):** Smart meters enable the quicker
location of outages and should assist in quicker restoration of outages when they
occur. This will tend to reduce CAIDI. PSE did not include the percent smart meters in
the SAIFI model due to a lack of a theoretical basis for how smart meters would
impact the frequency of outages.

**Percent congested urban in service territory (in CAIDI model only):** This variable
measures how the percent of service territory classified as congested urban impacts
the duration of outages when they occur. In highly urban settings, when an outage
occurs, traffic congestion and the complexity of the distribution system will tend to
increase outages when they occur. PSE anticipated the congested urban variable
would have a negative coefficient estimate on SAIFI. However, the variable was not
statistically significant, so we did not include it in the SAIFI model.
IEEE binary variable (in SAIFI model only): The IEEE standard is based on excluding a major event day if the day contains a large amount of customer outages (2.5 standard deviations beyond the norm). Essentially, a large SAIFI value will trigger whether a major event day (MED) is declared. We had no expectations on this parameter sign, as it is relative to the stringency in the non-IEEE definitions. PSE did not include the variable in the CAIDI model because the IEEE is triggered by the SAIFI metric and not the CAIDI metric.

b) The square kilometers per customer variable is calculated using GIS coordinates of each utility’s service area provided to PSE by Platts. For more information please see: https://www.spglobal.com/platts/en/products-services/oil/map-data-pro. The variable equals the total square kilometers of the area of the distributors service territory divided by the number of retail customers served. The customer variable is the same as the output variable that enters the total cost model.

c) Please see p. 19 of the PSE report for the source of the forestation GIS information. PSE matched the land area maps with the Platts dataset referenced in part (b) of each utility’s service territory using GIS mapping.

d) An hourly wind variable was gathered and calculated. The variable was considered in the model, but the parameter estimate had a negative sign in each model, which did not align with our a priori theory. Therefore, PSE did not include the wind variable.

e) PSE is not currently aware of any possible standards groupings that would merit their own binary variable. That is not to say that the research could not be advanced, and PSE would be open to considering additional variables.
f) Toronto Hydro was excluded from the estimation of the parameters used to benchmark Toronto Hydro. This is the same procedure used for the total cost benchmarks and provides an externally-derived benchmark of Toronto Hydro.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 39:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 38

Preamble:

PSE states:

“Toronto Hydro has consistently been below its expected benchmark levels. During the most recent historical period of 2015 to 2017, Toronto Hydro’s costs are 18.6% below the benchmark values. During the CIR period of 2020 to 2024, Toronto Hydro’s costs are 6.0% below the benchmark values on average” (Exhibit 1B / Tab 4 / Schedule 2 / p. 38).

a) Please provide a 95% confidence interval around the reported -18.6% and -6.0% results for Toronto Hydro. Please explain whether these results for Toronto Hydro are statistically significantly different from zero.

RESPONSE (PREPARED BY PSE):

a) A 95% confidence interval for the -18.6% is -29.7% to -7.5%. Therefore, the 2015-2017 performance score of -18.6% is statistically significantly different from zero at a 95% confidence level. A 95% confidence interval for the -6.0% is -12.6% to +0.6%. Therefore, the 2020-2024 performance score of -6.0% is not statistically significantly different from zero at a 95% confidence level.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 40:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 43

Preamble:
PSE states, “we use an estimator that corrects for cross-sectional heterogeneity and addresses the panel form of the data” (Exhibit 1B / Tab 4 / Schedule 2 / p. 43).

a) Please describe what estimator is used.

b) Please advise whether the estimator also corrects for within-panel autocorrelation.

RESPONSE (PREPARED BY PSE):
a) We used a Generalized Least Squares (GLS) estimator that uses cross-sectional cluster weights and White’s cross-sectional covariance method. The procedures are standard in the software package employed by PSE in EViews, version 10.

b) No, it does not. The presence of autocorrelation does not present bias and is unlikely to produce a meaningfully different result from a procedure with no autocorrelation.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 41:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, pp. 15, 26, 50

Preamble:
The benchmarking dataset includes 83 U.S. utilities and 7 Ontario electricity distributors, including Toronto Hydro. PSE states that:

“Ontario distributors were added if a portion of their service territory was classified as “congested urban” (see Section 2.3.4). This added six Ontario distributors to the sample. No other Ontario distributors have been identified as containing “congested urban” service territory.” (Exhibit 1B / Tab 4 / Schedule 2 / p. 15)

The six Ontario electricity distributors, other than Toronto Hydro, in the data set, are:

- Enersource Hydro Mississauga (now part of Alectra Utilities)
- EnWin
- Horizon Utilities (now part of Alectra Utilities)
- Hydro Ottawa
- Kitchener-Wilmot Hydro
- London Hydro

a) Please explain why PSE considers the sole criterion for inclusion of an Ontario distributor to be a non-zero “congested urban” variable.

b) Please advise whether PSE considered inclusion of other Canadian utilities, in other provinces, that also serve major urban centres (e.g., Hydro-Québec, BC
Hydro, Alberta Utilities). If so, why were these utilities not included? If they were not considered, please explain why not.

c) In Table 13 (Exhibit 1B / Tab 4 / Schedule 2 / p. 50), 40 of the U.S. utilities show a congested area (sq. km.) value of “0”, which, trivially translates to a “0” value for the urban congestion variable. There are 6 other U.S. utilities for which the small size of the congested urban sq. km. relative to the utility’s total service area translates into a congested urban variable of “0.00%” (rounded to 2 decimal places). In effect, more than half (46 out of 83) of the U.S. utility sample does not meet the criterion use by PSE to decide whether to include or exclude an Ontario distributor.

   i) Please provide PSE’s reasons for using different criteria for selecting Canadian or Ontario utilities relative to U.S. utilities.

   ii) Why does PSE consider the sample selected to be reasonable for comparing Toronto Hydro’s performance given the differences in selection criteria?

RESPONSE (PREPARED BY PSE):

a) Please refer to Toronto Hydro’s response to 1B-Staff-35 (c).

b) PSE did not consider inclusion of non-Ontario Canadian utilities or think it was necessary to do so. To our knowledge, the level of detail needed to assure cost definition consistency, outputs, business conditions, and input prices is not all publicly available for other Canadian utilities. The seven Ontario distributors and U.S. data have consistent definitions for costs, outputs, business conditions, and input prices.
This already provides stakeholders with an extremely strong sample and benchmarking model relevant for Toronto Hydro’s circumstances.

c) We do not fully agree with the characterization or premise of this question. In any event, please see response to 1B-Staff-35 (c) for why PSE only added the six Ontario distributors with congested urban service territory, rather than the entire Ontario sample.

The sample is strong and provides stakeholders with a robust benchmarking dataset that includes many utilities larger and smaller than Toronto Hydro and with operating characteristics that are diverse, which is a positive when employing the econometric benchmarking approach. In Toronto Hydro’s 2015 CIR application, both benchmarking experts (PSE and PEG) used a U.S.-only sample to benchmark Toronto Hydro. In that proceeding, PSE also produced an Ontario plus U.S. sample that included all the Ontario distributors. PEG subsequently produced a report that presented a U.S.-only sample to provide benchmarking results for Toronto Hydro.

Further, the Board Decision in the application cited three key benchmarking areas (urban variable, CDM costs, and asset price inflation projects) that we have endeavored to address in the current research. We, therefore, have used a U.S. only sample, plus we have nonetheless added six Ontario distributors to the sample to enhance it, because adding this additional data was helpful for purposes of the econometric benchmarking. Adding the Ontario distributors that had some congested urban service territory was the most reasonable and meaningfully comparable place to add in some Ontario distributors, while still being cognizant of the level of effort and availability of data.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 42:

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

Preamble:

PSE only included six other Ontario distributors based on the criterion that the urban congestion variable is non-zero. There are several GTA utilities (PowerStream (now part of Alectra), Hydro One Brampton Networks (now part of Alectra), Veridian Connections Inc., Oshawa PUC Networks, Burlington Hydro, Oakville Hydro) which have long-established cores (even if the “urban congestion” variable is not satisfied), and have many similarities to Toronto Hydro in terms of socioeconomic characteristics pertaining to population, economic activity, growth, etc.

There are other Ontario utilities, outside of the GTA, which may also display similar characteristics to Toronto in terms of socioeconomic characteristics, maintaining a network in a built-up urban centre established many decades ago in addition to servicing newer expansions. Utilities such as Kingston Hydro, Waterloo North Hydro, Energy+, Guelph Hydro (now part of Alectra), Niagara Peninsula Energy, Peterborough Utilities Commission, Whitby Hydro, Bluewater Power are obvious candidates. Thunder Bay Hydro, PUC Inc. (serving Sault Ste. Marie, ON), North Bay Hydro and Greater Sudbury Hydro may exhibit similarities to a lesser degree, but still have to deal with servicing long-established networks in more dense city centres in addition to serving more recently expanded networks as the communities have grown over time.

a) Please explain why PSE believes that the six Ontario distributors are adequate to get a balanced and representative comparator data set, along with the 83 U.S.
utilities.

b) In PSE’s opinion, would including a number of GTA-area and other Ontario distributors serving cities in Ontario improve the balance of the dataset on which to compare Toronto Hydro’s cost performance.

RESPONSE (PREPARED BY PSE):

a) Applying engineering theory and costs, PSE identified the congested urban service territory condition, which describes a service territory characteristic that is expected to significantly increase costs. While other distributors might have city centers or “cores,” they do not have them to the point where the cores are expected to significantly drive up costs. Please see the PSE report in section “3.1.1.1 Definition of Congested Urban Area” for a discussion on how we designated service territory as congested urban (must contain buildings seven stories and above) and why that designation was chosen. PSE believes that Ontario distributors that have been included were appropriate and useful.

Please also see the response to 1B-Staff-35 (c) and the response to 1B-Staff-41 (c).

b) Please see the response to 1B-Staff-35 (c) and the response to 1B-Staff-41 (c).
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 43:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, pp. 20, 22, 37

Preamble:

PSE states that its equation includes a new Ontario binary variable:
“The Ontario binary variable measures the estimated cost differences between operating in Ontario versus the U.S. The variable is set equal to “1” if the utility operates in Ontario and “0” if the utility operates in the States. This variable adjusts for regulatory and other differences that may impact distribution costs between the two countries” (Exhibit 1B / Tab 4 / Schedule 2 / p. 20).

The regression results filed in Table 6 (Exhibit 1B / Tab 4 / Schedule 2 / p. 37) show that the Ontario binary variable has a negative coefficient of -0.304 and is statistically significant (t-statistic of -35.592 and a p-value < 1%).

a) Please explain why PSE considers that the Ontario binary variable is necessary for this updated study.

b) Please discuss the regulatory differences between Canada (or Ontario) and the United States, which PSE has identified and considers to be reflected in this variable. In what manner do these differences affect the utilities’ costs for benchmarking purposes?

c) Please explain what “other differences“ between Canada (or Ontario) and the United States PSE identified, which it considers are reflected in this variable.
d) Please explain whether there are additional regulatory or “other” differences that
would influence the costs of U.S. utilities in different state jurisdictions. If so, why
it is not necessary to account for these differences to ensure that the comparison
is on an apples-to-apples basis?

e) Please explain why PSE decided that the Ontario binary variable is the appropriate
way of accounting for differences, instead of including quantitative variables that
directly reflect the drivers of any material differences.

f) Please provide PSE’s explanation of the statistically significant and negative
coefficient for the Ontario binary variable.

RESPONSE (PREPARED BY PSE):

a) Since we are benchmarking an Ontario utility (Toronto Hydro), including a variable
that captures the differences between Ontario and U.S. is useful to the accuracy of
the study. These differences could include regulatory items such as:

- Incentive regulation (Ontario) versus primarily cost of service regulation (U.S.),
- The presence of annual econometric benchmarking in Ontario
- Energy efficiency/renewable mandate differences

In addition to regulatory items, the variable could reflect other differences such as:

- Differences in currency
- The input prices assigned to Ontario versus the U.S.
- Pension and benefit differences between the countries
- Other unknown differences.
b) Please see the response to part (a) for a list of some of the possible differences. To take one example, the fact that Ontario regulates using incentive regulation and regularly evaluates total cost levels of the distributors could have an impact in lowering costs of Ontario distributors relative to the U.S., which is primarily regulated by cost of service in most states. Furthermore, in the U.S., the states generally do not have benchmarking initiatives to evaluate cost levels accurately.

c) Please see the response to part (a) for a list of some of the possible differences.

d) There certainly are differences between different state jurisdictions. However, they will not be nearly as pronounced as the differences between one country and another country. Further, we are benchmarking Toronto Hydro, so developing a variable that allows the model to adjust for the Ontario service territory condition and provide a comparison between Toronto Hydro and the U.S. utilities is far more important in the context of this application than making sure a comparison is being made between (e.g.) Wisconsin Power and Light and Florida Power and Light.

e) PSE agrees that generally including quantitative variables to account for service territory conditions is the better approach. However, in some cases the differences cannot be quantified, or are unknown to the researcher. This is one of those cases. PSE is of the opinion that there are numerous differences between Ontario and the U.S. in regard to regulatory structures, government policies, currencies, and input prices. These cannot be reasonably quantified into variables, nor do they need to be since they all have in common that the difference is operating a distribution utility in Ontario versus the U.S. By including the Ontario binary variable, all these differences can be accounted and adjusted for.
f) The negative coefficient implies that, all other variables being equal, the expected costs of an Ontario distributor will be statistically significantly lower than their U.S. counterpart having the exact same variable values.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 44:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 37

Preamble:
Table 6 (Exhibit 1B / Tab 4 / Schedule 2 / p. 37) highlights the regression statistics and estimates for the total cost equation, including the coefficient estimates and associated t-statistics.

PSE notes that the equation used a translog functional form, which would account for inclusion of squares and cross-products of some of the variables.

a) %AMI is the percentage of deployed meters with AMI capabilities. This includes smart meters as deployed to residential and small general service customers in Ontario. The variable %AMI² has an estimated coefficient of -0.029 and is statistically insignificant at a 5% significance level (t-statistic = -0.642). Please provide the following:
   i) The interpretation of the variable %AMI².
   ii) A discussion of why it is retained in the final model specification as the term is statistically insignificant.

b) %CU is the percentage of service area that is “congested urban”. %UG is the percentage of distribution plant that is underground. %UGU is the cross-product (%CU × %UG). The equation contains all of these variables and their squares (%CU, %CU², %UG, %UG², %UGU, %UGU²). All of these variables have estimated
coefficients which are statistically significant at a 5% significance level except %UG$. Please provide the following:

i) An explanation as to why %UG was retained in the final model, given its estimated coefficient of -0.002 and that it is statistically insignificant ($t$-statistic = -0.482).

ii) The rationale for including the square of the cross-product %UG in the model specification and interpretation of this variable.

c) More than half of the U.S. utilities in the sample would have a value of “0” for %CU. This would mean that %CU, %CU$^2$, %UGU and %UGU$^2$ would be “0” for all of these utilities. Having the same value for these four variables for half of the sample would detract from the ability of the Maximum Likelihood Estimation technique for the regression model. While recognizing that coefficients are statistically significant, indicating that there was adequate signal-to-noise in the values for the variables for other utilities in the sample, please explain what tests PSE performed for multicollinearity in the data. Please provide the results of such tests.

d) The following table summarizes, from Table 6 (Exhibit 1B / Tab 2 / Schedule 1 / p. 37), the estimated coefficients and associated $t$-statistics for these variables:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Estimated Coefficient</th>
<th>$t$-statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>%CU</td>
<td>160.845</td>
<td>19.382</td>
</tr>
<tr>
<td>%CU$^2$</td>
<td>-5664.714</td>
<td>-12.751</td>
</tr>
<tr>
<td>%UG</td>
<td>-0.077</td>
<td>-4.676</td>
</tr>
<tr>
<td>%UG$^2$</td>
<td>-0.002</td>
<td>-0.482</td>
</tr>
</tbody>
</table>
OEB staff interprets that the level of the coefficients for %CU, %CU\(^2\), %UGU and %UGU\(^2\) may reflect the fact that the base variables themselves are percentages, and some squares and cross-products of these variables will be even smaller quantitatively. However, it is not intuitive on how to interpret the signs of the majority of these variables, particularly for the squares and cross-products.

i) Please advise whether PSE had a priori assumptions about the coefficient signs for these variables. If so, what were these, and what was the basis for the a priori assumptions?

ii) Please provide PSE’s interpretation of the level and signs for each of these variables.

**RESPONSE (PREPARED BY PSE):**

a) The quadratic variable provides the curvature of the impact the variable has on total cost. In this case, the presence of AMI increases cost, but the negative quadratic implies that the costs increases due to AMI are reduced as the percentage AMI increases.

The principle “retain a variable only if it is correctly signed and statistically significant” only applies to first order terms. This is the same principle that is applied to the other interaction and quadratic terms in the equation and has been applied to all of PSE’s benchmarking research presented before the Board. This same principle is also applied in the 4th Generation IR benchmarking research as well.
b) Please see the response to part (a) of this interrogatory.

All quadratics of the business conditions were automatically included in the model. 
The interpretation of the quadratic on the urban undergrounding variable is: as the percentage of urban undergrounding increases, the cost impact increases, and it does so at a higher rate of increase at the upper range of the variable.

c) No tests were performed, nor are any necessary. Multicollinearity is when explanatory variables (such as percent congested urban and percent underground) tend to be correlated across sampled observations. While this is likely true for variables like percent congested urban and percent underground, it should not give us concern regarding the model precision or bias. The presence of multicollinearity does not introduce any bias into the sample.

What multicollinearity does produce is that it makes it harder for the model to distinguish between the impacts of two correlated explanatory variables (such as percent congested urban and percent undergrounding). However, despite the likely presence of multicollinearity, both variables are found to be statistically significant. This is due to the large sample size (1,318 observations) and the different cost impacts of the variables.

There are distinguishable differences between non-urban undergrounding, urban undergrounding, and serving a congested urban service territory. The model did in fact distinguish those impacts at a statistically significant level.

d) PSE had a priori assumptions on the first order terms of %CU and %UGU. We did not have a priori assumptions on the first order term for %UG and the quadratic terms of
%CU², %UG², and %UGU². Our a priori assumption on %CU was that the coefficient would be positive, and this assumption resulted from PSE’s engineering experience and analysis of the costs in serving a congested urban service territory.

For the engineering analysis, please see the Appendix of the 2015 PSE benchmarking report, which provides the capital cost estimates of serving different land use environments. The a priori assumption on the %UGU variable, which is the urban undergrounding variable, was that the coefficient would be positive. Undergrounding in congested urban environments is far more costly and complex than in rural or suburban settings where lines can oftentimes be open trenched and directly buried.

PSE did not have an a priori assumption on the %UG variable. Together with the presence of the %UGU variable, the %UG variable essentially measures the impact of undergrounding in non-urban environments. PSE is unsure of the cost impact from an engineering perspective. Undergrounding in non-urban environments can oftentimes be done at similar costs as constructing overhead lines, and maintenance costs of underground lines tends to be lower. However, underground costs will vary depending on the terrain, so PSE had no a priori assumptions on this variable.

The levels and signs of these variables either align with our a priori assumptions or appear reasonable to PSE.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 45:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, pp. 31-33, 51-140

Preamble:

PSE set out its new approach to accounting for “urban congestion” and states that its approach was modelled on cities with populations of at least 200,000 (Exhibit 1B / Tab 2 / Schedule 1 / p. 31).

PSE also states that it applied its approach to use GIS mapping data to also define “urban congestion” in cities over 200,000 population served by utilities in the sample (Exhibit 1B / Tab 2 / Schedule 1 / p. 33).

a) Please confirm that the 200,000 population criterion was also used, in addition to a non-zero “urban congestion” variable to restrict the Ontario sample to six distributors in addition to Toronto Hydro. In other words, were other GTA utilities, and utilities like Waterloo North Hydro, Kingston Hydro, Energy+, also excluded because of having populations less than 200,000.

b) It is not clear that all U.S. utilities in the sample serve areas containing cities with a population of at least 200,000. Examination of the maps (Exhibit 1B / Tab 2 / Schedule 1 / pp. 51-140) suggest at least some that may not meet this criterion:

i) Minnesota Power Inc. (Duluth - 86,066)¹

¹ <http://worldpopulationreview.com/us-cities/duluth-mn-population/>
Please identify all U.S. utilities in the sample that do not serve a city with a population of at least 200,000.

c) Please explain why PSE considers it appropriate to use a different criterion for including (or excluding) Ontario distributors than it uses for the U.S. utilities included in the sample.

d) Please explain why PSE considers its sample of U.S. and Ontario utilities constitutes a representative sample for benchmarking Toronto Hydro’s costs given the differences in selection criteria and the heterogeneity of the included U.S. utilities.

e) In the context of generally consistent data available for all Ontario distributors (i.e., through RRR data filings with the OEB and compiled in Statistical Yearbooks available on the OEB’s website) and given the heterogeneity of U.S. utilities, please provide the following:

i) A discussion explaining why a sample based on all Ontario electricity distributors (with possible exclusions of Hydro One Networks Inc. and Algoma Power Inc. due to significant rural service territories) combined with the U.S.

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2 <https://www.southdakotademographics.com/cities_by_population>
3 <http://worldpopulationreview.com/states/west-virginia-population/cities/>
4 <https://www.pennsylvaniademographics.com/cities_by_population>
utility sample would not be a better comparator set for assessing Toronto Hydro’s costs. Please advise whether PSE considered such a sample. If not, please explain.

RESPONSE (PREPARED BY PSE):

a) Confirmed - we only examined cities for congested urban territory if the city’s population was at or above 200,000.

b) The question above says, “It is not clear that all U.S. utilities in the sample serve areas containing cities with a population of at least 200,000.” To clarify, some U.S. utilities that serve areas with no cities having a population of at least 200,000 are included in the sample. The 200,000 population criterion was based on only examining those cities for congested urban conditions that met the 200,000 in population threshold. We included all U.S. investor-owned utilities that had available and plausible data values for all variables with no other criteria for exclusion.

c) We do not agree with the characterization or premise of this question. Please see the response to 1B-Staff-35, part (c) and the response to 1B-Staff-41, part (c). PSE used a U.S. only sample (for reasons described in response to 1B-Staff-41 (c)) and then supplemented and enhanced the sample with six Ontario distributors that contain congested urban service territory. We would not characterize that as having different selection criterion.

d) Please see the response to 1B-Staff-35, part (c) and the response to 1B-Staff-41, part (c) for the selection criteria portion of the question. Regarding the heterogeneity or diversity of the included U.S. utilities: The strength of the econometric benchmarking
method is that heterogeneity or diversity in the characteristics of the utilities can be accommodated and adjusted for through the econometric process. Heterogeneity or diversity should be helpful to the model, rather than a detriment. The econometric method uses the diversity of the dataset to determine how variables impact the expected costs or reliability, and these calculations can be made specific to the utility being studied.

e) Please see the response to 1B-Staff-35, part (c), the response to 1B-Staff-41, part (c), and the response to 1B-Staff-42, part (b). The PSE sample already is a strong one and provides a robust evaluation of Toronto Hydro’s total cost levels.
RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 46:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, pp. 18-19, 37

Preamble:
PSE includes a variable %E accounting for the fact that a number of U.S. utilities operate as both electricity and natural gas distributors in their service territories. They also assign a value of 100% to the seven Ontario distributors, including Toronto Hydro, in the data set.

PSE defines %E as follows:
“The percentage of electric customers measures the percentage of electric customers served by a utility out of total gas and electric customers. This variable measures the economies of scope available from serving both electric and gas customers. Billing and other customer-related activities can be shared between the gas and electric divisions when a utility serves its customers with both commodities. The value is set to 100% for Toronto Hydro and the six Ontario distributors, since they do not serve natural gas customers” (Exhibit 1B / Tab 4 / Schedule 2 / pp. 18-19).

In the total cost model, summarized in Table 6 (Exhibit 1B / Tab 4 / Schedule 2 / p. 37), both %E and %E^2 are included, with the estimated coefficients being both positive and statistically significant.

a) Please provide PSE’s interpretation of the estimated coefficient of 0.407 (t-statistic = 17.433) for %E.
b) Please provide PSE’s:
   
   i) Explanation for the inclusion of \(\%E^2\).
   
   ii) Interpretation of the significant positive coefficient of \(\%E^2\) (value = 0.348, \(t\)-statistic = 10.766).

RESPONSE (PREPARED BY PSE):

a) PSE’s interpretation of the coefficient is that it will tend to cost more to serve electric customers if some of those costs cannot be shared with serving gas customers.

b) PSE’s interpretation is that the cost impacts of the percent electric customer variable increases as the level of the variable increases.
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

INTERROGATORIES

INTERROGATORY 2:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 25, Figure 12

a) Please provide the number of outages for each of the years 2006 to 2018.

b) Please confirm an outage results in a customer interruption. If not, please explain.

RESPONSE:

a) Table 1: Number of outages 2006-2018

<table>
<thead>
<tr>
<th>Year</th>
<th>Customer Interruptions (Excl. LoS, MEDs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>1,247,848</td>
</tr>
<tr>
<td>2007</td>
<td>1,199,921</td>
</tr>
<tr>
<td>2008</td>
<td>1,132,890</td>
</tr>
<tr>
<td>2009</td>
<td>1,021,481</td>
</tr>
<tr>
<td>2010</td>
<td>1,067,276</td>
</tr>
<tr>
<td>2011</td>
<td>1,045,478</td>
</tr>
<tr>
<td>2012</td>
<td>910,167</td>
</tr>
<tr>
<td>2013</td>
<td>967,367</td>
</tr>
<tr>
<td>2014</td>
<td>863,787</td>
</tr>
<tr>
<td>2015</td>
<td>976,890</td>
</tr>
<tr>
<td>2016</td>
<td>967,610</td>
</tr>
<tr>
<td>2017</td>
<td>898,933</td>
</tr>
<tr>
<td>2018</td>
<td>1,247,848</td>
</tr>
</tbody>
</table>

b) In reference to part (a), an outage is a customer interruption.
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

INTERROGATORIES

INTERROGATORY 3:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 25, Figure 12

a) Please provide the total duration of outages in minutes for each of the years 2006 to 2018.

b) Please confirm outage minutes is the same thing as customer interruption minutes. If not, please explain.

RESPONSE:

a) Please see Table 1 below.

Table 1: Customer Minutes Out 2006-2018

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Customer Minutes Out (Excl LoS and MEDs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>47,524,682</td>
</tr>
<tr>
<td>2007</td>
<td>50,966,982</td>
</tr>
<tr>
<td>2008</td>
<td>49,742,033</td>
</tr>
<tr>
<td>2009</td>
<td>51,110,492</td>
</tr>
<tr>
<td>2010</td>
<td>49,312,130</td>
</tr>
<tr>
<td>2011</td>
<td>58,132,537</td>
</tr>
<tr>
<td>2012</td>
<td>42,206,105</td>
</tr>
<tr>
<td>2013</td>
<td>48,394,537</td>
</tr>
<tr>
<td>2014</td>
<td>39,018,251</td>
</tr>
<tr>
<td>2015</td>
<td>44,385,371</td>
</tr>
<tr>
<td>2016</td>
<td>41,216,468</td>
</tr>
</tbody>
</table>

Panel: Distribution System Capital and Maintenance
Panel: Distribution System Capital and Maintenance

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Customer Minutes Out (Excl LoS and MEDs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>41,607,079</td>
</tr>
<tr>
<td>2018</td>
<td>37,185,095</td>
</tr>
</tbody>
</table>

b) Toronto Hydro confirms that outage minutes is the same as customer interruption minutes.
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

INTERROGATORIES

INTERROGATORY 4:
Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 5


b) Please provide a copy of any reliability benchmarking reports that THESL has participated in within the last 5 years.

RESPONSE:

a) The standard is subject to copyright restrictions which prevent Toronto Hydro from converting its individually-purchased copy into a public document.

Toronto Hydro also notes that the standard may be purchased via the following link:

b) Please see the Econometric Benchmarking Report prepared by Power System Engineering, Inc. filed at Exhibit 1B, Tab 4, Schedule 2.
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

INTERROGATORIES

INTERROGATORY 5:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, pp. 7-8

a) Does THESL set annual forecast levels for number and duration of Scheduled Outages?

b) If yes to part a), please provide forecast and actuals for Scheduled Outages for the years 2013 to 2018.

RESPONSE:

a) Toronto Hydro does not set annual forecast levels for number and duration of Scheduled Outages.

b) Please see response to part (a)
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

INTERROGATORIES

INTERROGATORY 6:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 11, Table 2

a) Please confirm Table 2 excludes MEDs.

b) For each Cause Code in Table 2 plus add the cause code Major Event Days, please provide the percentage contribution to SAIFI and SAIDI for each of the years 2013 to 2018.

c) For each Cause Code in Table 2 please provide the # of interruptions and # of interruption minutes by year for each of the years 2013 to 2018 and the totals for each year.

d) For the Defective Equipment Cause Code, please provide the number of interruptions and # of interruption minutes by equipment type contributing to Defective Equipment for each of the years 2013 to 2018 and totals for each year.

e) Please discuss if the number of Defective Equipment interruptions equates to the number of asset failures each year. If not please provide the number of asset failures each year for each of the years 2013 to 2018.

f) With respect to Defective Equipment, please identify the equipment types that are the most critical when they fail and why.
Please discuss if the restoration approach, prioritization and timing for critical assets differs from non-critical assets.

Please confirm data for Major Event Days, Adverse Weather, Lightning and Tree Contacts is not included under Defective Equipment.

Please confirm data for Major Event Days, Adverse Weather and Lightning is not included under Tree Contacts.

RESPONSE:

a) Table 2 excludes MEDs.

b) Please see Table 1 and Table 2 below.

Table 1: SAIFI Contribution Including MEDs by Cause Code

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>ADVERSE ENVIRONMENT</td>
<td>0%</td>
<td>1%</td>
<td>10%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>ADVERSE WEATHER</td>
<td>40%</td>
<td>14%</td>
<td>10%</td>
<td>9%</td>
<td>8%</td>
<td>28%</td>
</tr>
<tr>
<td>DEFECTIVE EQUIPMENT</td>
<td>20%</td>
<td>32%</td>
<td>36%</td>
<td>35%</td>
<td>31%</td>
<td>20%</td>
</tr>
<tr>
<td>FOREIGN INTERFERENCE</td>
<td>4%</td>
<td>9%</td>
<td>7%</td>
<td>8%</td>
<td>9%</td>
<td>7%</td>
</tr>
<tr>
<td>HUMAN ELEMENT</td>
<td>2%</td>
<td>4%</td>
<td>7%</td>
<td>5%</td>
<td>1%</td>
<td>2%</td>
</tr>
<tr>
<td>LIGHTNING</td>
<td>1%</td>
<td>0%</td>
<td>1%</td>
<td>0%</td>
<td>1%</td>
<td>0%</td>
</tr>
<tr>
<td>LOSS OF SUPPLY</td>
<td>18%</td>
<td>22%</td>
<td>12%</td>
<td>9%</td>
<td>17%</td>
<td>20%</td>
</tr>
<tr>
<td>SCHEDULED OUTAGE</td>
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<td>1%</td>
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</tr>
<tr>
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<td>11%</td>
<td>9%</td>
</tr>
<tr>
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<td>13%</td>
<td>23%</td>
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<td>14%</td>
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</tbody>
</table>
Table 2: SAIDI Contribution Including MEDs by Cause Code

<table>
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<tbody>
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<tr>
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<td>55%</td>
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<tr>
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<td>50%</td>
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<td>13%</td>
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<tr>
<td>FOREIGN INTERFERENCE</td>
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<td>5%</td>
<td>7%</td>
<td>10%</td>
<td>3%</td>
</tr>
<tr>
<td>HUMAN ELEMENT</td>
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<td>1%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>LIGHTNING</td>
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<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>LOSS OF SUPPLY</td>
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<td>5%</td>
<td>7%</td>
<td>15%</td>
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<tr>
<td>SCHEDULED OUTAGE</td>
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<td>3%</td>
<td>6%</td>
<td>3%</td>
<td>1%</td>
</tr>
<tr>
<td>TREE CONTACTS</td>
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<td>5%</td>
<td>11%</td>
<td>26%</td>
<td>11%</td>
</tr>
<tr>
<td>UNKNOWN</td>
<td>0%</td>
<td>4%</td>
<td>3%</td>
<td>5%</td>
<td>4%</td>
<td>1%</td>
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</table>

Table 3: Customer Interruptions by Cause Code

<table>
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<tr>
<th></th>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>ADVERSE ENVIRONMENT</td>
<td>684</td>
<td>11,866</td>
<td>74,914</td>
<td>1,807</td>
<td>439</td>
<td>988</td>
</tr>
<tr>
<td>ADVERSE WEATHER</td>
<td>162,683</td>
<td>77,864</td>
<td>92,467</td>
<td>90,771</td>
<td>76,151</td>
<td>100,462</td>
</tr>
<tr>
<td>DEFECTIVE EQUIPMENT</td>
<td>382,908</td>
<td>387,519</td>
<td>433,324</td>
<td>370,901</td>
<td>344,853</td>
<td>308,064</td>
</tr>
<tr>
<td>FOREIGN INTERFERENCE</td>
<td>94,257</td>
<td>109,995</td>
<td>77,814</td>
<td>89,150</td>
<td>107,065</td>
<td>103,812</td>
</tr>
<tr>
<td>HUMAN ELEMENT</td>
<td>33,771</td>
<td>53,237</td>
<td>78,364</td>
<td>53,655</td>
<td>11,456</td>
<td>26,929</td>
</tr>
<tr>
<td>LIGHTNING</td>
<td>10,880</td>
<td>4,675</td>
<td>10,399</td>
<td>3,747</td>
<td>14,251</td>
<td>1,738</td>
</tr>
<tr>
<td>LOSS OF SUPPLY</td>
<td>74,934</td>
<td>154,383</td>
<td>104,096</td>
<td>91,577</td>
<td>191,909</td>
<td>263,344</td>
</tr>
<tr>
<td>SCHEDULED OUTAGE</td>
<td>30,323</td>
<td>31,634</td>
<td>16,495</td>
<td>25,226</td>
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<td>7,993</td>
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<tr>
<td>TREE CONTACTS</td>
<td>104,486</td>
<td>73,189</td>
<td>39,394</td>
<td>87,477</td>
<td>104,532</td>
<td>101,329</td>
</tr>
<tr>
<td>UNKNOWN</td>
<td>147,375</td>
<td>113,808</td>
<td>153,719</td>
<td>244,876</td>
<td>228,142</td>
<td>218,398</td>
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<tr>
<td>TOTAL</td>
<td>1,042,301</td>
<td>1,018,170</td>
<td>1,080,986</td>
<td>1,059,187</td>
<td>1,090,842</td>
<td>1,133,057</td>
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</tbody>
</table>

Panel: Distribution System Capital and Maintenance
Table 4: Customer Minutes Out by Cause Code

<table>
<thead>
<tr>
<th></th>
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<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>ADVERSE ENVIRONMENT</td>
<td>9,971</td>
<td>715,251</td>
<td>6,878,533</td>
<td>334,214</td>
<td>55,160</td>
<td>99,869</td>
</tr>
<tr>
<td>ADVERSE WEATHER</td>
<td>11,530,544</td>
<td>1,878,660</td>
<td>6,586,073</td>
<td>6,195,922</td>
<td>2,628,998</td>
<td>7,866,921</td>
</tr>
<tr>
<td>DEFECTIVE EQUIPMENT</td>
<td>19,837,121</td>
<td>21,112,359</td>
<td>19,670,840</td>
<td>21,508,392</td>
<td>19,018,823</td>
<td>16,107,148</td>
</tr>
<tr>
<td>FOREIGN INTERFERENCE</td>
<td>4,632,016</td>
<td>6,911,369</td>
<td>3,046,808</td>
<td>2,891,666</td>
<td>5,297,218</td>
<td>3,689,236</td>
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<tr>
<td>HUMAN ELEMENT</td>
<td>373,205</td>
<td>836,294</td>
<td>1,524,571</td>
<td>560,666</td>
<td>220,416</td>
<td>410,190</td>
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<tr>
<td>LIGHTNING</td>
<td>596,153</td>
<td>607,737</td>
<td>108,255</td>
<td>73,786</td>
<td>196,903</td>
<td>20,754</td>
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<tr>
<td>LOSS OF SUPPLY</td>
<td>1,250,818</td>
<td>5,173,951</td>
<td>2,943,342</td>
<td>2,151,954</td>
<td>3,540,551</td>
<td>7,916,922</td>
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<tr>
<td>SCHEDULED OUTAGE</td>
<td>2,780,052</td>
<td>2,017,457</td>
<td>1,750,791</td>
<td>2,709,951</td>
<td>1,409,265</td>
<td>1,347,899</td>
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<tr>
<td>TREE CONTACTS</td>
<td>7,340,837</td>
<td>3,767,841</td>
<td>3,030,233</td>
<td>4,962,889</td>
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<tr>
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<td>1,294,638</td>
<td>1,171,283</td>
<td>1,789,267</td>
<td>1,978,982</td>
<td>1,863,246</td>
<td>1,672,794</td>
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<tr>
<td><strong>TOTAL</strong></td>
<td>49,645,355</td>
<td>44,192,202</td>
<td>47,328,713</td>
<td>43,368,422</td>
<td>45,147,630</td>
<td>45,102,017</td>
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</table>

d) Please see Table 5 and Table 6 below.

Table 5: Customer Interruptions Due to Defective Equipment by Equipment Type

<table>
<thead>
<tr>
<th>Equipment Type</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead Conductors/Connections</td>
<td>32,695</td>
<td>16,738</td>
<td>31,503</td>
<td>34,974</td>
<td>39,158</td>
<td>24,029</td>
</tr>
<tr>
<td>Overhead Switch</td>
<td>30,973</td>
<td>48,844</td>
<td>34,413</td>
<td>28,612</td>
<td>27,736</td>
<td>31,766</td>
</tr>
<tr>
<td>Overhead Transformer</td>
<td>4,762</td>
<td>13,488</td>
<td>14,698</td>
<td>3,008</td>
<td>16,203</td>
<td>2,617</td>
</tr>
<tr>
<td>Pole and Pole Accessories</td>
<td>62,351</td>
<td>68,545</td>
<td>85,848</td>
<td>55,246</td>
<td>40,126</td>
<td>26,487</td>
</tr>
<tr>
<td>Stations</td>
<td>14,650</td>
<td>16,856</td>
<td>6,746</td>
<td>12,832</td>
<td>11,917</td>
<td>13,166</td>
</tr>
<tr>
<td>Underground Cable/Connections</td>
<td>208,126</td>
<td>161,365</td>
<td>193,028</td>
<td>172,930</td>
<td>153,421</td>
<td>147,208</td>
</tr>
<tr>
<td>Underground Switch</td>
<td>10,525</td>
<td>40,308</td>
<td>31,431</td>
<td>28,918</td>
<td>12,518</td>
<td>31,738</td>
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<tr>
<td>Underground Transformer</td>
<td>12,242</td>
<td>14,184</td>
<td>18,414</td>
<td>29,195</td>
<td>41,417</td>
<td>30,188</td>
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<tr>
<td>Others/Multiple</td>
<td>6,584</td>
<td>7,164</td>
<td>16,539</td>
<td>5,186</td>
<td>2,356</td>
<td>865</td>
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<tr>
<td>Network</td>
<td>-</td>
<td>27</td>
<td>704</td>
<td>-</td>
<td>1</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>382,908</td>
<td>387,519</td>
<td>433,324</td>
<td>370,901</td>
<td>344,853</td>
<td>308,064</td>
</tr>
</tbody>
</table>
Table 6: Customer Minutes Out Due to Defective Equipment by Equipment Type

<table>
<thead>
<tr>
<th>Equipment Type</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead Conductors/Connections</td>
<td>1,311,947</td>
<td>1,001,874</td>
<td>1,162,976</td>
<td>1,418,143</td>
<td>2,817,869</td>
<td>1,617,860</td>
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<tr>
<td>Overhead Switch</td>
<td>570,616</td>
<td>1,202,851</td>
<td>1,103,537</td>
<td>1,096,546</td>
<td>593,341</td>
<td>1,029,739</td>
</tr>
<tr>
<td>Overhead Transformer</td>
<td>375,465</td>
<td>344,721</td>
<td>296,073</td>
<td>171,421</td>
<td>661,599</td>
<td>331,914</td>
</tr>
<tr>
<td>Pole and Pole Accessories</td>
<td>3,890,454</td>
<td>4,032,372</td>
<td>3,920,873</td>
<td>2,023,961</td>
<td>1,305,345</td>
<td>1,493,958</td>
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<tr>
<td>Stations</td>
<td>1,270,515</td>
<td>1,661,919</td>
<td>445,515</td>
<td>1,108,094</td>
<td>578,333</td>
<td>1,091,387</td>
</tr>
<tr>
<td>Underground Cable/Connections</td>
<td>10,424,321</td>
<td>9,153,355</td>
<td>9,288,772</td>
<td>12,657,588</td>
<td>9,907,359</td>
<td>7,738,566</td>
</tr>
<tr>
<td>Underground Switch</td>
<td>394,132</td>
<td>1,744,208</td>
<td>1,623,321</td>
<td>1,557,320</td>
<td>1,419,014</td>
<td>1,438,469</td>
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<tr>
<td>Underground Transformer</td>
<td>1,488,365</td>
<td>1,092,338</td>
<td>1,234,342</td>
<td>1,202,537</td>
<td>1,673,370</td>
<td>1,235,185</td>
</tr>
<tr>
<td>Others/Multiple</td>
<td>111,306</td>
<td>876,067</td>
<td>558,940</td>
<td>272,782</td>
<td>62,536</td>
<td>130,070</td>
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<tr>
<td>Network</td>
<td>-</td>
<td>2,654</td>
<td>36,491</td>
<td>-</td>
<td>57</td>
<td>-</td>
</tr>
<tr>
<td>Total</td>
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<td>21,112,359</td>
<td>19,670,840</td>
<td>21,508,392</td>
<td>19,018,823</td>
<td>16,107,148</td>
</tr>
</tbody>
</table>

e) No, defective equipment interruptions in Exhibit 1B, Tab 2, Schedule 4 only include asset failures that result in outages. Please refer to Toronto Hydro’s response to interrogatory 2B-AMPCO-35 for the number of asset failures.

f) All distribution system assets are critical. Major electrical distribution assets including (but not limited to): transformers, conductors/cables, station transformers/switchgear, etc. are critical and will cause an outage should they fail. Other assets such as switches and SCADA systems are critical in ensuring the impact of an outage can be minimized by providing isolation points. Whereas, structural assets (e.g. poles) or civil assets (e.g. cable chambers), are critical as their failure can cause the electrical assets mounted to them to either fail or become inaccessible for restoration.

g) As stated in part (f), all distribution assets are considered critical assets. Toronto Hydro’s approach to power restoration following an unplanned outage is based on the
principle of minimizing the impact to the community and restoring the largest number of customers in the shortest amount of time. In general, restoration priorities are as follows:

- Critical and priority loads, such as hospitals, emergency services, and essential citywide systems such as water distribution facilities;
- Stations;
- Remaining primary feeders (typically would include larger customers that receive a high voltage supply);
- Remaining feeder laterals, which generally supply entire streets or neighbourhoods; and
- Remaining individual low voltage customer services.

Other factors that impact Toronto Hydro’s restoration approach include the nature of the fault, complexity, resource type required to resolve the issue, resource availability, and issues on the customer side of the meter that can prevent restoration.

h) Major Event Days are excluded from Table 2 of Exhibit 1B, Tab 2, Schedule 4, page 11. Adverse Weather, Lightning, and Tree Contacts are not included under Defective Equipment, as they are captured in separate line items in the table.

i) Major Event Days are excluded from Table 2 of Exhibit 1B, Tab 2, Schedule 4, page 11. Adverse Weather and Lightning are not included under Tree Contacts, as they are captured in separate line items in the table.
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

INTERROGATORIES

INTERROGATORY 7:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, pp. 18-21

Please complete the excel spreadsheet labelled 1B-AMPCO-7.

RESPONSE:

Please see the Excel spreadsheet entitled “1B-AMPCO-7.xlsx”.
1 Defective Equipment - # Customer Interruptions

<table>
<thead>
<tr>
<th>Asset Class</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead Equipment</td>
<td>130,781</td>
<td>151,656</td>
<td>174,224</td>
<td>125,565</td>
<td>123,765</td>
<td>85,490</td>
</tr>
<tr>
<td>Underground Equipment</td>
<td>230,893</td>
<td>215,884</td>
<td>243,577</td>
<td>231,043</td>
<td>207,357</td>
<td>209,134</td>
</tr>
<tr>
<td>Station Equipment</td>
<td>14,650</td>
<td>16,856</td>
<td>6,746</td>
<td>12,832</td>
<td>11,917</td>
<td>13,166</td>
</tr>
<tr>
<td>Others</td>
<td>6,584</td>
<td>3,123</td>
<td>8,777</td>
<td>1,461</td>
<td>1,814</td>
<td>274</td>
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</table>

2 Defective Equipment - # Customer Interruption Minutes

<table>
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<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead Equipment</td>
<td>6,148,482</td>
<td>6,778,851</td>
<td>6,664,511</td>
<td>4,809,672</td>
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<tr>
<td>Underground Equipment</td>
<td>12,306,818</td>
<td>11,992,555</td>
<td>12,182,926</td>
<td>15,417,445</td>
<td>12,999,800</td>
<td>10,412,220</td>
</tr>
<tr>
<td>Station Equipment</td>
<td>1,270,515</td>
<td>1,661,919</td>
<td>445,515</td>
<td>1,108,094</td>
<td>578,333</td>
<td>1,091,387</td>
</tr>
<tr>
<td>Others</td>
<td>111,306</td>
<td>679,034</td>
<td>377,888</td>
<td>173,181</td>
<td>11,930</td>
<td>88,025</td>
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</table>

3 Overhead Defective Equipment - # Customer Interruptions

<table>
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<th>Asset Class</th>
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<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead Transformers</td>
<td>4,762</td>
<td>13,488</td>
<td>14,698</td>
<td>3,008</td>
<td>16,203</td>
<td>2,617</td>
</tr>
<tr>
<td>Overhead Switches</td>
<td>30,973</td>
<td>48,844</td>
<td>34,413</td>
<td>28,612</td>
<td>27,736</td>
<td>31,766</td>
</tr>
<tr>
<td>Poles</td>
<td>7,987</td>
<td>8,241</td>
<td>18,576</td>
<td>1,632</td>
<td>537</td>
<td>4,243</td>
</tr>
<tr>
<td>Pole Hardware</td>
<td>54,364</td>
<td>60,304</td>
<td>67,272</td>
<td>53,614</td>
<td>39,589</td>
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</tr>
<tr>
<td>Others</td>
<td>32,695</td>
<td>20,779</td>
<td>39,265</td>
<td>38,699</td>
<td>39,700</td>
<td>24,620</td>
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</table>

4 Overhead Defective Equipment - # Customer Interruption Minutes

<table>
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<th>Asset Class</th>
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<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead Transformers</td>
<td>375,465</td>
<td>344,721</td>
<td>296,073</td>
<td>171,421</td>
<td>661,599</td>
<td>331,914</td>
</tr>
<tr>
<td>Overhead Switches</td>
<td>570,616</td>
<td>1,202,851</td>
<td>1,103,537</td>
<td>1,096,546</td>
<td>593,341</td>
<td>1,029,739</td>
</tr>
<tr>
<td>Poles</td>
<td>449,856</td>
<td>560,368</td>
<td>881,059</td>
<td>104,467</td>
<td>133,000</td>
<td>241,911</td>
</tr>
<tr>
<td>Pole Hardware</td>
<td>3,440,598</td>
<td>3,472,004</td>
<td>3,039,814</td>
<td>1,919,494</td>
<td>1,172,345</td>
<td>1,252,047</td>
</tr>
<tr>
<td>Others</td>
<td>1,311,947</td>
<td>1,198,907</td>
<td>1,344,028</td>
<td>1,517,744</td>
<td>2,868,475</td>
<td>1,659,905</td>
</tr>
</tbody>
</table>

5 Underground Defective Equipment - # Customer Interruptions

<table>
<thead>
<tr>
<th>Asset Class</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Underground Cables</td>
<td>186,564</td>
<td>130,449</td>
<td>167,854</td>
<td>156,387</td>
<td>138,659</td>
<td>132,845</td>
</tr>
<tr>
<td>Underground Switches</td>
<td>10,525</td>
<td>40,308</td>
<td>110,537</td>
<td>1,096,546</td>
<td>593,341</td>
<td>1,029,739</td>
</tr>
<tr>
<td>Underground Transformers</td>
<td>12,242</td>
<td>30,418</td>
<td>18,414</td>
<td>29,195</td>
<td>41,417</td>
<td>30,188</td>
</tr>
<tr>
<td>Others</td>
<td>21,562</td>
<td>30,943</td>
<td>25,878</td>
<td>16,543</td>
<td>14,763</td>
<td>14,363</td>
</tr>
</tbody>
</table>

6 Underground Defective Equipment - # Customer Interruption Minutes

<table>
<thead>
<tr>
<th>Asset Class</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Underground Cables</td>
<td>8,623,632</td>
<td>7,902,573</td>
<td>8,243,907</td>
<td>11,253,881</td>
<td>8,892,874</td>
<td>6,888,255</td>
</tr>
<tr>
<td>Underground Switches</td>
<td>394,132</td>
<td>1,744,208</td>
<td>1,623,321</td>
<td>1,557,320</td>
<td>1,419,014</td>
<td>1,438,469</td>
</tr>
<tr>
<td>Category</td>
<td>2016</td>
<td>2017</td>
<td>2018</td>
<td>2019</td>
<td>2020</td>
<td></td>
</tr>
<tr>
<td>---------------------</td>
<td>--------</td>
<td>--------</td>
<td>--------</td>
<td>--------</td>
<td>--------</td>
<td></td>
</tr>
<tr>
<td>Underground Transformers</td>
<td>1,488,365</td>
<td>1,092,338</td>
<td>1,234,342</td>
<td>1,202,537</td>
<td>1,673,370</td>
<td>1,235,185</td>
</tr>
<tr>
<td>Others</td>
<td>1,800,689</td>
<td>1,253,436</td>
<td>1,081,356</td>
<td>1,403,707</td>
<td>1,014,542</td>
<td>850,311</td>
</tr>
</tbody>
</table>
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

INTERROGATORIES

INTERROGATORY 8:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 19, Figure 21

Please provide a breakdown of the asset types that contribute to “Others” and provide the number of customer interruptions for each asset type.

RESPONSE:

The “Others” category includes overhead conductors, overhead connections, and fuse. Please see Table 1 below.

Table 1: Customer Interruptions by asset types in the “Others” category

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead conductors</td>
<td>21,024</td>
<td>9,086</td>
<td>10,577</td>
<td>16,358</td>
<td>24,977</td>
</tr>
<tr>
<td>Overhead connections</td>
<td>11,671</td>
<td>7,652</td>
<td>20,926</td>
<td>18,616</td>
<td>14,181</td>
</tr>
<tr>
<td>Fuse</td>
<td>0.00</td>
<td>4,041</td>
<td>7,762</td>
<td>3,725</td>
<td>542</td>
</tr>
</tbody>
</table>
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

INTERROGATORIES

INTERROGATORY 9:
Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 19, Figure 22

Please provide a breakdown of the asset types that contribute to “Others” and provide the number of customer interruption minutes for each asset type.

RESPONSE:
The “Others” category includes overhead conductors, overhead connection, and fuse.
Please see Table 1 below.

Table 1: Customer Minutes Outs breakdown by asset types in the “Others” category

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead conductors</td>
<td>834,784</td>
<td>595,429</td>
<td>655,011</td>
<td>624,563</td>
<td>1,902,530</td>
</tr>
<tr>
<td>Overhead connection failures</td>
<td>477,163</td>
<td>406,445</td>
<td>507,965</td>
<td>793,580</td>
<td>915,339</td>
</tr>
<tr>
<td>Fuse</td>
<td>0</td>
<td>197,033</td>
<td>181,052</td>
<td>99,601</td>
<td>50,606</td>
</tr>
</tbody>
</table>
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

INTERROGATORIES

INTERROGATORY 10:
Reference(s): Exhibit 1B, Tab 2, Schedule 5, p. 1, Appendix 2-G

a) Please provide the reliability chart for the years 2008-2012.

b) Please provide data for 2018.

RESPONSE:

a) Please see Table 1 below.

Table 1: Service Reliability Indicators 2008-2012

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Including all events</td>
<td>1.24</td>
<td>2.91</td>
<td>1.66</td>
<td>1.43</td>
<td>1.50</td>
<td>1.76</td>
<td>1.86</td>
<td>1.95</td>
<td>1.62</td>
<td>1.60</td>
</tr>
<tr>
<td>Excl. LoS</td>
<td>1.21</td>
<td>2.77</td>
<td>1.19</td>
<td>1.38</td>
<td>1.46</td>
<td>1.66</td>
<td>1.71</td>
<td>1.54</td>
<td>1.48</td>
<td>1.47</td>
</tr>
<tr>
<td>Excl. MED's</td>
<td>1.24</td>
<td>1.38</td>
<td>1.29</td>
<td>1.43</td>
<td>1.03</td>
<td>1.76</td>
<td>1.64</td>
<td>1.77</td>
<td>1.62</td>
<td>1.40</td>
</tr>
<tr>
<td>Excl. LoS and MED's</td>
<td>1.21</td>
<td>1.24</td>
<td>1.18</td>
<td>1.38</td>
<td>0.99</td>
<td>1.66</td>
<td>1.49</td>
<td>1.53</td>
<td>1.48</td>
<td>1.28</td>
</tr>
<tr>
<td>Excl. LoS, MED's &amp; Sch. Outages</td>
<td>1.18</td>
<td>1.21</td>
<td>1.02</td>
<td>1.29</td>
<td>0.94</td>
<td>1.63</td>
<td>1.44</td>
<td>1.46</td>
<td>1.44</td>
<td>1.22</td>
</tr>
</tbody>
</table>

b) Toronto Hydro does not currently have this data finalized for 2018.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 1:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, Appendix A

Please provide a table in the format which shows, for each forecast annual percentage increase bill, the percentage of change in THESL's distribution rate.

RESPONSE:
Please refer to Toronto Hydro’s response to interrogatory 1B-SEC-13 for base distribution bill impacts.
INTERROGATORY 2:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, Appendix A

Please confirm that data in Appendix A represent bill changes for the average volume customers in each rate class. If this is not the case, please explain.

RESPONSE:

The volumes used for each class bill impacts in Exhibit 1B, Tab 1, Schedule 1, Appendix A are shown in Table 1 below. They are a representative level of consumption, not an average.

**Table 1: Bill Impact Usage Levels**

<table>
<thead>
<tr>
<th>Class</th>
<th>kWh</th>
<th>kW</th>
<th>kVA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>750</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Competitive Sector Multi-Unit Residential</td>
<td>300</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>General Service &lt;50 kW</td>
<td>2,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>General Service 50-999 kW</td>
<td>79,000</td>
<td>180</td>
<td>200</td>
</tr>
<tr>
<td>General Service 1,000 – 4,999 kW</td>
<td>900,000</td>
<td>1,800</td>
<td>2,000</td>
</tr>
<tr>
<td>Large Use</td>
<td>4,100,000</td>
<td>8,900</td>
<td>9,700</td>
</tr>
<tr>
<td>Street Lighting</td>
<td>60</td>
<td>0.165</td>
<td>0.165</td>
</tr>
<tr>
<td>Unmetered Scattered Load</td>
<td>285</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 3:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, pp. 6-7

Please explain how these limits and caps were derived.

RESPONSE:

Please refer to Toronto Hydro’s response to interrogatories 1B-SEC-12 and 1B-SEC-47.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
INTERROGATORIES

INTERROGATORY 4:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 7

Please provide the actual and forecast operational plan budget (the number corresponding to the $277M cited on p7 for each of 2015, 2016, 2017, 2018, and 2019.

RESPONSE:
Please refer to Exhibit 4A, Tab 1, Schedule 3 (OEB Appendix 2-JB).
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 5:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 7

a) Please provide details of the $75M per year eliminated from THESL's capital plan in response to the $560M cap.

b) Please point to the specific customer responses that led to THESL revising the capex and OM&A amounts cited.

RESPONSE:

a) Please refer to Toronto Hydro’s response to interrogatory 2B-Staff-73.

b) The results of Phase 1 of the Planning-specific Customer Engagement are detailed in the Section 2.1 of the Executive Summary of the Innovative Report (Exhibit 1B, Tab 3, Schedule 1, Appendix A) and Phase 1 Appendices of the Innovative Report. These results informed the development of the Business Plan that underlies this application. For more information about Phase 1 of the Planning-Specific Customer Engagement please see Exhibit 1B, Tab 3, Schedule 1.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 6:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 14

Please provide comparable storm data for the previous eighteen (18) month period.

RESPONSE:

Table 1, below, provides storm data for the eighteen (18) month period prior to January 2017.

Table 1: Extreme Weather Events 2014-2016

<table>
<thead>
<tr>
<th>Event</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Severe thunderstorm (August 2016)</td>
<td>• Severe thunderstorms and high winds</td>
</tr>
<tr>
<td></td>
<td>• Approximately 8,600 Toronto Hydro customers out at peak</td>
</tr>
<tr>
<td>Severe thunderstorm (July 2016)</td>
<td>• Severe thunderstorms and high winds</td>
</tr>
<tr>
<td></td>
<td>• 90+ km/hr wind gusts</td>
</tr>
<tr>
<td></td>
<td>• Approximately 800 Toronto Hydro customers out at peak</td>
</tr>
</tbody>
</table>
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
INTERROGATORIES

INTERROGATORY 7:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 14

What steps is THESL taking to protect underground vaults and related equipment from future flooding? Please provide details.

RESPONSE:
Toronto Hydro performs routine inspections of underground vaults (i.e. below-grade equipment) as described in Exhibit 4A, Tab 2, Schedule 2, to identify substandard conditions inside vaults before they cause a failure. Where deficiencies are found, they are addressed through the Corrective Maintenance (Exhibit 4A, Tab 2, Schedule 4) and Reactive and Corrective Capital (Exhibit 2B, Section E6.7) programs.

Toronto Hydro’s DSP includes a number of investments and program activities intended to enhance its system to increase resiliency to changes in the weather and climate. Activities targeting flooding in underground vaults are summarized below.

- Replacement of existing transformers with stainless steel submersible transformers as part of Underground System Renewal – Horseshoe program (Exhibit 2B, Section E6.2);
- Replacement of non-submersible automatic transfer switches and remote power breakers with submersible equipment to tolerate flooding (Exhibit 2B, Section E6.4 Network System Renewal);
- Replacement of other end-of-life and deteriorated non-submersible protectors with submersible protectors to protect against flooding (Exhibit 2B, Section E6.4); and
- Network Condition Monitoring & Control program (Exhibit 2B, Section E7.3) that will help detect flooding in network vaults before equipment damage occurs.

For further information on Toronto Hydro’s ongoing efforts to renew and enhance its system to changes in the weather and climate, please refer to Exhibit 2B, Section D2.1.2.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 8:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, pp. 20-21

a) Please complete the Table on pp20 and 21. For the p21 Table, please list each of
the forty-four (44) performance measures, with an explanation of how each of the
forty-four (44) relates to the four (4) RRF Outcomes.

b) With respect to the p20 Table, please show for each of the forty-four (44)
performance measures, the projects and programs that are the subject of the
response are put in place to advance the measures.

RESPONSE:
a) Table 1 below provides the list of the 44 unique measures, mapped to Toronto
Hydro’s outcomes, and RRF Performance Outcomes (as presented in the Electricity
Distributor Scorecard).

Toronto Hydro’s six outcome based framework was derived from:

i) customer priorities identified through the utility’s customer engagement
activities;

ii) the utility’s corporate pillars; and

iii) The OEB’s RRF outcomes.
The six outcomes are aligned with the definitions provided by the OEB in the Utility Rate Handbook for the four RRFE outcomes.

Table 1: Toronto Hydro’s 44 Measures Mapped to Outcomes (RRFE & TH)

<table>
<thead>
<tr>
<th>RRF Outcomes</th>
<th>Toronto Hydro Outcomes</th>
<th>OEB Reporting Categories</th>
<th>Measures</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>2. Connection of New Services - High Voltage</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>3. Telephone Calls Answered on Time [Telephone Accessibility]</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>4. Scheduled Appointments Met on Time [Appointments Met]</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>5. Appointment Scheduling</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>6. Rescheduling a Missed Appointment</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>7. Telephone Call Abandon Rate</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>8. Emergency Response – Urban</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>9. Reconnection Performance Standards</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Customer Satisfaction</td>
<td>10. First Contact Resolution</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>11. Billing Accuracy</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>12. Written Responses to Enquiries</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>13. Customers on eBills</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>14. Customer Survey Satisfaction Results</td>
</tr>
<tr>
<td>Operational Effectiveness</td>
<td>Safety</td>
<td>Safety</td>
<td>15. Level of Public Awareness</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>16. Compliance with Ontario Reg. 22/04</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>17. Public Number of General Public Incidents</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>18. Rate per 10, 100, 1000 km of Line</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>19. Total Recorded Injury Frequency</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>20. Box Construction Conversion</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>21. Network Units Modernization</td>
</tr>
<tr>
<td></td>
<td></td>
<td>System Reliability</td>
<td>22. SAIDI</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>23. SAIFI</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>24. SAIDI - Defective Equipment</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>25. SAIFI - Defective Equipment</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>26. FESI-7 System</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>27. FESI-6 Large Customers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Asset Management</td>
<td>28. DSP Implementation Progress</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>29. System Capacity</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>30. System Health (Asset Condition) – Wood Poles</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>31. Direct Buried Cable Replacement</td>
</tr>
<tr>
<td>Financial Performance</td>
<td>Financial</td>
<td>Cost Control</td>
<td>32. Efficiency Assessment (Ontario Distributors)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>33. Total Cost per Customer</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>34. Total Cost per Km of Line</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>35. Average Wood Pole Replacement Cost</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>36. Vegetation Management Cost per Km</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Financial Ratios</td>
<td>37. Liquidity: Current Ratio</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>38. Leverage: Total Debt to Equity Ratio</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>39. Reg. ROE - Deemed vs. Achieved</td>
</tr>
</tbody>
</table>
Panel: Rates and CIR Framework

Note 1: Similar OEB measures with different names are included in square brackets.

b) Toronto Hydro maps all its projects to their respective programs. Please refer to the following evidence sections for discussion on majority of the proposed investments driving the performance of the 44 measures:

i) See Exhibit 2B, Section C0 – Performance Measurement.

ii) See Exhibit 1B, Tab 02, Schedule 02, Electricity Distributor Scorecard and 2015-2019 Distribution System Plan Performance Measures.

iii) See Exhibit 1B, Tab 02, Schedule 03, Service Quality Performance.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 9:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, pp. 22, Table 3

a) What are the reasons for the rather poor performance in Telephone Calls Answered On Time given that the overall trend is negative.

b) Please discuss steps THESL is taking to improve its performance in this area.

RESPONSE:

a) As discussed in Exhibit 1B, Tab 2, Schedule 2, page 5 and Exhibit 1B, Tab 2, Schedule 3, page 2, Table 1, Toronto Hydro’s average annual performance for this measure between 2013-2017 is nearly 75 percent, which consistently exceeded the Ontario Energy Board’s standard of 65 percent. Indeed, there is only one year of the last five where Toronto Hydro was marginally below the 65 percent OEB standard at 64.7 percent. Performance in 2016 was the result of various external factors that led to a 10 percent call volume increase compared to 2015, including rate increases during the year, and high bill enquiries due to the hot summer. In addition, with the exception of 2016, Toronto Hydro’s performance for this measure has steadily improved since 2014.

b) This question assumes Toronto Hydro’s performance has been substandard, which with respect and as discussed above, is incorrect: Toronto Hydro’s average performance has exceeded the OEB standard over the last five years. Nevertheless,
assuming sufficient funding, measures that Toronto Hydro could take in order to make incremental improvements to the operational factors that influence the performance of this measure include: agent supervision, training and tools to monitor and improve personnel performance, providing customers alternative channels (e.g. online self-service options), proactive prevention of customer complaints and enquiry drivers to reduce calls coming into the call centre, extension of Contact Centre hours, and enhancement of scheduling tools.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 10:

Reference(s): Exhibit 1B, Tab 1, Schedule 1 (General)

a) Please provide a summary of THESL's asset assessment which provides for each major asset category, the number and percentage of assets that are in very poor, poor, fair, good, and very good condition.

b) Please provide a copy of THESL's business plan for 2020, and whatever additional years are included in the 2020 plan.

RESPONSE:

a) Please note that the “very poor”, “poor”, “fair”, “good” and “very good” categories refer to the Weighted Arithmetic Summation Model which the utility no longer uses. The new condition categories as specified within this application do not represent a one-to-one translation to the former categories from the Weighted Arithmetic Summation Model. The new model, however, does incorporate a similar range of condition categories, from HI1 (new or good condition) to HI5 (end of serviceable life).

Information on the new condition model and its results can be found in Exhibit 2B, Section D, Appendix C.

b) Please refer to Toronto Hydro’s response to interrogatory 1A-CCC-1.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
INTERROGATORIES

INTERROGATORY 11:
Reference(s): Exhibit 1B, Tab 3, Schedule 1, p. 4, Table 1

The reference appears to be to Exhibit 1A, not 1B.

a) Please confirm that the cumulative distribution rate increase (arithmetic) over the 2020-2024 term of the IRM area Residential (750 kWh/month) is 8.8%, and General Service < 50 kW (2,000 kWh/month) is 9.5%.

b) What is the compounded growth rate in rates over five (5) year term that corresponds to the rate increases in part (a)?

c) Please provide answers to (a) and (b) above for each of the other rate classes.

d) For each of (a) and (b) above, the rate increases for customers with twice, three times, and four times, the monthly volumes used by THESL in their examples.

e) Please provide the same data for the current IRM five (5) year program which ends on December 31, 2019.
RESPONSE:

a) Table 1 below shows 5-year total distribution rate change for two periods 2015-2019 and 2020-2024.

Table 1: 5 Year Distribution Rate Change

<table>
<thead>
<tr>
<th>Sub-Total A</th>
<th>2015-2019</th>
<th>2020-2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>35.6</td>
<td>8.8</td>
</tr>
<tr>
<td>Competitive Sector Multi-Unit Residential</td>
<td>28.0</td>
<td>11.9</td>
</tr>
<tr>
<td>General Service &lt;50 kW</td>
<td>30.1</td>
<td>10.0</td>
</tr>
<tr>
<td>General Service 50-999 kW</td>
<td>38.3</td>
<td>11.1</td>
</tr>
<tr>
<td>General Service 1,000-4,999 kW</td>
<td>39.4</td>
<td>11.8</td>
</tr>
<tr>
<td>Large Use</td>
<td>40.5</td>
<td>11.9</td>
</tr>
<tr>
<td>Street Lighting</td>
<td>18.9</td>
<td>13.7</td>
</tr>
<tr>
<td>Unmetered Scattered Load</td>
<td>44.5</td>
<td>11.8</td>
</tr>
</tbody>
</table>

b) Table 2 below includes compounded annual growth rate change for two periods 2015-2019 and 2020-2024.

Table 2: Sub-Total A Compounded Annual Growth Rate

<table>
<thead>
<tr>
<th>Sub-Total A</th>
<th>2015-2019</th>
<th>2020-2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>6.3</td>
<td>1.7</td>
</tr>
<tr>
<td>Competitive Sector Multi-Unit Residential</td>
<td>5.1</td>
<td>2.3</td>
</tr>
<tr>
<td>General Service &lt;50 kW</td>
<td>5.4</td>
<td>1.9</td>
</tr>
<tr>
<td>General Service 50-999 kW</td>
<td>6.7</td>
<td>2.1</td>
</tr>
<tr>
<td>General Service 1,000-4,999 kW</td>
<td>6.9</td>
<td>2.3</td>
</tr>
<tr>
<td>Large Use</td>
<td>7.0</td>
<td>2.3</td>
</tr>
<tr>
<td>Street Lighting</td>
<td>3.5</td>
<td>2.6</td>
</tr>
<tr>
<td>Unmetered Scattered Load</td>
<td>7.6</td>
<td>2.3</td>
</tr>
</tbody>
</table>
c) Please see response to part (a) and (b)

d) Tables 3 and 4 summarize 2020-2024 rate changes for customers with twice, three times, and four times, the monthly volumes. Note that beginning in 2020, residential distribution rates are fully fixed.

Table 3: 5 Year Distribution Rate Change for 2020-2024

<table>
<thead>
<tr>
<th>Sub-Total A</th>
<th>Twice times monthly volume</th>
<th>Three times monthly volume</th>
<th>Four times monthly volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td>General Service &lt;50 kW</td>
<td>10.0</td>
<td>9.9</td>
<td>9.9</td>
</tr>
</tbody>
</table>

Table 4: Sub-Total A Compounded Annual Growth Rate for 2020-2024

<table>
<thead>
<tr>
<th>Sub-Total A</th>
<th>Twice monthly volume</th>
<th>Three times monthly volume</th>
<th>Four times monthly volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td>General Service &lt;50 kW</td>
<td>1.9</td>
<td>1.9</td>
<td>1.9</td>
</tr>
</tbody>
</table>

e) Please see response to part (a) and (b)
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
INTERROGATORIES

INTERROGATORY 12:

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

a) Please explain each of the four (4) THESL corporate pillars. Please rank order the six (6) customer priorities listed on p4, with an explanation for the ranking.

b) Please explain what is the low volume threshold for the four (4) groups referred to at p5.

c) How does each of the six (6) "key outcomes" set out on p5, relate to each of the four (4) RRFE outcomes? Please provide a detailed explanation.

RESPONSE:

a) Please see Exhibit 2B, Section C1, Figure 1 (Page 2) and Exhibit 2B, Sections C1 and C2 for detailed explanations about how the specific outcomes and measures correspond to and align with customer priorities and the RRF outcomes. Please see Exhibit 2B, Section D1, Figure 1 (page 4) for an explanation of each of Toronto Hydro’s corporate pillars.

b) The Phase I low-volume customers referenced at page 5 of the indicated exhibit refers to Residential and Small Commercial (GS<50kWh) customer groups.

c) Please see response to part (a).
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
(“BOMA”) INTERROGATORIES

INTERROGATORY 13:
Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 9

What is TRIF, for 2017; for 2018, to date; what are NEER costs, and WSIB performance index for 2017, and anticipated for 2018?

RESPONSE:
Please see Toronto Hydro’s response to interrogatory 1B-SEC-14.
INTERROGATORY 14:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 10

Why is the Restricted Work Severity Rate almost three times the CEA average?

RESPONSE:

Between 2011 and 2016, Toronto Hydro achieved and sustained an 87 percent reduction in restricted work days. A restricted work day is the number of calendar days to a maximum of 180 days during which an employee is subject to restricted work, based on the recommendation of a physician or licensed health care professional, for an individual case. The Restricted Work Severity rate is higher than the CEA average because Toronto Hydro’s approach is to provide meaningful and productive work for injured employees, rather than lay off injured employees to receive WSIB compensation. This policy is consistent with the Early and Safe return to work legislation.¹ The benefit of this approach is evident in Toronto Hydro’s lost time severity performance in 2017 was 0.75 and in 2018 was 8.81 days, which far exceeds the CEA average of 17.03 days for electrical distribution companies.

Having employees perform modified work, rather than be on leave due to their injury, promotes faster recovery times, lowers the utility’s costs and helps injured employees

¹ Workplace Safety and Insurance Act, 1997 S.O. 1997 Chapter 16 Schedule A Part V
stay motivated and engaged. For additional context please reference the WSIB “Better at Work” study.²

² Available from:
<http://www.wsib.on.ca/WSIBPortal/faces/WSIBDetailPage?cGUID=WSIB018904&rDef=WSIB_RD_ARTICLE&_afrLoop=3540901567146000&_afrWindowMode=0&_afrWindowId=qudwp8ik_43f%40%3FGUID%3DWSIB018904%26_afrWindowId%3Dqudwp8ik_43%26_afrLoop%3D3540901567146000%26rDef%3DWSIB_RD_ARTICLE%26_afrWindowMode%3D0%26_adf.ctrl.state%3Dqudwp8ik_71>
INTERROGATORY 15:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 11

Please explain the difference between sick days and absentee rate.

RESPONSE:

There is no difference between sick days and absentee rate. The terms are used synonymously in the evidence.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 16:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 12

What will be the impact of the elimination of NEER on THESL's WSIB premium costs?

RESPONSE:

Under the new framework, Toronto Hydro expects its WSIB premium costs to be more stable and better aligned with the utility’s claim history. However, it is difficult for the utility to forecast its WSIB premiums because the costs vary from year to year based on the number and value of historical claims. The industry rate is announced annually by the WSIB, which also adds to the challenge of forecasting the premiums beyond the immediate next year.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
(“BOMA”) INTERROGATORIES

INTERROGATORY 17:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 14

What accounts for the year to year variability in percentage of Orders to Operate completed prior to work execution?

RESPONSE:

In general, on an annual basis, work volume is lower in Q1, medium in Q2/Q3 and very high in Q4. The variability is a function of the following:

- Average daily volume of planned work requires require a higher volume of Orders to Operate (OTOs) to be prepared.
- Type and complexity of work drives variability in percentage of OTO’s completed. For example requiring electrical switching increases the number of switching steps for each OTO.
- External events can cause large volumes of unplanned work (e.g. due to storm response). Unplanned work can reduce the amount of controller time available to prepare OTOs for planned work.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 18:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 17

Preamble:
"Toronto Hydro’s Customer Care program invests in a number of automation processes that eliminates the need for manual work. This leads to cost savings. For instance, through various initiatives, the utility encourages the use of customer self-service features on Toronto Hydro’s website to provide easier customer access to information and to reduce the need for customer contact. This decreases the volume of customer contact for the call centres and allows optimization of the use of lower cost outsourced labour. For instance, since call-centre business hours were expanded to 8:00 p.m., Toronto Hydro’s third-party service provider has been used exclusively to provide lower cost call handling resources and customer service."

a) Please confirm that THESL has outsourced its call handling and customer service.

b) Please explain what aspects of customer service, including call-handling, are provided by a third party, the identity of the third party(ies) and the contract(s) between THESL and the third party(ies). Please explain why the outsourcing decision was made.
RESPONSE:

a) Toronto Hydro has outsourced a portion of its contact handling and customer service.

b) With respect to call handling and customer service, Toronto Hydro utilizes a third party to provide a portion of customer contact handling services and related quality control functions as well as manual transaction processing of customer move requests. Toronto Hydro has contracted Optima Communications International Inc. to provide these services. Toronto Hydro’s decision to outsource these functions was made to allow for greater labour flexibility, enable cost efficiencies, and to focus Toronto Hydro’s internal and specialized customer service personnel on more complex customer issues.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 19:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 18

Please provide details of the allocation of the proceeds of the sale of Eglinton property in 2018.

RESPONSE:

The net gain on sale related to the sale of the Eglinton property was allocated to a temporary variance account, and Toronto Hydro is seeking approval to clear the amount in this application. Details of the calculation of the after-tax gain and the amount to be cleared can be found in the response to interrogatory 8-Staff-146. Details of the proposed clearance amount can be found at Exhibit 8, Tab 1, Schedule 1, Section 4.7. Details of allocation to the rate classes and derivation of the rates riders associated with the sale (listed as Deferred Gain on Disposal) can be found at Exhibit 9, Tab 3, Schedule 1.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 20:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 19

a) Please provide a copy of a typical Mutual Assistance Agreement THESL uses.

b) Please provide details of further fleet reduction plans in 2020-2024.

RESPONSE:

a) A typical Mutual Assistance Agreement used by Edison Electric Institute (“EEI”) members, including Toronto Hydro, is posted on the EEI website.


b) As detailed in Exhibit 2B, Schedule E8.3.1, page 3, Toronto Hydro has continued in its efforts to rationalize its vehicle fleet which has resulted in a reduced fleet size from 660 units down to 588. The utility continues to look for opportunities and strategies to refine the fleet size and composition. The right-sizing of the fleet is expected to continue throughout 2020-2024, by considering the size and composition of the future work programs, staffing levels and crew compliments; as well as residual value, condition assessment, utilization, procurement cost and lead-time of vehicles, and equipment.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 21:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 20

Is the comment on answering calls on time correct?

RESPONSE:

Please refer to Toronto Hydro’s response to interrogatory 1B-BOMA-9.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 22:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 28

Why did the Customer study use a peer group of utilities with an average number of customers approximately fifty percent (50%) larger than the number of THESL customers?

RESPONSE (PREPARED BY LEI):

The purpose of LEI’s engagement was to study comparator utilities with fully functional backup control centers (“BUCCs”) in other jurisdictions. LEI’s methodology for identifying comparator utilities was to review the 20 largest US utilities and 5 largest Canadian distribution utilities by number of customers. While the selected comparator utilities generally had a higher number of customers, in terms of overall load significance the selected comparator utilities are appropriate. Figure 1 below summarizes the load significance of the selected utilities, which is extracted from Figure 4, page 8 of LEI’s report.

<table>
<thead>
<tr>
<th>Metric</th>
<th>Toronto Hydro</th>
<th>Hydro One</th>
<th>FPL</th>
<th>PG&amp;E</th>
<th>CECONY</th>
<th>SDGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Delivered electricity (GWh, 2016)</td>
<td>25,373</td>
<td>26,289</td>
<td>108,871</td>
<td>68,820</td>
<td>45,745</td>
<td>19,200</td>
</tr>
<tr>
<td>Number of customers (1,000)</td>
<td>768</td>
<td>1,355</td>
<td>4,900</td>
<td>5,400</td>
<td>3,400</td>
<td>1,400</td>
</tr>
<tr>
<td>Service area (km²)</td>
<td>630</td>
<td>962,774</td>
<td>71,613</td>
<td>181,299</td>
<td>1,564</td>
<td>10,619</td>
</tr>
<tr>
<td>Service area density (customers/km²)</td>
<td>1,219</td>
<td></td>
<td>1</td>
<td>68</td>
<td>30</td>
<td>2,174</td>
</tr>
<tr>
<td>Population of largest city served (1,000)</td>
<td>2,732</td>
<td></td>
<td>&lt;80</td>
<td>454</td>
<td>1,025</td>
<td>8,538</td>
</tr>
<tr>
<td>Serving provincial/state capital?</td>
<td>✓</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Serving national financial center?</td>
<td>✓</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>✓</td>
<td>-</td>
</tr>
<tr>
<td>% of national economic activity in utility's service territory</td>
<td>10.0%</td>
<td>&lt;6%***</td>
<td>3.3%</td>
<td>6.2%</td>
<td>4.0%</td>
<td>1.2%</td>
</tr>
</tbody>
</table>

Figure 1: Summary of identified utility distribution operations

Panel: General Plant, Operations, and Administration
Not only does Toronto Hydro fall within the range of the selected utilities in terms of electricity delivered annually, but it also serves a uniquely important load. Toronto Hydro serves the provincial capital as well as the economic and financial center of Canada; in fact, it serves the highest proportion of national economic activity out of all the identified utilities. In addition, Toronto Hydro has amongst the highest customer densities of the identified utilities and distributes approximately 19 percent of electricity consumed in Ontario.¹

¹ Toronto Hydro. About Us. <https://www.torontohydro.com/sites/corporate/AboutUs/Pages/AboutUs.aspx>
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
INTERROGATORIES

INTERROGATORY 23:

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

Please provide the data for 2018 (to date) and 2019 (forecast) against which forms the base for the 2020 cost of service test year forecast.

RESPONSE:
The 2018 and 2019 forecasts, which form the basis of the 2020 test year, are provided throughout the evidence, in accordance with the OEB’s Filing Requirements. Toronto Hydro intends to file year-end 2018 financial information as part of the planned update to the evidence, which is discussed in Exhibit 1A, Tab 3, Schedule 1, Appendix B. Please refer to Toronto Hydro’s response to interrogatory 1A-Staff-1 for a listing of the financial figures that Toronto Hydro plans to update.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
(“BOMA”) INTERROGATORIES

INTERROGATORY 24:
Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 7

a) Please explain the difference between the PSE forecasting model and the PEG forecasting model.

b) Please explain why THESL proposes to use the PSE model rather than the PSE model used by the Board.

RESPONSE:

a) Please refer to Toronto Hydro’s response to 1B-SEC-20.

b) Please refer to Toronto Hydro’s response to 1B-EP-12 part (d). This response is being provided prior to seeing any responding PEG report and model that it may rely on in this proceeding.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 25:

Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 7

a) Please confirm that under the Custom Capital Factor, the Board does not review each proposed capital project, as would be the case under a fourth generation IRM regime, using an I-X rate escalator, and ICM financing for capital expenditures above the general materiality threshold. How do the Board and stakeholders obtain an equivalent level of scrutiny of the five (5) year capital budget? Please explain fully.

b) Please confirm that the Custom Capital Factor is set at a rate which is inclusive of its reduction to avoid double billing, to provide the incremental funding required to finance the proposed capital budget over the five (5) year period.

RESPONSE:

a) The application was prepared and filed in accordance with the OEB’s Handbook for Utility Rate Applications and Filing Requirements for Electricity Distribution Rate Applications, including the guidance and requirements set-out specifically for five-year Custom Incentive Rate-setting applications. Toronto Hydro has provided detailed five-year justifications for its capital programs in accordance with the Chapter 5 filing requirements for “Material Investments”. Toronto Hydro notes the following key attributes of its program evidence:
• All capital projects are united by a specific capital program with one or more segments. The justification for each segment is the same for every project within it.

• Where Toronto Hydro has forecasted major capital projects within a capital program (e.g. Copeland TS – Phase 2 within the Stations Expansion program), the utility has provided incremental details and justification commensurate with the materiality of these proposed investments.

• Furthermore, all of Toronto Hydro’s capital programs and segments contain maps, tables and/or lists of the priority assets, areas, stations, feeders and/or locations that the utility expects to address over the 2020-2024 period, as well as the volumes of work proposed for the 2020-2024 period and an explanation of how the estimated costs of achieving those volumes relate to the actual costs of volumes achieved in the same segments over the 2015-2019 period.

For a detailed discussion of Toronto Hydro’s project development and prioritization process, please refer to the utility’s response to interrogatory 2B-SEC-36 (a) and (b).

b) Toronto Hydro confirms that the Custom Capital Factor, together with the other components of the CPCI, provide the appropriate level of funding for the 2021-24 period, and does not result in any double billing of customers.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 26:

Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 9

a) Please provide the forecast closing rate base (and rate base as at December 31, 2018) and the forecast closing rate base at December 31, 2019.

b) Are the rate base numbers cited in Table 2 average numbers, or opening, or closing numbers?

RESPONSE:

a) Please see Exhibit 2A, Tab 1, Schedule 1, page 2 for the forecast closing rate base for the year 2018 and 2019.

b) The rate base numbers cited in Table 2 is an average of the opening and closing Property, Plant, and Equipment net book value (P&E NBV) balance for the calendar year plus Working Capital Allowance.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 27:

Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 13, Table 5

Please provide a detailed calculation for the CPCI in 2020, which shows clearly how C_n (3.43) is reduced by S_cap (71.9) and g (0.2) to average at CPCI of 3.26. Please confirm that the same calculation applies for each subsequent year.

RESPONSE:

CPCI is not applicable to the rebasing year (i.e. 2020). It is applied to each subsequent year of the term (2021-2024).

When applied, C_n is not reduced by S_cap and g. As described at Exhibit 1B, Tab 4, Schedule 1, page 12, CPCI is determined by the following equation, and is reduced by S_cap and growth factors.

\[ CPCI = I - X + C_n - (S_{cap} * I) - g \]

Table 1 includes the calculation of CPCI for 2021 and Toronto Hydro confirms that the same calculation applies for each subsequent year.
Table 1: Calculation of CPCI\(^1\)

<table>
<thead>
<tr>
<th>CPCI Component (%)</th>
<th>2021</th>
<th>Audit Trail</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>1.20%</td>
<td>A</td>
</tr>
<tr>
<td>X – productivity</td>
<td>0.00%</td>
<td>B</td>
</tr>
<tr>
<td>X – custom stretch</td>
<td>-0.30%</td>
<td>C</td>
</tr>
<tr>
<td>Cn</td>
<td>3.43%</td>
<td>D</td>
</tr>
<tr>
<td>(S_{\text{cap}} \times I)</td>
<td>-0.87%</td>
<td>E=A*H</td>
</tr>
<tr>
<td>g</td>
<td>-0.20%</td>
<td>F</td>
</tr>
<tr>
<td>CPCI</td>
<td>3.26%</td>
<td>G=(\sum A:F)</td>
</tr>
<tr>
<td>(S_{\text{cap}})</td>
<td>71.9%</td>
<td>H</td>
</tr>
</tbody>
</table>

\(^1\) Please refer to Exhibit 1B, Tab 4, Schedule 1, page 13, Table 5.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
INTERROGATORIES

INTERROGATORY 28:
Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 3, Table 1

Please provide missing numbers in the "2017" column. Please provide actual ROE for 2018 (when available). Please provide the results for 2018 when available.

RESPONSE:
The following 2017 results for Toronto Hydro were published by Pacific Economics Group ("PEG") after the rate application was filed by Toronto Hydro:

- Efficiency Assessment – 5
- Total cost per customer - $1,042
- Total cost per km of line – $27,825

Toronto Hydro expects to file 2018 actuals as part of Toronto Hydro’s planned update to its evidence.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 29:
Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 5

a) What is the number for calls answered on time for 2018 to date?

b) Why does not THESL plan to improve upon the industry standards which seem extraordinarily low?

c) What are comparable standards in other provinces or US states?

RESPONSE:
a) Toronto Hydro expects to provide 2018 actual results as part of its RRR submission in April 2019.

b) Please refer to Toronto Hydro’s response to interrogatory 1B-BOMA-9.

c) Toronto Hydro is not aware of the comparable standards set by regulators in other provinces or the United States.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
INTERROGATORIES

INTERROGATORY 30:
Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 9

What measures does THESL plan to implement to increase its customer satisfaction rating from eighty-three percent (83%)?

RESPONSE:
Toronto Hydro’s overall informed satisfaction rating of 83% is made up of a number of sub-components, including power quality and reliability, and price. Toronto Hydro has developed a plan that incorporates customer needs and preferences (as discussed in detail at Exhibit 1B, Tab 3, Schedule 1), and the utility has developed a custom outcomes framework that aligns with those needs and preferences (as discussed in detail at Exhibit 1B, Tab 2, Schedule 1). Additionally, the operational and capital program evidence detailed in Exhibits 2B and 4A links Toronto Hydro’s investment proposals to outcomes that customers’ value.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 31:
Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 10

Please provide a copy of the most recent customer concerns survey (Electrical Safety Authority).

RESPONSE:
Toronto Hydro is not aware of an Electrical Safety Authority customer concerns survey.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
(“BOMA”) INTERROGATORIES

INTERROGATORY 32:

Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 10

Please provide SAIDI and SAIFI numbers for 2018. Why is THESL not proposing to improve on SAIDI/SAIFI over the 2020-2024 period?

RESPONSE:

Toronto Hydro does not currently have this data finalized for 2018.

Please refer to Exhibit 2B, Section E2.3.1.1, for a detailed discussion on the alignment of Toronto Hydro’s reliability objectives with customers’ priorities and preferences for reliability.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 33:

Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 11

Please provide the calculation that led to efficiency ranking of 5. How does 5 compare to the ranking of the largest Ontario utilities? Please provide 2017 numbers, and 2018 when available.

RESPONSE:

The calculation of the efficiency ranking of five is determined from the OEB-sponsored efficiency ranking reported by the Pacific Economics Group (“PEG”) and is based on PEG’s econometric benchmarking model. Descriptions of the calculations provided as part of EB-2010-0379. See the Report of the Board - Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario’s Electricity Distributors.¹

Toronto Hydro was set out in 2017 to be in Group five as published by PEG² and shown in the table below.

² Empirical Research in Support of Incentive Rate-Setting: 2017 Benchmarking Update; Report to the Ontario Energy Board (Revised); Aug 2018; Table 5

Panel: Rates and CIR Framework
<table>
<thead>
<tr>
<th>Group I</th>
<th>Group II</th>
<th>Group III</th>
<th>Group IV</th>
<th>Group V</th>
</tr>
</thead>
<tbody>
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<td>Stretch Factor = 0.0%</td>
<td>Stretch Factor = 0.15%</td>
<td>Stretch Factor = 0.30%</td>
<td>Stretch Factor = 0.45%</td>
<td>Stretch Factor = 0.60%</td>
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<td>Alectra Utilities Corporation</td>
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<td>Energy+ Inc.</td>
<td>Oakville Hydro Electricity Distribution Inc.</td>
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<td>Hydro Ottawa Limited</td>
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<td>Ottawa River Power Corporation</td>
<td>Rainfree Hydro Inc.</td>
<td>Peterborough Distribution Incorporated</td>
</tr>
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<td>Fort Frances Power Corporation</td>
<td>Greater Sudbury Hydro Inc.</td>
<td>Rideau St. Lawrence Distribution Inc.</td>
<td>PUC Distribution Inc.</td>
</tr>
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<td>Rideau St. Lawrence Distribution Inc.</td>
<td>Thunder Bay Hydro Electricity Distribution Inc.</td>
<td>Wellington North Power Inc.</td>
</tr>
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<tr>
<td>Orangeville Hydro Limited</td>
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<td>Waterloo North Hydro Inc.</td>
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<td>Wellington North Power Inc.</td>
</tr>
<tr>
<td>St. Thomas Energy Inc.</td>
<td>Welland Hydro-Electric System Corp.</td>
<td>Whirlby Hydro Electric Corporation</td>
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<td>Wellington North Power Inc.</td>
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</tbody>
</table>
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 34:

Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 21

a) What percentage of capital cost of project consists of direct labour and indirect
labour over the 2013-2017 period?

b) What accounts for the differential between projects constructed by internal crews
and contracted out projects?

RESPONSE:

a) Please see Table 1 for internal labour costs from direct vs. indirect labour compared to

b) The cost differential stems from higher overhead and administration expenditures
associated with the scale and scope of the utility’s operations in supporting the
execution of the capital work program as compared to the analogous cost drivers for
the external contractors.

Table 1: Internal Labour Costs from Direct versus Indirect Labour of Total Capital

<table>
<thead>
<tr>
<th>Category</th>
<th>Actual</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
</tr>
<tr>
<td>Direct Labour % of Total Capital</td>
<td>17.7%</td>
</tr>
<tr>
<td>Indirect Labour % of Total Capital</td>
<td>7.1%</td>
</tr>
</tbody>
</table>

Panel: General Plant, Operations, and Administration
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 35:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 7

a) Does THESL have a comprehensive plan to increase resiliency in the face of a growing number of extreme weather events?

b) Please provide 2018 figures for all graphs in this schedule when available.

RESPONSE:

a) Please refer to Exhibit 2B, Section D2.1.2, pages 8 and 9.

b) Toronto Hydro does not currently have this data finalized for 2018.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
(“BOMA”) INTERROGATORIES

INTERROGATORY 36:
Reference(s): Exhibit 1B, Tab 3, Schedule 1, p. 6

THESL states that Innovative had concluded that:

"majorities of residential, small business, mid-market and key account customers say [the utility] should stick with its proposed plan or do more”.

Please provide the basis for this statement, with reference to the results of specific questions on the Innovative surveys.

RESPONSE:
In the Phase 2 telephone surveys amongst residential, small business and mid-market customers, all customers who participated in the telephone surveys were asked the following question at the conclusion of the survey:

With regards to Toronto Hydro’s proposed plan, which of the following statements best represents your view? [READ LIST; ROTATE 01 and 03]

01 Toronto Hydro should improve service, as discussed on the previous pages, even if that means an annual increase that exceeds [Residential: 3.4%; Small Business: 4.4%; Mid-Market: 3.9%].

02 Toronto Hydro should stick with a [Residential: 3.4%; Small Business: 4.4%; Mid-Market: 3.9%] annual increase to deliver current levels of reliability and customer service for most customers and targeted improvement for
customers experiencing below average service or who have special reliability needs.

| 03 | Toronto Hydro should keep increases below [Residential: 3.4%; Small Business: 4.4%; Mid-Market: 3.9%] annually, even if that could mean reductions in service. |
| 88 | Other [Please specify] |
| 98 | Don’t know |

A summary of the results on this question, which is that a majority of respondents were supportive of the utility’s proposed plan, or a plan that improves services, can be found in the Customer Engagement Report (Exhibit 1B, Tab 3, Schedule 1, Appendix A, page 18).

Likewise, 29 of 37 Key Account customers interviewed felt that Toronto Hydro should either exceed the current plan to improve services beyond what is being proposed (4 of 37) or stick with the current plan and its expressed outcomes (25 of 37) (See the Customer Engagement Report, page 20).
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
(“BOMA”) INTERROGATORIES

INTERROGATORY 37:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, p. 12
DSP Exhibit 2B, Section D3, and Section E6.7

Why are Worst Performing Feeder Programs not integrated into the capital budget as a first priority. Please explain fully.

RESPONSE:
The worst performing feeder segment is a fully integrated part of the Reactive and Corrective Capital program discussed in Exhibit 2B, Section E6.7. The activities within this program are therefore contained within the capital budget, and are prioritized as being “near-term” and “urgent” as noted in the first sentence of this program narrative (Exhibit 2B, Section E6.7.1, Line 4) (emphasis added):

“The Reactive and Corrective Capital program (the “Program) addresses the replacement of failed and defective assets, and provides for near-term corrective actions on Toronto Hydro’s least reliable feeders. The work required under this Program is urgent and non-discretionary.”
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 38:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Attachment A, p. 2

Were customers able to review the cumulative rate impact of their choices and adjust them if needed? If not, why not?

RESPONSE:

Yes. Please see Exhibit 1B, Tab 3, Schedule 1, Appendix 2.1, pp. 61-63.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
(“BOMA”) INTERROGATORIES

INTERROGATORY 39:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Attachment A, p. 3

Preamble:

"Customers consistently, across rate classes value price and reliability above other
priorities, with price constantly at the top priority for non-large use customers."

Given that priority, why is THESL proposing a plan that will increase customer rates by
over three percent (3%) per year, over the plan term?

RESPONSE:

The average annual distribution rate increase over the five years of the plan that a typical
750 kWh residential customer would experience, inclusive of rate riders, is $0.77 or 1.7%,
or 0.4% on the overall electricity bill. This includes a decrease of $3.10 on the overall
electricity bill in 2020, the first year of the plan.

The justification for the proposed rate increase is summarized in the Executive Summary
and Business Plan Overview, at Exhibit 1B, Tab 1, Schedule 1, and in greater detail
throughout this application. Toronto Hydro’s plan was developed in consultation with its
customers, as described at Exhibit 1B, Tab 3, Schedule 1.

Focus groups engaged during Phase 1 of the Planning-specific Customer Engagement
identified six key customer outcomes: ensuring the safety of electrical infrastructure,
ensuring reliable electrical service, delivering reasonable electricity prices, providing
quality customer service, helping customers with electricity conservation and efficient
usage, and enabling the electrical system to support the reduction of greenhouse gases.

Following the focus groups, a telephone survey of low-volume customers asked
respondents about the importance of these outcomes. A majority of respondents replied
that each individual outcome was either “important” or “extremely important.”
However, when asked to rank those same outcomes, prices, reliability and safety ranked
the highest. Toronto Hydro observes that, while price was found to be the highest
priority for low volume customers, it is one among a set of outcomes that customers
clearly value as important to them. Based on the entirety of the Phase 1 results,
Innovative concluded that “customer and stakeholder feedback from Phase 1 can be
summarized by the following key points:

1. Keep distribution price increases as low as possible;
2. Maintain long-term performance for customer experiencing average or better
   service;
3. Improve service levels for customers experiencing below average service or who
   have special reliability needs (e.g. hospitals); and
4. Balance other customer priorities (e.g. customer service) with the need to contain
   rate increases.”

Toronto Hydro’s plan for 2020 to 2024 is the result of thorough business planning in
which customers’ needs and preferences were integrated from start to finish. The plan is
expected to produce performance outcomes that customers value and are willing to
financially support through their distribution rates. With the funding that these rates
would provide, Toronto Hydro expects to continue to meet the needs of its customers.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 40:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Attachment A, p. 7

Please provide a list of the key accounts.

RESPONSE:

Toronto Hydro refuses to provide the list of its key account customers on the basis of relevance. This information will not provide any probative value for the purpose of determining just and reasonable rates.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 41:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Attachment A, p. 8

a) Please reconcile the Summary of Customer Priorities Table on p5, with the Customer Priorities Table on p8 (and the Ranked Outcomes Table on p7), both of which said prices are the top priority for low volume customers, with the statement on p7, that:

"Similar to what was observed in the previous focus group research, safety, reliability, and price are seen as equally important to low-volume customers."

b) For key accounts, please confirm that reliability and performance were the key priorities (price 68%, reliability 72%).

RESPONSE:

a) The conclusion that low-volume customers weigh safety, reliability and price equally is based on the quantification of “net importance” when respondents were asked to assess the importance of each priority, as shown on page 7 of the Executive Summary of the Innovative Report at Exhibit 1B, Tab 3, Schedule 1, Appendix A. The conclusion that low-volume customers ranked prices, reliability, and safety in that order is based on the results of the subsequent question asking respondents to rank each priority, as shown on page 8 of the Executive Summary. Both are in reference to Phase 1 of the Planning-specific Customer Engagement.
b) As shown on page 11 of the Executive Summary of the Innovative Report at Exhibit 1B, Tab 3, Schedule 1, Appendix A, “Ensuring reliable electrical service” and “Delivering reasonable electricity prices” were the first and second-ranked answer by Total Mentions in the Phase 1 Key Accounts survey.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 42:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Attachment A, p. 15

Innovative asked small volume and mid-market customers the following question:

"Based, in part, on the initial customer input, Toronto Hydro has drafted a plan totaling approximately $4.3B over five years.

Toronto Hydro's proposed plan focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

This proposed plan translates into an average 3.4% increase in your distribution rates each year from 2020 to 2024. The distribution charges on the monthly bill would increase to $49 by 2024 for a typical residential customer."

Please confirm that the largest plurality of residential, small business, and mid-market customers disagreed with the annual rate increase proposed distribution rate increases (3.4% - Residential; 4.4% - Small Business; 3.9% - Mid-Market) to fund the $4.3B plan; they considered it the wrong approach.
RESPONSE (PREPARED BY INNOVATIVE):

When they were initially asked this question, yes this is correct. However, this was in the absence of a discussion of specific benefits for customers and other details regarding the proposed programs. While this is the only trade-off question where respondents appear to place price concerns above the maintenance of reliability and targeted improvements, it highlights the general concern about delivering reasonable electricity prices seen in the outcome section.

As customers became more engaged in discussing more detailed trade-offs and price implications, their responses favoured the other outcomes over bill impacts. Overall, Toronto Hydro customers were supportive of the utility’s proposed plan, or a plan that improves services, including investments that focus on improving reliability and safety or innovation and planning for the future and including the proposed rate increases (See pp. 18 of the above-noted schedule).
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 43:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Attachment A, p. 16

Why did Innovative ask customers specific trade-off question for specific investment projects, as it did recently in the Alectra proceeding (EB-2018-0016)?

RESPONSE:

One of the priorities of Planning-specific Customer Engagement was to focus on fundamental value choices, asking customers to choose among key outcomes, which equipped Toronto Hydro with a genuine understanding of its customers’ needs and preferences. Gathering feedback on specific investments is both responsive to OEB direction,¹ and allows customers to provide meaningful feedback on trade-offs between outcomes and costs, as well as the pacing and prioritization of investments.

INTERROGATORY 44:

Reference(s): Exhibit 1B, Tab 5, Schedule 1, p. 3

What specific additional escalators were applied to capital expenditures over the plan term?

RESPONSE:

Instead of applying a generic inflationary value to all capital programs, Toronto Hydro had regard for the terms set out in its commercial agreements in escalating the forecasted costs of applicable capital programs.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 45:
Reference(s): Exhibit 1B, Tab 5, Schedule 1, p. 9

a) In the event the board were to reduce the proposed five (5) year capital expenditures in the 2015-2019 level, plus six percent (6%), please provide a revised Table 6.

b) Please provide a comparable table, actuals and forecast, to Table 6 New Actual/Forecast Capex for the 2015-2019 plan period.

RESPONSE:

a) Toronto Hydro is unable to comment on what would be effect of an OEB decision to reduce capital expenditures by any given amount. The capital expenditure plan proposed for the 2020-2024 period is the minimum level of spending that Toronto Hydro assesses is required to strike a balance and responsive to: the utility’s legal requirements including safety, customer feedback, and business input through expert analysis and professional judgment to develop construction and operations programs that address technical and operational requirements. Achieving this balance includes mitigating the accumulation of risk and associated decline in performance over the medium and long term.

b) Toronto Hydro has developed and refined its plan having regard to customer feedback that limiting price increases was a paramount concern, to the degree that doing so
would not adversely affect service performance, and that performance would improve in certain areas. This means that its plan does not include all the reasonable funding requests that it assesses are appropriate given the needs of the system. Indeed, Toronto Hydro has constrained its capital plan, even though a higher level is preferable from an asset management perspective to better manage certain elevated asset risks.

Please refer to the table in Exhibit 2B, Section E4 at page 2.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
INTERROGATORIES

INTERROGATORY 46:
Reference(s): Exhibit 1B, Tab 5, Schedule 1, p. 14

a) Please provide the details of market competitive pay increase used for the 2015-2019 period (forecast and actual) and 2020-2024.

b) What has been the actual amount (percentage) and cost of short-term debt for each year of its 2015-2019 period?

RESPONSE:

a) General wage increases for PWU and SEP employees are as per the respective collective agreements. Actual pay ranges for non-unionized employees increased by an average of 1.9 percent per year from 2015 to 2018, which is consistent with data reported in independent compensation consultant market surveys. For 2019 and 2020, Toronto Hydro assumed a pay range increase assumption of 2 percent. Toronto Hydro’s OM&A framework is based on a forecast for 2020 and the application of its Custom Price Cap Index for 2021 through 2024.

b) Please refer to the following table for Toronto Hydro’s annual short-term debt proportion and expense.
Table 1: Toronto Hydro’s Annual Short-term Debt Proportion and Expense

<table>
<thead>
<tr>
<th>Year</th>
<th>Short-term Debt Relative to Total Debt</th>
<th>Interest Expense</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>8.9%</td>
<td>$4.5M</td>
</tr>
<tr>
<td>2016</td>
<td>2.3%</td>
<td>$3.6M</td>
</tr>
<tr>
<td>2017</td>
<td>5.6%</td>
<td>$3.3M</td>
</tr>
</tbody>
</table>

Toronto Hydro expects to provide 2018 actuals as part of the planned update to the evidence, which is discussed in Exhibit 1A, Tab 3, Schedule 1, Appendix B. 2019 information is not available at this time.

1 As at December 31 of each year.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
INTERROGATORIES

INTERROGATORY 116:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, Section 5.2

Performance Measurement and Management

Toronto Hydro is an efficient organization that strives to continue its history of performance, productivity, and customer cost savings, including its commitment to a strong performance management culture. Inherent in its focus on outputs and value is an emphasis on measuring and tracking performance, using internal and external benchmarking. (Reference: Section 5.2”

Please describe how the measurement and tracking of performance is applied in the assessments and compensation of executives and management staff at Toronto Hydro.

RESPONSE:

Executive and management staff, along with other non-bargaining unit employees, receive a total cash compensation package comprised of base salary and variable performance pay. Variable performance pay recognizes an employee’s individual performance as well as his or her contribution to corporate performance. Toronto Hydro tracks and measures corporate performance via the corporate scorecard, which can be viewed in the response to interrogatory 1B-SEC-8. Variable performance pay is determined annually at the end of the first quarter of a new year, with regard to the achievement of the performance objectives set out in the previous year’s scorecard.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION
INTERROGATORIES

INTERROGATORY 117:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 17
Exhibit 1B, Tab 2, Schedule 3, p. 8, 9
Exhibit 8, Tab 2, Schedule 1, p. 1

Remote Connection, Disconnection and Reconnection

Similarly, through the introduction of meters with remote disconnection capabilities, Toronto Hydro can decrease the number of physical visits to a customer’s property. (Reference: EB-2018-0165 Exhibit 1B Tab 2 Schedule 1 ORI gi na l Page 17 of 29)

Toronto Hydro has made investments to its metering system to allow remote reconnection for certain customers. This was part of a pilot project started in 2017 to improve the efficiency and timeliness of the reconnection process. Toronto Hydro is gradually upgrading its meters to have remote-control capabilities and as of the end of 2017 had over 48,000 meters with such capabilities in service. These new meters can be remotely disconnected, reconnected, or operated intermittently to interrupt load on a pre-set schedule, without the need for a site visit. As these meters become more commonplace, performance under this measure is expected to further improve, as the utility will increase its capability to remotely reconnect customers nearly instantaneously after a customer makes payment or enters into an arrears payment plan. For the 2020-2024 period, Toronto Hydro intends to meet or exceed the current OEB standard for this measure. Toronto Hydro’s performance under this measure is enabled by work including that in the Metering
(Exhibit 2B, Section E5.4) and Customer Care program (Exhibit 4A, Tab 2, Schedule 14). (Reference: EB-2018-0165 Exhibit 1B Tab 2 Schedule 3 ORIGINAL Pages 8, 9 of 9)

Selected Fees (Reference: EB-2018-0165 Exhibit 8 Tab 2 Schedule 1 ORIGINAL Page 1 of 5)

- Disconnect/Reconnect at meter - during regular hours: $120.00
- Install/Remove load control device - during regular hours: $120.00
- Install/Remove load control device - after regular hours: $400.
- Disconnect/Reconnect at pole - during regular hours: $300.00
- Disconnect/Reconnect at pole - after regular hours: $820.00

The OEB benchmarking with respect to disconnection and reconnection was based on the physical processes that predated meters with capability for remote connection.

a) Does Toronto Hydro anticipate that benchmarks will be developed that reflect a new standard based on remote capabilities so that comparisons can be made on the same basis?

b) Given that fees associated with disconnections and reconnections are cost based, does Toronto Hydro intend to develop new fees associated with the less expensive remote option?

RESPONSE:

a) Toronto Hydro cannot speak to whether the OEB plans to adjust any of its performance standards.
b) Toronto Hydro has not proposed any changes to its previously approved disconnect or reconnect charges. While as noted in the referenced evidence, the ability to remotely reconnect and disconnect is growing, there remains a significant amount of reconnects and disconnects that are performed in the field. Toronto Hydro also notes that the OEB is currently reviewing its Customer Service rules, which may impact the application of these charges.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

(“BOMA”) INTERROGATORIES

INTERROGATORY 118:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 9

Third Party Assessments

In this Application, the utility has also filed third party assessments of its plans, including a review of its asset management, benchmarking the IT function against peers, and an analysis of the proposal underlying the Control Operations Reinforcement Program. These studies provided Toronto Hydro with important insights and the reports are filed with the Application as commentary and support for the associated plans. (Reference: EB-2018-0165 Exhibit 1B Tab 1 Schedule 1

ORIGINAL, Page 9 of 34)

Interrogatory: Please provide the costs and benefits of each of the seven (7) third-party assessments.

RESPONSE:

Please see Toronto Hydro’s response to interrogatory 1B-CCC-8 for the costs of each of the seven third-party assessments filed in this application. Some of these third party assessments are mandatory pursuant to the OEB Handbook for Utility Rate Applications or OEB Filing Requirements. The justification for and benefits of the other assessments are set out in the evidence that introduces the assessments.
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 119:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, p. 1

Innovative Research Group

Toronto Hydro engaged Innovative Research Group (“Innovative”), a national consulting firm with expertise in public opinion research (and experience in energy policy in particular), to execute the utility’s Planning-specific Customer Engagement. The resulting final report (the “Innovative Report”) can be found in Appendix A to this Schedule. Innovative executed the Planning-specific Customer Engagement in two phases. Phase 1 provided input into the development of the business plan, including the penultimate Distribution System Plan ("DSP"). Phase 2 helped to refine the business plan

Phase 1

Low Volume Customer Focus Group Report
Mid-Market Customer Focus Group Report
Low-Volume Customer Needs & Preferences Survey Report
Key Account Needs & Preferences Survey Report
Stakeholder In-depth Interview Report
Customer Priorities Summary (Placemat)

Phase 2

Online Customer Feedback Portal Report
Residential Telephone Survey Report

Panel: Rates and CIR Framework
3.0 **Consultation Materials**

- Online Customer Feedback Portal Content (Print Version)
- Residential Telephone Questionnaire
- Small Business Telephone Questionnaire
- Mid-Market Telephone Questionnaire
- Key Account Online Questionnaire

(Reference: EB-2018-0165 Exhibit 1B Tab 3 Schedule 1 ORIGINAL Page 1 of 13)

Please provide the costs associated with each Phase and sub-phase of the Innovative Project as well as the total cost of the design and implementation of the total project.

**RESPONSE:**

Please see Table 1 below.

<table>
<thead>
<tr>
<th>Phase</th>
<th>Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase 1</td>
<td>$100,076.09</td>
</tr>
<tr>
<td>Phase 2</td>
<td>$302,684.21</td>
</tr>
<tr>
<td>Community Meetings Prep</td>
<td>$10,825.00</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$413,585.30</strong></td>
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</tbody>
</table>
RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION

INTERROGATORIES

INTERROGATORY 120:

Reference(s): Exhibit 2B, Section A4
Exhibit 1B, Tab 1, Schedule 1, p. 21
Exhibit 1B, Tab 3, Schedule 1, p. 6

New Technologies

New communication technology has revolutionized the way the grid can be managed. Toronto Hydro plans to take advantage of various new technologies wherever clear benefits can be established. However, Toronto Hydro can improve the reliability of its grid further by installing communication devices in the downtown underground network that detect fire, floods or other risks more quickly.

Toronto Hydro has already begun to integrate large-scale battery electricity storage into the system. They have now identified more opportunities to partner on a wider range of energy storage projects. Integrating storage into the system can improve reliability and help reduce greenhouse gases, but it is not required to maintain current levels of reliability. Microgrids would give customers more choices, while creating a more resilient and reliable grid. However, they are not required to maintain current reliability. (Reference: EB-2018-0165 Exhibit 2B Section A4 ORIGINAL)

Conservation First: In addition to traditional expansion investments, the Stations Expansion (Section E7.4) program includes a continuation of Toronto Hydro’s Local

Panel: Rates and CIR Framework
Demand Response activities introduced in the 2015-2019 DSP. These investments involve installing battery storage and implementing targeted demand response incentive programs to reduce peak demand by 10 MW, allowing the utility to defer an estimated $135 million of expansion investments at Cecil TS and Basin TS. (Reference: EB-2018-0165 Exhibit 1B Tab 1 Schedule 1 ORIGINAL Page 21 of 34)

However, certain parts of the plan, such as Microgrids, did not receive strong customer support. For example, a majority of customers favoured a more limited involvement by Toronto Hydro in support of microgrids, in contrast to strong support for increasing the pace of investments in monitoring and control equipment and network units. (Reference: EB-2018-0165 Exhibit 1B Tab 3 Schedule 1 ORIGINAL Page 6 of 13)

In the Innovative survey, only microgrids and storage were identified as having a cost impact with no improvement on current reliability.

a) Please provide Toronto Hydro’s analysis to support that these technologies would not improve current reliability.

b) What was the rationale for singling out these two technologies when the others referenced in the report also have cost impacts?

c) Why didn’t the Innovative project surveys indicate the $135 million in deferred costs as a benefit to consumers.

d) Please file Toronto Hydro’s analysis which identified the $135 million in deferred costs.
RESPONSE:

a) With respect to the Phase 2 telephone surveys, Toronto Hydro does not agree with the suggestion made in this interrogatory that microgrids and energy storage were identified as having no improvement on current reliability. The quotations provided in the interrogatory above state the opposite, that both technologies can improve reliability. The telephone surveys in Appendices 3.2.1 (Residential Ratepayer Survey), 3.2.2 (Small Business Ratepayer Survey) and 3.3.3 (Mid-Market Ratepayer Survey) of the Innovative Report at Exhibit 1B, Tab 3, Schedule 1, Appendix A also state that these technologies can improve reliability.

b) Energy storage and microgrids are both examples investments in Innovation and Planning for the Future, which encapsulates the deployment of new technologies and conventional technologies in new ways to modernize the distribution system and generate benefits that provide cost savings and better service levels.

c) The $135 million deferral cited in the above-noted reference in the DSP corresponds to investments in Local Demand Response activities, of which energy storage is one component. As noted at Page 31 of E7.4 of the DSP, “[t]he bulk of the total 2020-2024 Local DR program cost (e.g., incentives, labour) is not capitalized and therefore not included in Table 23. 60 percent of the $10.3 million total program cost is operating expenditures relating to program administration, customer incentives for DR activities, marketing and legal costs, and measurement and verification costs…”

d) Please refer to Tables 26 and 27 in Section E7.4.5.3 of Exhibit 2B.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 8:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 3

The evidence states that as part of its due diligence and recognizing the value of third
party perspectives, THESL engaged external experts to review significant parts of the plan
and is filing their work products as part of the Application:

a) Please provide a complete list of all of the reports, setting out for each one, the
nature of the work and the contractor, the costs incurred to date and the total
expected cost. Please provide for each contractor the final Terms of Reference.
How does THESL propose that these costs be recovered?

b) Please explain, in detail, how Toronto determined which areas of the application
should be reviewed and validated by external experts and which areas could be
reviewed internally.

c) Did Toronto Hydro develop a budget for this work? If so, please indicate what that
budget was and how was this budget developed. If now, why not?

d) Please indicate whether each piece of work was subject to an RFP process. In
those cases where there was no RFP please explain why.
RESPONSE:

a) Please see table below.

**Table 1: Summary of Third Party Reports**

<table>
<thead>
<tr>
<th>Consultant</th>
<th>Nature of the Work/Evidence Reference</th>
<th>RFP</th>
<th>Retainer</th>
<th>Cost to Date</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>UMS Group</strong></td>
<td><strong>DSP Asset Management Review (Exhibit 2B, Section D, Appendix A).</strong> UMS Group was retained to evaluate Toronto Hydro’s asset management practices as they relate to the formation and execution of its DSP.</td>
<td>Yes</td>
<td>App. A</td>
<td>$134,750.00</td>
</tr>
<tr>
<td></td>
<td><strong>Unit Cost Benchmarking Study (Exhibit 1B, Tab 2, Schedule 1, Appendix B).</strong> UMS Group was retained to conduct a third party independent review of the Toronto Hydro’s methodology for deriving unit costs and perform benchmarking comparisons of a pre-selected set of asset categories and maintenance programs.</td>
<td>Yes</td>
<td>App. B</td>
<td>$250,400.00</td>
</tr>
<tr>
<td><strong>PSE</strong></td>
<td><strong>Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels (Exhibit 1B, Tab 4, Schedule 2).</strong> PSE was retained to provide a report in connection with the benchmarking of Toronto Hydro’s key operating parameters (i.e. total costs and reliability).</td>
<td>No</td>
<td>App. C</td>
<td>339,309.00 USD</td>
</tr>
<tr>
<td><strong>Gartner Canada Inc.</strong></td>
<td><strong>IT Budget Assessment (Exhibit 2B, Section E8.4, Appendix A).</strong> Gartner was retained to carry out an assessment of Toronto Hydro’s IT budget,</td>
<td>No</td>
<td>App. E</td>
<td>$135,000.00</td>
</tr>
<tr>
<td>Consultant</td>
<td>Nature of the Work/Evidence Reference</td>
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<td>--------------------------------------------------------------------------------------------------------</td>
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<td>--------------------------</td>
</tr>
<tr>
<td>Toronto Hydro-Electric System Limited</td>
<td>including performing a comparison of high level IT metrics and spending and staffing distributions with a view to providing insight into how IT spending aligns with Toronto Hydro’s peers organizations.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>AECOM Consultants Inc.</td>
<td>Climate Change Vulnerability Assessment (Exhibit 2B, Section D, Appendix D). The study evaluates the vulnerability of Toronto Hydro’s electrical distribution system within the City of Toronto to a changing climate by employing PIEVC Protocol.</td>
<td>N/A</td>
<td>N/A</td>
<td>$84,000.00 of in-kind support¹</td>
</tr>
<tr>
<td>London Economics International LLC</td>
<td>Jurisdictional review and economic case for a dual distribution control centre (Exhibit 2B, Section E8.1, Appendix A). LEI was engaged to undertake an independent study of comparator utilities with fully functional backup control centers in other jurisdictions.</td>
<td>Yes</td>
<td>App. F</td>
<td>$79,985.00</td>
</tr>
<tr>
<td>Willis Towers Watson</td>
<td>2017 Post-Employment Benefits (4A-4-6). Willis Towers Watson was retained to review Toronto Hydro’s liabilities and costs in respect of the following post-retirement and post-employment benefits plans.</td>
<td>Yes</td>
<td>App G</td>
<td>$27,250.00</td>
</tr>
<tr>
<td></td>
<td>2018 Post-Employment Benefits (4A-4-6). Willis Towers Watson was retained to review Toronto Hydro’s liabilities and costs in respect of the following post-retirement and post-employment benefits plans.</td>
<td>Yes</td>
<td>App G</td>
<td>$57,125.00</td>
</tr>
<tr>
<td>Navigant Consulting</td>
<td>Working Capital Requirements of THESL’s Distribution Business (Exhibit 2A, Tab 3, Schedule 2). Navigant was retained to prepare an update to its prior working capital study (lead lag study).</td>
<td>Yes</td>
<td>App H</td>
<td>$78,188.75</td>
</tr>
</tbody>
</table>

¹ Please refer to Toronto Hydro’s response to interrogatory 2B-EP-35 for more information.
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</thead>
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<tr>
<td>Navigant Consulting</td>
<td>Distribution System Loss Factors for the Large User (&gt;5000kW) Class (Exhibit 8, Tab 4, Schedule 2).</td>
<td>Yes</td>
<td>App. I</td>
<td>$92,863.25</td>
</tr>
<tr>
<td></td>
<td>Navigant Consulting was engaged to update distribution system loss factors for its Large Users (demand greater than 5000kW) class.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mercer Consulting Canada</td>
<td>Non-Executive Compensation and Benefits Review (Exhibit 4A, Tab 4, Schedule 5).</td>
<td>Yes</td>
<td>App. J</td>
<td>$53,621.25</td>
</tr>
<tr>
<td></td>
<td>Mercer was engaged to complete a market review of compensation and benefits program competitiveness for non-executive management, non-union professional and union positions within Toronto Hydro.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Innovative Research Group</td>
<td>Customer Engagement (Exhibit 1B, Tab 3, Schedule 1, Appendix A).</td>
<td>Yes</td>
<td>App. K</td>
<td>$413,585.30</td>
</tr>
<tr>
<td></td>
<td>Innovative Research was engaged to help design, execute, and document the results of Toronto Hydro’s customer engagement process as part of the development of its Financial and Business Planning process and its 2020-2024 CIR Application, including its DSP.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The total expected costs of the consultants depends on the work required by these third parties to answer interrogatories, and the extent to which the OEB and intervenors seek to have these third parties attend the hearing and be involved with other procedural steps in this application. Therefore, while Toronto Hydro is unable to speculate as to a breakdown of the total costs, for the purposes of recovery Toronto Hydro has included these amounts to be recovered as part of the Rates and Regulatory Affairs OM&A budget (Exhibit 4A, Tab 2, Schedule 18). As indicated in Appendix 2-M of that schedule, total consulting costs (which includes the costs of the reports noted above) of $3.1M related to the CIR application are proposed to be amortized over the 2020-2024 period.
Please refer to Appendix A for copies of the retainers executed with each of these consultants.

Toronto Hydro does not have a retainer with AECOM. The Clean Air Partnership ("CAP") was a contracting legal entity that managed and administered a climate change vulnerability assessment study. Toronto Hydro was one of the entities that partnered with CAP to support the study.

b) Toronto Hydro used experience and professional judgment in determining which areas of the application would benefit by review and/or validation from external consultants. Factors included: guidance provided by the OEB in the RRF, the Handbook for Utility Rate Applications and the Filing Requirements; what may be helpful to the OEB in understanding and assessing Toronto Hydro’s application; and precedent from prior proceedings.

c) Toronto Hydro developed an initial high-level budget for this work, which it has updated periodically. The current budget for this work is included in the corrected OEB Appendix 2-M (Exhibit 4A, Tab 2, Schedule 18). Please note that not all of the third party studies and reports conducted formed part of this budget; some studies (e.g. Mercer Non-Executive Compensation and Benefits Review) were done within the normal course of our business and are not reflected in the budget.

d) Please refer to Table 1 in part (a) for a summary of which consultants were retained through an RFP process. In respect of the consultants that were not:

- PSE was engaged due to its expertise, understanding of Ontario’s regulated electricity sector, and its previous experience working with Toronto Hydro
on both the development of its proprietary econometric benchmarking
model and its prior review of Toronto Hydro's Standard Design Practices.

- Gartner Canada Inc. was engaged due to its depth of resources, research,
  expertise, and reputation as the leading firm providing advisory services for
  IT Executive, Managers, and Technical Staff.
BY EMAIL

CONFIDENTIAL — PRIVILEGED

April 12, 2018

UMS Group Inc.
Morris Corporate Center 1
300 Interspace Parkway, Suite C380
Parsippany, NJ 07054
U.S.A.

Attention: Mr. Jeffrey W. Cummings


Dear Mr. Cummings:

We represent Toronto Hydro-Electric System Limited (“THESL”) in connection with its planned 2020 Custom Incentive Rate application (the “Application”) to the Ontario Energy Board (the “Board”).

We confirm that, on behalf of and to assist us in providing legal advice to THESL in connection with the Application, TORYS LLP (“TORYS”) has agreed to retain the UMS Group (the “Consultant”) effective as of April 12, 2018 (the “Effective Date”) to provide consulting services as herein described. By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with TORYS effective on the Effective Date, subject to amendment by written agreement between the parties (the “Retainer Agreement”).

1. No Conflict

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice to THESL. You confirm that you are free to provide your services to TORYS in connection with TORYS’ representation of THESL in the Application. You agree that during this engagement you will not provide, directly or indirectly, any services to any other party in connection with the matters at issue in the Application.

25364596.1
2. **Consultant Expertise**

The Consultant has been selected to provide consulting services to TORYS in connection with the Application, namely by undertaking an independent review of THESL’s Distribution System Plan ("DSP") to evaluate the consistency of the planning practices, methods and tools used to develop the capital expenditure plan in the DSP with industry best practices. The sponsors of the work of the Consultant and the persons who have the relevant expertise will be Jeffrey W. Cummings, Steven J. Morris, Brett Shaw and Brian Kaiser (the "Sponsors").

3. **Scope of Services and Work Product**

The Consultant will:

(a) perform an assessment, and provide advice to TORYS in connection therewith, based on the Consultant’s independent review and evaluation of THESL’s DSP, with the view of determining whether the planning practices, methods and tools employed by THESL to develop and prioritize the capital expenditure plan presented in the DSP are consistent with industry best practices (the “Assessment”);

(b) if requested by TORYS, produce a written report detailing the methodology for the Assessment and the ensuing findings and recommendations (the “Report”); and

(c) if requested by TORYS, provide support during the hearing of the Application and testify before the Board in the Application, in connection with the scope of the services provided hereunder ("Application Support" and, together with the Assessment and the Report, the “Services”).

4. **Fees and Invoices**

By entering into this Retainer Agreement, the Consultant acknowledges that:

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<tr>
<th>Position/Title</th>
<th>All-Inclusive Hourly Rate (Off Site)</th>
<th>All-Inclusive Hourly Rate (On Site)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
All amounts stated herein are in Canadian dollars.

The Consultant shall direct all invoices relating to Services performed by it under this Retainer Agreement to THESL, to the attention of:

Mr. Matthew Higgins
Manager, Regulatory Applications
Toronto Hydro Electric-System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5
mhiggins@torontohydro.com

with a copy to Torys, to the attention of:

Mr. Charles Keizer
Torys LLP
79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2
ckeizer@torys.com

Any disbursements for additional incidentals incurred by the Consultant in relation to this Retainer Agreement must be pre-approved by THESL in writing. THESL reserves the right to deduct any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Retainer Agreement and remit such amounts to the applicable taxation authority.

5. Confidentiality

All work performed by the Consultant in connection with this Retainer Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Retainer Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of Torys or THESL. The Consultant agrees to designate all written communications and material accordingly. The Consultant further agrees to notify Torys in the event that the Consultant receives a request to disclose information relating to this matter, and agrees to cooperate with Torys, to the fullest extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material.

The Consultant agrees to hold in confidence: (a) all information provided to the Consultant, and (b) the Consultant’s opinions to Torys and to THESL as they relate to the information, whether the information or opinions are documentary or oral (collectively, the “Confidential Information”). The Consultant will not disclose the Confidential Information to any person unless Torys or THESL authorizes you in writing to do so. All documents given to the
Consultant in connection with this Retainer Agreement remain the property of Torys or of THESL, and are held in trust by the Consultant as agent. The Consultant agrees to return these documents on request.

The Consultant will not refer to Torys or to THESL, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of Torys or THESL, as the case may be.

6. **Intellectual Property**

Nothing in this Retainer Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to THESL or any of its representatives or any third party whose intellectual property is in THESL’s custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of THESL.

Torys and THESL shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Retainer Agreement, including without limitation any reports or other documents created by the Consultant, and any related works, modifications or additions thereto (the “Work Product”), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, THESL shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to THESL any such rights, and agrees to give THESL and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant’s employees, partners or other representatives.

7. **Termination**

Torys may terminate this Retainer Agreement at any time on written notice to the Consultant. Torys will pay, or will cause THESL to pay, for work performed up to the date of the notice of termination. Upon the termination or expiration of this Retainer Agreement, the Consultant shall return to Torys and delete any and all electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Retainer Agreement, including all Confidential Information (defined above) and Work Product, whether completed or not.

8. **Limitation of Liability**

Except for breach of confidentiality obligations, the Consultant’s total liability for any claim arising out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not limited to, loss of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind.

9. **Independence**
By entering into this Retainer Agreement, the Consultant acknowledges and agrees that the Sponsors have received a copy of Rule 13A of the Board’s Rules of Practice and Procedure concerning expert evidence, and agree to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy is attached as Schedule ‘A’ hereto.

10. **Entire Agreement**

This Retainer Agreement, together with all Schedules attached hereto and any agreements and other documents to be delivered pursuant to this Retainer Agreement, constitute the complete agreement between Torys and the Consultant or their respective agents with respect to the subject matter hereof and supersede any and all prior agreements and understandings. This Retainer Agreement may be amended only in a writing that refers to this Retainer Agreement and is signed by both parties.

Sincerely,

TORYS LLP

Per: [Signature]
Name: Charles Keizer

Accepted and agreed to by the UMS Group:

Signed [Signature]
Name (please print) JEFFREY W. CUMMINGS
SCHEDULE ‘A’

Rule 13A of the Board’s Rules of Practice and Procedure

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert’s area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert’s evidence shall, at a minimum, include the following:

(a) the expert’s name, business name and address, and general area of expertise;

(b) the expert’s qualifications, including the expert’s relevant educational and professional experience in respect of each issue in the proceeding to which the expert’s evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert’s evidence relates;

(d) the specific information upon which the expert’s evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert’s evidence, a summary of the points of agreement and disagreement with the other expert’s evidence; and

(f) an acknowledgement of the expert’s duty to the Board in Form A to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in Rule 13A.04 shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the Board;

(c) the costs associated with the conduct of the activities;
(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of
the activities referred to in paragraph (a) of Rule 13A.04; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to
accept, the responsibilities that are or may be imposed on the expert as set out in this Rule 13A and Form
A.¹

¹ Form “A” (Acknowledgement of Expert’s Duty) to the Board’s Rules of Practice and Procedure requires the
expert witness to acknowledge that it is his or her duty to provide evidence in relation to a proceeding before the
Board as follows:

(a) to provide opinion evidence that is fair, objective and non-partisan;

(b) to provide opinion evidence that is related only to matters that are within his or her area of expertise;

and

(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in
issue.

Form “A” further requires the expert witness to acknowledge that the duty referred to above prevails over any
obligation which he or she may owe to any party by whom or on whose behalf he or she is engaged.
BY EMAIL

CONFIDENTIAL — PRIVILEGED

July 19, 2017

UMS Group Inc.
Morris Corporate Center 1
300 Interspace Parkway, Suite C380
Parsippany, NJ 07054
U.S.A.

Attention: Mr. Jeffrey W. Cummings

Re: Retainer Letter Agreement – Toronto Hydro-Electric System Limited Unit Costs Benchmarking Study

Dear Mr. Cummings:

We represent Toronto Hydro-Electric System Limited (“THESL”) in connection with its planned 2020 Custom Incentive Rate application (the “Application”) to the Ontario Energy Board (the “Board”).

We confirm that, on behalf of and to assist us in providing legal advice to THESL in connection with the Application, TORYS LLP (“TORYS”) has agreed to retain the UMS Group (the “Consultant”) effective as of July 19, 2017 (the “Effective Date”) to provide consulting services as herein described. By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with TORYS effective on the Effective Date, subject to amendment by written agreement between the parties (the “Retainer Agreement”).

1. No Conflict

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice to THESL. You confirm that you are free to provide your services to TORYS in connection with TORYS’ representation of THESL in the Application. You agree that during this engagement you will not provide, directly or indirectly, any services to any other party in connection with the matters at issue in the Application.
2. **Consultant Expertise**

The Consultant has been selected to provide consulting services to Torys in connection with the Application, namely by undertaking an independent review of THESL’s methodology for determining the unit costs underlying its distribution system capital and maintenance programs and by carrying out a utility benchmarking study to compare THESL’s unit costs with those of its industry peers. The sponsors of the work of the Consultant and the persons who have the relevant expertise will be Jeffrey W. Cummings, Steven J. Morris, Thomas Myers, and Brett Shaw (the “Sponsors”).

3. **Scope of Services and Work Product**

The Consultant will:

(a) perform a study, and provide advice to Torys in connection with the study, based on the Consultant’s review and evaluation of THESL’s methodology for deriving unit costs, having regard for its current tracking and reporting capabilities, and which compares Toronto Hydro’s methodology to industry best practices, including with reference to specific examples from other utilities known to the Consultant from prior work, and/or identified in the course of the study (the “Study”);

(b) if requested by Torys, produce a written report detailing the study’s methodology, analysis performed and the ensuing findings and recommendations (the “Report”); and

(c) if requested by Torys, provide support during the hearing of the Application and testify before the Board in the Application, in connection with the scope of the services provided hereunder (“Application Support” and, together with the Study and the Report, the “Services”).

4. **Fees and Invoices**

By entering into this Retainer Agreement, the Consultant acknowledges that:

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</table>
All amounts stated herein are in Canadian dollars.

The Consultant shall direct all invoices relating to Services performed by it under this Retainer Agreement to THESL, to the attention of:

Ms. Daliana Coban  
Manager, Regulatory Law  
Toronto Hydro Electric-System Limited  
14 Carlton Street  
Toronto, Ontario M5B 1K5  
dcoban@torontohydro.com

with a copy to Torys, to the attention of:

Mr. Charles Keizer  
Torys LLP  
79 Wellington St. W., 30th Floor  
Box 270, TD South Tower  
Toronto, Ontario M5K 1N2  
ceizer@torys.com

Any disbursements for additional incidentals incurred by the Consultant in relation to this Retainer Agreement must be pre-approved by THESL in writing. THESL reserves the right to deduct any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Retainer Agreement and remit such amounts to the applicable taxation authority.

5. Confidentiality

All work performed by the Consultant in connection with this Retainer Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Retainer Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of Torys or THESL. The Consultant agrees to designate all written communications and material accordingly. The Consultant further agrees to notify Torys in the event that the Consultant receives a request to disclose information relating to this matter, and agrees to cooperate with Torys, to the fullest extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material.

The Consultant agrees to hold in confidence: (a) all information provided to the Consultant, and (b) the Consultant’s opinions to Torys and to THESL as they relate to the information, whether
the information or opinions are documentary or oral (collectively, the "Confidential Information"). The Consultant will not disclose the Confidential Information to any person unless Torys or THESL authorizes you in writing to do so. All documents given to the Consultant in connection with this Retainer Agreement remain the property of Torys or of THESL, and are held in trust the Consultant as agent. The Consultant agrees to return these documents on request.

The Consultant will not refer to Torys or to THESL, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of Torys or THESL, as the case may be.

6. **Intellectual Property**

Nothing in this Retainer Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to THESL or any of its representatives or any third party whose intellectual property is in THESL’s custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of THESL.

Torys and THESL shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Retainer Agreement, including without limitation any reports or other documents created by the Consultant, and any related works, modifications or additions thereto (the "Work Product"), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, THESL shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to THESL any such rights, and agrees to give THESL and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant’s employees, partners or other representatives.

7. **Termination**

Torys may terminate this Retainer Agreement at any time on written notice to the Consultant. Torys will pay, or will cause THESL to pay, for work performed up to the date of the notice of termination. Upon the termination or expiration of this Retainer Agreement, the Consultant shall return to Torys and delete any and all electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Retainer Agreement, including all Confidential Information (defined above) and Work Product, whether completed or not.

8. **Limitation of Liability**

Except for breach of confidentiality obligations, the Consultant’s total liability for any claim arising out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not
limited to, loss of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind.

9. **Independence**

By entering into this Retainer Agreement, the Consultant acknowledges and agrees that the Sponsors have received a copy of Rule 13A of the Board’s *Rules of Practice and Procedure* concerning expert evidence, and agree to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy is attached as Schedule ‘A’ hereto.

10. **Entire Agreement**

This Retainer Agreement, together with all Schedules attached hereto and any agreements and other documents to be delivered pursuant to this Retainer Agreement, constitute the complete agreement between Torys and the Consultant or their respective agents with respect to the subject matter hereof and supersede any and all prior agreements and understandings. This Retainer Agreement may be amended only in a writing that refers to this Retainer Agreement and is signed by both parties.

Sincerely,

TORYS LLP

Per:  
Name: Charles Keizer

Accepted and agreed to by Jeffrey W. Cummings

Signed

Name (please print)  **JEFFREY W CUMMINGS**
SCHEDULE 'A'

Rule 13A of the Board's Rules of Practice and Procedure

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert's evidence shall, at a minimum, include the following:

(a) the expert's name, business name and address, and general area of expertise;

(b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

(d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence; and

(f) an acknowledgement of the expert's duty to the Board in Form A to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in Rule 13A.04 shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the Board;

(c) the costs associated with the conduct of the activities;
(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of
the activities referred to in paragraph (a) of Rule 13A.04; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to
accept, the responsibilities that are or may be imposed on the expert as set out in this Rule 13A and Form
A\(^1\).

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\(^{1}\) Form “A” (Acknowledgement of Expert’s Duty) to the Board’s Rules of Practice and Procedure requires the
expert witness to acknowledge that it is his or her duty to provide evidence in relation to a proceeding before the
Board as follows:

(a) to provide opinion evidence that is fair, objective and non-partisan;

(b) to provide opinion evidence that is related only to matters that are within his or her area of expertise;
and

(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in
issue.

Form “A” further requires the expert witness to acknowledge that the duty referred to above prevails over any
obligation which he or she may owe to any party by whom or on whose behalf he or she is engaged.
BY EMAIL

CONFIDENTIAL — PRIVILEGED

August 15, 2017

Steve Fenrick
Power System Engineering Inc.
1532 W. Broadway
Madison, Wisconsin 53713
U.S.A.

Re: Retainer Letter Agreement – Toronto Hydro-Electric System Limited

Dear Mr. Fenrick:

We represent Toronto Hydro-Electric System Limited ("THESL") in connection with its 2020-2024 electricity distribution rate application (the "Application") before the Ontario Energy Board (the "Board").

We confirm that TORYS LLP ("Torys") has agreed to retain Power System Engineering Inc. (the "Consultant" or "you") on behalf of THESL effective as of July 5, 2017 (the "Effective Date") as a consultant in this matter. By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with Torys effective on the Effective Date, subject to amendment by written agreement between the parties (the "Retainer Agreement").

1. No Conflict

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice to THESL. You confirm that you are free to provide your services to Torys in connection with Torys' representation of THESL in the Application. You agree that during this engagement you will not provide, directly or indirectly, any services to any other party in connection with the matters at issue in the Application.

2. Consultant Expertise

The Consultant has been selected to provide consulting services to THESL in connection with benchmarking of THESL's key operating parameters. The sponsors of the work of the
Consultant and the persons who have the relevant expertise will be Steve Fenrick, Rich Macke, Erik Sonju, David Williams, Matt Sekeres and Logan Suhr (the “Sponsors”).

3. **Scope of Services and Work Product**

The Consultant will:

(a) provide us and THESL with advice in connection with benchmarking of THESL’s key operating parameters;

(b) prepare a report or reports for filing with the Board in the Application, if requested; and

(c) testify before the Board in the Application, if requested (the “Services”).

4. **Fees**

Any disbursements for additional incidentals incurred by the Consultant in relation to this Retainer Agreement must be pre-approved by THESL in writing. THESL reserves the right to deduct any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Retainer Agreement and remit such amounts to the applicable taxation authority.

5. **Confidentiality**

All work performed by the Consultant in connection with this Retainer Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Retainer Agreement, and any communications relating thereto, is strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of our firm or THESL. You agree to designate all written communications and material accordingly. You further agree to notify our firm in the event that you receive a request to disclose information relating to this matter, and agree to cooperate with us, to the fullest extent permitted by law, to prevent or limit
the disclosure of such material or otherwise preserve the privileged and confidential status of such material.

The Consultant agrees to hold in confidence: (a) all information provided to the Consultant, and (b) the Consultant’s opinions to us and to THESL as they relate to the information, whether the information or opinions are documentary or oral. The Consultant will not disclose the information or opinions to any person unless Torys or THESL authorizes you in writing to do so. All documents given to the Consultant in connection with this Retainer Agreement remain the property of Torys or of THESL, and are held in trust by you as agent. The Consultant agrees to return these documents on request.

The Consultant will not refer to Torys or to THESL, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of THESL.

6. Intellectual Property

Nothing in this Retainer Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to THESL or any of its representatives or any third party whose intellectual property is in THESL’s custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of THESL.

THESL shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Retainer Agreement, including without limitation any reports or other documents created by the Consultant, and any related works, modifications or additions thereto (the “Work Product”), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, THESL shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to THESL any such rights, and agrees to give THESL and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant’s employees, partners or other representatives.

7. Termination

THESL may terminate this Retainer Agreement at any time on written notice to the Consultant. THESL agrees to pay for work performed up to the date of the notice of termination. Upon the termination or expiration of this Retainer Agreement, the Consultant shall return to THESL and delete any and all electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Retainer Agreement, including all Confidential Information (defined below) and Work Product, whether completed or not.

8. Limitation of Liability

Except for breach of confidentiality obligations (for which Consultant’s maximum liability shall not exceed CAD$2,000,000.00), the Consultant’s total liability for any claim arising out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any
damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not limited to, loss of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind.

9. Independence

By entering into this Retainer Agreement, the Consultant acknowledges and agrees that the Sponsors have received a copy of Rule 13A of the Board’s Rules of Practice and Procedure concerning expert evidence, and agree to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board.

10. Entire Agreement

This Retainer Agreement, together with all Schedules attached hereto and any agreements and other documents to be delivered pursuant to this Retainer Agreement, constitute the complete agreement between the THESL and Consultant or their respective agents with respect to the subject matter hereof and supersedes any and all prior agreements and understandings. This Retainer Agreement may be amended only in a writing that refers to this Retainer Agreement and is signed by both parties.

Sincerely,

TORYS LLP

Per:  
Name: Myriam M. Seers

Accepted and agreed to by Power System Engineering Inc.

Signed  
Name (please print) Steve Fermick
February 19, 2018

Mr. Tarek Turk, P.Eng
Supervisor, Standards & Policy Planning
Toronto Hydro-Electric System Limited
500 Commissioners Street
Toronto, Ontario, M4M 3N7

Subject: Proposal – Procedures and Standards Review Study

Dear Tarek:

Per your request, Power System Engineering, Inc. (PSE) is pleased to extend a proposal to conduct an independent review of:

2. New and modified THESL Standards that have occurred since the Standards Review Study conducted by PSE in 2013.

The focus of the independent review is to determine if THESL’s procedures and Standards reflect the principles of safety, reliability, and efficiency, as well as follow industry best practices. We propose assembling a team of subject matter experts to conduct a high-level review. The team will consider how the reviewed procedures and Standards are unique or are common with industry-wide practices. For items found to be unique, the PSE team will identify how greatly they deviate from the industry in terms of influence on capital costs, electric distribution infrastructure reliability, and public and worker safety.

In addition to the review of the documented procedures and Standards, the PSE team will conduct conference call interviews of key personnel in the Standards Department to gain a general understanding of THESL’s approach to the development and revision of Standards. The final deliverable will be a formal report outlining the study scope, approach taken by the PSE team, items reviewed, general observations, unique deviations and their influences followed by an overall conclusion.

We anticipated the review process for items 1 and 2, as identified above, and subsequent formal report will take approximately 6 weeks from the time of receiving requested materials from THESL. The efforts for items 1 and 2, along with the report, is estimated at [redacted] and [redacted] respectively.

We appreciate this opportunity and look forward to helping THESL with this initiative. Please do not hesitate to contact me with questions or comments.

Sincerely,

Erik S. Sonju
BY EMAIL

CONFIDENTIAL — PRIVILEGED

November 29, 2017

[Redacted]

Gartner Canada Co.
1 Dundas Street West, Suite 2500
Toronto, Ontario M5G 1Z3

Re: Retainer Letter Agreement — Information Technology ("IT") Budget Assessment for Toronto Hydro-Electric System Limited (Gartner Reference Number: 330045299)

Dear [Redacted]:

We represent Toronto Hydro-Electric System Limited ("THESL" or "Toronto Hydro") in connection with its planned 2020 Custom Incentive Rate application (the "Application") to the Ontario Energy Board (the "Board").

We confirm that, on behalf of and to assist us in providing legal advice to THESL in connection with the Application, Torys LLP ("Torys") has agreed to retain Gartner Canada Co. (the "Consultant") effective as of November 29, 2017 (the "Effective Date") to provide consulting services as herein described. By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with Torys effective on the Effective Date, subject to amendment by written agreement between the parties (the "Retainer Agreement").

1. No Conflict

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice to THESL. You confirm that you are free to provide your services to Torys in connection with Torys' representation of THESL in the Application. You agree that during this engagement, including during the period of time during which the Consultant is providing or may be requested to provide Application Support services (as such services are described in section 3), the Consultant's project team members, as identified in the Statement of Work attached hereto as Schedule 'A', will not provide, directly or indirectly, services to any other party that has been granted intervenor status by the Board in connection with, or that otherwise intends to participate
in, the hearing of the Application by the Board, if the services to be provided to such other party relate to, or may be used by the party in connection with, the party’s intervention or other participation in the hearing of the Application. For the avoidance of doubt, the Consultant’s project team members shall not be restricted from providing services to any person that has not been granted intervenor status by the Board in connection with, or that otherwise does not participate in, the hearing of the Application by the Board.

2. Consultant Expertise

The Consultant has been selected to provide consulting services to Torys in connection with the Application, namely by undertaking an independent assessment of THESL’s IT budget. The sponsors of the work of the Consultant and the persons who have the relevant expertise will be [REDACTED] and [REDACTED] (the “Consultant Project Sponsors”). In addition, quality assurance for the Services will be provided by [REDACTED] and [REDACTED].

3. Scope of Services and Work Product

The Consultant will:

(a) carry out an assessment of THESL’s IT budget, including by performing a comparison of high level IT metrics and spending and staffing distributions with a view to providing insight into how IT spending aligns with THESL’s peer organizations (the “Study”);

(b) present the preliminary findings or indicative results of the Study to Torys and THESL by December 22, 2017 or at the earliest opportunity upon such preliminary findings or indicative results of the Study becoming available (the “Presentation of Preliminary Findings”);

(c) present the findings and results of the Study to Torys and THESL (the “Presentation of Findings”) January 12, 2018 or such other date as may be agreed to by the parties;

(d) if requested by Torys, produce a written report detailing the Study’s methodology, analysis performed and the ensuing findings and recommendations (the “Report”); and

(e) if requested by Torys, provide support during the hearing of the Application and testify before the Board in the Application, in connection with the scope of the Services provided hereunder (“Application Support”).

The Study, the Presentation of Preliminary Findings, the Presentation of Findings, the Report and the Application Support (together, the “Services”) shall be performed and provided in a manner that is generally consistent with the Statement of Work attached hereto as Schedule ‘A’.

4. Fees and Invoices

By entering into this Retainer Agreement, the Consultant acknowledges that:

24043055.5
- the price for the Consultant to perform the Study and deliver the Presentation of Preliminary Findings, the Presentation of Findings, as well as the Report if requested, will be a firm fixed price of [redacted], excluding taxes but inclusive of travel expenses (the “Fixed Fee”); and

- the price for the Consultant to provide Application Support services, if requested, will be charged at the Consultant’s rate of [redacted] per Consultant resource, provided that such Application Support services are delivered in 2017 or 2018 and, thereafter, the Consultant’s rate shall be at the then-current market rate as agreed upon between the parties in writing, together with all other reasonable pre-approved out-of-pocket expenses incurred by the Consultant in providing such Application Support, including, without limitation, cost of any travel. For greater certainty, this rate will apply to time spent by the Consultant’s employees for purposes of reviewing and providing comments on materials, responding or assisting in responding to questions (including interrogatories), testifying and preparing to testify, as well as assisting Torys and THESL in complying with the Application process or related investigations.

All amounts stated herein are in Canadian dollars.

The Consultant will issue an invoice for [redacted] at contract signing and for the remaining [redacted] upon delivery of the Presentation of Findings (other than any Application Support services that may be requested, which shall be invoiced upon completion thereof or as mutually agreed upon between the parties and which, in either case, shall include details about the activities to which the invoice pertains, including the names of the relevant employees and the nature and duration of the activities undertaken). Invoices are payable net 30 days from date of invoice. The Consultant agrees to and will comply with any reasonable requests for records substantiating its invoices.

The Consultant shall direct all invoices relating to Services performed by it under this Retainer Agreement to THESL, to the attention of:

Ms. Daliana Coban
Manager, Regulatory Law
Toronto Hydro Electric-System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5
dcoban@torontohydro.com

with a copy to Torys, to the attention of:

Mr. Charles Keizer
Torys LLP
79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2
ckeizer@torys.com

240436/5.5
Any disbursements for additional incidentals incurred by the Consultant in relation to this Retainer Agreement must be pre-approved by THESL in writing. THESL reserves the right to deduct any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Retainer Agreement and remit such amounts to the applicable taxation authority.

THESL, Torys and the Consultant shall enter into a third party payor addendum ("Payor Addendum") to this Retainer Agreement, as set forth in Schedule ‘C’, whereby THESL assumes payment responsibility for the Services and any Application Support. In the event THESL does not execute the Payor Addendum, Torys shall be the liable party for the fees and expenses of the Consultant set forth in this Retainer Agreement.

5. Confidentiality

Torys represents that it has THESL’s consent to provide THESL confidential information to the Consultant for the Consultant’s provision of Services.

All work performed by the Consultant in connection with this Retainer Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Retainer Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of Torys or THESL. The Consultant agrees to designate all written communications and material accordingly. The Consultant further agrees to notify Torys in the event that the Consultant receives a request to disclose information relating to this matter, and agrees to cooperate with Torys, to the fullest extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material.

The Consultant agrees to hold in confidence: (a) all information provided to the Consultant in connection with this Retainer Agreement or the Services, and (b) the Consultant’s opinions to Torys and to THESL as they relate to the information, whether the information or opinions are documentary or oral (collectively, the “Confidential Information”). The Consultant will not disclose the Confidential Information to any person unless Torys or THESL provides prior written authorization to the Consultant for such disclosure. All documents given to the Consultant in connection with this Retainer Agreement remain the property of Torys or of THESL, and are held in trust by the Consultant as agent. The Consultant agrees to return these documents immediately on request.

The Consultant will not refer to Torys or to THESL, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of Torys or THESL, as the case may be.

6. Intellectual Property

Nothing in this Retainer Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to THESL or any of its representatives or any third party whose intellectual property is in THESL’s custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of THESL.
Torys shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Retainer Agreement, including without limitation any reports or other documents created by the Consultant, and any related works, modifications or additions thereto (the "Work Product"), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, Torys shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to Torys any such rights, and agrees to give Torys and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant's employees, partners or other representatives.

Notwithstanding the foregoing, the Consultant shall retain sole and exclusive ownership of any pre-existing Consultant tools, methodologies, questionnaires, responses, and proprietary research and data, together with all intellectual property rights therein (the "Consultant Materials"). Consultant grants to Torys a fully paid up, perpetual, non-exclusive, royalty-free, assignable license to use the Consultant Materials contained within the Work Product, which includes providing the Work Product to the Board. The Consultant acknowledges that Torys intends to assign such license to THESL.

Notwithstanding anything to the contrary in this Retainer Agreement, the Consultant agrees that it will only use THESL's data in an aggregate and anonymous format when providing benchmarking services to others. Torys acknowledges that the contents of the benchmarking Work Product are based upon information which is proprietary to the Consultant and contained in the Consultant's database. THESL's data will become part of the database in an aggregate and anonymous format. The database will be used by the Consultant in future consulting and benchmarking engagements.

The Consultant acknowledges and consents to the assignment, by Torys to THESL, of all rights to and in relation to the Work Product and the Consultant Materials as described in this section 6.

7. Termination

Torys may terminate this Retainer Agreement at any time on written notice to the Consultant. Torys will pay, or will cause THESL to pay, for work performed up to the date of the notice of termination. Upon the termination or expiration of this Retainer Agreement, the Consultant shall return to Torys and delete any and all electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Retainer Agreement, including all Confidential Information (defined above) and Work Product, whether completed or not. The Consultant shall, upon request, provide Torys with a certificate of an officer of the Consultant certifying such deletion of electronic copies.

8. Limitation of Liability

Except for breach of confidentiality obligations, the Consultant’s total liability for any claim arising out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not limited
to, loss of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind.

9. **Independence**

By entering into this Retainer Agreement, the Consultant acknowledges and agrees that the Sponsors have received a copy of Rule 13A of the Board's *Rules of Practice and Procedure* concerning expert evidence, and agree to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy is attached as Schedule ‘B’ hereto.

10. **Intellectual Property Indemnification**

The Consultant will promptly defend, indemnify and hold Torys and THESL, their affiliates, their customers, and their respective officers, directors, employees, agents, successors and assigns harmless, at Consultant’s expense, for any claim or action brought against any of the foregoing parties to the extent that it is based upon a claim that the Services or the Work Product furnished hereunder infringe any patent, copyright or other intellectual property right or moral right of a third party (each an “IP Claim”), and will pay all costs and damages awarded against Torys and THESL provided that: (i) Consultant is provided with prompt written notice of the IP Claim; and (ii) Consultant shall be provided with reasonable assistance, information and authority as may be required to defend and settle the IP Claim, at Consultant’s expense.

11. **Warranty and Disclaimer**

The Consultant warrants that it shall perform the Services in a professional and workmanlike manner and the Services shall conform to the specifications set forth in this Retainer Agreement, including the Statement of Work.

The Consultant represents that the information in and relied upon to prepare the deliverables under this Retainer Agreement (including as described in the Statement of Work) has been obtained from sources that the Consultant believes to be reliable and that the Consultant uses reasonable best practices to ensure that the information is validated. As necessary and applicable, the Consultant further normalizes and refreshes the information contained in its benchmarking database on a continuous basis.

Except as prohibited by applicable law or otherwise set forth in this Retainer Agreement, the Consultant disclaims all other warranties, express or implied, statutory or otherwise, including, without limitation, any implied warranties of merchantability or fitness for a particular purpose.

With respect to the warranty and disclaimer in this section 11, all deliverables speak as of the date of delivery to Torys.

12. **Entire Agreement**

This Retainer Agreement, together with all Schedules attached hereto and any agreements and other documents to be delivered pursuant to this Retainer Agreement, constitute the complete agreement between Torys and the Consultant or their respective agents with respect to the subject
matter hereof and supersedes any and all prior agreements and understandings. This Retainer Agreement may be amended only in a writing that refers to this Retainer Agreement and is signed by both parties.

Sincerely,

TORYS LLP

Per:  
Name:  

Accepted and agreed to by GARTNER CANADA CO.

Signed  

Name (please print)  

November 29, 2017
SCHEDULE 'A'

STATEMENT OF WORK
1.0 Statement of Work

1.1 Project Tasks

1.1.1 Detailed Approach

Gartner will construct a specific peer profile based on Toronto Hydro's unique characteristics, revenue, industry and geography. Gartner will also take into account other attributes that Torys LLP and/or Toronto Hydro determine to be relevant.

Gartner will discuss data requirements for Toronto Hydro and clarify data definitions. If requested, Gartner can benchmark both current state and/or projected future state budget. Where prudent, we will identify shortcuts to collect and validate the data for the required scope as quickly as possible. Torys LLP will then ensure that Toronto Hydro submits summary quantitative data for IT spending and staffing, which will be validated by Gartner. We will discuss the criteria for selecting suitable peers with Torys LLP and Toronto Hydro and how we will deal with any Toronto Hydro budget data that does not map directly to the Gartner definitions. All data used will be annual or annualized.

An overview of the Gartner Approach and Methodology for this engagement is shown in Figure 1 below.

Figure 1. Gartner Approach and Methodology

<table>
<thead>
<tr>
<th>Phase I</th>
<th>Project Initiation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Finalize project schedule</td>
</tr>
<tr>
<td></td>
<td>Review data collection requirements</td>
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<tr>
<td></td>
<td>Identify and define participants</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Phase II</th>
<th>Assessment and Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Data capture</td>
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<tr>
<td></td>
<td>Populate financial model and templates</td>
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<tr>
<td></td>
<td>Peer group selection</td>
</tr>
<tr>
<td></td>
<td>Review collected data with client and freeze data</td>
</tr>
<tr>
<td></td>
<td>Perform assessment analysis</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Phase III</th>
<th>Final Deliverables</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Review assessment results</td>
</tr>
</tbody>
</table>

The IT Budget Assessment analysis will include business activity measures such as enterprise revenue, operating expense and employee count in relation to IT spending and staffing levels.

In addition, it is anticipated that the deliverables will include additional commentary and analysis to outline some of the unique impacts of union and other regulatory considerations on the results.

The IT functional areas in scope include:
Applications development and support
Enterprise computing and storage
End-user computing
IT service desk
Data networks
Voice services

The IT Budget Assessment analysis will provide the following metrics:

- Spending Measures
  - IT Spending as a Percentage of Revenue
  - IT Spending as a Percentage of Operating Expense
  - IT Spending per Company Employee
  - Capital vs. Operational Spending
  - Run vs. Grow vs. Transform Spending
  - Distribution of IT Spending by Category (Hardware, Software, Personnel, etc.)
  - Distribution of IT Spending by Domain (Apps Development, Apps Support, etc.)
  - Revenue per Employee
  - Other broad spending measures as mutually agreed

- Staffing Measures
  - IT Staff as a Percentage of Company Employees
  - IT Contractor Usage
  - Distribution of IT Staff by Domain

1.1.2 Project Schedule

Gartner anticipates completion of this engagement in approximately 4 weeks, as detailed in Figure 2. Phases 1 and 2 will begin concurrently and Gartner will provide indicative results as soon as possible for review with Torys LLP and such Toronto Hydro staff as Torys LLP may require. Our schedule is dependent on the assumptions included in this Statement of Work as described.
1.2 Gartner Project Team

1.2.1 Project Team Organization

Gartner will create an organization structure for this engagement that ensures high-level sponsorship and quality assurance, strong day-to-day project management and deep subject matter expertise.

1.2.2 Roles and Responsibilities

Gartner requires that the following roles with these defined responsibilities be identified among Torys LLP and Toronto Hydro.
### Table 1. Torys LLP / Toronto Hydro Roles and Responsibilities

<table>
<thead>
<tr>
<th>Role</th>
<th>Responsibilities</th>
</tr>
</thead>
</table>
| Engagement Sponsor  | • Primary contact for the engagement  
                      • Manage issues arising under the retainer  
                      • Attend the kickoff and management presentation  
                      • Receive all findings, including preliminary findings  
                      • Provide instructions to Gartner, including regarding any changes of scope, reporting  
                      • Support THESL Project Sponsor and THESL Project Manager in meeting their responsibilities |
| Project Sponsor     | • Confirm the objectives of the analysis  
                      • Ensure the full commitment of Toronto Hydro during the data collection and validation processes  
                      • Ensure that the results are acted on and used as agreed on by Toronto Hydro  
                      • Attend the kickoff and management presentation |
| Project Manager     | • Identify contacts within the enterprise who are responsible for components of the required data  
                      • Ensure that Toronto Hydro resources and data are made available in a timely manner  
                      • Ensure that the data is as accurate as possible  
                      • Ensure that Toronto Hydro adheres to agreed-on timelines  
                      • Ensure that teleconferences are attended and scheduled appropriately  
                      • Be knowledgeable about the details of Toronto Hydro’s annual operating expenditures |
| Data Suppliers      | • Populate the data collection tools with the necessary information to perform the benchmarking analysis  
                      • Be prepared to spend two to five days on data collection and validation, depending on the complexity of the enterprise and data repositories |

Following is a description of the Gartner roles and responsibilities for this engagement.

### Table 2. Project Team Roles and Responsibilities

<table>
<thead>
<tr>
<th>Gartner Associate</th>
<th>Role</th>
<th>Responsibilities</th>
</tr>
</thead>
</table>
|                   |      | • Be responsible for the day-to-day management of project initiatives  
                      • Ensure that project deliverables are completed on time and meet the Gartner quality standards  
                      • Act as the primary point of contact for the Gartner team  
                      • Work closely with Torys LLP and Toronto Hydro to ensure that Gartner is meeting its needs  
                      • Work with Torys LLP and Toronto Hydro during data collection and validation to ensure that the data |
1.3 Gartner Project Management Life Cycle

The Project Management Life Cycle Gartner uses for every engagement is based on our internal subject matter expertise and lessons learned, as well as external sources including the Project Management Institute's (PMI®'s) Project Management Body of Knowledge (PMBOK®) Guide. Gartner aligns with this globally recognized standard (ANSI/PMI 99-001-2008) to maximize value for our clients, minimize the risk for our clients' projects and ultimately ensure client satisfaction.

Figure 4. Stages of Gartner Project Management Life Cycle

Our approach is comprehensive — starting before the project kickoff and ending after the project close — to deliver results at every stage. The following table describes the typical activities, results
and value provided by Gartner during the project management life cycle. However, it is important to note that Gartner views a project as an event that happens with a client — not to a client. We work closely with our clients to adapt leading practices to fit each client’s environment and each project’s requirements.

1.4 Assumptions

The deliverables and schedule in this Statement of Work are based on the following assumptions:

- Toronto Hydro will provide data in an expedient and efficient manner according to project timelines, and will dedicate resources to the process of validating this same data with Gartner to ensure timeliness of the management report.
- All deliverables from this engagement shall not be utilized in discussions and/or negotiations with any external service providers for the purposes of measuring or evaluating the price efficiency of existing or proposed IT services contracts.
- All data collection will take place via a ShareFile site to be established and managed by Torsys LLP and interviews/workshops will take place via telephone or in person at Toronto Hydro offices in Toronto, Canada, as described in this Statement of Work and/or as agreed to at the project kickoff.
- Torsys LLP will ensure that Toronto Hydro assigns a project manager to coordinate Toronto Hydro activities, resources, and teleconference meetings.
- Data collection support from Gartner will be provided via telephone and e-mail and shall not extend past a two-week period.
- Torsys LLP, in consultation with Toronto Hydro as needed, will review and approve documents within five business days. If no formal approval or rejection is received within that time, the deliverable is considered to be accepted.
- Any changes to data requested after the sign-off at the data freeze milestone is considered a change in scope (See Changes to Scope section of this Statement of Work).
- Toronto Hydro’s project sponsor has the authority, willingness and ability to prioritize, control and manage all personnel who are required to contribute data for the analysis and to ensure successful project completion within the designated time frame.
- Toronto Hydro can arrange for the following key staff functions for the data collection activity (these key staff functions should include those individuals who are responsible for, or hold information about, the full scope of the assessment):
  - Financial analysts with full access to cost data relating to people and technology
  - Asset/inventory management staff with knowledge of the technologies that are used
  - Technology operations manager with full insight into how IT staff time is spent
- Any specific elements not defined as a part of the benchmark model are outside the scope of the benchmark. No requirement exists for any additional or special analysis for various divisions, sites, subgroups or other similar organizations inside the scope beyond one peer group and enterprise view of Toronto Hydro data in comparison to that peer group.
- No requirement exists for client-customized data collection or data reporting processes. Standard Gartner procedures for technology assessments and presentations described in this Statement of Work will be used exclusively.
Any requests for additional information (beyond the details described in the tasks above) that are made by TORYS LLP or TORONTO HYDRO will be considered a change in scope for this engagement and will be handled accordingly (see Changes to Scope section of this Statement of Work).

All deliverables will be developed in English using Microsoft products (for example, Project, Excel, Word and PowerPoint).

1.5 Changes to Scope

The scope of this engagement is defined by this Statement of Work. All TORYS LLP or TORONTO HYDRO requests for changes to the SOW must be in writing and must set forth with specificity the requested changes. As soon as practicable, GARTNER shall advise TORYS LLP and TORONTO HYDRO of the cost and schedule implications of the requested changes and any other necessary details to allow both parties to decide whether to proceed with the requested changes. The parties shall agree in writing upon any requested changes prior to GARTNER commencing work.

As used herein, “changes” are defined as work activities or work products not originally planned for or specifically defined by this SOW. By way of example and not limitation, changes include the following:

- Any activities not specifically set forth in this SOW
- Providing or developing any deliverables not specifically set forth in this SOW
- Any change in the respective responsibilities of GARTNER, TORYS LLP and TORONTO HYDRO set forth in this SOW, including any reallocation or any changes in engagement or project manager staffing
- Any rework of completed activities or accepted deliverables
- Any investigative work to determine the cost or other impact of changes requested by TORYS LLP or TORONTO HYDRO
- Any additional work caused by a change in the assumptions set forth in this SOW
- Any delays in deliverable caused by a modification to the acceptance criteria set forth in this SOW
- Any changes requiring additional research analyst time or changes to research analyst resources

1.6 Further Assurances

GARTNER Research and Consulting recommendations are produced independently by the Company’s analysts and consultants, respectively, without the influence, review or approval of outside investors, shareholders or directors. For further information on the independence and integrity of GARTNER Research, see “Guiding Principles on Independence and Objectivity” on our website, gartner.com or contact the Office of the Ombudsman at ombudsman@gartner.com or +1 203 316 3394.
Any questions regarding this Statement of Work should be addressed to:

Gartner Canada Co.
Gartner Canada - Toronto
1 Dundas Street West, Suite 2500
Toronto, Ontario M5G 1Z3

Telephone: [Redacted]
Email: [Redacted]@gartner.com
SCHEDULE 'B'

Rule 13A of the Board's Rules of Practice and Procedure

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert's evidence shall, at a minimum, include the following:

(a) the expert's name, business name and address, and general area of expertise;

(b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

(d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence; and

(f) an acknowledgement of the expert's duty to the Board in Form A to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in Rule 13A.04 shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the Board;

(c) the costs associated with the conduct of the activities;
(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of Rule 13A.04; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this Rule 13A and Form A.¹

¹ Form “A” (Acknowledgement of Expert’s Duty) to the Board’s Rules of Practice and Procedure requires the expert witness to acknowledge that it is his or her duty to provide evidence in relation to a proceeding before the Board as follows:

(a) to provide opinion evidence that is fair, objective and non-partisan;

(b) to provide opinion evidence that is related only to matters that are within his or her area of expertise; and

(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

Form “A” further requires the expert witness to acknowledge that the duty referred to above prevails over any obligation which he or she may owe to any party by whom or on whose behalf he or she is engaged.
Schedule C - Third Party Payor Addendum

This is an addendum ("Addendum") to the Retainer Agreement between Torys LLP ("Torys") and Gartner Canada Co. ("Gartner") dated November 29, 2017 (the "Retainer Agreement").

This Addendum is entered into on November 29, 2017 by and between Gartner, Torys and Toronto Hydro-Electric System Limited ("THESL"). For purposes of this Addendum, each of Gartner and THESL and Torys may also be referred to individually as "Party" and collectively as the "Parties."

The Parties hereby agree to the following additions, modifications and deletions to the payment terms and obligations of the Retainer Agreement. All terms not defined herein shall have the meaning set forth in the Retainer Agreement, as the same may be modified or amended from time to time.

1. Each Party agrees that all Fees for the Services provided to Torys under the Retainer Agreement shall be paid by THESL, as directed by Torys and in accordance with the terms of this Addendum.
2. Except for the payment obligations in the Retainer Agreement, Torys acknowledges and agrees that all of remaining terms and conditions of the Retainer Agreement shall remain in full force and effect and Torys shall continue to comply with them.
3. In the event THESL does not pay for the Services after Gartner's good faith attempts to collect, Torys shall pay for the Services.
4. This Addendum shall have a term consistent with the term of the Retainer Agreement. Except as expressly modified by this Addendum, the terms of the Retainer Agreement shall remain in full force and effect.

The Parties have hereby executed this Addendum by their duly authorized representatives on the date set forth above:

<table>
<thead>
<tr>
<th>Accepted for:</th>
<th>Torys LLP</th>
<th>Gartner Canada Co.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Signature/Date:</td>
<td>[Signature] Nov. 3, 2017</td>
<td>[Signature]</td>
</tr>
<tr>
<td>Print Name:</td>
<td>Cherie Klein</td>
<td></td>
</tr>
<tr>
<td>Title:</td>
<td>Partner</td>
<td></td>
</tr>
</tbody>
</table>

| Accepted for:          | Toronto Hydro-Electric System Limited |                                      |
| Signature/Date:        | December 5, 2017                     |                                      |
| Print Name:            | Amanda Klein                        |                                      |
| Title:                 | Executive Vice President Regulatory Affairs and General Counsel |                                      |
| Phone:                 |                                      |                                      |
| Fax:                   |                                      |                                      |
April 18, 2017

London Economics International LLC
390 Bay Street, Suite 1702
Toronto, ON, M5H 2Y2

Re: Retainer Letter Agreement – Toronto Hydro-Electric System Limited – Alternate Control Room Study

Dear Mr. Goulding:

We represent Toronto Hydro-Electric System Limited (“THESL”) in connection with its planned 2020 Custom Incentive Rate application (the “Application”) to the Ontario Energy Board (the “Board”).

We confirm that, on behalf of and to assist us in providing legal advice to THESL in connection with the Application, Torys LLP (“Torys”) has agreed to retain London Economics International LLC (the “Consultant”) effective as of March 23, 2018 (the “Effective Date”) to provide consulting services as herein described. By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with Torys effective on the Effective Date, subject to amendment by written agreement between the parties (the “Retainer Agreement”).
3. **Scope of Services and Work Product**

The Consultant will:

(a) collect the data required to undertake an analysis of comparator utilities with the alternate control centers in other jurisdictions (the “Study”);

(b) if requested by Torys, produce a written report detailing the Study’s methodology, analysis performed and the ensuing findings and recommendations (the “Report”), which may be filed with the Board in the Application; and

(c) if requested by Torys, provide support during the hearing of the Application and testify before the Board in the Application, in connection with the scope of the services provided hereunder (“Application Support” and, together with the Study and the Report, the “Services”).
Sincerely,

TORYS LLP

Per:  
Name: Jonathan Myers

Accepted and agreed to by London Economics International LLC

Signed

Name (please print)
SCHEDULE ‘A’

Rule 13A of the Board’s Rules of Practice and Procedure

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert’s area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert’s evidence shall, at a minimum, include the following:

(a) the expert’s name, business name and address, and general area of expertise;

(b) the expert’s qualifications, including the expert’s relevant educational and professional experience in respect of each issue in the proceeding to which the expert’s evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert’s evidence relates;

(d) the specific information upon which the expert’s evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert’s evidence, a summary of the points of agreement and disagreement with the other expert’s evidence; and

(f) an acknowledgment of the expert’s duty to the Board in Form A to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in Rule 13A.04 shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the Board;

(c) the costs associated with the conduct of the activities;
(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of
the activities referred to in paragraph (a) of Rule 13A.04; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to
accept, the responsibilities that are or may be imposed on the expert as set out in this Rule 13A and Form
A.\(^1\)

\(^1\) Form “A” (Acknowledgement of Expert’s Duty) to the Board’s Rules of Practice and Procedure requires the
expert witness to acknowledge that it is his or her duty to provide evidence in relation to a proceeding before the
Board as follows:

(a) to provide opinion evidence that is fair, objective and non-partisan;
(b) to provide opinion evidence that is related only to matters that are within his or her area of expertise;
and
(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in
issue.

Form “A” further requires the expert witness to acknowledge that the duty referred to above prevails over any
obligation which he or she may owe to any party by whom or on whose behalf he or she is engaged.
Agreement for Purchase of Actuarial Valuation of Post-Employment Benefits Services

THIS AGREEMENT is effective as of the 1st day of September, 2017,

BETWEEN:

Toronto Hydro Corporation
a corporation incorporated under the laws of Ontario
(hereinafter called "Toronto Hydro")

and

Towers Watson Canada Inc.,
a corporation incorporated under the laws of Canada
(hereinafter called the "Vendor")

WHEREAS:

A. Toronto Hydro requires certain actuarial valuation of post-employment benefits services, as detailed in SCHEDULE A (collectively, the “Services”);

B. the Vendor carries on the business of providing the services and has indicated to Toronto Hydro that it has the skill and expertise to provide the Services on the terms and conditions set forth herein;

C. the Vendor has agreed to provide the Services to Toronto Hydro and Toronto Hydro has agreed to purchase the Services, upon the terms and conditions as set forth below; and

D. this Agreement is issued in connection with RFP # 17P-015 dated March 1, 2017 (the “RFP”), including any schedules, attachments, amendments, supplements or addenda thereto and the Vendor’s submission in response thereto dated March 31, 2017 (the "Proposal").

NOW THEREFORE, in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. Interpretation

a) All capitalized terms in this Agreement shall have the meaning as defined in SCHEDULE C;

b) The recitals hereto shall form an integral part of this Agreement as if specifically restated herein;
c) Words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

d) The word “including” shall mean “including without limitation”;

e) Any reference to a statute shall mean the statute in force as of the date hereof, together with all regulations promulgated thereunder as may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise provided;

f) When calculating a period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded, and if the last day of such period is a Saturday, Sunday or statutory holiday, the period shall end on the next Business Day;

g) All dollar amounts in this Agreement are expressed in Canadian dollars, unless otherwise stated;

h) The division of this Agreement into separate articles, sections, subsections and Schedules and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement; and

i) Save and except as otherwise expressly defined within the body of this Agreement or in SCHEDULE C hereto, words or abbreviations which have well known or trade meanings are used herein in accordance with their recognized meanings.

2. Schedules, Exhibits and Appendices

The following schedules and appendices are attached to and form part of this Agreement:

a) SCHEDULE A – Services Required

b) SCHEDULE B – Purchase Price

1. Appendix A – Price Matrix 2017
2. Appendix B – Price Matrix 2018
3. Appendix C – Price Matrix 2019
4. Appendix D – Price Matrix 2020
5. Appendix E – Price Matrix 2021
6. Appendix F – Rate Table

c) SCHEDULE C – Defined Terms

d) SCHEDULE D – Information Protection and Privacy Contract Requirements

e) SCHEDULE E – Required Resources

In the event of a conflict between the terms of any schedule, exhibit or appendix and the terms of this Agreement, the terms of this Agreement shall govern unless the parties have specifically stated otherwise in writing.
3. Purchase and Sale

Subject to the terms and conditions of this Agreement, and in reliance on the representations, warranties and conditions set forth in this Agreement, Toronto Hydro agrees to purchase the Services from the Vendor and the Vendor agrees to supply the Services to Toronto Hydro during the Term of this Agreement.

4. Term

a) Subject to any termination rights herein, this Agreement shall be for a term of three (3) years, from September 1, 2017 to August 31, 2020 (the "Initial Term").

b) Toronto Hydro may, at its sole option, elect to renew this Agreement for two (2) additional one (1) year terms (each a "Renewal Term") by giving written notice to the Vendor at least sixty (60) days before the end of the Initial Term or the first Renewal Term (as applicable). The same terms and conditions contained herein shall apply during the Renewal Term(s), save and except as amended in writing by the parties.

c) The Initial Term and the Renewal Term(s), if any, shall hereinafter together be referred to as the "Term".

5. Price and Payment

a) The prices for the Services shall be as specified in SCHEDULE B hereto and, except as otherwise provided, shall be in Canadian dollars DDP Toronto Hydro’s location (INCOTERMS 2010), and shall represent the total cost to Toronto Hydro, excluding any value added taxes (including HST) but including without limitation all other applicable taxes, duties, packaging, handling and delivery costs. Toronto Hydro shall withhold any applicable non-resident withholding taxes from any amount owing in this Agreement and remit such taxes to the appropriate federal taxing authority. If no price is stipulated in this Agreement, the price must not exceed the last previous quotation made by the Vendor to Toronto Hydro for the same Services.

b) Unless otherwise provided in this Agreement, the Vendor shall invoice Toronto Hydro on a monthly basis. Invoices must be sent electronically to: TH-AP@opiscan.com and ap@torontohydro.com. Subject to approval of the invoice by Toronto Hydro and subject to receipt of all documents required by this Agreement, Toronto Hydro shall make payment to the Vendor via electronic funds transfer not later than thirty (30) days following receipt of an acceptable invoice and the EFT Information (as set out below). In order for Toronto Hydro to make payment to the Vendor via electronic funds transfer, the Vendor must provide Toronto Hydro with, in the case of the first payment only, (i) a void cheque, pre-printed deposit slip or bank confirmation letter and (ii) the email address where the Vendor wishes to receive remittance information (together, "EFT Information"). EFT Information must be sent electronically to efthelp@torontohydro.com or to 14 Carlton Street, Toronto, ON, M5B 1K5, Attention: Treasury Department. In the event that invoices are not paid within that time the Vendor shall be entitled to charge a late payment fee of the lesser of 1.0% per month or the maximum allowed by law.
6. **Delivery of Services**

a) All Services shall be performed in accordance with the terms, specifications and schedules included in SCHEDULE A. The Vendor shall promptly notify Toronto Hydro, in writing, of any circumstances known or suspected that may cause delay in performance of the Services. Unless otherwise agreed in writing, Toronto Hydro will not accept deliveries in excess of those specified in this Agreement and such deliveries shall be entirely at the Vendor’s risk and may be returned by Toronto Hydro to the Vendor at the Vendor’s sole cost and expense.

b) In the event of any question, dispute, disagreement or difference of opinion between Toronto Hydro and the Vendor relating to the quality or acceptability or rate of progress of any Services or relating to the interpretation of the specifications in SCHEDULE A or the performance of this Agreement, the parties agree to work cooperatively and use all reasonable efforts to resolve such question, dispute, disagreement or difference.

7. **Invoice Requirements**

The Vendor shall submit invoices to Toronto Hydro in accordance with Section 5 of this Agreement and the payment terms as set out in SCHEDULE B. Each invoice shall contain:

a) a detailed description of the Services performed during the invoice period;

b) the dates and the amount of time spent by the Vendor for the provision of the Services;

c) the hourly rates;

d) the total HST applicable to the Services during the invoice period, as well as the Vendor’s HST registration number; and

c) a detailed description of any applicable disbursements incurred around the invoice period, supported by documentation in a form acceptable to Toronto Hydro.

8. **Inspection**

All Services performed will be subject to final inspection and approval by Toronto Hydro after performance, notwithstanding any prior payment. In the event that Services are performed which are not in conformity with the terms and conditions and specifications of this Agreement, acting reasonably, Toronto Hydro may, at its option:

a) reject the Services and require the Vendor to promptly re-perform the Services;

b) negotiate with the Vendor an agreeable reduction in the price of the delivered, non-conforming Services; or

c) reject the non-conforming Services and require a repayment of applicable amounts for such deliverables.

9. **Representations, Warranties and Covenants**

The Vendor represents and warrants to Toronto Hydro that:
a) it has the corporate power and authority to enter into this Agreement and to perform its obligations hereunder, and that this Agreement constitutes a legal, valid, and binding obligation of the Vendor, enforceable against the Vendor in accordance with its terms;

b) the Vendor, after conducting due diligence, is not aware of any actions, suits or other legal proceedings which may affect its ability to perform this Agreement;

c) the Services shall be performed in a professional, diligent and competent manner and shall meet or exceed those standards generally observed by reputable and competent members of the same industry providing similar services;

d) it is an expert, trained, equipped and capable in providing the Services and shall only use reliable, qualified and Competent Persons to perform the Services;

e) it is in compliance with and has paid, and will continue to pay, all assessments and other amounts owing pursuant to the WSIA; and

f) it is satisfied with the conditions under which the Services will be performed, and shall assume full responsibility for understanding the conditions of supply, operations, and service.

10. Warranty

All Services shall be in compliance with all Applicable Laws and will conform to the specifications, as specified in SCHEDULE A hereto and will be fit and sufficient for their intended purpose. This warranty is in addition to all other warranties specified in SCHEDULE A or implied by law and shall survive acceptance and payment.

11. Resources

(a) Subject to Section 11(c) below, the Vendor shall ensure that all personnel designated as required resources ("Required Resources") in this Agreement shall be made available according to the allocations described therein.

(b) Any adjustment by the Vendor to the Required Resources shall be subject to the following:

   a. Subject to Section 11(c) below, the Vendor shall not substitute or remove a Required Resource at any time without the prior written consent of Toronto Hydro, not to be unreasonably withheld, unless: (A) any such Required Resource terminates his/her employment with the Vendor or is on an approved leave of absence, or (B) the security of Toronto Hydro’s information is at risk and there is no opportunity to obtain prior written consent in such circumstances;

   b. The Vendor shall ensure that each resource substituted for a Required Resource is at a job seniority level and skill level equivalent to or higher than those of the Required Resource;

   c. TheVendor shall ensure that each resource substituted for a Required Resource is introduced in sufficient time prior to the departure of such Required Resource (the "Overlap Period") so as to learn or become familiar with: (A) the implementation and development of the Services, and (B) those skills and duties necessary to function in place of such Required Resource. All costs incurred in relation to the Overlap Period shall be paid by the Vendor; and
d. The Vendor shall provide Toronto Hydro, if requested by Toronto Hydro, with copies of the current curriculum vitae of each Required Resource prior to the assignment of such Required Resource. The Vendor shall ensure that the Vendor has obtained the written consent of all Required Resources to provide Toronto Hydro with the foregoing information and that Toronto Hydro may distribute such information internally to others employed in connection with the development and implementation of the Services, as required (excluding any personnel, contractors or other individuals employed by or affiliated with a competitor of the Vendor).

(c) Notwithstanding Section 11(a) and 11(b)(i) above, the Parties acknowledge that the Vendor may only substitute the maximum number of Required Resources.

The Vendor shall inform Toronto Hydro of turnover of all personnel within its organization that are connected to the Services being provided by the Vendor to Toronto Hydro in a timely fashion, in order to allow Toronto Hydro to make arrangements for its protection.

12. Health and Safety

The Vendor shall be responsible for:

a) managing the health and safety of its own personnel and other Representatives;

b) ensuring its compliance with all Applicable Laws related to health and safety, including without limitation the OHSA; and

c) ensuring that its personnel and other Representatives are aware of any safety hazards involved in working in or around Toronto Hydro’s facilities and all Applicable Laws with respect thereto.

13. Permits and Applicable Laws

a) The Vendor shall, at its sole expense, obtain and maintain during the Term of this Agreement, all permits, licences and approvals required by all Applicable Laws to perform its obligations under this Agreement. The terms and conditions of this Agreement shall be carried out in strict compliance with all Applicable Laws and in the event of any conflict between any Applicable Laws, the Applicable Laws with the most stringent standard shall apply.

b) Without limiting the generality of subsection 13(a) above, both parties shall comply with their own obligations as they pertain to this Agreement under the Personal Information Protection and Electronic Documents Act (Canada), MFIPPA and any other applicable privacy legislation with respect to any personal information collected, used or disclosed in connection with this Agreement. Without limiting the generality of subsection 13(b) above, the Vendor shall comply with the Information Protection and Privacy Contract Requirements attached as SCHEDULE D hereto.

14. Compliance with Guidelines

The Vendor’s personnel shall comply with all rules and direction of Toronto Hydro that are provided in writing to the Vendor in advance, whether specified in this Agreement or otherwise, while working on Toronto Hydro’s premises, distribution system or when accessing or connecting to Toronto Hydro’s information technology systems, including rules and directions concerning health, safety, security and
environmental protection, including without limitation, Toronto Hydro’s Code of Business Conduct, the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the OEB, and Toronto Hydro’s Privacy Policy Statement, (together, the “Guidelines”).

15. Liability and Indemnification

Subject to the limitations or liability set out in this Agreement, the Vendor shall be liable for and shall indemnify and hold harmless Toronto Hydro and its Representatives from all third party claims, demands, actions, penalties, damages, losses, judgments and settlements, liabilities, costs, expenses, including legal fees and other related costs and expenses to the extent directly arising out of, or related to, the Vendor or any of its Representatives’ negligent acts or omissions or willful misconduct in the performance of the Services under this Agreement, including, without limitation:

a) any breach, violation or non-performance by the Vendor or any of its Representatives of any terms, conditions, warranties, obligations or covenants contained in this Agreement; and

b) any breach or violation by the Vendor or any of its Representatives of any Applicable Laws; and

c) wrongful act, omission, negligence or willful misconduct in the course of rendering the Services.

Notwithstanding anything else to the contrary in this Agreement,

(i) The aggregate liability of Vendor and its employees, directors, officers, agents and subcontractors (the “related persons”) to Toronto Hydro and its Representatives whether in contract, tort (including negligence), breach of statutory duty or otherwise for any losses arising from or in any way connected with Vendor’s services shall not exceed in aggregate the greater of (a) [REDACTED] or (b) the total amount of the fees paid to Vendor for the services provided pursuant to that statement of work during any 12-month period beginning with the commencement of that statement of work, unless otherwise agreed in writing. The parties agree that for breaches of confidentiality, the Vendor’s aggregate dollar liability set out in subsection (a) above shall be [REDACTED]. Nothing in these terms shall exclude or limit the liability of Vendor or its related persons in the case of: (a) death or personal injury resulting from its own negligence, (b) willful misconduct, (c) fraud, or (d) other liability to the extent that the same may not be excluded or limited as a matter of law.

(ii) Neither party shall be liable to the other party for any consequential, incidental or exemplary damages, including lost profits or other economic loss even if a party has been advised of the possibility of such damages.

16. Insurance

a) Unless otherwise specified in this Agreement, the Vendor shall, during the Term of this Agreement, and at its own expense, maintain and keep in full force and effect:

i. commercial general liability insurance on an occurrence basis having a minimum inclusive coverage limit, including personal injury and property damage, of not less than [REDACTED] per occurrence and in aggregate, which shall be extended to cover contractual liability, products and completed operations liability, owners/contractors protective liability and must also contain a cross liability clause and a severability of interest clause, and must name Toronto Hydro and its Affiliates as additional insureds; and
ii. automobile liability insurance on leased vehicles used in connection with this Agreement and such insurance coverage shall have a limit of not less than [redacted] per vehicle, in respect of bodily injury (including passenger hazard) and property damage inclusive of any one accident and mandatory accident benefits.

iii. Errors and Omissions insurance in the amount of not less than [redacted] in aggregate.

b) All insurance coverages and limits required to be maintained by the Vendor shall be primary to any insurance maintained by Toronto Hydro, which shall be excess and non-contributory. Prior to the commencement of the delivery of the Services, the Vendor shall deliver to Toronto Hydro a certificate of insurance which evidences the Vendor’s compliance with this Section. Vendor shall endeavour to provide thirty (30) day prior written notice of cancellation, non-renewal or adverse material change, to Toronto Hydro. The Vendor agrees that the insurance described herein does in no way limit the Vendor’s liability pursuant to the indemnity provisions of this Agreement.

c) A waiver of subrogation shall be provided by the insurer(s) to Toronto Hydro with respect to commercial general liability insurance.

17. Subcontractors

The Vendor may only subcontract any of the Service under this Agreement with the prior written consent of Toronto Hydro such consent not to be unreasonably withheld. If subcontracting is permitted, the Vendor shall be liable for any acts or omissions of its subcontractors as if such acts or omissions were those of persons directly employed by the Vendor. Any subcontract shall not relieve the Vendor from any of its obligations or liabilities under this Agreement.

18. Termination

a) Toronto Hydro may, for its convenience and at its sole option, terminate this Agreement by providing at least sixty (60) days prior written notice of such termination. Upon issuance of such notice, the Vendor shall stop performance of the Services under this Agreement, except as may be necessary to carry our such termination and take any other action which Toronto Hydro may reasonably direct. Upon a termination, Toronto Hydro shall pay for such Services requested by Toronto Hydro and provided or completed up until the effective date of such termination. Toronto Hydro shall not be liable to the Vendor for any other costs or damages whatsoever arising from such termination, including without limitation, any indirect, consequential or special damages such as a loss of profit or loss of opportunity.

b) If the Vendor fails to fulfill any covenant or material obligation under this Agreement, including, without limitation, the failure to meet the delivery schedule or any specification contained herein, or breaches any representation or warranty contained herein, then Toronto Hydro may, without prejudice to any other right or remedy Toronto Hydro may have, notify the Vendor in writing that the Vendor is in default of its contractual obligations and instruct the Vendor to correct the default within five (5) Business Days immediately following the receipt of such notice. If the Vendor fails to correct the default in the time specified, then, without prejudice to any other right or remedy Toronto Hydro may have, Toronto Hydro may terminate this Agreement. Upon a termination, Toronto Hydro shall pay for such Services requested by Toronto Hydro and provided or completed up until the effective date of such termination.
c) If bankruptcy or insolvency proceedings are instituted by or against the Vendor or the Vendor is adjudicated a bankrupt, becomes insolvent, makes an assignment for the benefit of creditors or proposes or makes arrangements for the liquidation of its debts, or a receiver or receiver and manager is appointed with respect to all or part of the assets of the Vendor, Toronto Hydro may, without prejudice to any other rights or remedies it may have, immediately terminate this Agreement.

d) The termination of this Agreement shall not affect any rights or obligations which may have accrued prior to such termination or any other rights which the terminating party may have arising out of either the termination or the event giving rise to the termination.

e) The Vendor may terminate this Agreement immediately where Toronto Hydro breaches any of the provisions of this Agreement and fails to cure any such breach within fifteen (15) days of a notice of such breach provided to Toronto Hydro.

19. Timing of the Services

The Vendor shall perform all Services in accordance with the dates and times for performance and delivery specified in SCHEDULE A hereto.

20. Force Majeure

a) As used herein, “Force Majeure” means events beyond the reasonable control of a party applying reasonable diligence and foresight given the nature of the Services being provided under the Agreement, including, as applicable, any acts of God and the public enemy, the elements; fire; accidents; vandalism; sabotage; power failure; strikes, lockouts or any other industrial, civil or public disturbances; any laws, orders, rules, regulations, acts or restraints of any government or governmental body or authority, civil or military, including the orders and judgments of courts and any other similar causes or acts.

b) If, by reason of Force Majeure, either party hereto (the “Frustrated Party”) is delayed or unable, in whole or in part, to perform or comply with any obligation or condition of this Agreement, then it will be relieved of liability and will suffer no prejudice for failing to perform or comply or for delaying such performance or compliance during the continuance and to the extent of the inability so caused from and after the happening of the event of Force Majeure, provided that it gives to the other party prompt notice of such inability, reasonably full particulars of the cause thereof and the expected cessation. If notice is not promptly given, then the Frustrated Party will only be relieved from performance or compliance from and after the giving of such notice. The Frustrated Party will use its reasonable efforts to remedy the situation and remove, so far as possible with reasonable dispatch, the cause of its inability to perform or comply, provided, however, that settlement of strikes, lockouts and other industrial disputes shall be within the discretion of the Frustrated Party. The Frustrated Party will give prompt notice of the cessation of Force Majeure. If at any time the Vendor cannot deliver the Services required to be provided pursuant to the Agreement due to Force Majeure, Toronto Hydro may engage any other party to provide such Services which the Vendor cannot provide. The benefit of this provision of Force Majeure shall only survive for thirty (30) days from the commencement of an event of Force Majeure. A requirement to disclose Confidential Information other than under Canadian law pursuant to the terms of this Agreement shall not be an event of Force Majeure. A failure by a sub-contractor to perform shall not be an event of Force Majeure for a Frustrated Party unless such sub-contractor is itself suffering from an event of Force Majeure and the provisos set forth above are followed.
21. Intellectual Property

Toronto Hydro shall retain ownership of all original data, information and materials, and the intellectual property rights therein provided to Vendor by Toronto Hydro or its Representatives. Toronto Hydro will have the right to use, reproduce and adapt the copies of the work product delivered to Toronto Hydro for its internal business purposes. Vendor shall retain the intellectual property rights in such work product, and the skills, know-how and methodologies used or acquired by Vendor during the course of providing any Services.

The Services Vendor performs, including the work product Vendor delivers to Toronto Hydro, are provided solely for the intended purpose, and may not be referenced or distributed to any other party without Vendor's prior written consent, except that Toronto Hydro may distribute Vendor’s work product to its Affiliates, provided that Toronto Hydro ensures that each such Affiliate complies with these terms and the applicable statement of work as if it were a party to them, and Toronto Hydro remains responsible for such compliance.

Toronto Hydro shall not refer to or include any of Vendor’s work product in any shareholder communication or in any offering materials (or fairness opinion provided by its professional advisers) prepared in connection with the public offering or private placement of any security, unless otherwise agreed in writing between the parties.

The Vendor expressly warrants that the manufacture, delivery, sale or use of the Vendor’s Services will not infringe any Canadian or foreign patents, trademarks, copyrights, industrial design or other intellectual property rights and the Vendor shall indemnify and save Toronto Hydro harmless from all such infringement claims, judgments and decrees that may be entered against Toronto Hydro or its Representatives to the extent all related damage, liability, costs and expenses (including legal fees and other attendant costs and expenses) are incurred by Toronto Hydro by reason of any such infringement or claim thereof.

22. Confidential Information

The parties agree and acknowledge that, subject to Applicable Laws or court order,

a) each party (the "Receiving Party") shall maintain in strict confidence the terms of this Agreement and any and all proprietary and confidential information about the business, operations or customers of the other party or any of their Affiliates, which it acquires in any form from the other party (the "Disclosing Party") by virtue of this Agreement ("Confidential Information") and will not disclose to any third party or make use of such Confidential Information for itself or any third party without the prior written consent of the Disclosing Party;

b) the Receiving Party may disclose such Confidential Information to any of the Representatives of the Receiving Party or any of its Affiliates who agree to be bound by the obligations of confidentiality herein and who have a reasonable need to know such Confidential Information in the course of their duties for the Receiving party but only for the purposes of the Receiving party exercising its rights and obligations under this Agreement;

c) Toronto Hydro is subject to MFIPPA and is governed by governmental authorities such as the IESO and the OEB and shall have the right to disclose Confidential Information in accordance with the provisions of MFIPPA or as required by the IESO or the OEB;
d) a party shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with any breach of obligations pursuant to this section;

e) the Receiving Party shall be responsible for any breach of this Agreement by it and its Representatives and by any other person to whom it discloses any Confidential Information. The Parties agree that the Disclosing Party may be irreparably injured by a breach of this Agreement by the Receiving Party, or by any person to whom it discloses any Confidential Information, and that monetary damages may not be a sufficient remedy. Therefore, in such event, the Disclosing Party shall be entitled to seek all available equitable relief, including injunctive relief without proof of actual damages, as well as specific performance. Such remedies shall not be deemed to be exclusive remedies for a breach of this Agreement but shall be in addition to all other remedies available at law or equity;

f) upon termination of this Agreement, or upon ten (10) days’ prior written notice from the Disclosing Party requesting return of any or all Confidential Information, the Receiving Party shall forthwith return to the Disclosing Party all Confidential Information, including without limitation all copies of any form of the Confidential Information, the Receiving Party has received and, at the option of the Disclosing Party, deliver to the Disclosing Party, or destroy or have destroyed (subject to Receiving Party’s usual destruction processes and timetables), any copies or other reproductions of the Confidential Information together with all notes, analyses, reports and other written material whatsoever prepared by, or on behalf of, the Receiving Party, from, or in respect of, the Confidential Information; provided that the Receiving Party shall be entitled to keep, subject always to all the provisions of this Agreement, one copy of such Confidential Information including notes, analyses, reports or other written material prepared by, or on behalf, the Receiving Party for its records. The Receiving Party shall provide to the Disclosing Party, upon request, a certificate of an officer of the Receiving Party certifying such destruction; and

g) notwithstanding section 22(a), in the event that the Receiving Party believes it is required by law to disclose, or is requested by a Governmental Authority to disclose, any Confidential Information to a Governmental Authority, the Receiving Party may so disclose, provided that it shall, to the extent permitted by law, first inform the Disclosing Party of the request or requirement for disclosure to allow an opportunity for the Disclosing Party to apply for an order to prohibit or restrict such disclosure.

23. Changes

a) Toronto Hydro may, without invalidating the Agreement, change or issue instructions or schedules for the Services, request the Vendor to perform extra or additional work, or require the Vendor to delete certain parts of the Services (any such change, a “Change Order”), with the purchase price and schedule for the Services being adjusted accordingly by the Change Order.

b) If the Vendor’s costs or ability to meet the schedule are impacted by any failure by Toronto Hydro to perform any of Toronto Hydro’s obligations under the Agreement in the manner or within the time periods required by the Agreement, the Vendor may submit a request for a Change Order pursuant to this Section for a change in the purchase price, the schedule or both, to the extent the Vendor incurs any additional costs or is delayed on account of Toronto Hydro’s failure.

c) Upon receipt of notice of a required change in the Services, the Vendor shall promptly, and in any event within five (5) Business Days of receiving such written request, provide Toronto Hydro with a written estimate of the additional costs for such change or the cost savings with respect to deleted portions of the Services, as well as the impact to the schedule. In each case the estimate shall show
the hours and costs to the Vendor for labour, materials, and equipment overhead, along with the impact on delivery, all with adequate supporting documentation.

d) After receipt of an estimate of costs related to a Change Order from the Vendor, Toronto Hydro will determine what amendments to the Agreement, if any, may be reasonably required by such changes. Any change to the scope of work will be agreed to by the parties prior to implementation and evidenced in a written Change Order signed by both parties provided that Toronto Hydro may direct the Vendor to proceed with a change pending dispute resolution.

e) Extra or additional work performed by the Vendor without a prior Change Order from Toronto Hydro shall be at the Vendor’s sole cost and expense and Toronto Hydro shall not be liable for any claim by the Vendor.

f) The Vendor shall not suspend the unaffected portions of the Services while Toronto Hydro is in the process of making such changes and any related adjustment unless so initiated by Toronto Hydro.

24. Suspension

Toronto Hydro may, at any time during the term by notice in writing, suspend all or a portion of the Services. Upon receipt of such written notice, the Vendor shall perform no further work other than as directed by Toronto Hydro, and shall be entitled to payment for time spent in performing the Services up to the date of suspension.

25. Toronto Hydro Not Responsible

Notwithstanding any other provision in this Agreement, Toronto Hydro shall not be responsible for and shall not have control or charge of any means, methods, techniques, sequences or procedures used for or in respect of the Services, or for the safety precautions or programs required for the Services or otherwise prescribed hereunder. Toronto Hydro shall not be responsible for or have control or charge over the acts or omissions of the Vendor, subcontractors (if any) or their agents, employees or other persons performing any of the Services.

26. Preparation of the Agreement

Notwithstanding the fact that this Agreement was drafted by Toronto Hydro and its legal and other profession advisors, the parties acknowledge and agree that any doubt or ambiguity in the meaning, application or enforceability of any term or provision of this Agreement will not be construed or interpreted against Toronto Hydro or in favour of the Vendor when interpreting such term or provision, by virtue of such fact.

27. Publicity

The Vendor shall not use Toronto Hydro’s (or its Affiliates’) name, corporate logos or trade-marks in advertising or publicity nor the fact that any agreement between the Vendor and Toronto Hydro has been entered into without Toronto Hydro’s express prior written consent, which may be withheld in the sole discretion of Toronto Hydro.
28. No Minimum Volume

The Vendor acknowledges and agrees that: (i) no portion of the Agreement shall be interpreted as imposing any minimum volume purchase commitment on Toronto Hydro; (ii) the Agreement does not obligate Toronto Hydro to award the procurement of any or all services associated with the Agreement to the Vendor, and services may be added or deleted in Toronto Hydro’s absolute and sole discretion at any time; and (iii) the volume of purchase of the Services may diminish or be eliminated prior to the termination date of the Agreement without any liability on the part of Toronto Hydro, including but not limited to any claims by the Vendor for loss of anticipated profits.

29. Non-Exclusive Contract

It is expressly understood that the Agreement is non-exclusive with respect to the Vendor and Toronto Hydro. Toronto Hydro may contract with others for the procurement of the Services described herein in its sole discretion.

30. Assignment

Save and except for the right of each party to assign this Agreement to any of their Affiliates, neither party may assign this Agreement or any of its rights or obligations hereunder, in whole or in part, without the prior written consent of the other party, which consent may not be unreasonably withheld.

31. Relationship of the Parties

Nothing contained in this Agreement shall be construed to constitute either party as the partner, employee or agent of, or joint venturer with the other party, nor shall either party have any authority to bind the other in any respect, it being intended that each party shall remain an independent contractor of the other. The Vendor is responsible for all deductions and remittances required by law in relation to its employees, including those required for Canada unemployment insurance, workers’ compensation and income tax.

32. Severability

In the event that any of the covenants herein shall be held unenforceable or declared invalid for any reason whatsoever, to the extent permitted by law, such unenforceability or invalidity shall not affect the enforceability or validity of the remaining provisions of this Agreement and such unenforceable or invalid portion shall be severable from the remainder of this Agreement.

33. No Waiver

A waiver of any provisions of this Agreement shall not constitute either a waiver of any other provisions or a continuing waiver, unless otherwise expressly indicated in writing.

34. Enurement

This Agreement and everything contained herein shall enure to the benefit of, and be binding upon, the parties hereto and their respective successors and permitted assigns.
35. **Notice**

All notices, requests, claims, demands and other communications hereunder shall be in writing and shall be deemed (in the absence of evidence of prior receipt) to have been validly and effectively given on the same day if personally served, the next Business Day if sent by facsimile or similar means of recorded communication or on the fifth Business Day next following if sent by registered mail. Notices shall be addressed as follows:

**to Toronto Hydro:**
- **Name:** Aida Cipolla
- **Title:** Executive Vice-President and Chief Financial Officer
- **Address:** 14 Carlton Street, Toronto, ON M5B 1K5
- **Telephone:** (416) 542-3092
- **Email:** acipolla@torontohydro.com

with copy to:
- **Title:** Executive Vice President, Regulatory Affairs and General Counsel
- **Address:** 14 Carlton Street, Toronto, ON M5B 1K5
- **Telephone:** (416) 542-3000
- **Facsimile:** (416) 542-2602
- **Email:** legal@torontohydro.com

**to the Vendor:**
- **Name:** [Redacted]
- **Title:** [Redacted]
- **Address:** [Redacted]
- **Telephone:** [Redacted]
- **Email:** [Redacted]

36. **Governing Law**

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. The parties irrevocably attorn to the jurisdiction of the courts of Ontario with respect to any matter arising under or related to this Agreement. Either party can terminate for cause without the obligation to engage in dispute resolution, mediation or arbitration. The parties agree to a waiver of jury trial.

37. ** Entire Agreement**

a) This Agreement, including all schedules and appendices referred to herein and subsequent amendments, constitutes the entire agreement between the Vendor and Toronto Hydro relating to the subject matter hereof. This Agreement supersedes the terms of the RFP, the Proposal, any purchase order, and all prior correspondence, representations, warranties, covenants, collateral undertakings, discussions, negotiations, understandings or agreements, oral or otherwise, express or implied, unless otherwise provided in this Agreement.

b) No modification or amendment to this Agreement shall be binding on either party unless agreed to in writing.
c) This Agreement only creates rights enforceable by Toronto Hydro and does not create any rights enforceable by any other party.

38. Further Assurances

The Vendor agrees to execute such further assurances and documents, including any bills of sale, and to do all such things and actions which shall be necessary or proper for the carrying out of the purposes and intent of this Agreement.

39. Survival

In addition to the terms of this Agreement that by their nature survive the expiry or termination of this Agreement, the terms of Sections 15 (Liability and Indemnification), 21 (Intellectual Property Protection), 22 (Confidential Information), 9 (Representations, Warranties and Covenants), 32 (Severability), 34 (Enurement), 35 (Notice) and 36 (Governing Law) shall survive the expiry or termination of this Agreement for a period of five (5) years.

40. Execution and Counterparts

This Agreement may be executed in any number of counterparts (including by way of facsimile or email) and all of such counterparts taken together shall be deemed to constitute one and the same instrument.

41. No Agency or Fiduciary Relationship.

Unless otherwise expressly agreed in writing, Vendor does not accept any agency, fiduciary or trust responsibilities or liability in connection with the performance of the Services. If a law deems the Vendor to be a fiduciary with respect to any services, the Vendor’s responsibility as a fiduciary shall extend only to its own actions and services and then only to those activities specifically deemed to be fiduciary activities under applicable law. The Vendor does not provide legal, accounting or tax advice.

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the day and year first written above:

Toronto Hydro Corporation

Per: ____________________________

Name: Aida Cipolla

Title: Executive Vice-President andChief Financial Officer

I have authority to bind the Vendor. I have authority to bind Toronto Hydro.
c) This Agreement only creates rights enforceable by Toronto Hydro and does not create any rights enforceable by any other party.

38. Further Assurances

The Vendor agrees to execute such further assurances and documents, including any bills of sale, and to do all such things and actions which shall be necessary or proper for the carrying out of the purposes and intent of this Agreement.

39. Survival

In addition to the terms of this Agreement that by their nature survive the expiry or termination of this Agreement, the terms of Sections 15 (Liability and Indemnification), 21 (Intellectual Property Protection), 22 (Confidential Information), 9 (Representations, Warranties and Covenants), 32 (Severability), 34 (Enurement), 35 (Notice) and 36 (Governing Law) shall survive the expiry or termination of this Agreement for a period of five (5) years.

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Unless otherwise expressly agreed in writing, Vendor does not accept any agency, fiduciary or trust responsibilities or liability in connection with the performance of the Services. If a law deems the Vendor to be a fiduciary with respect to any services, the Vendor’s responsibility as a fiduciary shall extend only to its own actions and services and then only to those activities specifically deemed to be fiduciary activities under applicable law. The Vendor does not provide legal, accounting or tax advice.

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the day and year first written above:

Towers Watson Canada Inc.  
Per: ____________________________  
Name: ____________________________  
Title: ____________________________  
I have authority to bind the Vendor.

Toronto Hydro Corporation  
Per: ____________________________  
Name: Aida Cipolla  
Title: Executive Vice-President and Chief Financial Officer  
I have authority to bind Toronto Hydro.
SCHEDULE A

Services Required

(i) Vision

Toronto Hydro is conducting a selection process for its actuarial valuator. Toronto Hydro believes that its consolidated financial statements and related disclosures are of high quality and emphasizes the integrity of the underlying financial processes. Therefore, the actuarial valuator must deliver a high level of assurance to Toronto Hydro’s senior management team and its stakeholders, including its shareholder, creditors, investors, and the rate payers for the City of Toronto.

(ii) Project Objectives and Mandate

The ultimate objective of the project is to successfully select an actuarial valuator for the year ended December 31, 2017 and the next 3 to 5 years.

The project mandate is as follows:

a) Select the actuarial valuation firm that best meets the expectations of Toronto Hydro senior management, the Audit Committee, the Board of Directors and the Shareholder.

b) Successfully transition to the actuarial valuator firm while minimizing business interruption and the impact to Toronto Hydro staff.

c) Ensure the successful Respondent can effectively work with Toronto Hydro and can bring experience and innovation, as it relates to the actuarial valuation and related disclosures.

d) Ensure that the successful Respondent is experienced in the electricity sector, and can fully represent Toronto Hydro’s interest locally, provincially, and internationally and provide access to the appropriate personnel.

e) Ensure that the actuarial valuation approach will utilize existing documentation.

f) For purposes of this RFP, Respondents are asked to assume that an extrapolation/roll-forward will be required for the year-ending December 31, 2017, a full valuation will be required as at January 1, 2018 and an extrapolation/roll-forward will be required for the year-ending December 31, 2018, including all required disclosures for financial reporting of other post-employment benefit expenses, liabilities and obligations, in accordance with IFRS.

(iii) Services Required

The engagement will involve work customarily performed by an actuarial valuation firm to a public company. Toronto Hydro will require an actuarial valuation report for a valuation of post-employments benefits on an annual basis for the consolidated entity and each of its affiliates. Full valuations are done every 2-3 years depending on the changes in plan provisions since the prior valuation that would materially impact the results, with an extrapolation or roll-forward done in the interim years.
The most recent actuarial valuation of Toronto Hydro's plan for accounting purposes was performed as at January 1, 2016 in accordance to IFRS.

The services required will include, but are not limited to, the following:

a) Performing an actuarial valuation or extrapolation/roll forward in accordance with requirements of IFRS
   a. To determine the benefit obligation for post-employment benefits as at December 31, 2017 and thereafter;
   b. To determine the net benefit cost to be recognized for financial statement purposes for the fiscal year ending December 31, 2017 and thereafter;
   c. To estimate the benefit obligation for post-employment benefits as at December 31, 2017 and thereafter;
   d. To estimate the net benefit cost to be recognized for financial statement purposes for the fiscal years ending December 31, 2017 and December 31, 2018 and thereafter;
   e. To provide sensitivity analysis on various assumptions, particularly the discount rate;
   f. To provide draft amounts and required disclosures for purposes of the consolidated financial statements and note disclosures as at December 31, 2017 in accordance with IFRS; and
   g. To provide the information and the actuarial opinion required by Toronto Hydro's auditors and assist as requested by auditors.

b) Providing an actuarial valuation report or roll forward/extrapolation and schedules with the required disclosures under IFRS, for Toronto Hydro and each of its affiliates.

c) Providing professional advice on which actuarial assumptions Toronto Hydro should use, including providing sensitivity analysis on the discount rate.

d) Obtaining an understanding of Toronto Hydro's employee benefits.

e) Utilizing existing internal documentation and schedules prepared by Toronto Hydro for the valuations or extrapolations, and providing requests for client information in advance to allow Toronto Hydro sufficient time to prepare the information.

f) Communicating matters required by professional standards to the appropriate level of management to the extent that such matters come to the attention of the successful Respondent during the engagement.

g) Attending planning meetings with Toronto Hydro senior management and presenting the actuarial valuation or extrapolation/roll-forward reports in a timely manner.

h) Identifying to Toronto Hydro senior management any significant and/or reportable conditions noted during the course of the valuation.

The Vendor will be expected to provide the following:

a) Experienced coordinating partner and actuarial team.

b) Proven ability to transition actuarial valuation engagements (as necessary) while minimizing business interruption and the impact on staff.
c) Demonstrated understanding of Toronto Hydro’s business, expectations of the actuarial valuation, quality and integrity of the actuarial valuation process and financial reporting requirements.

d) Firm’s process for delivering actuarial valuation services and approach to reaching consensus on related accounting policies and accounting issues.

e) Commitment to stability of the actuarial valuation team.

f) Qualifications and experience of the proposed staff with actuarial valuation and related disclosures and accounting policies relating to IFRS.

g) Details of how the transition will leverage Toronto Hydro’s current documentation and reports.

(iv) Expectations

Toronto Hydro management expects a high quality valuation team. Preference will be given to those with substantial knowledge and experience in the regulated electricity industry. It will be expected that the engagement partner selected to service Toronto Hydro is an experienced member of the actuarial valuation firm, capable of committing the firm.

Toronto Hydro management expects to be served by a firm that has professional credibility in Toronto Hydro’s industry and knowledge of the issues affecting Toronto Hydro. A representative list of clients in Toronto Hydro’s industry, including the types of services rendered, should be provided. Firm wide expertise and local expertise should be differentiated.

Toronto Hydro expects an efficient risk-based actuarial valuation which is focused on Toronto Hydro’s industry, business structure, and issues. It is expected that Toronto Hydro’s existing documentation and processes will be incorporated into the valuation process.

The actuarial valuator is expected to develop a collaborative relationship with Toronto Hydro’s finance and employee benefits groups.

Toronto Hydro senior management expects the actuarial valuation to be performed with professionalism in a timely manner which permits Toronto Hydro to meet its reporting requirements to the various governing authorities and in accordance with all Applicable Laws.

The majority of the work will be conducted at Toronto Hydro’s head office located at 14 Carlton Street in Toronto.

(v) Commencement of Services and Transition

The work will commence immediately upon Contract execution. During this time, the successful Respondent may need to co-ordinate with Toronto Hydro’s incumbent actuarial valuator, if required.
SCHEDULE B

Purchase Price

Pricing for the supply of the Services is outlined in the attached Appendices.

Appendices A, B, C, D and E (Price Matrix) list a breakdown of the Vendor’s annual fees for Services to be performed under the Agreement.

Appendix F (Rate Table) outlines a rate table for the Vendor’s key personnel (the “Rate Table”). The Rate Table shall apply only where Toronto Hydro has agreed, in writing, to acquire additional professional services beyond the scope of SCHEDULE A.
Pricing includes all labour, administration, work equipment, materials necessary to perform the Services, including insurance(s), WSIB/workers’ compensation and all other charges of every kind attributable to the work. No reimbursement will be provided for hospitality, food or incidentals. Any travel must be preapproved by Toronto Hydro.
Pricing includes all labour, administration, work equipment, materials necessary to perform the Services, including insurance(s), WSIB/workers’ compensation and all other charges of every kind attributable to the work. No reimbursement will be provided for hospitality, food or incidentals. Any travel must be preapproved by Toronto Hydro.
Pricing includes all labour, administration, work equipment, materials necessary to perform the Services, including insurance(s), WSIB/workers’ compensation and all other charges of every kind attributable to the work. No reimbursement will be provided for hospitality, food or incidentals. Any travel must be preapproved by Toronto Hydro.
Pricing includes all labour, administration, work equipment, materials necessary to perform the Services, including insurance(s), WSIB/workers’ compensation and all other charges of every kind attributable to the work. No reimbursement will be provided for hospitality, food or incidentals. Any travel must be preapproved by Toronto Hydro.
Pricing includes all labour, administration, work equipment, materials necessary to perform the Services, including insurance(s), WSIB/workers' compensation and all other charges of every kind attributable to the work. No reimbursement will be provided for hospitality, food or incidentals. Any travel must be preapproved by Toronto Hydro.
SCHEDULE C

Defined Terms

In this Agreement, the following definitions shall apply:

"Affiliates" shall have the meaning as prescribed in the Business Corporations Act (Ontario);

"Agreement" means this Agreement for Purchase of Services, including all Schedules and Appendices hereto and subsequent amendments;

"Applicable Laws" means all federal, provincial and municipal statutes, regulations, codes, by-laws, orders in council, directives, rules, guidelines and ordinances applicable to this Agreement, including without limitation all applicable OEB codes, rules or guidelines;

"Business Day" means a day on which banks are open for business in the City of Toronto, Ontario, but does not include a Saturday, Sunday, or a statutory holiday in the Province of Ontario;

"Change Order" has the meaning prescribed to it in Section 23;

"Competent Persons" shall have the meaning as prescribed in the OHSA;

"Confidential Information" has the meaning prescribed to it in Section 22;

"DDP" shall have the meaning prescribed to it in the Incoterms2010 rules published by the International Chamber of Commerce;

"Disclosing Party" has the meaning prescribed to it in Section 22;

"EFT Information" has the meaning prescribed to it in subsection 5(b);

"Force Majeure" has the meaning prescribed to it in Section 20;

"Frustrated Party" has the meaning prescribed to it in subsection 20(b);

"Governmental Authority" means any government, legislature, municipality, regulatory authority, agency, commission, department, board or court or other law, regulation or rule-making public entity of similar authority, including, without limitation the OEB;

"Guidelines" has the meaning prescribed to it in Section 14;

"HST" means Harmonized Sales Tax;

"IESO" means Independent Electricity System Operator;

"IFRS" means International Financial Reporting Standards;
"Initial Term" has the meaning prescribed to it in subsection 4(a);

"MFIPPA" means Municipal Freedom of Information and Protection of Privacy Act (Ontario) and the regulations thereunder, each, as amended;

"OEB" means Ontario Energy Board;

"OHSA" means Occupational Health and Safety Act (Ontario) and the regulations thereunder, each, as amended;

"Proposal" has the meaning prescribed to it in Recital D;

"Receiving Party" has the meaning prescribed to it in Section 22;

"Renewal Term" has the meaning prescribed to it in subsection 4(b);

"Representative" in respect of a party, means such party's directors, officers, employees, and contractors, the party's Affiliates, and all such Affiliates' respective directors, officers, employees, and contractors;

“Required Resources” has the meaning prescribed to it in subsection 11(a);

"RFP" has the meaning prescribed to it in Recital D;

“Services” has the meaning prescribed to it in Recital A;

"Term" has the meaning prescribed to it in subsection 4(c);

"Toronto Hydro" has the meaning prescribed to it in the preamble to this Agreement;

“Vendor” has the meaning prescribed to it in the preamble to this Agreement; and

"WSIA" means Workplace Safety and Insurance Act, 1997 (Ontario) and the regulations thereunder.
SCHEDULE D
INFORMATION PROTECTION AND PRIVACY CONTRACT REQUIREMENTS

Towers Watson Canada Inc. ("Vendor") shall comply with the all of the provisions of this Schedule D (the "IPPCR").

1. Definitions. In this IPPCR, the following terms have the following meanings and any capitalized terms that are not defined below have the meaning attributed to them in the Agreement:

(a) "access", in connection with TH Data, means capable of being accessed by a person, whether or not that person has the right or authority under any law or agreement to access the TH Data;

(b) Authorized Users" means those employees and representatives of Vendor and of any subcontractors of Vendor who require access to TH Data for the purpose of providing the Services;

(c) "disclose", in connection with TH Data, means the access of TH Data by or the transfer custody or control of TH Data to a third party who is not an Authorized User or a subcontractor using the TH Data solely for the purposes of the Agreement;

(d) "including" means including without limitation;

(e) "IPC" means the Information and Privacy Commissioner of Ontario;

(f) "Personal Information" means information about an identifiable individual including information that can be used to authenticate that individual, that is:

(i) Provided to Vendor by Toronto Hydro; or

(ii) collected, accessed, used, stored or disclosed by Vendor on behalf of Toronto Hydro in connection with Vendor’s obligations pursuant to the Agreement;

(g) "Privacy Laws" means all laws and regulations and orders, standards, guidelines and recommendations of a regulatory authority with jurisdiction regarding Personal Information, including the Municipal Freedom of Information and Protection of Privacy Act (Ontario) ("MFIPPA"), as amended from time to time, all regulations made pursuant to MFIPPA, and any applicable orders, standards, guidelines or recommendations of the IPC that are applicable to the Vendor in the provision of the Services under the Agreement;

(h) "Security Incident" means any set of facts or circumstances that would lead a reasonable person to conclude that there has been the loss of unencrypted or improper, unauthorized or unlawful access to, use of, destruction of, or disclosure of TH Data;
(i) “store” and “stored” means held, backed up or stored by any means whatsoever, including in hard and electronic formats and includes storage in a server or database or any form of electronic memory;

(j) “Toronto Hydro” means the Toronto Hydro-Electric System Limited;

(k) “TH Data” means (i) the Personal Information and (ii) any other data that is provided to Vendor by Toronto Hydro or its Representatives pursuant to the Agreement that is confidential or proprietary information of Toronto Hydro; and

(l) “use” means to handle TH Data in any manner, including to copy, download and temporarily hold TH Data.

2. **Conflict.** The provisions of this IPPCR are in addition to any obligations of Vendor under the Agreement. In the event of a conflict or inconsistency between this IPPCR and any other provision of the Agreement (including any contractual duties of confidentiality), the provisions of this IPPCR shall prevail to the extent of the conflict or inconsistency.

3. **Compliance.** Vendor represents, warrants, and covenants that it:

   (a) does and will comply with all Privacy Laws applicable to the Personal Information; and

   (b) has developed and implemented, and will maintain and monitor, a written and comprehensive information security program; and

   (c) will certify, in writing, its compliance with the foregoing annually upon request from Toronto Hydro.

4. **Relationship.** Vendor is a third party service provider to Toronto Hydro. Vendor is responsible for ensuring the compliance with the terms of this IPPCR by all of its Authorized Users and subcontractors.

5. **Ownership of TH Data.** Nothing in the Agreement provides Vendor, its subcontractors or Authorized Users with any rights in or to the TH Data. As between Vendor and Toronto Hydro, TH Data will remain under the control of Toronto Hydro, including without limitation, when Vendor is using or storing TH Data. Vendor shall not and shall not permit its subcontractors to aggregate or otherwise modify TH Data for any purpose other than as provided for in the Agreement. Vendor shall not and shall not permit its subcontractors to withhold any TH Data from Toronto Hydro to enforce any alleged payment obligation or in connection with any dispute relating to the terms of the Agreement or any other matter between Vendor and Toronto Hydro.

6. **Restrictions Relating to TH Data.** Vendor shall and shall cause its subcontractors to:

   (a) only collect, access, store, and use Personal Information to the extent required for the purpose of fulfilling Vendor’s obligations under the Agreement;

   (b) not disclose TH Data except (i) in accordance with the provisions of the Agreement and this IPPCR, (ii) if required by applicable law (provided, where not prohibited by law, Vendor provides notice in accordance with section 12 of this IPPCR), or (iii) with the written consent of Toronto Hydro; and
(c) ensure Authorized Users are bound by written policies, procedures or confidentiality agreements containing a duty to protect the confidentiality of the TH Data.

7. **Subcontractors.** Vendor shall only permit subcontractors to collect, access, store, use or disclose TH Data with the written approval of Toronto Hydro, acting reasonably, which approval may be withheld until Toronto Hydro has been provided with satisfactory evidence that the subcontractor has entered into a contract with Vendor containing (i) a duty to protect the security, integrity, confidentiality and availability of the TH Data and (ii) restrictions on the collection, access, storage, use and disclosure of the TH Data that are consistent with the terms of this IPPCR.

8. **Security Administration.**

(a) Vendor shall and shall require its subcontractors to establish and maintain administrative, technical and physical safeguards to protect the security, integrity, confidentiality and availability of the TH Data, including to protect the TH Data against any anticipated threats or hazards and to protect against any loss of or unauthorized or unlawful access to, use of, or disclosure of the TH Data.

(b) Vendor shall and shall require its subcontractors to take reasonable steps to ensure compliance by all Authorized Users and subcontractors with Vendor's privacy and security obligations under this IPPCR, which shall occur before such individuals are allowed access to TH Data and no less than annually thereafter.

(c) Without limiting the generality of paragraph 8(a), Vendor shall and shall require its subcontractors to implement the following safeguards in respect of the TH Data (unless otherwise agreed to in writing by Toronto Hydro):

(i) TH Data must not be accessed or accessible from outside of Canada or the U.S., except in accordance with paragraph 8(c)(vi);

(ii) TH Data must be stored in facilities meeting reasonable industry standards relating to the protection of sensitive personal information;

(iii) TH Data must be encrypted when transferred electronically between Vendor and Toronto Hydro;

(iv) TH Data must be encrypted in transit when accessed or transmitted over the Internet;

(v) TH Data may only be accessed by Authorized Users;

(vi) TH Data in electronic form must be logically segregated from other data stored by Vendor;

(vii) Each individual with access to TH Data in electronic form must be identified by a unique user ID;

(viii) The security access principles of "segregation of duties" and "least privilege" shall be implemented to restrict access to TH Data;
(ix) All sessions involving access to TH Data must be logged and logs retained for a sufficient period of time to permit an investigation into unauthorized access.

(x) All applicable and necessary security patches will be deployed promptly to all systems in which TH Data is stored or through which TH Data is accessed or used, including operating system and open source and application software; and

(xi) Only supported software (software under active maintenance, including operating system, open source, application software and/or the like) will be deployed on any systems in which TH Data is stored or through which it is accessed and used.

(d) Vendor shall and shall require its subcontractors to maintain and enforce retention policies for any and all reports, logs, audit trails and any other documentation that provides evidence of security, systems, and audit processes and procedures.

(e) Vendor shall and shall require its subcontractors to implement procedures to ensure that, upon termination of employment or affiliation with Vendor or its subcontractors, each Authorized User's ability to access TH Data is terminated, any and all TH Data being temporarily held by such Authorized User for the provision of the Services is returned to Vendor and such Authorized User is reminded of his or her continuing obligations with respect to the confidentiality of the TH Data.


(a) If, in the opinion of the Chief Security Officer of Toronto Hydro (or equivalent), acting reasonably, there is a real risk of the loss of or improper, unauthorized or unlawful access to, use of, destruction of, or disclosure of TH Data, Toronto Hydro may, in addition to any other rights it may have under the Agreement, suspend the Agreement until such risks are mitigated to the satisfaction of Toronto Hydro, acting reasonably. If the parties cannot agree, within 15 days, on a timeline for the implementation of remedial action to mitigate such risks, Toronto Hydro may terminate this Agreement pursuant to Section 18 of the Agreement. The parties agree to discuss in good faith, responsibility for the costs of any such correction of deficiency or improvement.

(b) Without limiting Toronto Hydro’s rights pursuant to paragraph 9(a) of this IPPCR, Vendor shall provide Toronto Hydro with written notice if Vendor materially modifies the process, method or means by which TH Data is stored, accessed or otherwise transmitted or handled.

10. Assurance and Assistance.

(a) Toronto Hydro may, during regular business hours and on reasonable prior notice to Vendor, visit and inspect any location from which Vendor accesses, uses or stores Personal Information. In connection with the inspection, Vendor shall and shall cause its subcontractors to:

(i) make available for examination all applicable policies and procedures governing the operation of any location or equipment used to access, use or store TH Data;

(ii) make available representatives of Vendor and any subcontractors to answer questions relating to the policies, procedures or equipment, subject only to
limitations required for Vendor to comply with applicable laws or contractual obligations of confidentiality to third parties; and

(iii) permit and provide reasonable assistance to Toronto Hydro to audit and verify, compliance by Vendor and each subcontractor with this IPPCR, subject only to limitations required for Vendor and its subcontractors to comply with applicable laws or contractual obligations of confidentiality to third parties.

(b) Toronto Hydro’s rights under paragraph 8(a) of this IPPCR may be exercised by an authorized representative of Toronto Hydro or by the IPC or other regulator with jurisdiction who enters into a confidentiality agreement with Vendor in a form acceptable to Vendor acting reasonably.

(c) Notwithstanding anything to the contrary in this Agreement, any audit permitted pursuant to this Agreement will be conducted no more than once per calendar year, if required, during reasonable business hours upon at least 2 weeks prior written notice to the Vendor. Such audit will be at Toronto Hydro’s sole cost and will be subject to the Vendor’s reasonable security requirements.

(d) Vendor acknowledges that Privacy Laws and regulatory requirements to which Toronto Hydro is subject may change during the term of the Agreement. Upon agreement, including agreement as to additional costs, Vendor shall:

(i) vary or eliminate any practice that causes Toronto Hydro to be in violation of Privacy Laws; and

(ii) provide information and assistance to Toronto Hydro, acting reasonably, that Toronto Hydro requires for privacy impact assessments and threat risk assessments.

11. **Security Incidents.** Vendor shall notify Toronto Hydro promptly of a Security Incident and, in any case, within 72 hours of becoming aware of the Security Incident. In the event that Vendor notifies Toronto Hydro of a Security Incident or the Vendor is notified by Toronto Hydro or any third party of a Security Incident, Vendor shall and shall cause its Authorized Users and subcontractors to:

(a) reasonably cooperate with Toronto Hydro and its third-party advisors in investigating and resolving the vulnerability giving rise to the Security Incident;

(b) provide Toronto Hydro with information regarding: (i) the Personal Information that is the subject of the Security Incident; (ii) the names and contact information (if known) of individuals who may be affected by the Security Incident; (iii) the steps taken to contain the Security Incident and to mitigate any harm to individuals as a result of the Security Incident; and (iv) any remedial actions taken to prevent further occurrences of the Security Incident;

(c) reasonably cooperate with Toronto Hydro with respect to Toronto Hydro: (i) reporting the Security Incident to the IPC and any other governmental authority with jurisdiction; (ii) answering all inquiries of the IPC and any other governmental authority with jurisdiction; (iii) providing notification to individuals affected by the Security Incident; and (iv) providing notification or reports to other third parties who may assist in mitigating the possible harm to affected individuals.
Unless otherwise required by applicable Privacy Laws or other laws, the decision whether to make a report to the IPC and any other governmental authority or to notify individuals and third parties, and the content of any such reports and notifications shall be solely at the discretion and direction of Toronto Hydro.

12. **Individual Access Requests.** Vendor shall and shall cause its subcontractors to:

(a) notify Toronto Hydro promptly of any request by an individual for access to or correction of Personal Information that is about that individual and promptly follow all instructions provided by Toronto Hydro with respect to responding to such requests;

(b) on a commercially reasonable basis and at Toronto Hydro’s cost, cooperate with Toronto Hydro:
   - in furnishing it with complete information concerning Vendor’s access and use of Personal Information, including responding, if requested to do so, to any inquiry by a privacy regulatory authority and/or to any complaint; and

13. **Judicial or Governmental Requests.** Vendor shall notify Toronto Hydro promptly of any request, order, subpoena, or warrant from a domestic or foreign court or governmental authority (including domestic or foreign law enforcement) for access to or the production of all or any part of the TH Data stored by Vendor or its subcontractors, unless Vendor or its subcontractors is prohibited from doing so by a law, court or governmental authority with jurisdiction over Vendor, its subcontractors or the TH Data. At Toronto Hydro’s expense, Vendor shall, if requested to do so, provide reasonable assistance to Toronto Hydro in objecting to access to or the production of all or part of the TH Data.

14. **Return of TH Data.** Upon the termination or expiry of the Agreement (for any reason), Vendor shall and shall cause each subcontractor to forthwith return to Toronto Hydro, as directed by Toronto Hydro, all TH Data being stored by Vendor or its subcontractors or, at Toronto Hydro’s option, delete all such TH Data from Vendor’s systems as directed by Toronto Hydro (including any copies thereof), and provide Toronto Hydro with an officer’s certificate attesting to such deletion. Vendor will securely delete data from servers and workstations before the device is repurposed, decommissioned or returned to the leasing vendor. Notwithstanding the foregoing, Vendor may retain one copy of the TH Data for archival purposes to permit defense of its work product and in accordance with legal, disaster recovery and records retention requirements, store copies of the TH Data in an archival format (e.g. tape backups), which will be destroyed at expiration of the applicable required retention period, provided that such copies shall continue to be subject to the confidentiality obligations contained herein.

15. **Survival.** Notwithstanding the termination or expiry of the Agreement, Vendor shall and shall cause each subcontractor to continue to govern itself in accordance with this IPPCR and the obligations of Vendor under this IPPCR shall survive the expiry or termination of the Agreement until Vendor and each subcontractor no longer has custody or access to the TH Data and has destroyed all copies of the TH Data in accordance with this IPPCR.
16. **Notices.** Any notice required in this IPPCR to be provided to Toronto Hydro shall be made in writing to:

Name: Aida Cipolla  
Title: Executive Vice-President and Chief Financial Officer  
Address: 14 Carlton Street, Toronto, ON M5B 1K5  
Telephone: (416) 542-3092  
Email: acipolla@torontohydro.com

with copy to:

Title: Executive Vice President, Regulatory Affairs and General Counsel  
Address: 14 Carlton Street, Toronto, ON M5B 1K5  
Telephone: (416) 542-3000  
Facsimile: (416) 542-2602  
Email: legal@torontohydro.com
SCHEDULE E

Required Resources
September 11, 2017

Navigant Consulting Ltd.
333 Bay Street, Suite 1250
Toronto, Ontario M5H 2R2
Attention: Craig Sabine

Re: Retainer Letter Agreement – Toronto Hydro-Electric System Limited – Lead Lag Study

Dear Mr. Sabine:

We represent Toronto Hydro-Electric System Limited ("THESL") in connection with its planned 2020 Custom Incentive Rate application (the "Application") to the Ontario Energy Board (the "Board").

We confirm that, on behalf of and to assist us in providing legal advice to THESL in connection with the Application, TORYS LLP ("TORYS") has agreed to retain Navigant Consulting Ltd. (the "Consultant") effective as of September 11, 2017 (the "Effective Date") to provide consulting services as herein described. By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with TORYS effective on the Effective Date, subject to amendment by written agreement between the parties (the "Retainer Agreement").

1. No Conflict

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice to THESL. You confirm that you are free to provide your services to TORYS in connection with TORYS' representation of THESL in the Application. You agree that during this engagement you will not provide, directly or indirectly, any services to any other party in connection with the matters at issue in the Application.

2. Consultant Expertise

The Consultant has been selected to provide consulting services to TORYS in connection with the Application, namely by conducting a lead lag study. The sponsors of the work of the Consultant
and the persons who have the relevant expertise will be Craig Sabine, Andy Tam, Jodi Amy and Bala Krishnamoorthy (the "Sponsors").

3. **Scope of Services and Work Product**

The Consultant will:

(a) conduct a lead lag study that meets the requirements described in THESL’s Request for Proposals No. 17P-066 (the “Study”);

(b) produce a written report detailing the study’s methodology, analysis performed and the ensuing findings and recommendations (the “Report”), which may be filed with the Board in the Application; and

(c) if requested by Torys, provide support during the hearing of the Application and testify before the Board in the Application, in connection with the scope of the services provided hereunder (“Application Support” and, together with the Study and the Report, the “Services”).

4. **Fees and Invoices**

By entering into this Retainer Agreement, the Consultant acknowledges that:

- [Redacted]

- [Redacted]

All amounts stated herein are in Canadian dollars.

The Consultant shall direct all invoices relating to Services performed by it under this Retainer Agreement to THESL, to the attention of:

Ms. Daliana Coban  
Manager, Regulatory Law  
Toronto Hydro Electric-System Limited  
14 Carlton Street  
Toronto, Ontario M5B 1K5  
dcoban@torontohydro.com

with a copy to Torys, to the attention of:

Mr. Charles Keizer

24205233.1
Consultant's invoices are due upon receipt and payment is expected within 30 days of the invoice date. THESL is responsible for payment to Consultant. Any objection to the invoice must be made within 60 days after the date of the invoice; lack of timely objection to an invoice shall evidence THESL's agreement to all invoiced amounts. Any disbursements for additional incidentals incurred by the Consultant in relation to this Retainer Agreement must be pre-approved by THESL in writing. THESL reserves the right to deduct any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Retainer Agreement and remit such amounts to the applicable taxation authority.

5. Confidentiality

All work performed by the Consultant in connection with this Retainer Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Retainer Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of Torys or THESL. The Consultant agrees to designate all written communications and material accordingly. The Consultant further agrees to notify Torys in the event that the Consultant receives a request to disclose information relating to this matter, and agrees to cooperate with Torys, to the fullest extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material. If Consultant is requested or compelled to testify as a witness in any legal proceeding related to its services under this Agreement other than Application Support, by subpoena or otherwise, or it is made a party to any litigation related to this Agreement, Torys shall compensate, or shall cause THESL to compensate, Consultant at its standard billing rates for its professional fees and expenses, including reasonable attorneys' fees (internal and external), involved in responding to such action.

The Consultant agrees to hold in confidence: (a) all information provided to the Consultant, and (b) the Consultant's opinions to Torys and to THESL as they relate to the information, whether the information or opinions are documentary or oral (collectively, the "Confidential Information"). The Consultant will not disclose the Confidential Information to any person unless Torys or THESL authorizes you in writing to do so. All documents given to the Consultant in connection with this Retainer Agreement remain the property of Torys or of THESL, and are held in trust the Consultant as agent. The Consultant agrees to return these documents on request.

The Consultant will not refer to Torys or to THESL, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of Torys or THESL, as the case may be.

6. Intellectual Property
Nothing in this Retainer Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to THESL or any of its representatives or any third party whose intellectual property is in THESL’s custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of THESL.

Torys and THESL shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Retainer Agreement, including without limitation any reports or other documents created by the Consultant, and any related works, modifications or additions thereto (the “Work Product”), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, subject to Consultant Property, THESL shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to THESL any such rights, and agrees to give THESL and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant’s employees, partners or other representatives. Notwithstanding the foregoing, the Consultant shall retain sole and exclusive ownership of any pre-existing Consultant tools, methodologies, questionnaires, responses, and proprietary research and data, together with all intellectual property rights therein (the “Consultant Property”). Consultant grants to Torys and its client THESL a fully paid up, perpetual, non-exclusive, royalty-free, license to use the Consultant Property contained within the Work Product for the purposes intended in this agreement (including providing the Work Product to the Board).

7. Termination

Torys may terminate this Retainer Agreement at any time on written notice to the Consultant. Torys will pay, or will cause THESL to pay, for work performed up to the date of the notice of termination. Upon the termination or expiration of this Retainer Agreement, the Consultant shall return to Torys and delete any and all electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Retainer Agreement, including all Confidential Information (defined above) and Work Product, whether completed or not.

8. Limitation of Liability

Except for breach of confidentiality obligations, the Consultant’s total liability for any claim arising out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not limited to, loss of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind. With regard to breach of confidentiality obligations, the Consultant’s total liability will not exceed $2,000,000.

9. Independence
By entering into his Retainer Agreement, the Consultant acknowledges and agrees that the Sponsors have received a copy of Rule 13A of the Board’s Rules of Practice and Procedure concerning expert evidence, and agree to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy is attached as Schedule ‘A’ hereto.

10. **Entire Agreement**

This Retainer Agreement, together with all Schedules attached hereto and any agreements and other documents to be delivered pursuant to this Retainer Agreement, constitute the complete agreement between Torys and the Consultant or their respective agents with respect to the subject matter hereof and supersedes any and all prior agreements and understandings. This Retainer Agreement may be amended only in a writing that refers to this Retainer Agreement and is signed by both parties.

11. **THESL Authorization**

Torys represents that THESL has reviewed this agreement, agrees to be bound by the provisions contained herein and has authorized Torys to enter into this agreement on THESL’s behalf.

Sincerely,

TORYS LLP

Per:  
Name:  

Accepted and agreed to by:

Signed  

Name (please print)  

Craig Sabine, Director  

Navigant
SCHEDULE A

Rule 13A of the Board’s Rules of Practice and Procedure

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert’s area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert’s evidence shall, at a minimum, include the following:

(a) the expert’s name, business name and address, and general area of expertise;

(b) the expert’s qualifications, including the expert’s relevant educational and professional experience in respect of each issue in the proceeding to which the expert’s evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert’s evidence relates;

(d) the specific information upon which the expert’s evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert’s evidence, a summary of the points of agreement and disagreement with the other expert’s evidence, and

(f) an acknowledgement of the expert’s duty to the Board in Form A to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in Rule 13A.04 shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the Board;

(c) the costs associated with the conduct of the activities;
(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of
the activities referred to in paragraph (a) of Rule 13A.04; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to
accept, the responsibilities that are or may be imposed on the expert as set out in this Rule 13A and Form
A¹.

¹ Form "A" (Acknowledgement of Expert's Duty) to the Board's Rules of Practice and Procedure requires the
expert witness to acknowledge that it is his or her duty to provide evidence in relation to a proceeding before the
Board as follows:

(a) to provide opinion evidence that is fair, objective and non-partisan;

(b) to provide opinion evidence that is related only to matters that are within his or her area of expertise;

and

(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in

issue.

Form "A" further requires the expert witness to acknowledge that the duty referred to above prevails over any
obligation which he or she may owe to any party by whom or on whose behalf he or she is engaged.
Agreement for Professional Consulting Services

THIS AGREEMENT is made this 1st day of November, 2017,

BETWEEN:

Toronto Hydro-Electric System Limited,

a corporation incorporated under the laws of Ontario

(hereinafter called "Toronto Hydro")

and

Navigant Consulting Ltd.,

a corporation incorporated under the laws of Ontario

(hereinafter called the "Consultant")

1. No Conflict

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice to Toronto Hydro as per the terms of this agreement for professional consulting services (the "Agreement"). The Consultant confirms that it is free to provide its services to Toronto Hydro in connection with its 2020 Custom Incentive Rate application (the "Application"). You agree that during this engagement you will not provide, directly or indirectly, any services to any other party in connection with the matters at issue in the Application.

2. Consultant Expertise

The Consultant has been selected to provide consulting services to Toronto Hydro in connection with the Application, namely by conducting a system losses calculation for the large user customer class. The sponsors of the work of the Consultant and the persons who have the relevant expertise will be Eugene Shlatz, Benjamin Grunfeld, Andrea Roszell, and Michael De Paolis (the “Sponsors”).

3. Scope of Services and Work Product

The Consultant will:

(a) conduct a system losses calculation that meets the requirements described in Toronto Hydro’s Request for Proposals No. 17P-072 (the “Study”);
(b) produce a written report detailing the Study’s methodology, analysis performed and the ensuing findings and recommendations (the “Report”), which may be filed with the Ontario Energy Board (the “Board”) in the Application; and

(c) if requested by Toronto Hydro, provide support during the hearing of the Application and testify before the Board in the Application, in connection with the scope of the services provided hereunder (“Application Support” and, together with the Study and the Report, the “Services”).

4. Fees and Invoices

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<th>Resource Type</th>
<th>High Level Tasks Description</th>
<th>Estimate Hours</th>
<th>Resource Type Hourly Cost ($/hour)</th>
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All amounts stated herein are in Canadian dollars.

The Consultant shall direct all invoices relating to Services performed by it under this Agreement to Toronto Hydro, to the attention of:

Mr. Elias Lyberogiannis  
Director, Engineering Planning  
Toronto Hydro Electric-System Limited  
500 Commissioners St  
Toronto, Ontario M4M 3N7  
clyberogiannis@torontohydro.com
Consultant’s invoices are due upon receipt and payment is expected within 30 days of the invoice date. Toronto Hydro is responsible for payment to Consultant. Any objection to the invoice must be made within 60 days after the date of the invoice; lack of timely objection to an invoice shall evidence Toronto Hydro’s agreement to all invoiced amounts. Any disbursements for additional incidentals incurred by the Consultant in relation to this Agreement must be pre-approved by Toronto Hydro in writing. Toronto Hydro reserves the right to deduct any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Agreement and remit such amounts to the applicable taxation authority.

5. Confidentiality

All work performed by the Consultant in connection with this Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of Toronto Hydro. The Consultant agrees to designate all written communications and material accordingly. The Consultant further agrees to notify Toronto Hydro in the event that the Consultant receives a request to disclose information relating to this matter, and agrees to cooperate with Toronto Hydro, to the fullest extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material. If Consultant is requested or compelled to testify as a witness in any legal proceeding related to its services under this Agreement other than Application Support, by subpoena or otherwise, or it is made a party to any litigation related to this Agreement, Toronto Hydro shall compensate the Consultant at its standard billing rates for its professional fees and expenses, including reasonable attorneys’ fees (internal and external), involved in responding to such action.

The Consultant agrees to hold in confidence: (a) all information provided to the Consultant, and (b) the Consultant’s opinions to Toronto Hydro as they relate to the information, whether the information or opinions are documentary or oral (collectively, the “Confidential Information”). The Consultant will not disclose the Confidential Information to any person unless Toronto Hydro authorizes you in writing to do so. All documents given to the Consultant in connection with this Agreement remain the property of Toronto Hydro, and are held in trust the Consultant as agent. The Consultant agrees to return these documents on request.

The Consultant will not refer to Toronto Hydro, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of Toronto Hydro.

6. Intellectual Property

Nothing in this Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to Toronto Hydro or any of its representatives or any third party whose intellectual property is in Toronto Hydro’s custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of Toronto Hydro.

Toronto Hydro shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Agreement, including without limitation any reports or other documents created by the Consultant, and any related works, modifications or additions thereto (the “Work Product”), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, subject to Consultant Property, Toronto Hydro shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to Toronto Hydro any
such rights, and agrees to give Toronto Hydro and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant’s employees, partners or other representatives. Notwithstanding the foregoing, the Consultant shall retain sole and exclusive ownership of any pre-existing Consultant tools, methodologies, questionnaires, responses, and proprietary research and data, together with all intellectual property rights therein (the “Consultant Property”). Consultant grants to Toronto Hydro a fully paid up, perpetual, non-exclusive, royalty-free, license to use the Consultant Property contained within the Work Product for the purposes intended in this agreement (including providing the Work Product to the Board.)

7. Termination

Toronto Hydro may terminate this Agreement at any time on written notice to the Consultant. Toronto Hydro will pay for work performed up to the date of the notice of termination. Upon the termination or expiration of this Agreement, the Consultant shall return to Toronto Hydro and delete any and all electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Agreement, including all Confidential Information (defined above) and Work Product, whether completed or not.

8. Limitation of Liability

Except for breach of confidentiality obligations, the Consultant’s total liability for any claim arising out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not limited to, loss of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind. With regard to breach of confidentiality obligations, the Consultant’s total liability will not exceed $2,000,000.

9. Independence

By entering into this Agreement, the Consultant acknowledges and agrees that the Sponsors have received a copy of Rule 13A of the Board’s Rules of Practice and Procedure concerning expert evidence, and agree to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy is attached as SCHEDULE A hereto.

10. Entire Agreement

This Agreement, together with all schedules attached hereto and any agreements and other documents to be delivered pursuant to this Agreement, constitute the complete agreement between Toronto Hydro and the Consultant or their respective agents with respect to the subject matter hereof and supersede any and all prior agreements and understandings. This Agreement may be amended only in a writing that refers to this Agreement and is signed by both parties.
IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the date first written above:

Navigant Consulting Ltd.

Per:  
Name:  Benjamin Grunfeld  
Title:  Managing Director  
I have authority to bind the Consultant.

Toronto Hydro-Electric System Limited

Per:  
Name:  Elias Lyberogiannis  
Title:  Director, Engineering Planning  
I have authority to bind Toronto Hydro.
SCHEDULE A

Rule 13A of the Board’s Rules of Practice and Procedure

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert’s area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert’s evidence shall, at a minimum, include the following:

(a) the expert’s name, business name and address, and general area of expertise;

(b) the expert’s qualifications, including the expert’s relevant educational and professional experience in respect of each issue in the proceeding to which the expert’s evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert’s evidence relates;

(d) the specific information upon which the expert’s evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert’s evidence, a summary of the points of agreement and disagreement with the other expert’s evidence; and

(f) an acknowledgement of the expert’s duty to the Board in Form A to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in Rule 13A.04 shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the Board;

(c) the costs associated with the conduct of the activities;
(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of Rule 13A.04; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this Rule 13A and Form A.1.

---

1 Form “A” (Acknowledgement of Expert’s Duty) to the Board’s Rules of Practice and Procedure requires the expert witness to acknowledge that it is his or her duty to provide evidence in relation to a proceeding before the Board as follows:

(a) to provide opinion evidence that is fair, objective and non-partisan;
(b) to provide opinion evidence that is related only to matters that are within his or her area of expertise; and
(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

Form “A” further requires the expert witness to acknowledge that the duty referred to above prevails over any obligation which he or she may owe to any party by whom or on whose behalf he or she is engaged.
Project Initiation Form (PIF)

13 June 2017

The objective of this Project Initiation Form (PIF) is to confirm the scope of our work and our fees. The terms and conditions provided in our existing Engagement Letter with Toronto Hydro Corporation apply, however, with respect to the services described here, should there be any difference between existing terms and conditions and those outlined here, the terms and conditions outlined in this PIF will apply.

Project Details

1. Client name: Toronto Hydro Corporation
2. Project name or services: 2017 Total Remuneration Review
3. Description of Mercer responsibilities:

To assist THC in understanding its overall positioning relative to the markets it competes with for talent, Mercer will work with THC to complete executive, management/staff, and represented employee total remuneration reviews, encompassing cash compensation, active employee benefits and pensions as defined below.

Executive Compensation Review
We will conduct a market review of Toronto Hydro's executive compensation program using the following approach:

Step 1 – Comparator Group Confirmation:
•

Step 2 – Market Analysis and Recommendations:
•
Step 3 – Preliminary Report

Step 4 – Presentation to Board / Committee:
- Be available to attend a Board or Committee meeting to discuss the report.

Step 5 – Update 2015 Mercer Report to the City of Toronto:
- Mercer will refresh the previous March 2015 report to the city of Toronto ("City Manager Proposal" on executive compensation) and supplement with new information as appropriate

Executive Job Descriptions
We will assist in the updating of executive job descriptions to ensure that accurate information regarding accountabilities and skills is available for the completion of the total remuneration reviews using the following approach:

-
Benefits and Pension Relative Value Analysis

- 
- 
- 
- 
- 

Non-Executive Compensation Review
Step 1 – Benchmark Confirmation

- 
- 
- 

Step 2 – Market Research and Analysis

-
Step 3 – Preliminary Report

- 
- 
- 
- 

Step 4 – Presentation to Senior Management / Board / Committee:

- Be available to attend a senior management team, Board or Committee meeting to discuss the reports.

4. Description of client responsibilities: Provide Mercer access to necessary data and information (including executive compensation data needed from [redacted]) as required. Be available to answer questions.

5. Estimated period of time over which work will be performed: May 2017 to 30th September 2017
Fee Structure

Mercer's estimated compensation for the services will be professional fees in the amount of CAD [redacted]. This includes:

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<tr>
<th>Project Component</th>
<th>Estimated Fees</th>
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<tr>
<td>Executive Compensation Review</td>
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<tr>
<td>Executive Job Descriptions</td>
<td>[redacted]</td>
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<tr>
<td>Non-Executive Compensation Review</td>
<td>[redacted]</td>
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<tr>
<td>Benefits &amp; Pension Relative Value Analysis</td>
<td>[redacted]</td>
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<tr>
<td>TOTAL</td>
<td>[redacted]</td>
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In addition to such compensation, Mercer also bills for necessary travel and other expenses related to the services requested.

We appreciate the opportunity to continue to work with Toronto Hydro Corporation. Please acknowledge your agreement to the project terms by sending us a reply e-mail.

**MERCER (CANADA) LIMITED**

By: [Signature]

Name: Alex Bell  Date: 31 June 2017

Title: Principal
Agreement for Purchase of Services

THIS AGREEMENT is made this 1st day of June, 2015,

BETWEEN:

Toronto Hydro-Electric System Limited,
a corporation incorporated under the laws of the Province of Ontario
(hereinafter called "Toronto Hydro")

and

Innovative Research Group Inc.
a corporation incorporated under the laws of the Province of Ontario
(hereinafter called the "Vendor")

WHEREAS:

A. Toronto Hydro requires the supply of market research services as detailed in SCHEDULE A (collectively, the “Services”);

B. the Vendor carries on business as a full-service marketing and social survey research firm and has indicated to Toronto Hydro that it has the skill and expertise to provide the Services on the terms and conditions set forth herein;

C. the Vendor has agreed to provide the Services to Toronto Hydro and Toronto Hydro has agreed to purchase the Services, upon the terms and conditions as set forth below; and

D. this Agreement is issued in connection with RFP #15P-005 dated January 23, 2015 (the “RFP”), including any schedules, attachments, amendments, supplements or addenda thereto and the Vendor’s submission in response thereto dated February 12, 2015 (the “Proposal”).

NOW THEREFORE, in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. Interpretation

   a) All capitalized terms in this Agreement shall have the meaning as defined in SCHEDULE C;

   b) The recitals hereto shall form an integral part of this Agreement as if specifically restated herein;
c) Words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

d) The word “including” shall mean “including without limitation”;

e) Any reference to a statute shall mean the statute in force as of the date hereof, together with all regulations promulgated thereunder as may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise provided;

f) When calculating a period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded, and if the last day of such period is a Saturday, Sunday or statutory holiday, the period shall end on the next Business Day;

g) All dollar amounts in this Agreement are expressed in Canadian dollars, unless otherwise stated;

h) The division of this Agreement into separate articles, sections, subsections and Schedules and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement; and

i) Save and except as otherwise expressly defined within the body of this Agreement or in SCHEDULE C hereto, words or abbreviations which have well known or trade meanings are used herein in accordance with their recognized meanings.

2. Schedules, Exhibits and Appendices

The following schedules are attached to and form part of this Agreement:

   a) SCHEDULE A - Services Required

   b) SCHEDULE B - Purchase Price

   c) SCHEDULE C - Defined Terms

   d) SCHEDULE D - Privacy Terms and Conditions

In the event of a conflict between the terms of any schedule, exhibit or appendix, except for Schedule D - Privacy Terms and Conditions, and the terms of this Agreement, the terms of this Agreement shall govern.

3. Purchase and Sale

Subject to the terms and conditions of this Agreement, and in reliance on the representations, warranties and conditions set forth in this Agreement, Toronto Hydro agrees to purchase the Services from the Vendor and the Vendor agrees to supply the Services to Toronto Hydro during the Term of this Agreement.

4. Term
a) Subject to any termination rights herein, this Agreement shall be for a term of three (3) years, from June 1, 2015 to May 31, 2018 (the "Initial Term").

b) Toronto Hydro may, at its sole option, elect to renew this Agreement for up to two (2) additional one (1) year terms (each a "Renewal Term") by giving written notice to the Vendor at least sixty (60) days before the end of the Initial Term or the first Renewal Term (as applicable). The same terms and conditions contained herein shall apply during the Renewal Term(s), save and except as amended in writing by the parties.

c) The Initial Term and the Renewal Term(s), if any, shall hereinafter together be referred to as the "Term".

5. Price and Payment

a) The prices for the Services shall be as specified in SCHEDULE B hereto and, except as otherwise provided, shall be in Canadian dollars DDP Toronto Hydro's location (INCOTERMS 2010), and shall represent the total cost to Toronto Hydro, excluding any value added taxes (including HST but including without limitation all other applicable taxes, duties, packaging, handling and delivery costs. Toronto Hydro shall withhold any applicable non-resident withholding taxes from any amount owing in this Agreement and remit such taxes to the appropriate federal taxing authority. If no price is stipulated in this Agreement, the price must not exceed the last previous quotation made by the Vendor to Toronto Hydro for the same Services.

b) Unless otherwise provided in this Agreement, the Vendor shall invoice Toronto Hydro after final inspection and acceptance by Toronto Hydro of the Services supplied and subject to receipt of all documents required by this Agreement. **Invoices must be sent electronically to: TH-AP@opiscnu.com and ap@torontohydro.com**. Subject to approval of the invoice by Toronto Hydro and subject to receipt of all documents required by this Agreement and final inspection by Toronto Hydro, Toronto Hydro shall make payment to the Vendor via electronic funds transfer not later than thirty (30) days following receipt of an acceptable invoice and the EFT Information (as set out below). In order for Toronto Hydro to make payment to the Vendor via electronic funds transfer, the Vendor must provide Toronto Hydro with, in the case of the first payment only, (i) a void cheque, pre-printed deposit slip or bank confirmation letter and (ii) the email address where the Vendor wishes to receive remittance information (together, “EFT Information”). EFT Information must be sent electronically to efthelp@torontohydro.com or to 14 Carlton Street, Toronto, ON, M5B 1K5, Attention: Treasury Department.

6. Delivery of Services

a) All Services shall be performed in accordance with the terms, specifications and schedules included in SCHEDULE A. The Vendor shall immediately notify Toronto Hydro, in writing, of any circumstances known or suspected that may cause delay in the delivery of the Services. Unless otherwise agreed in writing, Toronto Hydro will not accept deliveries in excess of those specified in this Agreement and such deliveries shall be entirely at the Vendor’s risk and may be returned by Toronto Hydro to the Vendor at the Vendor’s sole cost and expense.

b) In the event of any question, dispute, disagreement or difference of opinion between Toronto Hydro and the Vendor relating to the quality or acceptability or rate of progress of any Services or relating to the interpretation of the specifications in SCHEDULE A or the performance of this Agreement,
the opinion of Toronto Hydro or its authorized Representative shall govern and be binding on the parties hereto.

7. Invoice Requirements

The Vendor shall submit invoices to Toronto Hydro in accordance with Section 5 of this Agreement and the payment terms as set out in SCHEDULE B. Each invoice shall contain:

a) a detailed description of the Services performed during the invoice period;

b) the dates and the amount of time spent by the Vendor for the provision of the Services;

c) the hourly rates;

d) the total HST applicable to the Services during the invoice period, as well as the Vendor’s HST registration number; and

e) a detailed description of any applicable disbursements incurred around the invoice period, supported by documentation in a form acceptable to Toronto Hydro.

8. Inspection

All Services performed will be subject to final inspection and approval by Toronto Hydro after performance, notwithstanding any prior payment. In the event that Services are performed which are not in conformity with the terms and conditions and specifications of this Agreement, Toronto Hydro may, at its option:

a) reject the Services and require the Vendor to immediately re-perform the Services;

b) negotiate with the Vendor an agreeable reduction in the price of the delivered, non-conforming Services;

c) rework, or cause to be reworked, the delivered, non-conforming Services. at the Vendor’s expense, which expense shall constitute a proper set-off by Toronto Hydro against amounts otherwise due to the Vendor under this Agreement; or

d) reject the Services and require a repayment of applicable amounts for such deliverables.

9. Representations, Warranties and Covenants

The Vendor represents and warrants to Toronto Hydro that:

a) it has the corporate power and authority to enter into this Agreement and to perform its obligations hereunder, and that this Agreement constitutes a legal, valid, and binding obligation of the Vendor, enforceable against the Vendor in accordance with its terms;

b) the Vendor, after conducting due diligence, is not aware of any actions, suits or other legal proceedings which may affect its ability to perform this Agreement;
c) the Services shall be performed in a professional, diligent and competent manner and shall meet or exceed those standards generally observed by reputable and competent members of the same industry providing similar services;

d) it is an expert, trained, equipped and capable in providing the Services and shall only use reliable, qualified and Competent Persons to perform the Services;

e) it is in compliance with and has paid, and will continue to pay, all assessments and other amounts owing pursuant to the WSIA; and

f) it is satisfied with the conditions under which the Services will be performed, and shall assume full responsibility for understanding the conditions of supply, operations, and service.

10. Warranty

All Services shall be in compliance with all Applicable Laws and will conform to the specifications, drawings, samples, symbols or other descriptions as specified in SCHEDULE A hereto and will be fit and sufficient for their intended purpose, merchantable and free from defects in material and workmanship. This warranty is in addition to all other warranties specified in SCHEDULE A or implied by law and shall survive acceptance and payment.

11. Personnel

(a) Subject to Section (c) below, the Vendor shall ensure that all personnel designated as required resources ("Required Resources") in this Agreement shall be made available according to the allocations described therein.

(b) Any adjustment by the Vendor to the Required Resources shall be subject to the following:

a. Subject to Section (c) below, the Vendor shall not substitute or remove a Required Resource at any time without the prior written consent of Toronto Hydro, not to be unreasonably withheld, unless: (A) any such Required Resource terminates his/her employment with the Vendor, or (B) the security of Toronto Hydro’s information is at risk and there is no opportunity to obtain prior written consent in such circumstances;

b. The Vendor shall ensure that each resource substituted for a Required Resource is at a job seniority level and skill level equivalent to or higher than those of the Required Resource;

c. The Vendor shall ensure that each resource substituted for a Required Resource is introduced in sufficient time prior to the departure of such Required Resource (the “Overlap Period”) so as to learn or become familiar with: (A) the implementation and development of the Services, and (B) those skills and duties necessary to function in place of such Required Resource. All costs incurred in relation to the Overlap Period shall be paid by the Vendor; and

d. The Vendor shall provide Toronto Hydro, if requested by Toronto Hydro, with copies of the current curriculum vitae of each Required Resource prior to the assignment of such Required Resource. The Vendor shall ensure that the Vendor has obtained the written consent of all Required Resources to provide Toronto Hydro with the foregoing information and that Toronto Hydro may distribute such information internally to others employed in connection with the development and implementation of the Services, as
required (excluding any personnel, contractors or other individuals employed by or affiliated with a competitor of the Vendor).

(c) Notwithstanding Section (a) and (b)(i) above, the Parties acknowledge that the Vendor may only substitute the maximum number of Required Resources.

(d) The Vendor shall also inform Toronto Hydro of turnover of all personnel within their organization that is connected to the Services being provided by the Vendor to Toronto Hydro (whether a Required Resource or not) in a timely fashion, but in no case longer than five (5) Business Days from such effective termination, in order to allow Toronto Hydro to make arrangements for its protection.

12. Health and Safety

The Vendor shall be responsible for:

a) managing the health and safety of its own personnel and other Representatives;

b) ensuring compliance with all Applicable Laws related to health and safety, including without limitation the OHSA; and

c) ensuring that its personnel and other Representatives are aware of any safety hazards involved in working in or around Toronto Hydro’s facilities and all Applicable Laws with respect thereto.

Neither Toronto Hydro, nor its Representatives, shall be liable for any loss, damages or claims arising directly or indirectly from the Vendor’s work in or around Toronto Hydro’s facilities, and the Vendor hereby waives any claims to which it may become entitled for loss or damage and releases Toronto Hydro and its Representatives from any and all such claims.

13. Permits and Applicable Laws

a) The Vendor shall, at its sole expense, obtain and maintain during the Term of this Agreement, all permits, licences and approvals required by all Applicable Laws to perform its obligations under this Agreement. The terms and conditions of this Agreement shall be carried out in strict compliance with all Applicable Laws and in the event of any conflict between any Applicable Laws, the Applicable Laws with the most stringent standard shall apply.

b) Without limiting the generality of subsection 13(a) above, the Vendor shall comply with the Privacy Terms and Conditions attached as SCHEDULE D hereto.

14. Compliance with Guidelines

The Vendor’s personnel shall comply with all rules and direction of Toronto Hydro, whether specified in this Agreement or otherwise, while working on Toronto Hydro’s premises, distribution system or when accessing or connecting to Toronto Hydro’s information technology systems, including rules and directions concerning health, safety, security and environmental protection, including without limitation, Toronto Hydro’s Code of Business Conduct, Toronto Hydro’s Disclosure Policy, Toronto Hydro’s Social Media and Digital Communication Guidelines, Toronto Hydro’s Workplace Harassment Policy, Toronto Hydro’s Violence Prevention in the Workplace Policy, Toronto Hydro’s Environmental Policy, Toronto Hydro’s Occupational Health & Safety Policy, Toronto Hydro’s Privacy Policy Statement, Toronto Hydro’s Cyber Security Policy, Toronto Hydro’s Technology Use Guidelines and the Affiliate Relationships Code for
Electricity Distributors and Transmitters issued by the OEB (together, the “Guidelines”). The Vendor acknowledges that it has been provided with a copy of the Guidelines, has provided and will provide a copy of the Guidelines to each of its Representatives and that it agrees to comply with and to direct its Representatives to comply with such Guidelines, as amended.

15. Liability and Indemnification

The Vendor shall be liable for and shall indemnify and hold harmless Toronto Hydro and its Representatives from all claims, demands, actions, penalties, damages, losses, judgments and settlements, liabilities, costs, expenses, including legal fees and other related costs and expenses arising out of, related to, or incident to, the Vendor or any of its Representatives’ performance of the Services under this Agreement, including, without limitation:

a) any breach, violation or non-performance by the Vendor or any of its Representatives of any terms, conditions, warranties, obligations or covenants contained in this Agreement;

b) any breach or violation by the Vendor or any of its Representatives of any Applicable Laws; and

c) any actions, omissions, negligence or wilful misconduct of the Vendor or any of its Representatives.

16. Insurance

Unless otherwise specified in this Agreement, the Vendor shall, during the Term of this Agreement, and at its own expense, maintain and keep in full force and effect:

a) commercial general liability insurance on an occurrence basis having a minimum inclusive coverage limit, including personal injury and property damage, of not less than five million dollars ($5,000,000.00) per occurrence, which shall be extended to cover contractual liability, products and completed operations liability, owners/contractors protective liability and must also contain a cross liability clause and a severability of interest clause, and must name Toronto Hydro and its Affiliates as additional insureds; and

b) automobile liability insurance on all owned and non-owned vehicles used in connection with this Agreement and such insurance coverage shall have a limit of not less than two million dollars ($2,000,000.00) per vehicle, in respect of bodily injury (including passenger hazard) and property damage inclusive of any one accident and mandatory accident benefits.

All insurance coverages and limits required to be maintained by the Vendor shall be primary to any insurance maintained by Toronto Hydro, which shall be excess and non-contributory. Prior to the commencement of the delivery of the Services, the Vendor shall deliver to Toronto Hydro a certificate of insurance which evidences the Vendor’s compliance with this Section, including the provision of a thirty (30) day prior written notice of cancellation, non-renewal or adverse material change, to Toronto Hydro. The Vendor agrees that the insurance described herein does in no way limit the Vendor’s liability pursuant to the indemnity provisions of this Agreement.

17. Subcontractors

The Vendor may only subcontract any of the Service under this Agreement with the prior written consent of Toronto Hydro. If subcontracting is permitted, the Vendor shall enter into agreements with such subcontractors to require them to perform the Services in accordance with all Applicable Laws and the terms of this Agreement and the Vendor shall be liable for any acts or omissions of such subcontractors as
if such acts or omissions were those of persons directly employed by the Vendor. The Vendor agrees to incorporate the terms of this Agreement into all subcontract agreements with its subcontractors. Any subcontract shall not relieve the Vendor from any of its obligations or liabilities under this Agreement.

18. **Termination**

a) Toronto Hydro may, for its convenience and at its sole option, terminate this Agreement by providing at least sixty (60) days prior written notice of such termination. Upon issuance of such notice, the Vendor shall stop performance of the Services under this Agreement, except as may be necessary to carry out such termination and take any other action which Toronto Hydro may reasonably direct. Upon a termination for convenience, Toronto Hydro shall pay for such Services requested and accepted by Toronto Hydro up until the effective date of such termination. Toronto Hydro shall not be liable to the Vendor for any other costs or damages whatsoever arising from such termination, including without limitation, any indirect, consequential or special damages such as a loss of profit or loss of opportunity.

b) If the Vendor fails to fulfil any covenant or material obligation under this Agreement, including, without limitation, the failure to meet the delivery schedule or any specification contained herein, or breaches any representation or warranty contained herein, then Toronto Hydro may, without prejudice to any other right or remedy Toronto Hydro may have, notify the Vendor in writing that the Vendor is in default of its contractual obligations and instruct the Vendor to correct the default within five (5) Business Days immediately following the receipt of such notice. If the Vendor fails to correct the default in the time specified, then, without prejudice to any other right or remedy Toronto Hydro may have, Toronto Hydro may either correct such default and deduct the cost thereof from any payment then or thereafter due to the Vendor and/or terminate this Agreement.

c) If bankruptcy or insolvency proceedings are instituted by or against the Vendor or the Vendor is adjudicated a bankrupt, becomes insolvent, makes an assignment for the benefit of creditors or proposes or makes arrangements for the liquidation of its debts, or a receiver or receiver and manager is appointed with respect to all or part of the assets of the Vendor, Toronto Hydro may, without prejudice to any other rights or remedies it may have, immediately terminate this Agreement.

d) The termination of this Agreement shall not affect any rights or obligations which may have accrued prior to such termination or any other rights which the terminating party may have arising out of either the termination or the event giving rise to the termination.

19. **Time of the Essence**

Time is of the essence in this Agreement. The Vendor shall perform all Services in accordance with the dates and times for performance and delivery specified in SCHEDULE A hereto and Toronto Hydro shall have the right to take possession of and use any completed or partially completed portions notwithstanding any provisions expressed or implied to the contrary.

20. **Force Majeure**

a) As used herein, “Force Majeure” means events beyond the reasonable control of a party applying reasonable diligence and foresight given the nature of the Services being provided under the Agreement, including, as applicable, any acts of God and the public enemy, the elements; fire; accidents; vandalism; sabotage; power failure; strikes, lockouts or any other industrial, civil or public disturbances; any laws, orders, rules, regulations, acts or restraints of any government or
governmental body or authority, civil or military, including the orders and judgments of courts and any other similar causes or acts.

b) If, by reason of Force Majeure, either party hereto (the “Frustrated Party”) is delayed or unable, in whole or in part, to perform or comply with any obligation or condition of this Agreement, then it will be relieved of liability and will suffer no prejudice for failing to perform or comply or for delaying such performance or compliance during the continuance and to the extent of the inability so caused from and after the happening of the event of Force Majeure, provided that it gives to the other party prompt notice of such inability, reasonably full particulars of the cause thereof and the expected cessation. If notice is not promptly given, then the Frustrated Party will only be relieved from performance or compliance from and after the giving of such notice. The Frustrated Party will use its best efforts to remedy the situation and remove, so far as possible with reasonable dispatch, the cause of its inability to perform or comply, provided, however, that settlement of strikes, lockouts and other industrial disputes shall be within the discretion of the Frustrated Party. The Frustrated Party will give prompt notice of the cessation of Force Majeure. If at any time the Vendor cannot deliver the Services required to be provided pursuant to the Agreement due to Force Majeure, Toronto Hydro may engage any other party to provide such Services which the Vendor cannot provide. The benefit of this provision of Force Majeure shall only survive for thirty (30) days from the commencement of an event of Force Majeure. A requirement to disclose Confidential Information other than under Canadian law pursuant to the terms of this Agreement shall not be an event of Force Majeure. A failure by a sub-contractor to perform shall not be an event of Force Majeure for a Frustrated Party unless such sub-contractor is itself suffering from an event of Force Majeure and the provisos set forth above are followed.

21. Intellectual Property Protection

The Vendor expressly warrants that the manufacture, delivery, sale or use of the Vendor’s Services will not infringe any Canadian or foreign patents, trademarks, copyrights, industrial design or other intellectual property rights and the Vendor shall indemnify and save Toronto Hydro harmless from all claims, judgments and decrees that may be entered against Toronto Hydro or its Representatives and against all damage, liability, costs and expenses (including legal fees and other attendant costs and expenses) Toronto Hydro incurs by reason of any infringement or claim thereof.

22. Confidential Information

The parties agree and acknowledge that, subject to Applicable Laws or court order,

a) each party (the "Receiving Party") shall maintain in strict confidence the terms of this Agreement and any and all proprietary and confidential information about the business, operations or customers of the other party or any of their Affiliates, which it acquires in any form from the other party (the "Disclosing Party") by virtue of this Agreement ("Confidential Information") and will not disclose to any third party or make use of such Confidential Information for itself or any third party without the prior written consent of the Disclosing Party;

b) the Receiving Party may disclose such Confidential Information to any of the Representatives of the Receiving Party or any of its Affiliates who agree to be bound by the obligations of confidentiality herein and who have a reasonable need to know such Confidential Information in the course of their duties for the Receiving party but only for the purposes of the Receiving party exercising its rights and obligations under this Agreement;
c) Toronto Hydro is subject to MFIPPA and is governed by governmental authorities such as the OPA and the OEB and shall have the right to disclose Confidential Information in accordance with the provisions of MFIPPA or as required by the OPA or the OEB;

d) a party shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with any breach of obligations pursuant to this section;

e) the Receiving Party shall be responsible for any breach of this Agreement by it and its Representatives and by any other person to whom it discloses any Confidential Information. The Parties agree that the Disclosing Party would be irreparably injured by a breach of this Agreement by the Receiving Party, or by any person to whom it discloses any Confidential Information, and that monetary damages would not be a sufficient remedy. Therefore, in such event, the Disclosing Party shall be entitled to all available equitable relief, including injunctive relief without proof of actual damages, as well as specific performance. Such remedies shall not be deemed to be exclusive remedies for a breach of this Agreement but shall be in addition to all other remedies available at law or equity;

f) upon termination of this Agreement, or upon ten (10) days’ prior written notice from the Disclosing Party requesting return of any or all Confidential Information, the Receiving Party shall forthwith return to the Disclosing Party all Confidential Information, including without limitation all copies of any form of the Confidential Information, the Receiving Party has received and, at the option of the Disclosing Party, deliver to the Disclosing Party, or destroy or have destroyed, any copies or other reproductions of the Confidential Information together with all notes, analyses, reports and other written material whatsoever prepared by, or on behalf of, the Receiving Party, from, or in respect of, the Confidential Information; provided that the Receiving Party shall be entitled to keep, subject always to all the provisions of this Agreement, one copy of such notes, analyses, reports or other written material prepared by, or on behalf of, the Receiving Party for its records. The Receiving Party shall provide to the Disclosing Party, upon request, a certificate of an officer of the Receiving Party certifying such destruction; and

g) notwithstanding section 22(a), in the event that the Receiving Party believes it is required by law to disclose, or is requested by a Governmental Authority to disclose, any Confidential Information to a Governmental Authority, the Receiving Party may so disclose; provided that it shall, to the extent permitted by law, first inform the Disclosing Party of the request or requirement for disclosure to allow an opportunity for the Disclosing Party to apply for an order to prohibit or restrict such disclosure.

23. Ownership of the Deliverables

Ownership of the intellectual property rights in the deliverables and ownership of any related tangible deliverables shall vest in Toronto Hydro upon their creation, unencumbered subject only to Toronto Hydro’s obligation to pay for such deliverables in accordance with the terms of the Agreement. The Vendor will cause all applicable employees and independent contractors to have waived all moral rights in the applicable deliverables in favour of Toronto Hydro and its successors, assigns and novatees. All electronic source files, printing specifications or other materials used in design production for Toronto Hydro must be returned to Toronto Hydro upon request at no additional charge.

24. Publicity

The Vendor shall not use Toronto Hydro’s (or its Affiliates’) name, corporate logos or trade-marks in advertising or publicity nor the fact that any agreement between the Vendor and Toronto Hydro has been
entered into without Toronto Hydro’s express prior written consent, which may be withheld in the sole discretion of Toronto Hydro.

25. **Toronto Hydro Not Responsible**

Notwithstanding any other provision in this Agreement, Toronto Hydro shall not be responsible for and shall not have control or charge of any means, methods, techniques, sequences or procedures used for or in respect of the Services, or for the safety precautions or programs required for the Services or otherwise prescribed hereunder. Toronto Hydro shall not be responsible for or have control or charge over the acts or omissions of the Vendor, subcontractors (if any) or their agents, employees or other persons performing any of the Services.

26. **Suspension**

Toronto Hydro may, at any time during the term by notice in writing, suspend all or a portion of the Services. Upon receipt of such written notice, the Vendor shall perform no further work other than as directed by Toronto Hydro, and shall be entitled to payment for time spent in performing the Services up to the date of suspension.

27. **No Minimum Volume**

The Vendor acknowledges and agrees that: (i) no portion of this Agreement shall be interpreted as imposing any minimum volume purchase commitment on Toronto Hydro; (ii) this Agreement does not obligate Toronto Hydro to award the procurement of any or all services associated with this Agreement to the Vendor, and services may be added or deleted in Toronto Hydro’s absolute and sole discretion at any time; and (iii) the volume of purchase of the Services may diminish or be eliminated prior to the termination date of this Agreement without any liability on the part of Toronto Hydro, including but not limited to any claims by the Vendor for loss of anticipated profits.

28. **Non-Exclusive Agreement**

It is expressly understood that this Agreement is non-exclusive with respect to the Vendor and Toronto Hydro. Toronto Hydro may contract with others for the procurement of the Services described herein in its sole discretion.

29. **Assignment**

Save and except for Toronto Hydro’s right to assign this Agreement to any of its Affiliates, neither party may assign this Agreement or any of its rights or obligations hereunder, in whole or in part, without the prior written consent of the other party, which consent may not be unreasonably withheld.

30. **Relationship of the Parties**

Nothing contained in this Agreement shall be construed to constitute either party as the partner, employee or agent of, or joint venturer with the other party, nor shall either party have any authority to bind the other in any respect, it being intended that each party shall remain an independent contractor of the other. The Vendor is responsible for all deductions and remittances required by law in relation to its employees, including those required for Canada unemployment insurance, workers’ compensation and income tax.

31. **Severability**
In the event that any of the covenants herein shall be held unenforceable or declared invalid for any reason whatsoever, to the extent permitted by law, such unenforceability or invalidity shall not affect the enforceability or validity of the remaining provisions of this Agreement and such unenforceable or invalid portion shall be severable from the remainder of this Agreement.

32. **No Waiver**

A waiver of any provisions of this Agreement shall not constitute either a waiver of any other provisions or a continuing waiver, unless otherwise expressly indicated in writing.

33. **Enurement**

This Agreement and everything contained herein shall enure to the benefit of, and be binding upon, the parties hereto and their respective successors and permitted assigns.

34. **Notice**

All notices, requests, claims, demands and other communications hereunder shall be in writing and shall be deemed (in the absence of evidence of prior receipt) to have been validly and effectively given on the same day if personally served, the next Business Day if sent by facsimile or similar means of recorded communication or on the fifth Business Day next following if sent by registered mail. Notices shall be addressed as follows:

**to Toronto Hydro:**

Name: Carolyn Guthrie  
Title: Supply Chain Specialist  
Address: 601 Milner Avenue, Toronto, ON M1B 2K4  
Telephone: 416-542-2904  
Facsimile: 416-542-2663

with copy to:

Title: Executive Vice President, Regulatory Affairs and General Counsel  
Address: 14 Carlton Street, Toronto, ON M5B 1K5  
Telephone: (416) 542-3000  
Facsimile: (416) 542-2602  
Email: legal@torontohydro.com

**to the Vendor:**

Name: Jason Lockhart  
Title: Vice President  
Address: 56 The Esplanade, Suite 310, Toronto, ON M5E 1A7  
Telephone: 416-642-6340  
Facsimile: 416-640-5988  
Email: jlockhart@innovativeresearch.ca

35. **Governing Law**

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. The parties irrevocably attorn to the jurisdiction of the courts.
of Ontario with respect to any matter arising under or related to this Agreement. Either party can terminate for cause without the obligation to engage in dispute resolution, mediation or arbitration.

36. **Entire Agreement**

   a) This Agreement, including all schedules and appendices referred to herein and subsequent amendments, constitutes the entire agreement between the Vendor and Toronto Hydro relating to the subject matter hereof. This Agreement supersedes the terms of the RFP, the Proposal, any purchase order, and all prior correspondence, representations, warranties, covenants, collateral undertakings, discussions, negotiations, understandings or agreements, oral or otherwise, express or implied, unless otherwise provided in this Agreement.

   b) No modification or amendment to this Agreement shall be binding on Toronto Hydro unless agreed to in writing.

37. **Preparation of the Agreement**

   Notwithstanding the fact that this Agreement was drafted by Toronto Hydro and its legal and other professional advisors, the parties acknowledge and agree that any doubt or ambiguity in the meaning, application or enforceability of any term or provision of this Agreement will not be construed or interpreted against Toronto Hydro or in favour of the Vendor when interpreting such term or provision, by virtue of such fact.

38. **Further Assurances**

   The Vendor agrees to execute such further assurances and documents, including any bills of sale, and to do all such things and actions which shall be necessary or proper for the carrying out of the purposes and intent of this Agreement.

39. **Survival**

   In addition to the terms of this Agreement that by their nature survive the expiry or termination of this Agreement, the terms of Sections 15 (Liability and Indemnification), 21 (Intellectual Property Protection), 22 (Confidential Information), 9 (Representations, Warranties and Covenants), 31 (Severability), 33 (Enurement), 34 (Notice) and 35 (Governing Law) shall survive the expiry or termination of this Agreement for a period of five (5) years.

34. **Execution and Counterparts**

   This Agreement may be executed in any number of counterparts (including by way of facsimile or email) and all of such counterparts taken together shall be deemed to constitute one and the same instrument.
IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the day and year first written above:

**Innovative Research Group Inc.**

Per: [Signature]

Name: [Signature]

Title: President

I have authority to bind the Vendor.

**Toronto Hydro-Electric System Limited**

Per: [Signature]

Name: [Signature]

Title: EVP Chief Customer Care & Conservation Officer

I have authority to bind Toronto Hydro.
SCHEDULE A

Services Required

A. Description of Services

Toronto Hydro requires market research services, including, but not limited to, the following:

- Pre-research consultation
- Survey and script development
- Consumer based research
- Business to Business based research
- Stakeholder based research
- Surveying - phone, in-person, digital, panel
  - Raw data, tables, models, online reporting tools
- Focus groups and interviews.
  - Video interviews, audio files, transcripts
- Screening criteria and quota recommendations
- List procurement and data management
- Reporting
  - Data Models
  - Full written reports
  - Comprehensive slide decks
  - Onsite workshop and presentations
  - Interactive reporting tools
  - Executive briefings
  - Written management summaries
  - Translation services
  - Provide expert opinion to oversight committees or boards.

B. Required Resources

The following members of Innovative Research Group Inc. are available to work on projects for Toronto Hydro.

Jason Lockhart, Vice President (THESL Account Manager)

With a Bachelor of Commerce degree and a Master of Science degree in Managerial Economics, both from Queen’s University, Jason’s electricity experience includes infrastructure siting, conservation program evaluation, public consultation, consumer protection, and communications testing. Jason has managed a number of consumer consultation programs in Ontario to support rate applications, customer satisfaction studies to support Ontario distributor’s OEB Scorecard reporting requirements, as well as research to support the Central Toronto IRRP and the OEB’s ECPA Review.

Greg Lyle, President

As a former Principal Secretary, Greg has built a career at the intersection of public policy, communications and public opinion. With over 25 years of communications and opinion research experience, Greg uses a full range of research tools. Greg’s work includes siting energy infrastructure,
supply mix and electricity pricing models as well as the sale of public utilities. Greg’s research has been highlighted in media across the country and at energy industry conferences.

Susan Oakes, Vice President

Susan Oakes has been providing research-based strategic advice since 1995 to North American and Australian clients both through survey analysis and as also an experienced focus group moderator and executive interviewer. In addition to siting a corporate reputation work for electricity operators, Susan has helped lead a number of Ontario-based distributors, including Toronto Hydro through their customer and stakeholder engagements required for their regulated rate applications with the Ontario Energy Board (OEB).

Colin Whelan, Senior Consultant

With a BA in political science from SFU and an MA in political science from UBC. Colin has managed research projects in the energy sector addressing strategic communications, market assessment, customer engagement, and stakeholder outreach. Specializing in quantitative analysis, in the past Colin has taught research methods at Simon Fraser University (SFU), worked on a wide variety of academic research projects, and worked as a researcher at the BC Legislature.

Zach Finkelstein, Senior Consultant

Zach Finkelstein is a Senior Consultant at Innovative Research Group. Since 2006, Zach has conducted research for a variety of clients in the energy sector. Zach provides a strong qualitative and quantitative skillset to the team, from survey design to SPSS regression and cluster analysis to final report and deck creation. Zach Finkelstein has a Bachelor of Political Science (Honours) degree from McGill University in Montreal, QC.

Steve Hung, Research Consultant

With a BA in Psychology from York University and an MPA from Queen’s University. Steve Hung provides quantitative and qualitative analysis for electricity rate applications, infrastructure refurbishment, and environmental campaigns working with clients such as the Canadian Electricity Association, Canadian Nuclear Association and the Essex Powerlines Corporation. Previously, Steve worked at a Toronto-based health charity, crafting key messages for advocacy campaigns.

Julian Garas, Research Consultant

Julian Garas specializes in qualitative analysis, crafting communications and final reports. Julian completed a postgraduate program in Government Relations and Corporate Communications at Seneca College and a Bachelor of Arts and Contemporary Studies (Honours) from Ryerson University. Recent work in the energy sector includes qualitative analysis for customer consultation programs to support rate applications and consultations to support Integrated Regional Resource Planning (IRRP).


SCHEDULE B

Purchase Price

Pricing for the supply of the Services during the Term, exclusive of applicable taxes, shall be as follows:

A. Telephone Survey Pricing Estimate

The following table details the estimated pricing for a 15 minute (45 question) telephone survey based on 100 Toronto Hydro residential customers and the costs structure for each activity.

<table>
<thead>
<tr>
<th>Activity</th>
<th>$</th>
<th>Cost Structure*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project management:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Survey development:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assume 45 close-ended questions</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CATI system survey programming and testing:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Field work:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assume completing 100 residential telephone interviews</td>
<td></td>
<td></td>
</tr>
<tr>
<td>List procurement:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assume sample of residential telephone numbers provided by Toronto Hydro</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Data management:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assume data preparation for CATI system upload and coding and cleaning for analysis</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Analysis and reporting:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assume statistical analysis, banner table production, report writing in MS PowerPoint</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Presentation:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assumes no travel expenses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Estimated Project Costs</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* Assumes 15 minute (45 question) telephone survey based Toronto Hydro residential customers with variable sample sizes. Altering the audience, questionnaire length would have an impact on the “fixed costs” associated with this hypothetical project.

B. Online Survey Pricing Estimate

The following table details the estimated pricing for a 15 minute (45 question) online survey based on 100 Toronto Hydro residential customers:

<table>
<thead>
<tr>
<th>Activity</th>
<th>$</th>
<th>Cost Structure*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project management:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Survey development:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>---------------------------------------------</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>Assume 45 close-ended questions</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Online survey programming and testing:</th>
<th></th>
<th></th>
</tr>
</thead>
</table>

| Field work:                                 |   |   |
| Assume completing 100 residential online interviews |   |   |

<table>
<thead>
<tr>
<th>List procurement:</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Assume sample of residential email addresses provided by Toronto Hydro</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Data management:</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Assume data preparation for online system upload and coding and cleaning for analysis</td>
<td></td>
<td></td>
</tr>
</tbody>
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<table>
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<tr>
<th>Analysis and reporting:</th>
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<th>Presentation:</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Assumes no travel expenses</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Total Estimated Project Costs |   |   |

* Assumes 15 minute (45 question) telephone survey based Toronto Hydro residential customers with variable sample sizes. Altering the audience, questionnaire length would have an impact on the “fixed costs” associated with this hypothetical project.

### C. Professional Hourly Rates

While most of the Vendor’s pricing is based on fixed cost contracts, from time to time Toronto Hydro may hire the Vendor’s staff for strategic counsel and advisory services. Under this arrangement, staff will bill back their professional time at an hourly rate. The following table contains the hourly rates of staff who will be working for Toronto Hydro under this Agreement:

<table>
<thead>
<tr>
<th>INNOVATIVE Project Team</th>
<th>Hourly Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jason Lockhart, Vice President (THESL Account Manager)</td>
<td></td>
</tr>
<tr>
<td>Greg Lyle, President</td>
<td></td>
</tr>
<tr>
<td>Susan Oakes, Vice President</td>
<td></td>
</tr>
<tr>
<td>Colin Whelan, Senior Consultant</td>
<td></td>
</tr>
<tr>
<td>Zach Finkelstein, Senior Consultant</td>
<td></td>
</tr>
<tr>
<td>Steve Hung, Research Consultant</td>
<td></td>
</tr>
<tr>
<td>Julian Garas, Research Consultant</td>
<td></td>
</tr>
</tbody>
</table>
SCHEDULE C

Defined Terms

In this Agreement, the following definitions shall apply:

"Affiliates" shall have the meaning as prescribed in the *Business Corporations Act* (Ontario);

"Agreement" means this Agreement for Purchase of Services, including all Schedules and Appendices hereto and subsequent amendments;

"Applicable Laws" means all federal, provincial and municipal statutes, regulations, codes, by-laws, orders in council, directives, rules, guidelines and ordinances applicable to this Agreement, including without limitation all applicable OEB codes, rules or guidelines;

"Business Day" means a day on which banks are open for business in the City of Toronto, Ontario, but does not include a Saturday, Sunday, or a statutory holiday in the Province of Ontario;

"Competent Persons" shall have the meaning as prescribed in the OHSA;

"Confidential Information" has the meaning prescribed to it in Section 22;

"DDP" shall have the meaning prescribed to it in the Incoterms2010 rules published by the International Chamber of Commerce;

"Disclosing Party" has the meaning prescribed to it in Section 22;

"EFT Information" has the meaning prescribed to it in subsection 5(b);

"Force Majeure" has the meaning prescribed to it in Section 2020;

"Frustrated Party" has the meaning prescribed to it in subsection 20(a);

"Governmental Authority" means any government, legislature, municipality, regulatory authority, agency, commission, department, board or court or other law, regulation or rule-making public entity of similar authority, including, without limitation the OEB;

"Guidelines" has the meaning prescribed to it in Section 0;

"HST" means Harmonized Sales Tax;

"Initial Term" has the meaning prescribed to it in subsection 4.1(a);

"MFIPPA" means *Municipal Freedom of Information and Protection of Privacy Act* (Ontario) and the regulations thereunder, each, as amended;

"OEB" means Ontario Energy Board;
"OPA" means Ontario Power Authority;

"OHSA" means *Occupational Health and Safety Act* (Ontario) and the regulations thereunder, each, as amended;

"Proposal" has the meaning prescribed to it in Recital D;

"Receiving Party" has the meaning prescribed to it in Section 22;

"Renewal Term" has the meaning prescribed to it in subsection 4.a);

"Representative" in respect of a party, means such party's directors, officers, employees, agents and contractors, the party's Affiliates, and all such Affiliates' respective directors, officers, employees, agents and contractors;

"Required Resources" has the meaning prescribed to it in subsection 11(a);

"RFP" has the meaning prescribed to it in Recital D;

"Services" has the meaning prescribed to it in Recital A;

"Term" has the meaning prescribed to it in subsection 4.c);

"Toronto Hydro" has the meaning prescribed to in the preamble to this Agreement;

"Vendor" has the meaning prescribed to in the preamble to this Agreement; and

"WSIA" means *Workplace Safety and Insurance Act, 1997* (Ontario) and the regulations thereunder.
SCHEDULE D

Privacy Terms and Conditions

1. Definitions. In these privacy terms and conditions, the following terms have the following meanings, any capitalized terms that are not defined below have the meaning attributed to them in the Agreement and references to Vendor include Authorized Users where appropriate in the context:

(a) “access” in connection with Personal Information means capable of being accessed by a person, whether or not that person has the right or authority under any law or agreement to access the Personal Information;

(b) “Authorized Users” means those employees and representatives of Vendor and of any permitted subcontractors of Vendor who require access to Personal Information for the purpose of providing the Services;

(c) “MFIPPA” means the Municipal Freedom of Information and Protection of Privacy Act (Ontario) and the regulations made thereunder as amended from time to time;

(d) “Personal Information” means information about an identifiable individual including without limitation, his or her gender, marital status, address, telephone number, and identifying numbers such as account numbers to which Vendor has access by virtue of its provision of Services under the Agreement;

(e) “Privacy Law” means MFIPPA and any other statute or regulation, which has as a purpose the protection of Personal Information, to which Toronto Hydro is subject from time to time;

(f) “Privacy Requirements” means collectively, Privacy Law, any written privacy policy of Toronto Hydro that is provided to Vendor from time to time and these privacy terms and conditions;

(g) “store” and “stored” means held, backed up or stored by any means whatsoever, including in hard and electronic formats and includes storage in a server or database or any form of electronic memory;

(h) “use” means to handle Personal Information in any manner, including to copy, download and temporarily hold Personal Information, but not including to de-identify Personal Information.

2. Relationship of the Parties, Application of Privacy Law. Vendor acknowledges and agrees that:
(a) Toronto Hydro is subject to MFIPPA and has legal obligations and restrictions in regard to its collection, use, disclosure and retention of Personal Information;

(b) Vendor is a third party service provider to Toronto Hydro;

(c) the Services provided by Vendor under this Agreement are intended to facilitate Toronto Hydro’s ordinary operations;

(d) it may be necessary for the purpose and in the course of providing the Services, for Vendor to access and use Personal Information on behalf of Toronto Hydro.

3. **Receipt of Privacy Policy.** Vendor acknowledges that it has been provided with a copy of Toronto Hydro’s privacy policy and warrants that it has read that policy.

4. **Ownership of Personal Information.** Nothing in this Agreement provides Vendor with any rights to Personal Information other than the ability to access and use Personal Information as set out in these privacy terms and conditions and Vendor acknowledges and agrees that Personal Information shall remain under the control of Toronto Hydro, including without limitation, when Vendor is using Personal Information to provide the Services or storing Personal Information in accordance with these privacy terms and conditions.

5. **Restrictions Relating to Personal Information.** Vendor shall:

   (a) only access and use Personal Information to the extent required for the purpose of providing the Services and shall not access or use Personal Information on its own behalf or for its own purposes;

   (b) without limiting the generality of the preceding paragraph 5(a), not aggregate or otherwise modify Personal Information for any purpose including without limitation, creating statistics relating to electricity consumption;

   (c) not disclose Personal Information, which for clarity, does not include the provision of Personal Information by Vendor to any of its Authorized Users, which provision of Personal Information shall be a use of that information by Vendor and not a disclosure;

   (d) comply with Privacy Law and Toronto Hydro’s privacy policy, to the extent that they apply to Vendor in its capacity as a service provider to Toronto Hydro, and with these privacy terms and conditions; and

   (e) provide the Services in such manner that its acts or omissions do not result in Toronto Hydro being in violation of the Privacy Requirements.

6. **Notification of Toronto Hydro by Vendor.** Vendor shall immediately give Toronto Hydro written notice:
(a) if it believes that any practice or procedure in which it is engaging in the course of providing the Services contravenes Privacy Law, or if it receives or learns of any complaint or allegation to that effect, but any decision to change any such practice shall be made by Toronto Hydro in its sole discretion;

(b) upon becoming aware of the loss, theft, or unauthorized access, disclosure, copying, use or modification of any Personal Information;

(c) upon becoming aware of any breach of its security, including any potential breach of its systems or the physical security of its premises or equipment, that could have an impact on the security and integrity of Personal Information;

(d) if it receives any privacy-related requests or complaints in relation to the Services;

(e) if it receives any subpoena or foreign order relating to Personal Information; and

(f) of the particulars of the non-compliance and of the steps it proposes to take to address or prevent the non-compliance, if for any reason, Vendor does not comply, or anticipates that it will not be able to comply in any respect with a provision of these privacy terms and conditions.

7. Assistance with Inquiries and Complaints. If Toronto Hydro notifies Vendor that it requires assistance in investigating or responding to any inquiry or complaint with respect to Personal Information (whether or not first received by Vendor), Vendor shall cooperate with Toronto Hydro by:

(a) furnishing it with complete information concerning Vendor's access and use of Personal Information, including responding, if requested to do so, to any inquiry by a privacy regulatory authority and/or to any complaint; and

(b) co-operating in the conduct of any regulatory or court proceedings arising out of a complaint relating to the management of Personal Information, including attending hearings and assisting in securing and giving evidence and obtaining the attendance of witnesses.

8. Requests for Access and Correction. If Vendor receives a request for access to or correction of Personal Information from any person other than Toronto Hydro, Vendor shall direct the requestor to Toronto Hydro.

9. Inspection and Audit. Toronto Hydro or a person appointed by Toronto Hydro or by a privacy regulatory body with jurisdiction over Toronto Hydro may, in addition to any other rights of inspection they may have, at any reasonable time during regular business hours and on reasonable prior notice to Vendor, visit and inspect any location from which Vendor accesses, uses and/or stores Personal Information, to examine all equipment used, and all records maintained, in connection therewith (and to make copies of such records),
to question Vendor’s personnel (including any subcontractors and suppliers), and otherwise to audit and verify, both physically and electronically, compliance by Vendor with these privacy terms and conditions. Vendor shall permit and provide reasonable assistance with any such inspection and audit and shall maintain appropriate information to facilitate the conduct of same. Toronto Hydro shall have no duty to make any such visit, inspection, examination, audit or verification and shall not incur any liability or obligation by reason of doing or not doing so.

10. **Change in Privacy Requirements.** Vendor acknowledges that the Privacy Law and other privacy requirements to which Toronto Hydro is subject may change during the term of the Agreement and to the extent that there are any such changes that affect the Services, Toronto Hydro has the right to amend the Agreement to vary or eliminate any practice or procedure of Vendor that causes Toronto Hydro to be in violation of its privacy requirements, and Vendor shall meet with Toronto Hydro in good faith to address any issues arising out of such amendments made by Toronto Hydro.

11. **Security.** In addition to the other security measures set out in the Privacy Requirements, Vendor shall comply with the following security measures.

(a) Except with the prior written approval of Toronto Hydro, any Personal Information held by Vendor in accordance with these privacy terms and conditions shall be held in a secure physical and electronic environment in Ontario meeting or exceeding then-current industry standards relating to the protection of sensitive personal information.

(b) Except with the prior written approval of Toronto Hydro, Vendor shall ensure that Personal Information is not transferred to any of its Authorized Users while they are outside of Canada or accessed by Authorized Users from outside of Canada.

(c) Promptly upon notice from Toronto Hydro, Vendor shall undertake to remedy any security deficiency or improvement identified or requested by Toronto Hydro that is reasonable under the circumstances and the parties agree to discuss in good faith, responsibility for the costs of any such correction of deficiency or improvement.

(d) Vendor shall ensure the segregation of Personal Information from other data held by Vendor.

(c) Vendor shall maintain appropriate access controls in all circumstances where access to Personal Information is permitted under these privacy terms and conditions.

(f) Vendor shall ensure the security of its information systems and shall periodically review the steps it takes to prevent any unauthorized access to Personal Information.
(g) Vendor covenants to provide Toronto Hydro, prior to the execution of this Agreement and on an annual basis thereafter, with a report outlining its policies and procedures relating to the protection of Personal Information and on request, such reports shall include the names of all Authorized Users.

(h) Vendor shall provide information and assistance to Toronto Hydro, acting reasonably, that Toronto Hydro requires for assessments relating to the Services, including without limitation, privacy impact assessments and threat risk assessments.

(i) Vendor shall ensure that any permitted subcontractor it retains to assist it in providing the Services agrees to comply with these privacy terms and conditions.

(j) Vendor shall log and within twenty-four (24) hours of a request by Toronto Hydro, provide Toronto Hydro with a record of Vendor’s access to Personal Information, which record shall include the date and duration of the access and the identity of the person who accessed the Personal Information.

(k) Vendor shall not, and hereby forever waives any and all right to, withhold any Personal Information from Toronto Hydro to enforce any alleged payment obligation or in connection with any dispute relating to the terms of the Agreement or any other matter between Vendor and Toronto Hydro.

12. Limitation of Access/Use. Vendor shall:

(a) ensure that only such of its employees and representatives and the employees and representatives of any permitted contractor as have a need to know Personal Information for the performance of the Services have access to Personal Information;

(b) ensure that each Authorized User is familiar with the Vendor’s privacy and confidentiality obligations under the Agreement;

(c) take reasonable steps, through training, confidentiality agreements and the application of appropriate sanctions, to ensure compliance by all Authorized Users with Vendor’s privacy and confidentiality obligations under the Agreement; and

(d) ensure that upon termination of employment or affiliation with Vendor, each Authorized User’s ability to access Personal Information is terminated, any and all Personal Information being temporarily held by such Authorized User for the provision of the Services is returned to Vendor and such Authorized User is reminded of his or her continuing obligations with respect to Personal Information and Confidential Information of Toronto Hydro.
13. **Subcontractors.** Vendor shall not retain any third parties to assist it in providing the services unless and until such third parties are approved by Toronto Hydro in writing and have signed a written agreement incorporating the obligations of confidentiality and privacy applicable to Vendor under the Agreement.

14. **Termination by Toronto Hydro.** Toronto Hydro may, without prejudice to any other rights or remedies Toronto Hydro is entitled to at law or in equity, including the right to seek an injunction or other equitable relief in any court of competent jurisdiction enjoining a threatened or actual breach of these privacy terms and conditions by Vendor, terminate the Agreement immediately upon written notice to Vendor if Vendor is not in compliance with the Privacy Requirements.

15. **Return of Personal Information.** In the event of any termination or on the expiry of the Agreement, Vendor shall forthwith return to Toronto Hydro, as directed by Toronto Hydro, any Personal Information being temporarily held or stored by Vendor pursuant to the Agreement (including any copies thereof) or, at Toronto Hydro’s option, destroy all such Personal Information as directed by Toronto Hydro (including any copies thereof), and provide Toronto Hydro with an officer’s certificate attesting to such destruction.

16. **Indemnification.** Vendor shall indemnify and hold harmless Toronto Hydro (which in this section 1616 includes its officers, directors, employees and representatives) from and against any and all claims, demands, suits, losses, damages, causes of action, fines or judgements (including related expenses and legal fees) that it may incur related to or arising from any non-compliance by Vendor with these privacy terms and conditions.

17. **Survival.** Notwithstanding the termination of the Agreement, to the extent that Vendor continues to have access to Personal Information for any reason, Vendor shall continue to govern itself in accordance with these privacy terms and conditions and the obligations of Vendor under these privacy terms and conditions shall survive the expiry or termination of the Agreement until Vendor has terminated its access to Personal Information and destroyed all copies of Personal Information it is temporarily holding or storing pursuant to these privacy terms and conditions.

18. **Conflict.** In the event of a conflict or inconsistency between these privacy terms and conditions and any other part of the Agreement, the provisions of these privacy terms and conditions shall prevail to the extent of the conflict or inconsistency.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 9:

Reference(s): Exhibit 1B, Tab 1, Schedule 1

THESL has filed and Executive Summary and Business Plan Overview. Please file the actual 2020-2024 Business Plan approved by the THESL Board. Please provide a detailed description of the Business Planning process.

RESPONSE:

The Business Plan that underpins this Application and that was approved by the Board of Directors is filed at Appendix A to interrogatory 1A-CCC-1. As this was the final Business Plan leading to the eventual filing of Toronto Hydro’s rate application, it included the penultimate forecasted capital expenditure plan for the full 2020-2024 period. As explained in the following description of business planning, the 2018-2020 Business Plan was a corporate deliverable within the business planning process that led to the final plan filed in this application.

Toronto Hydro’s Business Planning Process for the 2020-2024 Custom IR Application

1. Beginning in late 2016, Toronto Hydro generated a high-level assessment of its operational needs, and undertook a first phase of customer engagement to receive feedback on customer needs and priorities. Please see Exhibit 1B, Tab 3, Schedule 1, for more details about Toronto Hydro’s Phase 1 Customer Engagement.
2. The utility considered the results of this first phase of customer engagement alongside its legal obligations and business input to set its outcomes framework and high-level planning parameters in early 2017.

3. Next, Toronto Hydro proceeded with its operational planning and financial planning (i.e. budgeting) processes, building out and refining a business plan and strategic parameters for 2018-2024 that was completed in November 2017.

4. Toronto Hydro then took this plan back to customers in April and May of 2018, including a detailed breakdown of the plan. Please see Exhibit 1B, Tab 3, Schedule 1, for more details about Toronto Hydro’s Phase 2 Customer Engagement.

5. Taking into account the feedback received in this second phase of Customer Engagement, the utility made additional refinements and adjustments to the plan, including changes to shift funding between certain programs to better reflect customer preferences. The supporting evidence was finalized and the application filed in August 2018. Please see Exhibit 2B, Section E2.3.2.3 and Toronto Hydro’s response to interrogatory 2B-Staff-71, parts (a) and (b) for more details about changes Toronto Hydro made to its plan to reflect customer feedback received during Phase 2.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 10:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 7

The evidence states that THESL has set upper limits of $560 million for the average annual capital plan budget and $277 million for the 2020 operational plan budget. Please set out, in detail, how THESL arrived at these caps. To what extent have the credit balances in the Deferral and Variances influenced the establishment of these caps, if at all?

RESPONSE:
Please refer to Toronto Hydro’s response to 2B-SEC-47. The credit balances in the deferral and variance accounts did not influence the establishment of the upper limits for capital expenditures or OM&A.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 11:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 7

The evidence states that THESL eliminated $75 million per year from its capital plan in response to a price limit of 3% (base rates). Please specifically identify the areas where the reductions were made. What process did THESL undertake to arrive at these reductions? How was the amount of $75 million arrived at?

RESPONSE:
Please refer to Toronto Hydro’s response to interrogatory 2B-Staff-73 part (a) for a comparison of the capital expenditures included in each of the iterations of the capital plan. Exhibit 2B, Section E2.2 describes in detail the process that Toronto Hydro undertook to arrive at these amounts.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 12:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 11

The evidence states that 24% of the utility’s asset base continues to operate beyond useful life, and an estimated 9% will reach that point by 2025. Please explain how these numbers were calculated. Specifically, what process does THESL use to determine whether assets are beyond their useful life? How does THESL define “beyond useful life”?

RESPONSE:

Unless otherwise specified, the term “Useful Life” used throughout Toronto Hydro’s application refers specifically to an asset’s Mean Useful Life (“Mean UL”).

Derivation of Mean Useful Life
For each of its major system asset types, Toronto Hydro derives a Mean UL from the estimated Useful Life Ranges provided in the 2009 Kinectrics report, “Toronto Hydro-Electric System Useful Life of Assets”.¹ The Useful Life Range is defined in part by a Minimum Useful Life (“MIN UL”) and a Maximum Useful Life (“MAX UL”), where the MIN UL is “the age when a small percentage of assets reaches physical end-of-life” and “the failure rate starts increasing exponentially,” and the MAX UL is the “age when most assets reach physical end-of-life.” The Mean UL is the “arithmetic average value of the end-of-life year data” and is equal to the mid-point between the MIN UL and MAX UL.²

¹ Toronto Hydro has provided a copy of this report as Appendix A to its response to interrogatory 2B-SEC-38.
² Kinectrics Report, “Asset Depreciation Study for the Ontario Energy Board” (July 8, 2010) at pages 10 and 159.
Assessing Assets Past Useful Life

Toronto Hydro considers an asset to be operating “beyond” or “past useful life” if it remains in service at an age that is greater than its Mean UL. Toronto Hydro calculates the percentage of Assets Past Useful Life (“APUL”) by comparing the age demographics of its asset population to the Mean UL for each asset class or type.

Please refer to Exhibit 2B, Section E2.2.2.1 for additional information about the Assets Past Useful Life (APUL) metric.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 13:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 16

The evidence states that 23% of THESL’s workforce – or approximately 340 FTEs are forecast to retire between 2020 and 2024. How did THESL arrive at these numbers? Is THESL referring to those employees eligible to retire or actually forecast to retire?

RESPONSE:

As outlined in Exhibit 4A, Tab 4, page 20, Toronto Hydro projects retirements using a combination of age and years of service that when added reach the threshold of 92 (i.e. the “92 Factor”). Given the personal nature of the decision to retire, Toronto Hydro cannot predict when an employee will actually retire. Toronto Hydro uses the 92 Factor to estimate the timing of retirements based on how many individuals meet the threshold in a given year. The threshold is not based on eligibility, although the employees who meet this threshold are eligible to collect an unreduced Ontario Municipal Employees Retirement System ("OMERS") pension by virtue of the criteria under that plan. Rather, the threshold was determined through an analysis of historical retirements, which showed that the 92 Factor approach for projecting retirements produced the most reliable year over year and cumulative results. The results are shown in Table 1 below, and have been updated to include 2018 retirements.
Table 1: 92 Factor Historical Retirement Analysis

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Cumulative</th>
</tr>
</thead>
<tbody>
<tr>
<td>92 Factor Projection</td>
<td>58</td>
<td>38</td>
<td>71</td>
<td>82</td>
<td>80</td>
<td>329</td>
</tr>
<tr>
<td>Actual Retirements</td>
<td>71</td>
<td>37</td>
<td>77</td>
<td>82</td>
<td>72</td>
<td>339</td>
</tr>
</tbody>
</table>
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 14:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 21

The evidence states that THESL has proposed a ratemaking framework for this Application that provides incentives for the utility to seek out further productivity and efficiency improvements over the 2020-2024 period. Please explain how the rate framework incents productivity. Please set out for each year 2015-2019 the productivity gains achieved for both OM&A and Capital. What are the specific productivity initiatives expected for the period for 2020-2024 both with respect to capital and OM&A? Please provide a detailed list.

RESPONSE:

As described in Exhibit 1B, Tab 2, Schedule 1, Toronto Hydro is proposing an incentive-based rate framework that encourages the utility to continuously seek efficiencies. This incentive is created by including the OEB’s productivity factor and a custom stretch factor in the custom Price Cap Index (“PCI”). In doing so, Toronto Hydro is committing to share with its customers the benefits of these efficiencies before they are realized, by directly reducing rates funding. This approach provides customers with a guaranteed, up-front share in productivity generated by the utility.

The evidence in Exhibit 1B, Tab 2, Schedule 1 provides an overview of Toronto Hydro’s historical productivity and performance, including specific examples of productivity and process improvements at Exhibit 1B, Tab 2, Schedule 1, at pages 8 through 20. For additional examples over the 2015-2019 period, please refer to the OM&A program evidence at Exhibit 4A, Tab 2 (Cost Management and Productivity sections of each OM&A...
program and segment), and the Capital program evidence at Exhibit 2B, Sections E5 through E8. Specific interrogatory responses also provide additional details: see for example, Toronto Hydro’s response to 2B-BOMA-77.

The references to the OM&A and Capital programs above also detail examples of the investments and initiatives that will support the utility’s efforts to control costs and increase productivity over the 2020-2024 period. For example, Exhibit 2B, Section A4.4 highlights some of these activities including: grid modernization, capacity improvements, standardization, area rebuilds, conservation first, safety and environmental costs, enhanced work coordination, and facilities asset management system and procurement.

At this time, Toronto Hydro is unable to quantify the estimates of cost savings of the planned initiatives. As part of continuous improvements throughout the plan period, Toronto Hydro intends to evaluate the operational efficiencies gained, as well as the reduced and avoided costs. The cost savings realized will help Toronto Hydro to realize the savings required by the incentive-based rate framework that encourages the utility to continuously seek efficiencies by including the OEB’s productivity factor and a custom stretch factor in the custom PCI, and to deliver on the planned outcomes for customers.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 15:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 31

The evidence refers to the “success of Toronto Hydro’s 2015-2019 capital plan”. Please explain how THESL has determined the 2015-2019 capital plan was “successful”.

RESPONSE:

Table 1 below provides examples of measurable improvements in Toronto Hydro’s performance, including with respect to its capital plan. Toronto Hydro has detailed numerous improvements and successes at both the performance measure and capital program level throughout this application. See, for example, Exhibit 1B, Tab 2; Exhibit 2B, Section C; Exhibit 2B, Sections E5 through E8.

Table 1: Examples of Measurable Improvements

<table>
<thead>
<tr>
<th>Measure</th>
<th>% Improvement</th>
<th>2014</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Box Construction Conversion</td>
<td>43%</td>
<td>5,573</td>
<td>3,151</td>
</tr>
<tr>
<td>Total Recordable Injury Frequency</td>
<td>10%</td>
<td>1.18</td>
<td>1.06</td>
</tr>
<tr>
<td>Number of General Public Incidents</td>
<td>67%</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td>System Capacity</td>
<td>13%</td>
<td>15</td>
<td>13</td>
</tr>
<tr>
<td>SAIDI - Defective Equipment</td>
<td>13%</td>
<td>0.48</td>
<td>0.42</td>
</tr>
<tr>
<td>SAIFI - Defective Equipment</td>
<td>15%</td>
<td>0.53</td>
<td>0.45</td>
</tr>
<tr>
<td>FESI 7 System</td>
<td>67%</td>
<td>36</td>
<td>12</td>
</tr>
<tr>
<td>FESI-6 Large Customers</td>
<td>69%</td>
<td>26</td>
<td>8</td>
</tr>
<tr>
<td>Outages Caused by Defective Equipment (# of Outages)</td>
<td>32%</td>
<td>711</td>
<td>484</td>
</tr>
<tr>
<td>Direct Buried Cable Replacement</td>
<td>26%</td>
<td>1,099</td>
<td>809</td>
</tr>
<tr>
<td>Number of Customers on eBills</td>
<td>147%</td>
<td>90,990</td>
<td>224,420</td>
</tr>
<tr>
<td>Measure</td>
<td>% Improvement</td>
<td>2014</td>
<td>2017</td>
</tr>
<tr>
<td>----------------------------------------------</td>
<td>---------------</td>
<td>------</td>
<td>------</td>
</tr>
<tr>
<td>Telephone Calls Answered On Time</td>
<td>8%</td>
<td>72%</td>
<td>78%</td>
</tr>
<tr>
<td>Written Response to Enquires</td>
<td>15%</td>
<td>86%</td>
<td>99%</td>
</tr>
<tr>
<td>First Contact Resolution</td>
<td>9%</td>
<td>82%</td>
<td>88%</td>
</tr>
<tr>
<td>Connection of New Services-Low Voltage(LV)</td>
<td>7%</td>
<td>92%</td>
<td>98%</td>
</tr>
<tr>
<td>Billing Accuracy</td>
<td>3%</td>
<td>97%</td>
<td>99%</td>
</tr>
</tbody>
</table>
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 16:

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

The evidence states that THESL’s proposed custom measures reflect a thorough understanding of customer priorities and provide assurance that value for money will be achieved through the utility’s 2020-2024 Distribution System Plan. Please explain how THESL will measure whether it has achieved “value for money” for its customers during the 2020-2024 rate plan.

RESPONSE:

Please refer to Exhibit 1B, Tab 2, Schedule 1, wherein Toronto Hydro describes its approach to performance management and outlines how it proposes to report in relation to the plan. The Custom Performance Measures set out in Table 1, in combination with other scorecard reporting, will result in Toronto Hydro annually reporting on 44 performance outcome measures. Over the course of the plan, these measures will demonstrate Toronto Hydro’s progress in delivering value for money.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 17:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B

Please explain the implications for the UMS Group Report given “50 percent of the utilities responding to the survey could not provide unit costs for three of the four maintenance programs.”

RESPONSE (PREPARED BY UUMS):

There are no implications. As stated in Section II-Executive Summary of the UMS Benchmarking Study, the fact that 50 percent of the utilities that responded to the survey could not provide unit costs for three of the four maintenance programs was not a surprise. UMS Group accounted for this when choosing the size of peer group for its analysis. Furthermore,

- Eight utilities did provide unit cost information for the three maintenance programs in question.

- The range of responses, summarized in Table 1 below, were congruent (i.e.; there were no apparent outliers and THESL’s positioning with respect to the median was consistent), and finally,

- Given the industry standard for benchmarking of “directional accuracy” (please refer to Section III, “Project Approach,” under the heading “Benchmarking”), UMS Group accepts the conclusion that THESL’s comparative position for these three programs in the second quartile is valid.
Table 1: Summary of Maintenance Unit Costs

<table>
<thead>
<tr>
<th>Maintenance Program</th>
<th>Unit Cost</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>THESL</td>
<td>Median</td>
<td>Minimum</td>
<td>Maximum</td>
</tr>
<tr>
<td>Pole Test and Treat (Each)</td>
<td>18</td>
<td>19</td>
<td>13</td>
<td>23</td>
</tr>
<tr>
<td>OH Line Patrol (Line KM)</td>
<td>44</td>
<td>47</td>
<td>38</td>
<td>60</td>
</tr>
<tr>
<td>Vault Inspection (Each)</td>
<td>253</td>
<td>272</td>
<td>234</td>
<td>308</td>
</tr>
</tbody>
</table>
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 18:
Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B

UMS Group selected a Peer Group Panel of 17 electric utilities. Please describe the process used to develop the Peer Group Panel. Please identify utilities that were considered and rejected – and provide an explanation as to why they were rejected. Was the study overseen by Torys or THESL, or by some combination? Please describe in detail the involvement of both Torys and THESL Staff.

RESPONSE (PREPARED BY UMS GROUP):
UMS Group developed an initial list of candidate utilities for the Peer Group by leveraging its relationship across the industry and identifying those utilities that have previously expressed an interest to improve their work productivity and were willing to participate in the associated studies. To narrow the search to those utilities that are similar to Toronto Hydro’s demographics and operating environment, UMS Group applied criteria described in its response to 1B-SEC-15 (c) and 1B-HANN-19. The initial list of candidates resulted in 20 electric utilities, from which UMS Group solicited participation. For the purpose of its unit cost study, UMS Group anticipated an acceptance rate of 60 percent (i.e. 12 participants). Receiving the acceptance of 17 electric utilities¹ exceeded UMS Group’s expectations and provided a firm basis for the subsequent benchmarking analyses. The three utilities (i.e. Public Service Electric and Gas, Commonwealth Edison and Consolidated Edison) declined to participate.

¹ For a list of 17 utilities, refer to Section III of the UMS Group Benchmarking Study.

Panel: Expert Witnesses
Throughout the study, UMS Group maintained its objectivity and independence. Neither Torys nor THESL shaped its analytical approach, reviewed the details of the analysis, or developed any findings or conclusions. UMS Group had meetings with both Torys and THESL staff to ensure the accurate understanding of THESL procedures and methodologies as they relate to the unit cost study. As part of those meetings, clarifying questions were asked by all parties but in no instances UMS Group views were rebutted.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 19:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B

The UMS Group study concludes that, “continued refinement is called for in the reporting, collecting and synthesizing of cost and installation data, particularly as the industry drives to adopt unit costing as a means for trending and comparing performance.” Please explain, specifically how THESL could improve upon reporting, collecting and synthesizing cost and installation data. From the Consultants’ perspective what jurisdictions are the most advanced in unit cost and performance benchmarking?

RESPONSE (PREPARED BY UMS GROUP):

THESL is already on the right path to improvements in reporting, collecting and synthesizing cost and installation data. The new Asset Assembly Unit (“AAU”) structure for tracking in-house capital projects will, when coupled with the Unit Pricing Contract Management System (“UPCMS”), (a) offer the granularity necessary to consistently track and compare worker productivity (i) within THESL and (ii) between THESL and outside contractors), (b) improve estimating, and (c) report progress on a routine basis. Similarly, efforts to unitize maintenance program work performed by in-house staff will link naturally with the information already provided by the maintenance contractors.

The industry is widely dispersed in its use of unit cost information:

- Most electric utilities use it to develop order-of-magnitude estimates, define staffing levels, create resource-loaded schedules, and support financial reporting requirements,
• Few have attempted to use this information to drive efficiencies (i.e. improve productivity / lower costs) or improve estimating practices, and

• There does not appear to be an industry drive in North America to standardize practices among utilities to facilitate valid comparisons.

Of the North American electric utilities that are most advanced in unit cost and performance benchmarking, UMS Group would point to the larger utilities that include nuclear generation in their portfolio. Their drive to reduce refueling outages from months to days forced a number of disciplines around productivity management that are easily transferrable to other utility organizations. Otherwise, THESL, from UMS Group’s view, is among a small percentage of electric utilities that are proactively addressing unit cost and performance benchmarking.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 20:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix C

Please recast Appendix 5-A providing the forecast metrics for 2018-2024.

RESPONSE:

Please refer to Appendix A to this interrogatory.
Appendix A (IR reference 1B-CCC-20)

<table>
<thead>
<tr>
<th>Metric Category</th>
<th>Metric</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost</td>
<td>Total Cost per Customer(^1)</td>
<td>948</td>
<td>675</td>
<td>787</td>
<td>774</td>
<td>903</td>
<td>899</td>
<td>884</td>
</tr>
<tr>
<td></td>
<td>Total Cost per km of Line(^2)</td>
<td>25,280</td>
<td>18,056</td>
<td>21,099</td>
<td>20,817</td>
<td>24,365</td>
<td>24,340</td>
<td>24,017</td>
</tr>
<tr>
<td></td>
<td>Total Cost per MW(^3)</td>
<td>173,918</td>
<td>125,565</td>
<td>148,608</td>
<td>149,077</td>
<td>177,595</td>
<td>179,755</td>
<td>177,767</td>
</tr>
<tr>
<td>CAPEX</td>
<td>Total CAPEX(^4) per Customer</td>
<td>790</td>
<td>512</td>
<td>625</td>
<td>612</td>
<td>741</td>
<td>737</td>
<td>722</td>
</tr>
<tr>
<td></td>
<td>Total CAPEX(^4) per km of Line</td>
<td>21,054</td>
<td>13,680</td>
<td>16,751</td>
<td>16,454</td>
<td>19,988</td>
<td>19,947</td>
<td>19,609</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>Total O&amp;M per Customer</td>
<td>158</td>
<td>164</td>
<td>162</td>
<td>162</td>
<td>162</td>
<td>162</td>
<td>162</td>
</tr>
<tr>
<td></td>
<td>Total O&amp;M per km of Line</td>
<td>4,226</td>
<td>4,376</td>
<td>4,348</td>
<td>4,363</td>
<td>4,378</td>
<td>4,393</td>
<td>4,408</td>
</tr>
</tbody>
</table>

1 Total Cost per Customer is the sum of a distributor's capital and O&M expenditures divided by the total number of customers that the distributor serves. The expenditure and customer amounts are as presented in the Yearbooks.

2 Total Cost per km of Line is the sum of a distributor's capital and O&M expenditures divided by the total number of kilometres of line that the distributor operates to serve its customers. The expenditure and kilometre amounts are as presented in the Yearbooks.

3 The Total Cost per MW is the sum of the distributor's capital and O&M expenditures divided by the total peak MW that the distributor serves. The expenditure and peak demand amounts are as presented in the Yearbooks.

4 Annual CapEx amounts are as presented as per RRR definition of Capital Expenditure.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 21:
Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 12

Please provide a forecast for the rate plan period for Total Cost per Customer and Total Cost per Km of Line.

RESPONSE:
Table 1 provides the total cost per customer and total cost per km of line forecasts for the period 2020-2024.

Table 1: Forecasted total cost per customer and total cost per km of line (2020-2024)

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total cost per customer</td>
<td>1,304</td>
<td>1,349</td>
<td>1,402</td>
<td>1,444</td>
<td>1,514</td>
</tr>
<tr>
<td>Total cost per km of line</td>
<td>34,958</td>
<td>36,269</td>
<td>37,832</td>
<td>39,098</td>
<td>41,118</td>
</tr>
</tbody>
</table>
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 22:
Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 3

The actual ROE for THESL was 10.71% for 2015 and 12.18% for 2016. Please explain what factors contributed to the overearning in each of these years. What is the expected ROE for 2018?

RESPONSE:
Actual (i.e. achieved) ROE for 2015, as reported in the RRR, was greater than the deemed ROE of 9.30 percent primarily due to the following:

1) Accounting recognition in 2015 of items pre-dating the 2015-2019 CIR term. Items which pre-date the 2015-2019 CIR term (i.e. do not form 2015 base CIR rates) and contribute to the earnings results included the recognition 2008-2010 Smart Meter program and 2011-2014 LRAM.

2) Following the prescribed treatment to calculate achieved ROE, the activity in regulatory accounts (e.g. foregone revenue) was excluded from the determination of tax expense for ROE purposes which resulted in greater reported earnings relative to the same included in 2015 base rates.

1 RRR 2.1.5.6 ROE Complete Filing Guide, for Electricity Distributors’ Reporting and Record Keeping Requirements (RRR), March 2016, Section A.6 (i), Page 23.
3) Partially offset by the ROE consequences resulting from the inconsistent rate and calendar years. The synchronization of the rate and fiscal (calendar) years, as approved by the OEB, became effective on January 1, 2016. Therefore, for the 2015 reporting (i.e. calendar) year, Toronto Hydro’s results reflected four months (January to April) of earnings based on lower 2014 rates and eight months (May to December) of 2015 approved rates. This served to lower Toronto Hydro’s 2015 earnings.

Actual ROE for 2016 was greater than the deemed ROE of 9.30 percent primarily due to the accounting recognition in 2015 of: (i) 2012-2014 ICM results, following OEB approval in July 2016; and (ii) 2008-2010 Smart Meter results.

Toronto Hydro does not currently have the actual ROE for 2018 finalized.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 23:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, p. 1

Please file the 2018 Service Reliability Indicators for 2018 when they become available.

RESPONSE:

Toronto Hydro does not currently have this data finalized for 2018.
INTERROGATORY 24:

Reference(s): Exhibit 1B, Tab 3, Schedule 1

Was the work undertaken by Innovative Research Group Inc. subject to an RFP process? If not, why not? If so, please provide the RFP and the subsequent Terms of Engagement. What was the cost of the work provided by Innovative Research? Please describe, in detail, THESL’s role in the work undertaken by Innovative Research Group Inc.

RESPONSE:

Yes, the work was subject to an RFP, which is attached as Appendix A. For the cost of Innovative Research Group’s (IRG) work and the retainer, please see Toronto Hydro’s response to interrogatory 1B-CCC-8.

The IRG Report at Exhibit 1B, Tab 3, Schedule 1, Appendix A contains the work undertaken by Innovative. Innovative was engaged by Toronto Hydro to help it design, execute, and document the results of Toronto Hydro’s customer engagement process as part of the development of its Plan and this Application. Through a two-phased approach, IRG collected customer feedback using multiple methodologies, including an online customer feedback portal, focus groups, one-on-one interviews, telephone surveys and online surveys. Toronto Hydro provided IRG the information required to meaningfully engage customers, and in turn, to provide Toronto Hydro the information it required to develop and refine its business plan.
REQUEST FOR PROPOSALS

Number 15P-005

for

the supply of Marketing Research Services

to

Toronto Hydro-Electric System Limited
(“Toronto Hydro”)

January 23, 2015
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REQUEST FOR PROPOSALS

1. INTRODUCTION

1.1 Introduction

This RFP is being issued and administered by the Supply Chain Services Department in order to obtain Proposals from one or more Respondents that would result, if accepted by Toronto Hydro, in the successful Respondent(s) entering into negotiations to execute a Contract with Toronto Hydro for the supply of the goods/services as further described herein.

1.2 Sections

This RFP is divided into five (5) sections and schedules, as follows:

1. Introduction
2. RFP Rules and Procedures
3. Proposal Requirements
4. Goods/Services Required
5. Contract Negotiations

Schedule A: RFP Procedures
Schedule B: Proposal Requirements and Goods/Services Required
Schedule C: Standard Terms and Conditions
Schedule C-2: Additional Terms and Conditions
Appendix A: Privacy Terms and Conditions
Schedule D: Proposal Cover Sheet
Schedule E: Respondent's Certificate
Schedule F: Defined Terms

1.3 Defined Terms

(a) All capitalized terms in this RFP shall be as defined in SCHEDULE F, unless otherwise defined herein.

(b) Words and abbreviations that have well known technical or trade meanings are used in this RFP in accordance with such recognized meanings.
2. **RFP RULES AND PROCEDURES**

2.1 **Rules and Procedures**

The submission of a Proposal by the Respondent shall be deemed to signify that the Respondent has read, understood and agrees to comply with all of the terms and conditions of this RFP including without limitation all RFP Rules and Procedures as detailed in this Section 2.

2.2 **Respondents**

(a) This RFP is being issued to a limited number of organizations that have been pre-selected by Toronto Hydro. Toronto Hydro reserves the right to contact additional parties regarding this RFP, or issue a separate or supplementary RFP, for this or any related matter, in its discretion and at any time.

(b) A Respondent’s pre-selection signifies that a Respondent has met Toronto Hydro’s minimum requirements and does not mean that the Respondent is on equal footing with other approved Respondents. Notwithstanding a Respondent’s pre-selection, Toronto Hydro reserves the right to consider such criteria as described in Section 2.13 below in selecting or rejecting any Proposal.

2.3 **Communications**

(a) All questions or other communications regarding this RFP, including any notices required hereunder and the submission of Proposals, are to be addressed solely to the Supply Chain Services Department, in writing, to the attention of the Supply Chain Specialist identified in SCHEDULE A.

(b) **Respondents shall communicate only with the Supply Chain Services Department and shall not communicate with any other department or Representative of Toronto Hydro regarding this RFP.**

2.4 **RFP Schedule**

Subject to any modifications in Toronto Hydro's discretion, and subject to all other terms of this RFP, the schedule and timelines set out in SCHEDULE A will apply to this RFP.

2.5 **Questions and Clarifications regarding this RFP**

(a) Upon review of this RFP, Respondents shall immediately notify the Supply Chain Services Department, in writing, of any omissions, discrepancies, ambiguities or details contained in this RFP requiring further clarification.

(b) All questions regarding the RFP shall be made in writing to the Supply Chain Services Department **by no later than 1:59:59 p.m. EST on the Deadline for Submission of Questions in SCHEDULE A.** Questions and responses will be recorded by the Supply Chain Services Department, and may be distributed to all Respondents, in Toronto
Hydro's discretion. The Supply Chain Services Department will respond to those questions that, in Toronto Hydro's discretion, provide clarification to this RFP.

2.6 Amendments or Supplements to RFP

Toronto Hydro reserves the right to issue addenda, supplements and make amendments to this RFP at any time, in its discretion. All addenda, supplements or amendments to this RFP shall be delivered to all parties having received a copy of this RFP (unless such party has advised the Supply Chain Services Department, in writing, of its intent not to respond to the RFP) and shall be deemed to form an integral part of this RFP as if specifically restated herein.

2.7 Submitting the Proposal

(a) **IN ORDER TO BE CONSIDERED BY TORONTO HYDRO, A RESPONDENT MUST SUBMIT ITS PROPOSAL TO THE SUPPLY CHAIN SERVICES DEPARTMENT IN ACCORDANCE WITH THE TERMS IN SCHEDULE A.**

(b) Proposals shall be delivered to the Supply Chain Services Department by personal delivery, or by courier. No facsimile transmission of Proposals will be accepted. Proposals shall be deemed received by the Supply Chain Services Department on the date of acceptance, as evidenced by signature of a Toronto Hydro security desk representative. Respondents shall be entirely responsible to ensure that Proposals are received by the Toronto Hydro security desk representative by the Submission Deadline as described in SCHEDULE A. Toronto Hydro will not be responsible for any issues or problems related to the delivery or receipt of any Proposal by the Submission Deadline. Without limitation, Respondents are solely responsible for ensuring that Proposals are delivered to the security desk representative as indicated in SCHEDULE A so as to allow the representative sufficient time to receive and time stamp the Proposal to indicate receipt before the time described in SCHEDULE A.

2.8 Modifications or Withdrawal of Proposals before Submission Deadline

(a) Proposals submitted prior to the Submission Deadline may be modified or withdrawn by the Respondent at any time prior to the Submission Deadline, by written notice to the Supply Chain Services Department, delivered personally or by courier.

(b) Respondents may not make modifications to their Proposal after the Submission Deadline.

(c) To modify a Proposal prior to the Submission Deadline, the Respondent must withdraw the original Proposal and submit another Proposal to the Supply Chain Services Department, prepared in accordance with the terms of this RFP, bearing the same signature of the authorized representative of the Respondent who executed the original Proposal (or such other authorized representative if the original representative is no longer available, provided a written explanation regarding same is included), clearly marked to show that it supersedes and invalidates the Proposal(s) previously delivered. No other method of Proposal modification shall be considered.
(d) To withdraw a Proposal prior to the Submission Deadline, the Respondent shall submit to the Supply Chain Services Department a letter to this effect, bearing the same signature of the authorized representative of the Respondent who executed the original Proposal (or such other authorized representative if the original representative is no longer available, provided a written explanation regarding same is included. No other method of Proposal withdrawal shall be considered.

(e) Proposals not submitted by the Submission Deadline will not be considered by Toronto Hydro.

2.9 Irrevocability of Proposals

Proposals submitted and not withdrawn prior to the Submission Deadline shall be irrevocable by the Respondent and shall remain in effect and open for acceptance by Toronto Hydro from 1:59:59 p.m. EST on the Submission Deadline until the Irrevocability Date, as stated in SCHEDULE A.

2.10 Ownership of Proposals

Subject to any written agreement to the contrary, all Proposals and other support documentation received by the Supply Chain Services Department from Respondents shall become the property of Toronto Hydro and will not be returned to Respondents. Toronto Hydro will not disclose the Respondent's Proposal to any third party, save and except for disclosure to any Toronto Hydro Representative as may be required to administer this RFP and any resulting Contract or as required by court order or other legal compulsion including, without limitation, disclosure required by the Municipal Freedom of Information and Protection of Privacy Act (Ontario) and requests made by any Governmental Authority.

2.11 Verification of Information

In submitting a Proposal, the Respondent acknowledges and agrees that Toronto Hydro and its Representatives may, in their discretion, independently verify any information provided in a Proposal.

2.12 Clarifications or Supplements to Proposals

Toronto Hydro and its Representatives reserve the right, in their discretion, to seek further information or clarification from any Respondent and Toronto Hydro is entitled to utilize the information or clarifications received in evaluating any Proposal, and may require one or more or all of the Respondents to answer questions or submit supplementary documentation clarifying any matters contained in their Proposals.

2.13 Evaluation of Proposals

(a) Proposals will be opened in private by the Supply Chain Services Department and a Toronto Hydro representative (in Toronto Hydro’s discretion). Toronto Hydro is under
no obligation to disclose to any Respondent(s) the contents of the Proposals received or to reveal the Proposal prices.

(b) The successful Respondent(s), if any, will be selected by Toronto Hydro, in its sole discretion, based on Toronto Hydro's assessment of which Proposal is considered to be the most beneficial to Toronto Hydro based on any number of criteria which Toronto Hydro, in its discretion, considers relevant, including, without limitation, the following (not necessarily in order of importance):

(i) completeness of the Proposal and responsiveness to this RFP;
(ii) qualifications, experience and ability of the Respondent to provide the requested goods/services;
(iii) proposed price;
(iv) other value-added services that may be offered by the Respondent;
(v) reputation of the Respondent and its past relationship with Toronto Hydro or any of its Affiliates;
(vi) the specific evaluation criteria set out in PART B of SCHEDULE B, if any; and
(vii) any other factor that Toronto Hydro, in its discretion, deems relevant.

(c) Toronto Hydro is not obliged to inform the Respondents of the relative weight to be given to any particular evaluation criterion, or to provide reasons to any Respondent with respect to any exercise of Toronto Hydro’s discretion.

(d) Toronto Hydro reserves the right, in its discretion, to negotiate with the Respondent, which, in the opinion of Toronto Hydro, has submitted the most beneficial Proposal, or with any other Respondent or Respondents concurrently. Toronto Hydro and its Representatives shall incur no liability to any other Respondents as a result of such negotiations.

2.14 Selection of Proposals

(a) This RFP does not constitute a call for tenders or a contract to purchase goods or services, and Toronto Hydro is under no obligation or commitment whatsoever to select any Proposal and expressly reserves the right, in its discretion, to reject any or all Proposals without notice or reasons including, without limitation, the lowest priced Proposal. Alternatively, Toronto Hydro reserves the right to select the Proposal that, in its discretion, it deems most advantageous, notwithstanding any custom, usage or agreement in the industry or trade, or any other policy or practice to the contrary.

(b) Toronto Hydro reserves the right, in its discretion, to select any Proposal, irrespective of whether such Proposal is informal, irregular, incomplete, or non-compliant with any of the terms of this RFP, including, without limitation, the terms described in Sections 2.7, 2.19, SCHEDULE A and SCHEDULE B.
(c) Without limiting the generality of the foregoing, Toronto Hydro may, in its discretion and at any time without notice or reasons, and without liability, take any steps it deems appropriate in connection with this RFP process including, without limitation:

(i) modify the terms of or terminate this RFP;

(ii) decline to permit any Respondent to participate in this RFP process;

(iii) terminate discussions or negotiations with any or all Respondents;

(iv) reject any, or part of any, or all Proposals; or

(v) negotiate with any third party regarding matters covered by or related to this RFP, whether such party has been invited to submit a Proposal or not.

(d) If Toronto Hydro does not receive any satisfactory Proposals, which only Toronto Hydro, in its discretion, may determine, or if an insufficient number of Proposals are submitted, or where unforeseen circumstances arise before the Date for Selection of the Successful Respondent(s), it may, in its discretion, either:

(i) revise the scope of work identified in this RFP by issuing post-RFP addenda and inviting one or more of the Respondents to resubmit a Proposal;

(ii) negotiate modifications of any term of this RFP with any Respondent, or Respondents, concurrently;

(iii) include any of the Respondents in post-Submission Deadline negotiations;

(iv) reject all Proposals and re-issue the RFP to some or all of the Respondents and any third parties selected by Toronto Hydro, in its absolute discretion; or

(v) cancel this RFP.

(e) Neither Toronto Hydro nor any of its Representatives shall incur any obligation or liability to any Respondent in the exercise of any of the rights noted above.

2.15 Confidentiality

(a) This RFP, and all information and data disclosed by Toronto Hydro in relation thereto, including without limitation all information related to Toronto Hydro's business operations, processes or technology, whether marked as confidential or not, constitutes “Confidential Information” which is, and will remain, the property of Toronto Hydro, and is not to be copied or distributed without the prior written approval of Toronto Hydro.

(b) Notwithstanding the foregoing, Confidential Information does not include any information or data which:
is or becomes publicly known through no breach of the terms or conditions of this RFP; or

(ii) is independently developed by a third party without reference to Confidential Information and without breach of the terms or conditions of this RFP.

(c) The Respondent agrees to maintain the confidentiality of the Confidential Information, and further agrees not to use or duplicate such Confidential Information for any purpose other than responding to this RFP, and will not, without the prior written consent of Toronto Hydro, disclose or make any Confidential Information available to any third party.

(d) Notwithstanding any obligations of confidentiality herein, the Respondent may disclose Confidential Information where required to do so by court order or other legal compulsion, provided the Respondent gives Toronto Hydro prior notice, as permitted by law, of the compulsory disclosure.

(e) Upon request, the Respondent shall forthwith return to the Supply Chain Services Department all Confidential Information, including any copies thereof; and, where such Confidential Information is in electronic form, destroy such Confidential Information and provide the Supply Chain Services Department with a certificate from a senior officer of the Respondent attesting to such destruction.

(f) The terms of this Section 2.15 shall survive any termination or expiry of this RFP for the longer of five (5) years after (i) the Submission Deadline; and (ii) the termination or expiry of this RFP.

2.16 No Representations or Warranties

(a) Nothing in this RFP is intended to relieve Respondents of their responsibility to form their own opinions and conclusions in respect of the matters addressed in this RFP and to satisfy themselves independently regarding the accuracy and completeness of the information provided and the assumptions made in this RFP. Toronto Hydro and its Representatives make no representations or warranties, either express or implied, in fact or in law, with respect to the accuracy or completeness of the information provided in this RFP.

(b) Without limiting the generality of the foregoing, Toronto Hydro and its Representatives shall not be liable for any claim, action, cost, loss, damage or liability whatsoever arising from or related to any information or advice or any errors or omissions that may be contained in this RFP or any data, materials, or documents disclosed or provided to the Respondent pursuant to this RFP or otherwise. The only representations and warranties made by Toronto Hydro or its Representatives, if any, will be those contained in the Contract.
2.17 No Damages

(a) All costs, expenses, losses, damages and liabilities which may be incurred by the Respondents as a result of or arising out of the submission, acceptance or rejection of their Proposals, including the cost of preparing and submitting a Proposal, shall be borne entirely by the Respondents. Toronto Hydro and its Representatives shall not be liable for any costs and expenses incurred by the Respondents, or to reimburse the Respondents in any manner whatsoever or under any circumstances, including, without limitation, in the event of rejection of all Proposals, rejection of the Respondent’s Proposal, selection of another Respondent’s Proposal, waiver or non-waiver of a non-compliance by any Respondent, including the matters described in Sections 2.7, 2.19, SCHEDULE A and SCHEDULE B, issuance of a post-RFP addenda, a decision not to include any Respondent in post-Submission Deadline negotiations, or cancellation of this RFP.

(b) Without limiting the generality of the foregoing, Toronto Hydro and its Representatives shall not be liable, in contract, tort, restitution or any other legal theory, to a Respondent for any claim, action, costs, losses, damages or liability whatsoever arising from any act or omission by Toronto Hydro or its Representatives, including the rejection of any or all of the Proposals, the consideration or evaluation of any or all of the Proposals, negotiations in respect to the Proposals, the selection of a Respondent, the decision to issue post-RFP addenda to some or all of the Respondents, the decision not to include a Respondent in post-Submission Deadline negotiations, the decision to waive or not to waive a non-compliance by a Respondent, including in respect of the matters described in Sections 2.7, 2.19, SCHEDULE A and SCHEDULE B, or for any information or advice or any errors or omissions that may be contained in this RFP or any data, materials, or documents disclosed or provided to a Respondent pursuant to this RFP or otherwise.

2.18 No Collusion

Each Respondent's Proposal shall be prepared without any connection, knowledge, comparison of information, or arrangement with any other Respondent (or any Representative thereof) and each Respondent shall be responsible to ensure that its participation in this RFP process is conducted fairly and without collusion or fraud.

2.19 Conflicts of Interest

The Respondent is required to disclose in its Proposal and on an ongoing basis thereafter any conflict of interest, real or perceived, that exists now or may exist in the future, with respect to this RFP, any resulting Contract, or in relation to Toronto Hydro or its Representatives.

2.20 Assignment

The Respondent may not assign the right to issue a Proposal in response to this RFP to any third party, including any of the Respondent's Affiliates, without Toronto Hydro's prior written consent.
2.21 Governing Law

This RFP, all Proposals submitted in response thereto, and any resulting Contract, shall be governed by the laws in force in the Province of Ontario and the laws of Canada applicable therein.

3. PROPOSAL REQUIREMENTS

All Proposals shall contain the information set out in PART A of SCHEDULE B.

4. GOODS/SERVICES REQUIRED

Toronto Hydro is seeking Proposals from Respondents for the goods and/or services described in PART B of SCHEDULE B, including any Appendices thereto. Respondents shall indicate in their Proposals whether they can meet the requirements and specifications listed in Part B of SCHEDULE B, including any Appendices thereto.

5. CONTRACT NEOTIATIONS

5.1 Contract Terms and Conditions

If selected by Toronto Hydro, the successful Respondent(s) shall enter into a Contract with Toronto Hydro which shall be in a form satisfactory to Toronto Hydro, and shall include, without limitation, reference to the specifications and requirements in PART B of SCHEDULE B, the Standard Terms and Conditions of SCHEDULE C and any Additional Terms and Conditions as may be set out in SCHEDULE C-2, subject to any negotiated amendments or modifications thereto acceptable to Toronto Hydro in its discretion.

5.2 Contract Negotiations

(a) Toronto Hydro anticipates that it will enter into negotiations with the successful Respondent(s), if any, with a view to finalizing and, where applicable, signing the Contract by no later than the Date for Execution of the Contract specified in SCHEDULE A.

(b) If the terms of the Contract cannot be finalized by the Date for Execution of the Contract specified in SCHEDULE A, or such other period to be determined solely by Toronto Hydro, then Toronto Hydro may, in its discretion, terminate negotiations with such Respondent(s), reject the Respondent's Proposal, issue a post-RFP addenda, issue a new RFP or negotiate a Contract with another Respondent or any other party.

(c) Upon agreement of the Contract terms, the Respondent agrees to return the signed Contract, where applicable, together with the specified certificate of insurance, surety bonds and Workplace Safety and Insurance Board certificates, as may be applicable, to Toronto Hydro within one (1) week from the date of Toronto Hydro’s delivery of said Contract.
5.3 No Liability

No Respondent shall have any rights against Toronto Hydro or its Representatives arising from the selection or non-selection of any Respondent(s) including the selection of a Respondent with a Proposal that is non-compliant with the terms of this RFP. Any and all commitments, representations, warranties or obligations of Toronto Hydro or its Representatives shall be limited to those specifically stated in an executed Contract between Toronto Hydro and a successful Respondent(s), if any.
SCHEDULE A

RFP PROCEDURES

(a) QUESTIONS/COMMUNICATIONS WITH TORONTO HYDRO

All questions or communications regarding this RFP are to be addressed solely to:

Attention: Carolyn Guthrie, Supply Chain Specialist
Supply Chain Services Department
Reference: RFP No. 15P-005
Toronto Hydro-Electric System Limited
2nd floor, 500 Commissioners Street
Toronto, Ontario M4M 3N7
E-mail: cguthrie@torontohydro.com
Facsimile: 416-542-2663
Telephone: 416-542-2904

Proposals shall be delivered to the 500 Commissioners Street security desk (Ground Floor).

(b) RFP SCHEDULE

Issue of RFP                                      Friday January 23, 2015
Deadline for Submission of Questions             Tuesday February 3, 2015
Submission Deadline                               Thursday February 12, 2015
Date for Selection of Successful Respondent(s)   Wednesday March 18, 2015
Date for Execution of the Contract               Wednesday April 1, 2015
Irrevocability Date                              Wednesday July 1, 2015

(c) SUBMISSION OF PROPOSALS

A Respondent shall submit four (4) original hard copy of its Proposal, signed by an authorized individual in accordance with Section (c) of PART A of SCHEDULE B the RFP and should include as well 4 (four) hard copies of its Proposal, [in addition to providing an electronic copy of its Proposal on CD or memory stick] to the Supply Chain Specialist as indicated in paragraph (a) above by no later than 1:59:59 p.m. EST on the Submission Deadline. In the event of any inconsistency or conflict, the original, signed hard copy shall be paramount.
PART A -- PROPOSAL REQUIREMENTS

All Proposals shall contain the following information, and be presented in the following order:

(a) **Title Page**

The cover page of all Proposals should be in the form of SCHEDULE D.

(b) **Table of Contents**

All Proposals in excess of five (5) pages should contain a table of contents showing all required sections and all submitted appendices, if any.

(c) **Respondent's Certificate**

Respondents shall complete, sign, and attach a copy of the Respondent's Certificate in SCHEDULE E to their Proposal. The Respondent's Certificate must be dated, signed by an individual authorized to bind the Respondent pursuant to the terms and conditions of this RFP.

(d) **Letter of Introduction and Summary of Proposal**

The next section of each Proposal shall consist of a letter, no more than two (2) pages in length, that introduces the Respondent and highlights the key features of the Respondent's Proposal.

(e) **Information Regarding Respondent**

The next section of the Proposal shall provide details regarding the Respondent, including without limitation, and as may be applicable:

(i) a description of the Respondent's corporate structure, including an organizational chart identifying the Respondent's parent, subsidiaries or other Affiliated corporations, partnerships or organizations;

(ii) if the Proposal is submitted by a partnership, the correct name, firm and style of such partnership must be given, together with the names of all partners;

(iii) a current copy of the Respondent's current credit report and name of rating agency (required);

(iv) a description of the strength and size of the Respondent's business in the Ontario market, with particular emphasis on Toronto-based operations (such information may include, for example, annual dollar sales, or market share percentage);

(v) a copy of all regulatory licences, approvals and authorizations held by Respondent in Ontario that may be relevant to the Contract; and
(vi) any further information relating to the Respondent as may be required in PART B OF SCHEDULE B.

(f) **Price Offer**

This section of the Proposal contains the Respondent's detailed itemized pricing information for all goods or services as required in PART B OF SCHEDULE B.

All pricing shall be expressed in Canadian currency.

The pricing information shall also include:

(i) a description of any conditions or qualifications relevant to the Respondent's ability to contract with Toronto Hydro at the quoted prices or generally;

(ii) all prices shall indicate any applicable taxes (including Harmonized Sales Tax), duties or charges separately;

(iii) any alternative pricing offer(s), as may be available in the Respondent's discretion; and

(iv) any further details or description of the Respondent's proposed price offer which the Respondent deems relevant or important to disclose, including details regarding how volume adjustments would be managed, and what impact such adjustments would have on the price, if any, should Toronto Hydro wish to reduce or increase volumes during the Contract term.

Any alternative price offers may be considered by Toronto Hydro, in its sole discretion.

(g) **Additional Goods/Services**

The Respondent shall provide a description of any additional or related goods or services that it can offer to Toronto Hydro, if any, and clearly specify any and all additional costs related thereto.

(h) **Additional Information**

This section shall provide any additional information that the Respondent estimates, in its discretion, will assist Toronto Hydro in reviewing and assessing the Proposal.

(i) **Sustainability**

Respondents shall provide answers to the following questions regarding its policies, guidelines, and standards relating to ethics, human rights, and sustainability:

(a) *Ethical Behaviour and Social Responsibility Policies:*

   a. Please provide all standards, policies, and/or procedures that incorporate ethical, social, health and safety, and gender equality criteria for personnel, suppliers, and stakeholders.
b. Does your organization have policies and procedures regarding reporting of unethical behaviour (such as whistleblower mechanisms)? If so, please provide.

(b) ISO26000

a. Please provide any policies and procedures that your organization has relating to the following: organizational governance, human rights, labour practices, fair operating practices, consumer issues, and community involvement and development.

b. Do any of your operations occur in non-OECD jurisdictions¹? If so, please indicate in which jurisdictions you operate, and provide evidence of human rights standards, policies, and procedures applicable to those jurisdictions.

(c) Sustainable Resource Use

a. Does your organization have programs or targets to reduce energy and/or water use from its operations? If so, please provide documentation and examples to support this.

b. Does your organization have programs to use renewable resources in its operations? If so, please provide documentation and examples to support this.

(d) Climate Change

a. Has your organization evaluated the risks of climate change on your operations?

b. In the event of a disaster or catastrophe, does your organization have developed and tested business continuity plans?

c. If the answer to either of the above is yes, please provide evidence.

d. Do you require your suppliers to meet such standards? Please provide evidence of such evaluation.

¹ As of March, 2014, the OECD jurisdictions are Australia, Austria, Belgium, Canada, Chile, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, South Korea, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, UK, and the US.
PART B – GOODS/SERVICES REQUIRED

(a) Introduction

Toronto Hydro is issuing this RFP to solicit responses from companies that have a proven track record in the development and execution of market research projects specifically designed to achieve set goals.

The successful respondent(s) will work with Toronto Hydro to support market research requirements in areas such as reputation management, brand management, customer experience, as well as research on specific projects such as outages, productivity, and IT requirements.

(b) Information Regarding Respondent

Please provide the information requested in Section (e) of PART A of this RFP and any additional information the Respondent feels may assist Toronto Hydro in the evaluation of this RFP. Please limit any additional information to a maximum of one page.

(c) Term

The initial term of the contract will be three (3) years from the date of signing with an option to extend an additional two (2) years. At the end of the first three (3) year period the successful Respondent will have an opportunity to renegotiate the various rates in the RFP. Execution of the option to extend the contract will be by mutual consent of Toronto Hydro and the Respondent.

(d) Goods/Services Required

Toronto Hydro is procuring market research services (as described more fully herein, the “Services”). Services can include but are not limited to the following:

- Pre-research consultation
- Survey and script development
- Consumer based research
- Business to Business based research
- Stakeholder based research
- Surveying – phone, in-person, digital, panel
  - Raw data, tables, models, online reporting tools
- Focus groups and interviews.
  - Video interviews, audio files, transcripts
- Screening criteria and quota recommendations
- List procurement and data management
- Reporting
Data Models
- Full written reports
- Comprehensive slide decks
- Onsite workshop and presentations
- Interactive reporting tools
- Executive briefings
- Written management summaries
- Translation services
- Provide expert opinion to oversight committees or boards.

(e) Intellectual Property

All work done for Toronto Hydro will remain the property of Toronto Hydro. All electronic source files, printing specifications or other materials used in design production for Toronto Hydro must be returned to Toronto Hydro upon request at no additional charge.

(f) Pricing Requirements/Payment Terms

The Respondent shall provide pricing for the Services described in Section (d) above (Goods/Services Required). Details for volume discounts shall be provided where applicable. Pricing should be provided based on all-in pricing for individual projects. Fees must include all costs associated with providing the Services. All disbursements and additional expenses included in a Respondent’s fees must be outlined. All pricing for projects must be specified in Canadian dollars including separate line item for HST or PST/GST.

(g) Subcontractors

Toronto Hydro must be notified if sub-contractors are to be used and reserves the right to pre-approve in writing any proposed subcontractor.

(h) Timeframes

The Respondent is to confirm how it will ensure that dedicated appropriate resources will be working on Toronto Hydro projects and that matters will be dealt with within reasonable turn-around times. Timelines should be provided by Respondents in their Proposals in response to this RFP.
Please structure your Proposal in the following numbered order:

1. Firm’s relevant electricity industry experience and knowledge
2. Biographies for key team members (75 words or less)
3. Provide details of your quality assurance (QA) and data protection/disaster recovery practices
4. How do you ensure sample qualifications
5. Data management, list procurement and privacy regulation adherence
6. Three (3) examples showcasing market research completed in one or more of the following: Trust and Reputation, Customer Experience, Conservation and Demand management in the energy sector (limited to 250 words or less per example)
7. Provide three written testimonials or referrals (100 words or less)
8. Account administration (budget control, project management, etc.)
9. Proximity to Toronto
10. Availability of senior level executives/principals
11. Full suite of services (listed)
12. Outsourcing of work e.g. focus groups etc.
13. Work with other companies or stakeholders within electricity industry e.g. OPA and Ministry of Energy, LDC’s
14. Final reports (formats available)
15. Type of support offered post report delivery
16. Fee/billing structure. Provide pricing for both a 15 minute telephone survey and a web based survey to 100 residential customers (should include the following components):
   i. Research/Strategy/Project Management
   ii. Survey development (approx. number of core and demographic questions)
   iii. Field work
   iv. List procurement
   v. Data management
   vi. Analysis and reporting
   vii. Presentations (breakout travel if applicable)

(j) Environmental Attributes of Good or Service

- Measures available in the use of resources (including items such as raw materials, electricity, water) in providing your good or service

- The procedure by which you dispose of waste, any measures of the amount of wasted produce and whether recycling is a component of such procedures.

(k) Respondent’s (Vendor) presentation

An oral presentation by one or more Respondents may be required for clarification purposes only after Toronto Hydro receives written Proposals. If a presentation is required, Toronto Hydro will schedule a time and meeting location. Respondents required to make a presentation shall be
prepared to discuss and substantiate any areas of the Proposal submitted as well as discussing the Respondent’s own qualifications as a provider.
SCHEDULE C

STANDARD TERMS AND CONDITIONS

1. Standard Terms and Conditions

The Vendor’s commencement of performance of the terms of the Contract, including delivery of all or part of the goods/services, shall be deemed to conclusively evidence the Vendor’s agreement and acceptance of these Standard Terms and Conditions and the Additional Terms and Conditions in SCHEDULE C-2, if any. Toronto Hydro’s acceptance of the Vendor’s goods or services shall not constitute acceptance of any additional or different terms in the Vendor’s invoice or other documentation. No modification or amendment to these Standard Terms and Conditions shall be binding on Toronto Hydro unless agreed to in writing.

2. Term

Subject to any termination rights in the Contract, the term of the Contract shall be as set out in the Contract.

3. Price and Payment

a) The price shall be as specified in the Contract and, except as otherwise provided, shall be in Canadian dollars DDP Toronto Hydro’s location (INCOTERMS 2010), and shall represent the total cost to Toronto Hydro, excluding any value added taxes (including Harmonized Sales Tax) but including all other applicable taxes, duties, packaging, handling and delivery costs. Toronto Hydro shall withhold any applicable non-resident withholding taxes from any amount owing under the Contract and remit such taxes to the appropriate federal taxing authority. If no price is stipulated in the Contract, the price must not exceed the last previous quotation made by the Vendor to Toronto Hydro for the same goods or services.

b) Unless otherwise provided in the Contract, the Vendor shall invoice Toronto Hydro after final inspection and acceptance by Toronto Hydro of the goods and services supplied and subject to receipt of all documents required by the Contract. Invoices must be sent electronically to: TH-AP@opiscan.com and ap@torontohydro.com. Subject to approval of the invoice by Toronto Hydro, Toronto Hydro shall make payment to the Vendor via electronic funds transfer not later than thirty (30) days following receipt of an acceptable invoice.

4. Delivery of Goods/Services

a) All goods and services shall be delivered and/or performed in accordance with the terms, specifications and schedules specified in the Contract. The Vendor shall immediately notify Toronto Hydro, in writing, of any circumstances known or suspected that may cause delay in the delivery of goods/services. Unless otherwise agreed in writing, Toronto Hydro will not accept deliveries in excess of those specified in the Contract and
such deliveries shall be entirely at the Vendor’s risk and may be returned by Toronto Hydro to the Vendor at the Vendor’s sole cost and expense.

b) In the event of any question, dispute, disagreement or difference of opinion between Toronto Hydro and the Vendor relating to the quality or acceptability or rate of progress of any goods or services or relating to the interpretation of the specifications in the Contract or the performance of the Contract, the opinion of Toronto Hydro or its authorized Representative shall govern and be binding on the parties hereto.

5. **Subcontractors**

The Vendor may only subcontract any of the services or the manufacture or delivery of any goods under the Contract with the prior written consent of Toronto Hydro. If subcontracting is permitted, the Vendor shall enter into agreements with such subcontractors to require them to perform the services and manufacture or deliver the goods in accordance with all Applicable Laws and the terms of the Contract and the Vendor shall be liable for any acts or omissions of such subcontractors as if such acts or omissions were those of persons directly employed by the Vendor. The Vendor agrees to incorporate the terms of the Contract into all subcontract agreements with its subcontractors. Any subcontract shall not relieve the Vendor from any of its obligations or liabilities under the Contract.

6. **Risk of Loss**

All goods shall be safely and securely packed for shipment. Title to and risk in the goods shall pass to Toronto Hydro on delivery. All delivery costs, including insurance, are for the account of the Vendor.

7. **Invoice Requirements**

The Vendor must render two (2) copies of invoices with the bill of lading attached, on the same day that shipment is made.

The Vendor shall submit invoices to Toronto Hydro in accordance with the payment terms as set out in SCHEDULE B containing:

(i) a detailed description of the Services performed during the invoice period;

(ii) the dates and the amount of time spent by the Vendor for the provision of the Services;

(iii) the hourly rates;

(iv) the total HST applicable to the Services during the invoice period, as well as the Vendor’s HST registration number; and

(v) a detailed description of any applicable disbursements incurred around the invoice period, supported by documentation in a form acceptable to Toronto Hydro.
8. **Time of the Essence**

Time is of the essence in the Contract. The Vendor shall deliver all goods and/or perform all services in accordance with the dates and times for performance and delivery specified in the Contract and Toronto Hydro shall have the right to take possession of and use any completed or partially completed portions notwithstanding any provisions expressed or implied to the contrary.

9. **Force Majeure**

a) As used herein, “Force Majeure” means events beyond the reasonable control of a party applying reasonable diligence and foresight given the nature of the goods/services being provided under the Contract, including, as applicable, any Acts of God and the public enemy, the elements; fire; accidents; vandalism; sabotage; power failure; strikes, lockouts or any other industrial, civil or public disturbances; any laws, orders, rules, regulations, acts or restraints of any government or governmental body or authority, civil or military, including the orders and judgments of courts and any other similar causes or acts.

b) If, by reason of Force Majeure, either party hereto (the “Frustrated Party”) is delayed or unable, in whole or in part, to perform or comply with any obligation or condition of this Contract, then it will be relieved of liability and will suffer no prejudice for failing to perform or comply or for delaying such performance or compliance during the continuance and to the extent of the inability so caused from and after the happening of the event of Force Majeure, provided that it gives to the other party prompt notice of such inability, reasonably full particulars of the cause thereof and the expected cessation. If notice is not promptly given, then the Frustrated Party will only be relieved from performance or compliance from and after the giving of such notice. The Frustrated Party will use its best efforts to remedy the situation and remove, so far as possible with reasonable dispatch, the cause of its inability to perform or comply, provided, however, that settlement of strikes, lockouts and other industrial disputes shall be within the discretion of the Frustrated Party. The Frustrated Party will give prompt notice of the cessation of Force Majeure. If at any time the Vendor cannot deliver any of the goods or services required to be provided pursuant to the Contract due to Force Majeure, Toronto Hydro may engage any other party to provide such goods or services which the Vendor cannot provide. The benefit of this provision shall only survive for thirty (30) days from the commencement of an event of Force Majeure. A requirement to disclose Confidential Information other than under Canadian law pursuant to the terms of the Contract shall not be an event of Force Majeure. A failure by a sub-contractor to perform shall not be an event of Force Majeure for a Frustrated Party unless such sub-contractor is itself suffering from an event of Force Majeure and the provisos set forth above are followed.

10. **Representations and Warranties**

The Vendor represents and warrants to Toronto Hydro that:

a) it has the corporate power and authority to enter into the Contract and to perform its obligations thereunder, and that the Contract constitutes a legal, valid, and binding obligation of the Vendor, enforceable against the Vendor in accordance with its terms;
b) the Vendor, after conducting due diligence, is not aware of any actions, suits or other legal proceedings which may affect its ability to perform the Contract;

c) it is the absolute beneficial owner of the goods, with good and marketable title, free and clear of all liens, charges, encumbrances or rights of others and is exclusively entitled to possess and dispose of the same;

d) the services shall be performed in a professional, diligent and competent manner and shall meet or exceed those standards generally observed by reputable and competent members of the same industry providing similar services;

e) it is an expert, trained, equipped and capable in providing the services and shall only use reliable, qualified and competent persons, as that term is defined in the Occupational Health and Safety Act (Ontario) (the “OHSA”), to perform the services;

f) it is in compliance with and has paid, and will continue to pay, all assessments and other amounts owing pursuant to the Workplace Safety and Insurance Act, (1997) (Ontario); and

g) it is satisfied with the conditions under which the Goods will operate, and shall assume full responsibility for understanding the conditions of supply, operation, and service.

11. Warranty

All Goods and/or Services shall be in compliance with all Applicable Laws and will conform to the specifications, drawings, samples, symbols or other descriptions as specified in SCHEDULE A hereto and will be fit an sufficient for their intended purpose, merchantable and free from defects in material and workmanship. This warranty is in addition to all other warranties specified in the Contract or implied by law and shall survive acceptance and payment.

12. Inspection

All goods delivered and services performed will be subject to final inspection and approval by Toronto Hydro after delivery or performance, notwithstanding any prior payment. In the event that goods are delivered or services are performed which are not in conformity with the terms and conditions and specifications of the Contract, Toronto Hydro may, at its option:

a) reject the goods and services and require the Vendor to immediately re-deliver the goods and re-perform the services;

b) negotiate with the Vendor an agreeable reduction in the price of the delivered, non-conforming goods and services;

c) rework, or cause to be reworked, the delivered, non-conforming goods and services, at the Vendor’s expense, which expense shall constitute a proper set-off by Toronto Hydro against amounts otherwise due to the Vendor under the Contract; or
13. **Termination**

a) Toronto Hydro may, for its convenience and at its sole option, terminate the Contract by providing at least sixty (60) days prior written notice of such termination. Upon issuance of such notice, the Vendor shall stop delivery of the goods and performance of the services under the Contract, except as may be necessary to carry out such termination and take any other action which Toronto Hydro may reasonably direct. Upon a termination for convenience, Toronto Hydro shall pay for such goods and services requested and accepted by Toronto Hydro up until the effective date of such termination. Toronto Hydro shall not be liable to the Vendor for any other costs or damages whatsoever arising from such termination, including, without limitation, any indirect, consequential or special damages such as a loss of profit or loss of opportunity.

b) If the Vendor fails to fulfil any covenant or material obligation under the Contract, including, without limitation, the failure to meet the delivery schedule or any specification contained therein, or breaches any representation or warranty contained therein, then Toronto Hydro may, without prejudice to any other right or remedy Toronto Hydro may have, notify the Vendor in writing that the Vendor is in default of its contractual obligations and instruct the Vendor to correct the default within five (5) Business Days immediately following the receipt of such notice. If the Vendor fails to correct the default in the time specified, then, without prejudice to any other right or remedy Toronto Hydro may have, Toronto Hydro may either correct such default and deduct the cost thereof from any payment then or thereafter due to the Vendor and/or terminate the Contract.

c) If bankruptcy or insolvency proceedings are instituted by or against the Vendor or the Vendor is adjudicated a bankrupt, becomes insolvent, makes an assignment for the benefit of creditors or proposes or makes arrangements for the liquidation of its debts, or a receiver or receiver and manager is appointed with respect to all or part of the assets of the Vendor, Toronto Hydro may, without prejudice to any other rights or remedies it may have, immediately terminate the Contract.

d) The termination of the Contract shall not affect any rights or obligations which may have accrued prior to such termination or any other right which the terminating party may have arising out of either the termination or the event giving rise to the termination.

14. **Liability and Indemnification**

The Vendor shall be liable for and shall indemnify and hold harmless Toronto Hydro and its Representatives from all claims, demands, actions, penalties, damages, losses, judgments and settlements, liabilities, costs, expenses, including legal fees and other related costs and expenses arising out of, related to, or incident to, the Vendor or any of its Representatives’ supply of the goods or performance of the services under the Contract, including, without limitation:
a) any breach, violation or non-performance by the Vendor or any of its Representatives of any terms, conditions, warranties, obligations or covenants contained in the Contract;

b) any breach or violation by the Vendor or any of its Representatives of any Applicable Laws; and

c) any actions, omissions, negligence or wilful misconduct of the Vendor or any of its Representatives.

15. **Health and Safety**

a) The Vendor shall be responsible for:

(v) managing the health and safety of its own personnel and other Representatives;

(vi) ensuring compliance with all Applicable Laws related to health and safety, including without limitation the OHSA; and

(vii) ensuring that its personnel and other Representatives are aware of any safety hazards involved in working in or around Toronto Hydro’s facilities and all Applicable Laws with respect thereto.

b) Neither Toronto Hydro, nor its Representatives, shall be liable for any loss, damages or claims arising directly or indirectly from the Vendor’s work in or around Toronto Hydro’s facilities, and the Vendor hereby waives any claims to which it may become entitled for such loss or damage and releases Toronto Hydro and its Representatives from any and all such claims.

16. **Insurance**

a) Unless otherwise specified in the Contract, the Vendor shall, during the term of the Contract, and at its own expense, maintain and keep in full force and effect:

(i) commercial general liability insurance on an occurrence basis having a minimum inclusive coverage limit, including personal injury and property damage, of not less than five million dollars ($5,000,000.00) per occurrence, which shall be extended to cover contractual liability, products completed, operations liability, owners/contractors protective liability and must also contain a cross liability clause and a severability of interest clause, and must name Toronto Hydro and its Affiliates as additional insureds; and

(ii) automobile liability insurance on all owned and non-owned vehicles used in connection with the Contract and such insurance coverage shall have a limit of not less than two million dollars ($2,000,000.00) per vehicle, in respect of bodily injury (including passenger hazard) and property damage inclusive of any one accident and mandatory accident benefits.
b) All insurance coverages and limits required to be maintained by the Vendor shall be primary to any insurance maintained by Toronto Hydro, which shall be excess and non-contributory. Prior to the commencement of the delivery of the goods or performance of the services, the Vendor shall deliver to Toronto Hydro a certificate of insurance which evidences the Vendor’s compliance with this Section, including the provision of a thirty (30) day prior written notice of cancellation, non-renewal or adverse material change, to Toronto Hydro. The Vendor agrees that the insurance described herein does in no way limit the Vendor’s liability pursuant to the indemnity provisions of the Contract.

17. **Intellectual Property Protection**

The Vendor expressly warrants that the manufacture, delivery, sale or use of the Vendor’s goods or services will not infringe any Canadian or foreign patents, trademarks, copyrights, industrial design or other intellectual property rights and the Vendor shall save Toronto Hydro and its Representatives harmless from all claims, judgments and decrees that may be entered against Toronto Hydro or its Representatives and against all damage, liability, costs and expenses (including legal fees and other attendant costs and expenses) Toronto Hydro or its Representatives incurs by reason of any infringement or claim thereof.

18. **Confidential Information**

The parties agree and acknowledge that, subject to Applicable Laws or court order:

a) each party (the "Receiving Party") shall maintain in strict confidence the terms of the Contract and any and all proprietary and confidential information about the business, operations or customers of the other party or any of their Affiliates, which it acquires in any form from the other party (the "Disclosing Party") by virtue of the Contract ("Confidential Information") and will not disclose to any third party or make use of such Confidential Information for itself or any third party without the prior written consent of the Disclosing Party;

b) the Receiving Party may disclose such Confidential Information to any of the Representatives of the Receiving Party or any of its Affiliates who agree to be bound by the obligations of confidentiality herein and who have a reasonable need to know such Confidential Information in the course of their duties for the Receiving Party but only for the purposes of the Receiving Party exercising its rights and obligations under the Contract;

c) Toronto Hydro is subject to MFIPPA and is governed by governmental authorities such as the OPA and the OEB and shall have the right to disclose Confidential Information in accordance with the provisions of MFIPPA or as required by the OPA or the OEB;

d) a party shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with any breach of obligations pursuant to this section;

e) the Receiving Party shall be responsible for any breach of the Contract by it and its Representatives and by any other person to whom it discloses any Confidential
Information. The Parties agree that the Disclosing Party would be irreparably injured by a breach of the Contract by the Receiving Party, or by any person to whom it discloses any Confidential Information, and that monetary damages would not be a sufficient remedy. Therefore, in such event, the Disclosing Party shall be entitled to all available equitable relief, including injunctive relief without proof of actual damages, as well as specific performance. Such remedies shall not be deemed to be exclusive remedies for a breach of the Contract but shall be in addition to all other remedies available at law or equity; and

f) upon termination of this Agreement, or upon ten (10) days prior written notice from the Disclosing Party requesting return of any or all Confidential Information, the Receiving Party shall forthwith return to the Disclosing Party all Confidential Information, including without limitation all copies of any form of the Confidential Information, the Receiving Party has received and, at the option of the Disclosing Party, deliver to the Disclosing Party, or destroy or have destroyed, any copies or other reproductions of the Confidential Information together with all notes, analyses, reports and other written material whatsoever prepared by, or on behalf of, the Receiving Party, from, or in respect of, the Confidential Information; provided that the Receiving Party shall be entitled to keep, subject always to all the provisions of the Contract, one copy of such notes, analyses, reports or other written material prepared by, or on behalf of, the Receiving Party for its records. The Receiving Party shall provide to the Disclosing Party, upon request, a certificate of an officer of the Receiving Party certifying such destruction; and

g) notwithstanding section 17(a), in the event that the Receiving Party believes it is required by law to disclose, or is requested by a Governmental Authority to disclose, any Confidential Information to a Governmental Authority, the Receiving Party may so disclose; provided that it shall, to the extent permitted by law, first inform the Disclosing Party of the request or requirement for disclosure to allow an opportunity for the Disclosing Party to apply for an order to prohibit or restrict such disclosure.

19. Assignment

Save and except for Toronto Hydro's right to assign the Contract to any of its Affiliates, neither party may assign the Contract or any of its rights or obligations thereunder, in whole or in part, without the prior written consent of the other party, which consent may not be unreasonably withheld.

20. Relationship of the Parties

Nothing contained in the Contract shall be construed to constitute either party as the partner, employee or agent of, or joint venturer with the other party, nor shall either party have any authority to bind the other in any respect, it being intended that each party shall remain an independent contractor of the other. The Vendor is responsible for all deductions and remittances required by law in relation to its employees, including those required for Canada employment insurance, workers’ compensation and income tax.
21. **Severability**

In the event that any of the covenants herein shall be held unenforceable or declared invalid for any reason whatsoever, to the extent permitted by law, such unenforceability or invalidity shall not affect the enforceability or validity of the remaining provisions of the Contract and such unenforceable or invalid portion shall be severable from the remainder of the Contract.

22. **No Waiver**

A waiver of any provisions of the Contract shall not constitute either a waiver of any other provisions or a continuing waiver, unless otherwise expressly indicated in writing.

23. **Enurement**

The Contract and everything contained therein shall enure to the benefit of, and be binding upon, the parties thereto and their respective successors and permitted assigns.

24. **Notice**

All notices, requests, claims, demands and other communications under the Contract shall be in writing and shall be deemed (in the absence of evidence of prior receipt) to have been validly and effectively given on the same day if personally served, the next Business Day if sent by facsimile or similar means of recorded communication or on the fifth Business Day next following where sent by registered mail. Notices shall be addressed to the representatives of the parties indicated in the Contract.

25. **Permits and Applicable Laws**

a) The Vendor shall, at its sole expense, obtain and maintain during the term of the Contract, all permits, licences and approvals required by all Applicable Laws to perform its obligations under the Contract. The terms and conditions of the Contract shall be carried out in strict compliance with all Applicable Laws and in the event of any conflict between any Applicable Laws, the Applicable Laws with the most stringent standard shall apply.

b) Without limiting the generality of subsection 25(a) above, the Vendor shall comply with the *Personal Information Protection and Electronic Documents Act* (Canada), MFIPPA and any other applicable privacy legislation with respect to any personal information collected, used or disclosed in connection with the Contract and shall indemnify and hold harmless Toronto Hydro and its Representatives from and against any and all claims, demands, suits, losses, damages, causes of action, fines or judgments (including related expenses and legal costs) they may incur related to or arising out of any non-compliance therewith by the Vendor or its Representatives.
26. Compliance with Guidelines

The Vendor’s personnel shall comply with all rules and direction of Toronto Hydro, whether specified in this Agreement or otherwise, while working on Toronto Hydro’s premises, distribution system or when accessing or connecting to Toronto Hydro’s information technology systems, including rules and directions concerning health, safety, security and environmental protection, including without limitation, Toronto Hydro’s Code of Business Conduct, Toronto Hydro’s Disclosure Policy, Toronto Hydro’s Social Media and Digital Communication Guidelines, Toronto Hydro’s Accessibility Standards for Customer Service Policy, Toronto Hydro’s Workplace Harassment Policy, Toronto Hydro’s Violence Prevention in the Workplace Policy, Toronto Hydro’s Environmental Policy, Toronto Hydro’s Occupational Health & Safety Policy, Toronto Hydro’s Privacy Policy Statement, Toronto Hydro’s Cyber Security Policy, Toronto Hydro’s Technology Use Guidelines, Toronto Hydro’s External Supplier Access to Application Services and the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the OEB (together, the “Guidelines”). The Vendor acknowledges that it has been provided with a copy of the Guidelines, has provided and will provide a copy of the Guidelines to each of its Representatives and that it agrees to comply with and to direct its Representatives to comply with such Guidelines, as amended.

27. Governing Law

The Contract shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. The Parties irrevocably attorn to the jurisdiction of the courts of Ontario with respect to any matter arising under or related to the Contract. Either party can terminate for cause without the obligation to engage in dispute resolution, mediation, or arbitration.

28. Further Assurances

The Vendor agrees to execute such further assurances and documents, including any bills of sale, and to do all such things and actions which shall be necessary or proper for the carrying out of the purposes and intent of the Contract.

29. Survival

In addition to the terms of the Contract that by their nature survive the expiry or termination of the Contract, the terms of Sections 10 (Representations and Warranties), 13 (Liability and Indemnification), 16 (Intellectual Property Protection), 17 (Confidential Information), 20 (Severability), 22 (Enurement), 23 (Notice) and 26 (Governing Law) shall survive the expiry or termination of the Contract for a period of five (5) years.

30. Definitions

a) In these Standard Terms and Conditions, “Vendor” means the provider of the goods/services under the Contract.
b) Any capitalized terms used in these Standard Terms and Conditions but not defined herein shall have the meaning as defined in the RFP.
SCHEDULE C-2

ADDITIONAL TERMS AND CONDITIONS

1. Toronto Hydro Not Responsible

Notwithstanding any other provision in this Agreement, Toronto Hydro shall not be responsible for and shall not have control or charge of any means, methods, techniques, sequences or procedures used for or in respect of the Services, or for the safety precautions or programs required for the Services or otherwise prescribed hereunder. Toronto Hydro shall not be responsible for or have control or charge over the acts or omissions of the Vendor, subcontractors (if any) or their agents, employees or other persons performing any of the Services.

2. Suspension

Toronto Hydro may, at any time during the term by notice in writing, suspend all or a portion of the Services. Upon receipt of such written notice, the Vendor shall perform no further work other than as directed by Toronto Hydro, and shall be entitled to payment for time spent in performing the Services up to the date of suspension.

3. Preparation of the Agreement

Notwithstanding the fact that this Agreement was drafted by Toronto Hydro and its legal and other profession advisors, the parties acknowledge and agree that any doubt or ambiguity in the meaning, application or enforceability of any term or provision of this Agreement will not be construed or interpreted against Toronto Hydro or in favour of the Vendor when interpreting such term or provision, by virtue of such fact.

4. Publicity

The Vendor shall not use Toronto Hydro’s (or its Affiliates’) name, corporate logos or trademarks in advertising or publicity nor the fact that any agreement between the Vendor and Toronto Hydro has been entered into without Toronto Hydro’s express prior written consent, which may be withheld in the sole discretion of Toronto Hydro.

5. No Minimum Volume

The Vendor acknowledges and agrees that: (i) no portion of this Agreement shall be interpreted as imposing any minimum volume purchase commitment on Toronto Hydro; (ii) this Agreement does not obligate Toronto Hydro to award the procurement of any or all services associated with this Agreement to the Vendor, and services may be added or deleted in Toronto Hydro’s absolute and sole discretion at any time; and (iii) the volume of purchase of the services may diminish or be eliminated prior to the termination date of this Agreement without any liability on the part of Toronto Hydro, including but not limited to any claims by the Vendor for loss of anticipated profits.
6. **Non-Exclusive Agreement**

It is expressly understood that this Agreement is non-exclusive with respect to the Vendor and Toronto Hydro. Toronto Hydro may contract with others for the procurement of the services described herein in its sole discretion.

7. **Privacy**

The Vendor shall comply with the Privacy Terms & Conditions attached hereto as Appendix A to this Schedule C-2.
APPENDIX A

PRIVACY TERMS AND CONDITIONS

1. **Definitions.** In these privacy terms and conditions, the following terms have the following meanings, any capitalized terms that are not defined below have the meaning attributed to them in the Contract (the “Agreement”) and references to successful Respondent include Authorized Users where appropriate in the context:
   
   a. “access” in connection with Personal Information means capable of being accessed by a person, whether or not that person has the right or authority under any law or agreement to access the Personal Information;

   b. “Authorized Users” means those employees and representatives of the successful Respondent and of any permitted subcontractors of the successful Respondent who require access to Personal Information for the purpose of providing the Services;

   c. “MFIPPA” means the Municipal Freedom of Information and Protection of Privacy Act (Ontario) and the regulations made thereunder as amended from time to time;

   d. “Personal Information” means information about an identifiable individual including without limitation, his or her gender, marital status, address, telephone number, and identifying numbers such as account numbers to which the successful Respondent has access by virtue of its provision of Services under the Agreement;

   e. “Privacy Laws” means, collectively, MFIPPA and any other statute or regulation, which has as a purpose the protection of Personal Information, to which Toronto Hydro is subject from time to time;

   f. “Privacy Requirements” means, collectively, Privacy Laws, any written privacy policy of Toronto Hydro that is provided to successful Respondent from time to time and these privacy terms and conditions;

   g. “store” and “stored” means held, backed up or stored by any means whatsoever, including in hard and electronic formats and includes storage in a server or database or any form of electronic memory;

   h. “use” means to handle Personal Information in any manner, including to copy, download and temporarily hold Personal Information, but not including to de-identify Personal Information.

2. **Relationship of the Parties, Application of Privacy Law.** Successful Respondent acknowledges and agrees that:
a. Toronto Hydro is subject to MFIPPA and has legal obligations and restrictions in regard to its collection, use, disclosure and retention of Personal Information;

b. Successful Respondent is a third party service provider to Toronto Hydro;

c. the Services provided by successful Respondent under this Agreement are intended to facilitate Toronto Hydro’s ordinary operations;

d. it may be necessary for the purpose and in the course of providing the Services, for successful Respondent to access and use Personal Information on behalf of Toronto Hydro.

3. **Receipt of Privacy Policy.** Successful Respondent acknowledges that it has been provided with a copy of Toronto Hydro’s privacy policy and warrants that it has read that policy.

4. **Ownership of Personal Information.** Nothing in this Agreement provides successful Respondent with any rights to Personal Information other than the ability to access and use Personal Information as set out in these privacy terms and conditions and successful Respondent acknowledges and agrees that Personal Information shall remain under the control of Toronto Hydro, including without limitation, when successful Respondent is using Personal Information to provide the Services or storing Personal Information in accordance with these privacy terms and conditions.

5. **Restrictions Relating to Personal Information.** Successful Respondent shall:

a. only access and use Personal Information to the extent required for the purpose of providing the Services and shall not access or use Personal Information on its own behalf or for its own purposes;

b. without limiting the generality of the preceding paragraph 5a, not aggregate or otherwise modify Personal Information for any purpose including without limitation, creating statistics relating to electricity consumption;

c. not disclose Personal Information, which for clarity, does not include the provision of Personal Information by Vendor to any of its Authorized Users, which provision of Personal Information shall be a use of that information by successful Respondent and not a disclosure;

d. comply with Privacy Law and Toronto Hydro’s privacy policy, to the extent that they apply to successful Respondent in its capacity as a service provider to Toronto Hydro, and with these privacy terms and conditions; and

e. provide the Services in such manner that its acts or omissions do not result in Toronto Hydro being in violation of the Privacy Requirements.
6. **Notification of Toronto Hydro by Vendor.** Successful Respondent shall immediately give Toronto Hydro written notice:

   a. if it believes that any practice or procedure in which it is engaging in the course of providing the Services contravenes Privacy Law, or if it receives or learns of any complaint or allegation to that effect, but any decision to change any such practice shall be made by Toronto Hydro in its sole discretion;

   b. upon becoming aware of the loss, theft, or unauthorized access, disclosure, copying, use or modification of any Customer Information;

   c. upon becoming aware of any breach of its security, including any potential breach of its systems or the physical security of its premises or equipment, that could have an impact on the security and integrity of Personal Information;

   d. if it receives any privacy-related requests or complaints in relation to the Services;

   e. if it receives any subpoena or foreign order relating to Personal Information; and

   f. of the particulars of the non-compliance and of the steps it proposes to take to address or prevent the non-compliance, if for any reason, successful Respondent does not comply, or anticipates that it will not be able to comply in any respect with a provision of these privacy terms and conditions.

7. **Assistance with Inquiries and Complaints.** If Toronto Hydro notifies successful Respondent that it requires assistance in investigating or responding to any inquiry or complaint with respect to Personal Information (whether or not first received by successful Respondent), successful Respondent shall cooperate with Toronto Hydro by:

   a. furnishing it with complete information concerning successful Respondent’s access and use of Personal Information, including responding, if requested to do so, to any inquiry by a privacy regulatory authority and/or to any complaint; and

   b. co-operating in the conduct of any regulatory or court proceedings arising out of a complaint relating to the management of Personal Information, including attending hearings and assisting in securing and giving evidence and obtaining the attendance of witnesses.

8. **Requests for Access and Correction.** If successful Respondent receives a request for access to or correction of Personal Information from any person other than Toronto Hydro, successful Respondent shall direct the requestor to Toronto Hydro.

9. **Inspection and Audit.** Toronto Hydro or a person appointed by Toronto Hydro or by a privacy regulatory body with jurisdiction over Toronto Hydro may, in addition to any other rights of inspection they may have, at any reasonable time during regular business
hours and on reasonable prior notice to successful Respondent, visit and inspect any location from which successful Respondent accesses, uses and/or stores Personal Information, to examine all equipment used, and all records maintained, in connection therewith (and to make copies of such records), to question successful Respondent’s personnel (including any subcontractors and suppliers), and otherwise to audit and verify, both physically and electronically, compliance by successful Respondent with these privacy terms and conditions. Successful Respondent shall permit and provide reasonable assistance with any such inspection and audit and shall maintain appropriate information to facilitate the conduct of same. Toronto Hydro shall have no duty to make any such visit, inspection, examination, audit or verification and shall not incur any liability or obligation by reason of doing or not doing so.

10. **Change in Privacy Requirements.** Successful Respondent acknowledges that the Privacy Law and other privacy requirements to which Toronto Hydro is subject may change during the term of the Agreement and to the extent that there are any such changes that affect the Services, Toronto Hydro has the right to amend the Agreement to vary or eliminate any practice or procedure of successful Respondent that causes Toronto Hydro to be in violation of its privacy requirements, and successful Respondent shall meet with Toronto Hydro in good faith to address any issues arising out of such amendments made by Toronto Hydro.

11. **Security.** In addition to the other security measures set out in the Privacy Requirements, successful Respondent shall comply with the following security measures.

a. Except with the prior written approval of Toronto Hydro, any Personal Information held by successful Respondent in accordance with these privacy terms and conditions shall be held in a secure physical and electronic environment in Ontario meeting or exceeding then-current industry standards relating to the protection of sensitive personal information.

b. Except with the prior written approval of Toronto Hydro, successful Respondent shall ensure that Personal Information is not transferred to any of its Authorized Users while they are outside of Canada or accessed by Authorized Users from outside of Canada.

c. Promptly upon notice from Toronto Hydro, successful Respondent shall undertake to remedy any security deficiency or improvement identified or requested by Toronto Hydro that is reasonable under the circumstances and the parties agree to discuss in good faith, responsibility for the costs of any such correction of deficiency or improvement.

d. Successful Respondent shall ensure the segregation of Personal Information from other data held by successful Respondent.

e. Successful Respondent shall maintain appropriate access controls in all circumstances where access to Personal Information is permitted under these privacy terms and conditions.
f. Successful Respondent shall ensure the security of its information systems and shall periodically review the steps it takes to prevent any unauthorized access to Personal Information.

g. Successful Respondent covenants to provide Toronto Hydro, prior to the execution of this Agreement and on an annual basis thereafter, with a report outlining its policies and procedures relating to the protection of Personal Information and on request, such reports shall include the names of all Authorized Users.

h. Successful Respondent shall provide information and assistance to Toronto Hydro, acting reasonably, that Toronto Hydro requires for assessments relating to the Services, including without limitation, privacy impact assessments and threat risk assessments.

i. Successful Respondent shall ensure that any permitted subcontractor it retains to assist it in providing the Services agrees to comply with these privacy terms and conditions.

j. Successful Respondent shall log and within twenty-four (24) hours of a request by Toronto Hydro, provide Toronto Hydro with a record of Vendor’s access to Personal Information, which record shall include the date and duration of the access and the identity of the person who accessed the Personal Information.

k. Successful Respondent shall not, and hereby forever waives any and all right to, withhold any Personal Information from Toronto Hydro to enforce any alleged payment obligation or in connection with any dispute relating to the terms of the Agreement or any other matter between successful Respondent and Toronto Hydro.

12. **Limitation of Access/Use.** Vendor shall:

a. ensure that only such of its employees and representatives and the employees and representatives of any permitted contractor as have a need to know Personal Information for the performance of the Services have access to Personal Information;

b. ensure that each Authorized User is familiar with the successful Respondent’s privacy and confidentiality obligations under the Agreement;

c. take reasonable steps, through training, confidentiality agreements and the application of appropriate sanctions, to ensure compliance by all Authorized Users with Vendor’s privacy and confidentiality obligations under the Agreement; and

d. ensure that upon termination of employment or affiliation with successful Respondent, each Authorized User's ability to access Personal Information is terminated, any and all Personal Information being temporarily held by such Authorized User for the provision of the Services is returned to successful Respondent and such Authorized User is reminded of his or her continuing obligations with respect to Personal Information and Confidential Information of Toronto Hydro.
13. **Subcontractors.** Successful Respondent shall not retain any third parties to assist it in providing the Services unless and until such third parties are approved by Toronto Hydro in writing and have signed a written agreement incorporating the obligations of confidentiality and privacy applicable to successful Respondent under the Agreement.

14. **Termination by Toronto Hydro.** Toronto Hydro may, without prejudice to any other rights or remedies Toronto Hydro is entitled to at law or in equity, including the right to seek an injunction or other equitable relief in any court of competent jurisdiction enjoining a threatened or actual breach of these privacy terms and conditions by successful Respondent, terminate the Agreement immediately upon written notice to successful Respondent if successful Respondent is not in compliance with the Privacy Requirements.

15. **Return of Personal Information.** In the event of any termination or on the expiry of the Agreement, successful Respondent shall forthwith return to Toronto Hydro, as directed by Toronto Hydro, any Personal Information being temporarily held or stored by successful Respondent pursuant to the Agreement (including any copies thereof) or, at Toronto Hydro's option, destroy all such Personal Information as directed by Toronto Hydro (including any copies thereof), and provide Toronto Hydro with an officer’s certificate attesting to such destruction.

16. **Indemnification.** Successful Respondent shall indemnify and hold harmless Toronto Hydro (which in this section 16 includes its officers, directors, employees and representatives) from and against any and all claims, demands, suits, losses, damages, causes of action, fines or judgements (including related expenses and legal fees) that it may incur related to or arising from any non-compliance by successful Respondent with these privacy terms and conditions.

17. **Survival.** Notwithstanding the termination of the Agreement, to the extent that successful Respondent continues to have access to Personal Information for any reason, successful Respondent shall continue to govern itself in accordance with these privacy terms and conditions and the obligations of successful Respondent under these privacy terms and conditions shall survive the expiry or termination of the Agreement until successful Respondent has terminated its access to Personal Information and destroyed all copies of Personal Information it is temporarily holding or storing pursuant to these privacy terms and conditions.

18. **Conflict.** In the event of a conflict or inconsistency between these privacy terms and conditions and any other part of the Agreement, the provisions of these privacy terms and conditions shall prevail to the extent of the conflict or inconsistency.
PROPOSAL COVER SHEET

PROPOSAL
of
________________________________________
in response to
Toronto Hydro's
RFP No. __________

Date of Submission of Proposal: ________________

Respondent Contact Information:

Company Name: ______________________________
Primary Contact Name: __________________________
Primary Contact Title: __________________________
Address: _____________________________________
Email: ________________________________________
Telephone: ____________________________________
Fax: _________________________________________
SCHEDULE E

RESPONDENT'S CERTIFICATE

I, the undersigned, in submitting the accompanying Proposal to Toronto Hydro in response to RFP No. ___________ (the “RFP”) on behalf of ____________________________ (the “Respondent”) do hereby certify, on behalf of the Respondent and not in my personal capacity that:

1. I have read, understand and agree to comply with the terms of this RFP.

2. I have read, understand and agree to comply with the statements made in this Certificate.

3. I understand that the accompanying Proposal may be disqualified if this Certificate is found not to be true and complete in every respect.

4. I am authorized by the Respondent to sign this Certificate, and to submit the accompanying Proposal, on behalf of the Respondent.

5. Each person whose signature appears on the accompanying Proposal has been authorized by the Respondent to determine the terms of, and to sign, the Proposal, on behalf of the Respondent.

6. For the purposes of this Certificate and the accompanying Proposal, I understand that the word “Competitor” shall include any individual or organization, other than the Respondent, whether or not affiliated with the Respondent, who:

   (a) has been requested to submit a Proposal in response to the above-noted RFP; or

   (b) could potentially submit a Proposal in response to the above-noted RFP, based on their qualifications, abilities or experience.

7. The Respondent has arrived at the accompanying Proposal independently from, and without consultation, communication, agreement or arrangement with, any Competitor.

8. The terms of the accompanying Proposal have not, and will not be disclosed by the respondent, directly or indirectly, to any Competitor.

9. Any and all potential conflicts of interest between the Respondent and Toronto Hydro (or any Representative thereof) are expressly identified and fully disclosed by the Respondent in the attached Proposal, including the disclosure of any personal or business relationships between the Respondent and Toronto Hydro (or any Representative thereof) and the Respondent (or any Representative thereof).
10. The Respondent, by means of the attached Proposal, hereby offers to enter into a Contract with Toronto Hydro at the prices, and according to the terms and conditions, as set forth in the Proposal and the RFP.

11. The Respondent agrees that this Proposal shall remain open for acceptance by Toronto Hydro until the Irrevocability Date, as set out in SCHEDULE A of the RFP.

12. Any capitalized terms used in this Certificate but not defined herein shall have the meaning as defined in the RFP.

_____________________________________________
Respondent's Full Corporate Name

_____________________________________________
Authorized Representative's Signature

_____________________________________________
Name

_____________________________________________
Title

_____________________________________________
Date

Please Affix Respondent’s Corporate Seal Here
SCHEDULE F

DEFINED TERMS

In this RFP, the following definitions shall apply:

“Additional Terms and Conditions” means the terms and conditions, if any, found in SCHEDULE C-2;

“Affiliates” has the meaning prescribed to it in the Business Corporations Act of Ontario;

“Applicable Laws” means all federal, provincial and municipal statutes, regulations, codes, by-laws, orders in council, directives, rules, guidelines and ordinances applicable to this RFP and any resulting Contract, including without limitation all applicable OEB codes, rules or guidelines;

“Business Day” means a day on which banks are open for business in the City of Toronto, Ontario, but does not include a Saturday, Sunday, or a statutory holiday in the Province of Ontario;

“Confidential Information” has the meaning prescribed to it in Section 2.15;

“Contract” means the definitive written agreement, if any, which may be entered into between the successful Respondent and Toronto Hydro, as a result of this RFP process, which may be in the form of an agreement executed by the successful Respondent and Toronto Hydro or, if no such agreement is executed, may be in the form of a purchase order issued by Toronto Hydro to the successful Respondent that shall be deemed to incorporate by reference the Standard Terms and Conditions in SCHEDULE C and the Additional Terms and Conditions in SCHEDULE C-2, if any, subject to any negotiated amendments or modifications thereto acceptable to Toronto Hydro in its discretion;

“Date for Execution of the Contract” has the meaning prescribed to it in SCHEDULE A;

“Date for Selection of Successful Respondent(s)” has the meaning prescribed to it in SCHEDULE A;
“Deadline for Submission of Questions” has the meaning prescribed to it in SCHEDULE A;

“EST” means Eastern Standard Time or Eastern Daylight Time, whichever is applicable in the City of Toronto, Ontario on the date and at the time in question;

“Governmental Authority” means any government, legislature, municipality, regulatory authority, agency, commission, department, board or court or other law, regulation or rule-making public entity of similar authority, including, without limitation the OEB;

“Irrevocability Date” has the meaning prescribed to it in SCHEDULE A;

“OEB” means Ontario Energy Board;

“Proposal” means the document(s) submitted by a Respondent to the Supply Chain Services Department in response to this RFP;

“Representative” in respect of a party, means such party's directors, officers, employees, agents and contractors, the party's Affiliates, and all such Affiliates' respective directors, officers, employees, agents and contractors;

“Respondent” means each party that submits a Proposal to the Supply Chain Services Department in response to this RFP;

“RFP” means this Request for Proposals, including any and all schedules, attachments, amendments, supplements or revisions thereto;

“Standard Terms and Conditions” means the terms and conditions found in SCHEDULE C;

“Submission Deadline” has the meaning prescribed to it in SCHEDULE A;

“Supply Chain Services Department” means the Supply Chain Services Department of THESL;

“Supply Chain Specialist” means the Representative of the Supply Chain Services Department identified in Section (a) of SCHEDULE A; and

“Toronto Hydro” has the meaning identified on the cover page of this RFP.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 25:
Reference(s): Exhibit 1B, Tab 3, Schedule 1

Please provide a detailed timeline for the Innovative Research Group Inc. work from the time THESL conducted its RFP process (if this was part of the process) to the time the Report was finalized.

RESPONSE:
The following is the list of Customer Engagement activities, in order of start date.

Phase 1 Activities:
- Low Volume Customer Focus Group: 5 December and 6 December 2016
- Key Account Needs & Preferences Survey: 23 February to 24 March 2017
- Mid-Market Customer Focus Group: 28 February and 1 March 2017
- Stakeholder in-depth Interviews: 12 June to 30 June 2017

Phase 2 Activities:
- Online Customer Feedback Portal: 26 April to 28 May 2018
- Residential Telephone Survey: 1 May to 10 May 2018
- Small Business Telephone Survey: 2 May to 14 May 2018
- Mid-Market Telephone Survey: 3 May to 11 May 2018
- Key Account Online Survey: 7 June to 18 June 2018
1 Final Report:

2  - Innovative Report received by Toronto Hydro:  31 July 2018
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 26:

Reference(s):  Exhibit 1B, Tab 5, Schedule 1, p. 1

Please reconcile Table 1 – Change in Monthly Bill with the Table 1 provided at Ex. 1A/T3/S1/p. 4. Please recast Table 1 in this exhibit excluding the rate riders.

RESPONSE:

Please note that both tables referenced are reconcilable back to the Bill impact tables under Exhibit 8, Tab 6, Schedule 1 (OEB Appendix 2-W).

The “Summary of Bill impacts (Distribution Only)” table (Exhibit 1A, Tab 3, Schedule 1, page 4) displays Sub-total A bill impacts which include changes only to Service/Connection Charge, Distribution Volumetric rate, and Rate Riders (excluding pass thorough). The “Bill Impacts – Change in Monthly Bill” table (Exhibit 1B, Tab 5, Schedule 1, page 1) shows approximate impacts per month on the Total Bill which includes distribution related impacts, as well as for 2020 only, changes due to estimated Transmission charges and due to the proposed (lower) loss factors.

Please find below the “Bill Impacts – Change in Monthly Bill” table with Rate Riders excluded.
### Table 1: Bill Impacts – Change in Monthly Bill (Excluding Rate Riders)

<table>
<thead>
<tr>
<th>Service</th>
<th>Change in bill</th>
<th>2020 Proposed</th>
<th>2021 Proposed</th>
<th>2022 Proposed</th>
<th>2023 Proposed</th>
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<tr>
<td>Residential €/30 days</td>
<td>-0.09</td>
<td>1.44</td>
<td>1.12</td>
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<tr>
<td>%</td>
<td>-0.1</td>
<td>1.1</td>
<td>0.9</td>
<td>1.5</td>
<td>1.5</td>
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</tr>
<tr>
<td>Competitive Sector Multi-Unit Residential €/30 days</td>
<td>0.06</td>
<td>1.14</td>
<td>0.89</td>
<td>1.58</td>
<td>1.52</td>
<td></td>
</tr>
<tr>
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<td>1.3</td>
<td>2.2</td>
<td>2.1</td>
<td></td>
</tr>
<tr>
<td>General Service &lt;50 kW €/30 days</td>
<td>2.11</td>
<td>3.62</td>
<td>2.81</td>
<td>4.98</td>
<td>4.82</td>
<td></td>
</tr>
<tr>
<td>%</td>
<td>0.6</td>
<td>1.1</td>
<td>0.9</td>
<td>1.5</td>
<td>1.4</td>
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</tr>
<tr>
<td>General Service 50-999 kW €/30 days</td>
<td>-26.94</td>
<td>63.57</td>
<td>49.55</td>
<td>87.48</td>
<td>84.52</td>
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</tr>
<tr>
<td>%</td>
<td>-0.2</td>
<td>0.5</td>
<td>0.4</td>
<td>0.6</td>
<td>0.6</td>
<td></td>
</tr>
<tr>
<td>General Service 1,000-4,999 kW €/30 days</td>
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<td>406.45</td>
<td>717.98</td>
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<td>%</td>
<td>-0.3</td>
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<td>0.5</td>
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<tr>
<td>Large Use €/30 days</td>
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<td>2,692.82</td>
<td>2,098.05</td>
<td>3,704.72</td>
<td>3,579.26</td>
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<td>%</td>
<td>0.3</td>
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<td>0.3</td>
<td>0.5</td>
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<td>Street Lighting €/30 days</td>
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<td>4,577.71</td>
<td>3,585.65</td>
<td>6,320.80</td>
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<tr>
<td>%</td>
<td>1.2</td>
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<td>1.2</td>
<td>2.1</td>
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<tr>
<td>Unmetered Scattered Load €/30 days</td>
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<td>0.93</td>
<td>1.62</td>
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<td>1.8</td>
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<td>2.4</td>
<td>2.3</td>
<td></td>
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</table>
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 27:

Reference(s): Exhibit 1B, Tab 5, Schedule 1, p. 3

Please provide copies of all budget directives provided to staff in preparing the budgets included in the 2020-2024 Application. Please provide the timeline for preparation of the budgets starting with the initial directive up to the time of the Application filing.

RESPONSE:

Toronto Hydro respectfully declines to provide disclosure of the requested information on the basis that this information provides no probative value to the OEB in deciding the issues in this proceeding. The information sought by the intervenor is contained throughout the evidence.

For example, the direction provided to utility staff in preparing the capital and operational expenditures plans presented in this application is contained within the strategic parameters described in the pre-filed evidence. In particular, with respect to budgets, evidence states that “Toronto Hydro set upper limits of approximately $560 million for the average annual capital plan budget and $277 million for the 2020 operational plan budget, which corresponded with capping infrastructure and operations spending predominantly at sustainment levels.”

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1 Exhibit 1B, Tab 1, Schedule 1 at page 6.
Additionally, in the response to interrogatory 2B-SEC-47, Toronto Hydro explains the basis
for the strategic parameters, and in 1A-CCC-9 the utility provides a comprehensive
description of the business planning process for this application. A copy of the underlying
Business Plan is filed at Appendix A to interrogatory 1A-CCC-1.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 28:

Reference(s): Exhibit 1B, Tab 5, Schedule 1, p. 9

Please recast Table 6 – Capital Investment Expenditures by Categories to include forecast and actual amounts in each of the categories for the years 2015-2019.

RESPONSE:

Please see Table 1 in Exhibit 2B, Section E4.1 at page 2.
RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 29:
Reference(s): Exhibit 1B, Tab 5, Schedule 1, p. 10

Please explain the difference between a program and a segment for both Capital and OM&A.

RESPONSE:
An expenditure program (capital or OM&A) is a group of activities and/or projects that have similar outputs. Where it was possible and helpful to provide a more granular breakdown of the activities or projects within a program, Toronto Hydro created two or more segments to present this information.

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1 OEB Letter re Update to Chapters 1, 2 and 3 of the Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013): [https://www.oeb.ca/oeb/_Documents/2014EDR/Ltr_FilingRequirements_20130717.pdf](https://www.oeb.ca/oeb/_Documents/2014EDR/Ltr_FilingRequirements_20130717.pdf)
RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1:
Reference(s): Exhibit 1B, Tab 3, Schedule 1

Exhibit 1B, Tab 3, Schedule 1, Appendix A

Preamble:
THESL engaged Innovative Research Group (Innovative) to carry out the utility's planning-specific customer engagement. Innovative carried out two phases of work. Phase I sought to provide THESL with input on customer needs and preferences and Innovative conducted exploratory focus groups, a representative low-volume customer survey, and a survey of "key account" customers. Phase II sought to engage customers in order to align THESL's 2020 CIR DSP and operational programs with customer expectations.

a) Please provide a copy of all written instructions provided by THESL to Innovative in relation to Innovative's customer engagement mandate for the 2020 CIR Application and the report provided in Exhibit 1B, Tab 3, Schedule 1, Appendix A.

b) Innovative hosted focus groups for residential (December 5 and 6, 2016), small business (December 5 and 6, 2016), mid-market (February 28 and March 1, 2017), and stakeholders (June 12-30, 2017). Please describe all measures undertaken by THESL and Innovative to invite and ensure the participation of EV stakeholders and other distributed energy resource (DER) customers (including EV drivers, owners of DERs, EV associations, and DER industry associations) in the focus groups. In addition, please provide any and all notes from the focus groups relating to EVs/DERs that are supplementary to the reports provided in Appendix 1 to Exhibit
1c) Innovative conducted low-volume telephone surveys of residential and small business customers between December 7 and 14, 2016. Innovative also conducted an online survey of large use customers between February 23 and March 24, 2017. Please identify and list, in chart format, any and all questions used related to, and responses received pertaining to, EVs, batteries, EV charging, energy storage, and DERs generally.

**RESPONSE:**

a) Please see Toronto Hydro’s response to interrogatory 1B-CCC-24 for the RFP and 1B-CCC-8 for the associated Retainer that established Innovative’s mandate pursuant to which the customer engagement work was performed.

b) Residential, small business, and mid-market focus group participants were randomly recruited from complete Toronto Hydro customer lists. Therefore, each customer in these rate classes had an equally random opportunity of being contacted to participate in the groups. Toronto Hydro does not have a registry of all its customers who own EVs or DERs with which to target invitations, or to know if those who did participate were EV or DER owners.

There are no additional notes from the focus groups relating to EVs/DERs that are supplementary to the reports provided in Appendix 1 to Exhibit 1B, Tab 3, Schedule 1, Appendix A.
c) These dates correspond with Phase I of Toronto Hydro’s Planning-specific Customer Engagement. During Phase I, no specific questions were asked of customers pertaining to EVs, batteries, EV charging, energy storage, or DERs generally. The objective of Phase I was to attain input on customer needs and preferences at the start of the planning process. At that time, the OEB had just released the Handbook for Utility Rate Applications with a clear focus on outcomes. Toronto Hydro’s existing work had explored needs and a wide variety of trade-offs but had not explicitly addressed outcomes. Phase I focused on filling that gap by developing a list of outcomes important to customers and then establishing customer priorities among those outcomes.
RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 2:

Reference(s): Exhibit 1B, Tab 2, Schedule 2, Table 1

a) Are batteries and EVs reflected in the "Performance Outcome" titled "Public Policy Responsiveness"? If not, where are they reflected?

b) If at all, how has THESL considered EVs and DERs to enhance electricity reliability generally and in any specific low-reliability areas of its service territory?

RESPONSE:

a) Batteries and EVs are not reflected in Public Policy Responsiveness outcome in Toronto Hydro’s Electricity Distributor Scorecard. They are reflected in the Customer Service outcome of “connecting customers of all types (including distributed energy resources) on time and cost-effectively, without harming system performance for existing customers.” Please refer to Exhibit 2B, Section E2.2.1 for further discussion of this outcome.

b) As noted in Exhibit 2B, Section E7.2 at pages 2-3, Toronto Hydro plans to invest $5.5 million in energy storage systems (ESS) to enhance grid performance, including to remediate power quality problems (e.g. voltage sags), improve reliability by reducing the number or duration of outages, and increase the capacity of feeders at peak periods.
Further, as detailed in the Expenditure Plan at Section E7.2.2.4, page 13, one of the projects considered in the Grid Performance ESS segment involves a feeder from Richview TS that has experienced poor reliability. Toronto Hydro expects that installing Grid Performance ESS on this feeder can reduce the average number of interruptions for customers in the area from 22 to one interruption per year.

With respect to EVs, Toronto Hydro continues to monitor the development of the technology and its effect on the safety and reliability of the distribution system. Given the evolving state of the technology and the need for further analysis, Toronto Hydro’s plans in this Application do not include deploying EV technology for reliability enhancement purposes.
RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 3:
Reference(s): Exhibit 1B, Tab 2, Schedule 4
Exhibit 1B, Tab 2, Schedule 5

a) Are DERs and/or EVs used by THESL to improve SAIDI and/or SAIFI? If not, why not?

b) How would the weather impacts to SAIFI and SAIDI (Figures 13 and 14) be affected if 5 per cent, 10 per cent, and 25 per cent of load was provided through use of DERs?

c) In Exhibit 1B, Tab 2, Schedule 5, certain indicators are listed for "Low Voltage Connections", "High Voltage Connections", and "Micro-Embedded Generation Facilities". What percentage of these connections and facilities are EV chargers (please include type, e.g., Level I, Level II, DCFC), DERs, and energy storage facilities?

RESPONSE:

a) Please refer to Toronto Hydro’s response to interrogatory 1B-DRC-2(b).

b) In Exhibit 2B, Section 7.2, Toronto Hydro has proposed Energy Storage System ("ESS") investments through which Toronto Hydro seeks to improve grid performance for customers and enable renewable energy generation, as well as evaluate the stacked benefits such as opportunities to leverage DERs to mitigate weather impacts to SAIFI.
c) The requested percentages are not available for EVs. Customers are not required to indicate to Toronto Hydro that they will be connecting an EV charger to their electrical system.

DERs and Energy Storage facilities are not included in the “Low Voltage Connections” or “High Voltage Connections” indicators.

DER and Energy Storage facilities are tracked as part of the "Micro-Embedded Generation Facilities". Table 1 below shows the breakdown by generation type.

<table>
<thead>
<tr>
<th>Type</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>EV Chargers</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>DER</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Energy Storage</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
</tbody>
</table>
RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 4:

Reference(s): Exhibit 1B, Tab 4, Schedule 1

Preamble:

THESL states that its rate framework is comprehensive, covers the entirety of the application's term, and is informed by THESL's forecasts. Distribution rates in years 2 through 5 are adjusted annually by a Custom Price Cap Index (CPCI), as follows:

\[
\text{CPCI} = I - X + C - g
\]

Where,

- "I" is the OEB's inflation factor, determined annually;
- "X" is the sum of:
  - The OEB's productivity factor, as of the date of filing; and
  - THESL's custom stretch factor;
- "C" provides funds incremental to "I - X" that are necessary to reconcile THESL's capital need within a PCI framework;
- "g" captures revenue growth occurring due to customer and/or load charges over the forecast period, based on THESL's forecast of loads and customers for the 2021-2024 period.

a) Please outline THESL's assumptions in the "C" term of the above CPCI equation regarding capacity, change of load, and leveraging due to EVs and other DERs in each of the years of the CIR.
b) Please outline THESL’s assumptions in the "g" term of the above CPCI equation regarding capacity, change of load, and leveraging of EVs and other DERs in each of the years due to the CIR.

c) Please indicate whether THESL intends to include EV charging infrastructure as an eligible "C" term expense, and, if so, how? If not, how will it fit in the CPCI formula or otherwise be treated for rate-making purposes.

d) How were each of DERs, EVs, and EV charging infrastructure treated for the purpose of setting the "I" factor that at which THESL arrived. Please provide all related working papers.

RESPONSE:

a) Please see Exhibit 1B, Tab 4, Schedule 1, section 3.3. The "C" factor in Toronto Hydro’s proposed CPCI is derived from the utility’s rates-funded capital spending as outlined in the Distribution System Plan ("DSP"). To the extent that these capital investments are considered to be DERs, they directly affect the C-Factor. One example of this is Energy Storage Systems Program in Exhibit 2B, Section E7.2.

EVs and other DERs may also indirectly affect the C-Factor. Toronto Hydro builds its infrastructure to meet its legal obligations (e.g. access to the grid) and the needs of the customers it serves (e.g. safety, reliability). Where capital spending is required to achieve these results for customers with EVs or DERs, Toronto Hydro makes those investments. Those investments affect the C-Factor.
b) As detailed in Exhibit 1B, Tab 4, Schedule 1, section 3.4, the “g” term in the proposed CPCI is derived based on the forecast of loads and customers over the 2021-2024 period. The load and customer forecast, which is detailed in Exhibit 3, Tab 1, Schedule 1, Section 3.2 does not include any specific additional loads associated with EVs or DERs due to uncertainty about the future, as noted in that evidence. However, the forecasting methodology will capture any historical load growth due to EV or DER in the load models.

c) Toronto Hydro has not incorporated any EV charging infrastructure in its Distribution System Plan, and therefore there is no component in the “C” factor. If in the future, Toronto Hydro seeks to recover costs in rate base related to EV charging infrastructure, Toronto Hydro will assess at the time the most appropriate mechanism to apply to recover these costs in rates.

d) As detailed in Exhibit 1B, Tab 4, Schedule 1, section 3.1, the “I” term in the CPCI is provided by the OEB, and reflects historical price increases based on a 30/70 weighting of labour and non-labour sub-indices provided by Statistics Canada. EVs, EV charging and DERs are not explicitly included in the value of I. However, to the extent that the Statistics Canada price indices used reflect any pricing for these services, they may be included implicitly.
RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 5:

Reference(s): Exhibit 1B, Tab 4, Schedule 1

a) Has THESL considered the rate, grid, and/or emissions impacts of offering extremely low-cost electricity distribution charges during the lowest-peak period (i.e., overnight) for EV charging? If so, please provide any and all working papers.

RESPONSE:

a) No, Toronto Hydro has not considered it.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1:
Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 3

a) Please expand on the definitions used for SAIDI and SAIFI in the above reference.

b) Please provide a Table and graphical presentation of the SAIDI and SAIFI reliability measures with the 2017 and 2018 data added

c) Please reconcile the data to the following
   i) TH evidence at Exhibit 1B, Tab 2, Schedule 5 and other evidence
   ii) PSE Evidence

RESPONSE:

a) In Exhibit 1B, Tab 2, Schedule 2, page 3, Table 1: “Toronto Hydro EDS Performance 2013-2017”, SAIDI and SAIFI definitions are as per the OEB Electricity Reporting and Record Keeping Requirements¹ where:
   • “Average Number of Hours that Power to a Customer is Interrupted” is SAIDI Excluding Loss of Supply and Major Event days; and
   • “Average Number of Times that Power to a Customer is Interrupted” is SAIFI Excluding Loss of Supply and Major Event days.

¹ https://www.oeb.ca/sites/default/files/RRR-Electricity-20181129-1.pdf
b) Please refer to Toronto Hydro’s response to interrogatory 1B-BOMA-35(b).

c) (i) SAIFI and SAIDI as reported in the EDS (Exhibit 1B, Tab 2, Schedule 2, p. 3), can be compared to SAIFI and SAIDI in the SRI (Exhibit 1B, Tab 2, Schedule 5), “Excl. LoS and MED’s”, which refers to Excluding Loss of Supply and Major Event Days.

There may be differences between the 2013-2018 SAIFI results reported in the EDS and other parts of the evidence. These differences will depend on the context and the varying filters used, similar to the ones in the SRI.

(ii) 2013-2017 SAIDI and SAIFI results reported in the EDS and in PSE evidence are not comparable due to the different thresholds used to define momentary interruptions:

- EDS reliability data (and all of Toronto Hydro’s reliability data) follows OEB’s RRR and defines an interruption as a complete loss of voltage for one minute or more; and
- Consistent with utility reporting in the United States, the PSE results are based on a five minute threshold for an interruption.

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2 Exhibit 1B, Tab 4, Schedule 2, page 9.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 2:

Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 3

a) Please expand on the definitions used for Cost Control in the above reference.

b) Please provide a table and graphical presentation of the cost per customer and per kM of line reliability measures with the 2017 and 2018 data added.

c) Reconcile the above data to

   i) Exhibit 1B, Tab 2, Schedule 1, Appendix C, OEB Appendix 5A,
   ii) PSE Evidence.

RESPONSE:

a) Please see Appendix A to this response. The Cost Control measures are defined at page 6 of the OEB’s Scorecard – Performance Measures Descriptions document.¹

b) Please see Figures 1 and 2 below for the graphical representations of the actual 2013-2017 total cost per customer and total cost per km of line, respectively. Toronto Hydro expects the OEB to publish the 2018 results in September 2019.


Panel: Distribution System Capital and Maintenance
c) Please see below the table 1 for reconciliation for total cost per customer and total cost per km of line as per electricity distributor scorecard ('EDS'), Exhibit 1B, Tab 2, Schedule 1, Appendix C, OEB Appendix 5A, and PSE evidence.
### Table 1: Reconciliation between EDS, Exhibit 1B, Tab 2, Schedule 1, Appendix C, OEB Appendix 5A, and PSE evidence.

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total cost per customers</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EDS</td>
<td>924</td>
<td>967</td>
<td>1,000</td>
<td>1,044</td>
<td>1,042</td>
</tr>
<tr>
<td>Difference</td>
<td>-233</td>
<td>-186</td>
<td>-234</td>
<td>-77</td>
<td>-172</td>
</tr>
<tr>
<td>Appendix 5A</td>
<td>691</td>
<td>781</td>
<td>766</td>
<td>967</td>
<td>870</td>
</tr>
</tbody>
</table>

Difference: The EDS values result from PEG’s econometric model while the values in Appendix 5A represent the sum of capital additions and O&M expenses from the OEB’s Yearbook.

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total cost per customers</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EDS</td>
<td>924</td>
<td>967</td>
<td>1,000</td>
<td>1,044</td>
<td>1,042</td>
</tr>
<tr>
<td>Difference</td>
<td>79</td>
<td>90</td>
<td>104</td>
<td>91</td>
<td>140</td>
</tr>
<tr>
<td>PSE Evidence</td>
<td>1,003</td>
<td>1,057</td>
<td>1,104</td>
<td>1,135</td>
<td>1,182</td>
</tr>
</tbody>
</table>

Difference: The EDS values result from PEG’s econometric model while the PSE values result from PSE’s econometric model. Please refer to Toronto Hydro’s response to interrogatory 1B-SEC-20.

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total cost per km of line</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EDS</td>
<td>66,793</td>
<td>70,688</td>
<td>73,309</td>
<td>27,819</td>
<td>27,825</td>
</tr>
<tr>
<td>Difference</td>
<td>-16,830</td>
<td>-13,616</td>
<td>-17,155</td>
<td>-2,051</td>
<td>-4,591</td>
</tr>
<tr>
<td>Appendix 5A</td>
<td>49,963</td>
<td>57,072</td>
<td>56,154</td>
<td>25,768</td>
<td>23,234</td>
</tr>
</tbody>
</table>

Difference: The EDS values result from PEG’s econometric model while the Appendix 5A represent the sum of capital additions and O&M expenses from the OEB’s Yearbook.

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total cost per km of line</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EDS</td>
<td>66,793</td>
<td>70,688</td>
<td>73,309</td>
<td>27,819</td>
<td>27,825</td>
</tr>
<tr>
<td>Difference</td>
<td>4,777</td>
<td>5,649</td>
<td>6,599</td>
<td>2,294</td>
<td>3,624</td>
</tr>
<tr>
<td>PSE Evidence</td>
<td>71,570</td>
<td>76,337</td>
<td>79,908</td>
<td>30,113</td>
<td>31,449</td>
</tr>
</tbody>
</table>

Difference: The EDS values result from PEG’s econometric model while the PSE values result from PSE’s econometric model. Please refer to Toronto Hydro’s response to interrogatory 1B-SEC-20.
## Efficiency Assessment

A total cost benchmarking evaluation is used to produce a single efficiency ranking of Ontario’s distributors. The efficiency ranking is then segmented into five groups based on the size of the difference between each distributor’s actual costs and its predicted costs as estimated in the benchmarking evaluation. Distributors whose actual costs are lower than their predicted costs are considered more efficient.

This is divided into five groups based on how big the difference is between each utility’s actual and predicted costs. Utilities whose actual costs are lower than predicted are considered more efficient and will be assigned to Group 1 or Group 2. Utilities that are considered average performers will be assigned to Group 3. Utilities whose actual costs are higher than predicted will be assigned to Group 4 or Group 5.

<table>
<thead>
<tr>
<th>Group</th>
<th>Demarcation Points for Relative Cost Performance</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Actual costs are 25% or more below predicted costs</td>
</tr>
<tr>
<td>2</td>
<td>Actual costs are 10% to 25% below predicted costs</td>
</tr>
<tr>
<td>3</td>
<td>Actual costs are within +/-10% of predicted costs</td>
</tr>
<tr>
<td>4</td>
<td>Actual costs are 10% to 25% above predicted costs</td>
</tr>
<tr>
<td>5</td>
<td>Actual costs are 25% or more above predicted costs</td>
</tr>
</tbody>
</table>

### Cost Control

<table>
<thead>
<tr>
<th>Measure</th>
<th>Technical Definitions</th>
<th>Plain Language Description</th>
<th>How Measure may be Compared</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Cost per Customer</td>
<td>Total cost is calculated as the sum of a distributor’s capital costs and OM&amp;A costs, including certain adjustments to make the costs more comparable between distributors, per reporting period. This amount is then divided by the total number of customers that the distributor serves.</td>
<td>A simple measure that can be used as a comparison with other utilities is the utility’s total cost per customer. Total cost is a sum of all the costs incurred by the utility to provide service to its customers. The amount is then divided by the utility’s total number of customers.</td>
<td>✓ Year-over-Year</td>
</tr>
<tr>
<td>Total Cost per Km of Line</td>
<td>Total cost is calculated as the sum of a distributor’s capital costs and OM&amp;A costs, including certain adjustments to make the costs more comparable between distributors, per reporting period. This amount is then divided by the total number of customers that the number of kilometers of line that the distributor operates to serve its customers.</td>
<td>Another simple measure is the utility’s total cost per length of line. Total cost is a sum of all the costs incurred by the utility to provide service to its customers. The amount is then divided by the number of kilometers of line the utility operates to serve its customers.</td>
<td>✓ Distributor-to-Distributor</td>
</tr>
</tbody>
</table>
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION
INTERROGATORIES

INTERROGATORY 3:
Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B, UMS Benchmarking
Table IV-1

a) For the 12 asset costs in the referenced Table, please provide a list of those that are within +10% of the Benchmarks for Median 1 and Median 2

b) List those that are outside + 10%.

c) What opinion has UMS regarding TH position in the Peer Group?

d) Please provide an opinion on trends/outlook in unit costs for these utility assets.

RESPONSE (PREPARED BY UMS):
In responding to items (a) and (b), UMS Group cannot list the utilities that comprised the peer group panel within each of the categories described above. UMS Group has confidentiality restrictions and assurances to protect client anonymity and data. Furthermore, guarantee of anonymity of participating utilities was one of the requirements to garner utilities participation in the study. Nevertheless, UMS Group is willing to provide the number of utilities that fall within and outside of the + / - 10% of medians 1 and 2.
a) Please refer to Table 1 below.

b) Please refer to Table 1 below.

<table>
<thead>
<tr>
<th>Category / Program</th>
<th>No. within +/- 10%</th>
<th>No. outside +/- 10%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Asset Categories</td>
<td>Median 1</td>
<td>Median 2</td>
</tr>
<tr>
<td>Wood Pole Replacement</td>
<td>11</td>
<td>11</td>
</tr>
<tr>
<td>UG Cable Replacement</td>
<td>13</td>
<td>11</td>
</tr>
<tr>
<td>OH Switches Replacement</td>
<td>11</td>
<td>7</td>
</tr>
<tr>
<td>Pole Top Transformer Replacement</td>
<td>5</td>
<td>6</td>
</tr>
<tr>
<td>Padmount/UG Transformer Replacement</td>
<td>13</td>
<td>13</td>
</tr>
<tr>
<td>Network Transformer / Protector Replacement</td>
<td>15</td>
<td>17</td>
</tr>
<tr>
<td>Breaker Replacement</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Switchgear Replacement</td>
<td>Note 1</td>
<td>Note 1</td>
</tr>
<tr>
<td>Maintenance Practices</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vegetation Management</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Pole Test and Treat</td>
<td>7</td>
<td>5</td>
</tr>
<tr>
<td>Overhead Line Patrol</td>
<td>5</td>
<td>4</td>
</tr>
<tr>
<td>Vault Inspection</td>
<td>5</td>
<td>6</td>
</tr>
</tbody>
</table>

Note 1: We removed the Switchgear Replacements from the study due to lack of comparative data from the peer group (only one switchgear replacement from the 17 electric utilities over the three-year period).

c) As described in Section 2 – Executive Summary of UMS Group Benchmarking Study, THESL is in a strong position with respect to unit costs (2nd quartile or better in all but one of the asset categories / maintenance programs reviewed as part of the project).

d) Presuming continuance of the external factors included in Table B-2 (found in Appendix B of the UMS Group Benchmarking Study), UMS Group would anticipate incremental (in contrast to stepped) improvements in unit costs moving forward.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION

INTERROGATORIES

INTERROGATORY 4:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 6, 7, Table 1

a) For Reliability Targets please provide the numeric targets associated with “Maintain” or “improve” for SAIDI, SAIFI, FESI-6 and FESI-7.

b) Please compare the result to the data for SAIDI, SAIFI/CAIDI provided to PSE for its 2020-2024 reliability projections.

c) Does TH have Targets for the following reliability measures? If so please provide these. If not please discuss why not:

i) CAIDI,

ii) MAIFI and

iii) Worst/poor Performing Circuits

RESPONSE:

a) Please refer to Toronto Hydro’s response to Interrogatory 2B-VECC-11 (a) for reasons why Toronto Hydro has provided targets without specific (numeric) values.

b) Please refer to Toronto Hydro’s response to interrogatory 1B-EP-1 (c).
c)  

i) Please refer to Toronto Hydro’s response to interrogatory 1B-Staff-14 (a) Table 1 for why THESL does not have target for CAIDI.

ii) Please refer to Toronto Hydro’s response to interrogatory 1B-Staff-14 (a) Table 1 for why THESL does not have target for MAIFI.

iii) THESL measures worst/poor performing circuits using FESI-7 and FESI-6. Please refer to part (a) of this question for why THESL hasn’t quantified the targets for these measures.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION

INTERROGATORIES

INTERROGATORY 5:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 6, 7, Table 1

a) For Cost Control please provide the baseline cost numbers for Wood Poles and Vegetation Management associated with “Monitor”.

b) Why has TH not set quantitative Targets for these costs? Please explain.

RESPONSE:

a) As these are new measures, baseline cost numbers for Wood Poles and Vegetation Management are not available. Please refer to Exhibit 2B, Section C2, pages 4-5, 22-23.

b) Please refer to Toronto Hydro’s response to interrogatory 2B-PWU-3, and 2B-VECC-11.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION

INTERROGATORIES

INTERROGATORY 6:

Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 17, Figure 1

a) Please discuss why the CAIDI trend in Figure 1 is “Flat”?

b) Please provide the CAIDI Metrics for each year 2013-2017

c) Please provide the latest SAIDI/SAIFI/CAIDI data for 2018

RESPONSE:

a) Toronto Hydro notes that there is actually a slight improvement in the trend line for CAIDI from 2013 to 2017. CAIDI is a function of both SAIFI and SAIDI, such that when there is a corresponding improvement in SAIDI and SAIFI metrics, it has a null effect on CAIDI. Because SAIDI has improved marginally faster than SAIFI over the 2013-2017 period, there is a slight improvement in CAIDI over this period.

b) Please refer to Toronto Hydro’s response to interrogatory 1B-SEC-17.

c) Toronto Hydro does not currently have this data finalized for 2018.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION
INTERROGATORIES

INTERROGATORY 7:
Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 18, Figure 2

a) Please provide more information on Momentary Interruptions since 2013
   Specifically,
   i) Please provide the Cause Codes for MAIFI
   ii) Please explain Why MAIFI is/is not improving with replacement of defective
equipment.

b) Is the definition/use of one minute interruption appropriate, given customers’
sensitive power equipment such as Computers/Modems, Microwaves, Digital
Clocks, Smart TVs etc.?

c) Please comment and specifically indicate if Toronto Hydro is advocating battery
back-up for all such equipment.

d) In EB-2013-0116 in its IR responses TH indicated it would monitor and track
momentary interruptions. Please provide a summary of the Data 2013-2018E.

e) Please discuss if Toronto Hydro is able to measure momentary interruptions of
less than one minute? Please define/indicate current technical limits.
RESPONSE:

a) MAIFI uses the same cause codes as SAIFI and SAIDI as per OEB Electricity Reporting and Record Keeping Requirements. Please refer to Toronto Hydro’s response to interrogatory 2B-EP-32 part (d) for MAIFI cause codes.

ii) As illustrated in Toronto Hydro’s response to interrogatory 2B-EP-32 part (d), defective equipment is a small contributor to MAIFI (approximately 16% based on the 5 year average). The majority of MAIFI is due to unknown causes (approximately 61 percent based on the 5 year average) or external causes.

b) Toronto Hydro uses the one minute interruption definition as per the OEB Electricity Reporting and Record Keeping Requirements.

c) As per Toronto Hydro's Conditions of Service, Section 2.3.1 "Toronto Hydro will endeavour to use reasonable diligence in providing a regular and uninterrupted supply of electricity but does not guarantee a constant supply ", and "Consumers or Customers requiring higher degree of security than that of normal electricity supply are responsible to provide their own back-up or standby facilities. Consumers or customers may require special protective equipment at their premises to minimize the effect of momentary power interruptions."

While Toronto Hydro does not advocate any particular technological approach to enhancing the reliability, power quality, or other attributes of the electricity that a customer receives from the grid, per the foregoing, Toronto Hydro is mindful that

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1 OEB Electricity Reporting and Record Keeping Requirements
some customers may choose to do so. In some instances, Toronto Hydro can assist individual customers or groups of customers on a particular feeder in doing so, such as through Energy Storage Systems, as described in Exhibit 2B, Section 7.2.

d) Historical MAIFI results are available in Exhibit 1B, Tab 2, Schedule 2, page 18, Figure 2: MAIFI. Toronto Hydro does not currently have this data finalized for 2018.

e) Toronto Hydro is able to measure momentary interruptions of less than one minute on feeders that have SCADA-enabled relays at the station circuit breakers. However, not all station circuit breakers have SCADA-enabled relays.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION
INTERROGATORIES

INTERROGATORY 8:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 10

a) Confirm Figures 11 and 12 show a reduction in outages due to defective
equipment of ~8% (SAIFI) and ~5% (SAIDI).

b) Discuss reasons why Toronto Hydro attributes this improvement to increased
Replacement Capital investment.

c) Confirm that for SAIFI, unknown cause events have increased from ~20% to 30%
apparently offsetting gains from replacing defective equipment.

d) Has Toronto Hydro attempted to determine the reasons/causes for this trend?
Please discuss.

e) Discuss if the “unknown” designation used by TH is appropriate.

f) Please discuss how TH is attempting to diagnose and remedy increased frequency
of unknown events/interruptions.

RESPONSE:

a) Please note that the numbers shown in Figures 11 and 12 are not percentages but
rather the SAIFI and SAIDI results.
- SAIFI had a ~15% improvement between 2013 and 2017 (From 0.53 to 0.45)
- SAIDI had a ~9% improvement between 2013 and 2017 (From 0.46 to 0.42)

b) The replacement of aging infrastructure and equipment in Toronto Hydro’s distribution system has a direct effect on the number of failures as newer equipment has a lower likelihood of failure.

c) Please note that the numbers shown in Figure 11 are not percentages but rather the SAIFI results (Average Number of Interruptions per Customer). SAIFI with ‘Unknown’ cause code has increased from 0.20 Outages to 0.30 Outages between 2013 and 2017. They have offset some gains in other categories leading to an overall flat SAIFI.

d) Toronto Hydro regularly reviews feeders for outage patterns and trends over a period of time, and even individual outages. In many of these cases, these ‘Unknown’ outages do not have any patterns. For example, in 2017, there were over 150 outage incidents with an ‘Unknown’ cause code. These outages were spread out across 115 distinct feeders, with very few feeders having repeated issues. The causes of these outages are typically attributed to tree contacts, weather events, animal contacts, or even contamination causing flash overs. However, once the fault condition has cleared and the power is completely restored, there is no easy way to identify the root cause.

e) Toronto Hydro follows the OEB Electricity Reporting and Record Keeping Requirements, and Canadian Electricity Association rules for the reporting of unknown events.
f) As described in part d), Toronto Hydro regularly reviews outage patterns and trends to minimize outage impacts to customers. Also, as part of Toronto Hydro’s Preventative and Predictive Maintenance programs (see Exhibit 4A, Tab 2, Schedule 1 and 2) and Reactive and Corrective Capital program (see Exhibit 2B, Section E6.7), Toronto Hydro regularly performs inspections and addresses deficiencies thereby having a positive impact on system reliability.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION
INTERROGATORIES

INTERROGATORY 9:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, Page 10, Poor Performing Circuits-
Innovative Survey, Appendix 2.1, Page 32,
Exhibit 2B, Section E6.7

a) Please define Poor Performing Circuits per IEEE or CEA and/or if TH has different
definition to that accepted by the Board. Delineate Overhead vs Underground if
possible.

b) Please list/group PPCs by type(s) and for each type/group, the remedial actions
2013-2017 and 5 year Capital Investment.

c) Please add the 2018 YTD Performance re PPC Customer Interruptions.

d) For the CIR Period 2020-2024 provide the list of Poor Performing circuits to be
dealt with under the DSP, and the associated capital investments.

e) Please provide the specific performance Targets for PPCs for the 5 year CIR period
2020-24. Are these on the Scorecard?

f) How many PPCs will remain after the CIR period?
RESPONSE:

a) Poor Performing Circuits is referring to Toronto Hydro’s Worst Performing Feeders Segment of the Reactive and Corrective Capital Program. This is a program that has been defined by Toronto Hydro to improve overall service reliability for customers supplied from poorly performing feeders. There is no delineation between overhead and underground feeders. Please refer to Exhibit 2B, Section E6.7.3.3 for more details.

b) Please refer to part (a) for the definition and what the Worst Performing Feeder Program encompasses. Please refer to Exhibit 2B, Section E6.7.3.3, E6.7.4.2 for the work completed in the past and planned for the upcoming years.

c) Please refer to Exhibit 2B, Section E6.7.3.3 for the definition of Worst Performing Feeder. Toronto Hydro does not currently have this data finalized for 2018.

d) Since feeder performance varies over time, the specific feeders that make it to the list of Poor Performing Circuits or Worst Performing Feeders cannot be predicted. Capital Investments are prepared for an as-realized basis focusing on mitigation to be completed on the Poor Performing Circuits as a short term mitigation measure. Please refer to Exhibit 2B, Section E6.7.4 for the expenditure plan.

e) Toronto Hydro tracks the performance of Poor Performing Circuits using the FESI-7 system and FESI-6 large customer’s measures. Please refer to Toronto Hydro’s response to interrogatory 2B-VECC-11.
f) As discussed in part (d), the list of Poor Performing Circuits is dynamic. Therefore, 

Toronto Hydro cannot predict how many Poor Performing Circuits will remain at the end of the CIR period.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION

INTERROGATORIES

INTERROGATORY 10:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, Tables 6 and 7

Preamble:
EP wishes to understand better the 2018 PSE Econometric Model at a similar level of detail as provided in the 2014 Report and Evidence (EB-2014-0116 Exhibit B, Tab 2, Schedule 5).

a) Please provide the full PSE Econometric Model specification and formulation in reasonable detail with explanatory notes.

b) Please provide additional information as to how the T-statistic for the Explanatory Variables was calculated and the significance of each of the Statistics.

c) Please provide more information on the Trend, Constant, Coefficients and the calculation of the adjusted R-Squared.

d) Please provide a Comparison Table with the 2014 Model/Report Table 4 and the 2018 Model/Report Table 6. List and discuss the rationale for, the changes to the Explanatory Variables, including specifically addition of Congested Urban and Ontario Binary variables and elimination of Capital Price and Density.

e) Explain how these changes specifically address the Board’s concerns expressed in the EB-2014-0116 Decision.
f) Please describe/provide the THESL data for each of the variables underlying each of the coefficients and projections corresponding to the results presented in Table 7.

g) How did PSE determine the appropriate Coefficient for each cost variable? Please provide details of the methods.

h) Is the structure/formulation of the PSE model “standard” and used for other utilities (examples) or “custom” for Toronto Hydro please explain in terms of the Model specifications and variables.

i) Please indicate and show if and which variables/coefficients were changed to provide different/alternative benchmark costs and the associated statistics. Compare to the results in Table 7.

j) Please clarify how the Congestion and Underground plant variables are related. Please provide examples

**RESPONSE (PREPARED BY PSE):**

a) Please see the PSE working papers provided and Chapter 2 of the PSE Report, entitled “Total Cost Benchmarking Model: Dataset, Model Details, Variables.”

b) The T-statistic is the ratio of the estimated coefficient to the value of the standard error. Its significance is that it provides a measurement of whether the coefficient value is statistically significantly different from zero. If the T-Statistic has an absolute value of 1.645 or greater, we have 90 percent confidence that the variable coefficient
is statistically different from zero (i.e. we have 90 percent confidence that the variable has an impact on total cost).

c) The trend variable captures a general industry total cost level trend over the studied period. The time trend reflects the general industry cost trends. All other variables remaining equal, including inflation, it measures the industry expected cost change from moving to one year to the next. It is sometimes thought of as measuring the technological progress and efficiency gains from year to year. Time trend variables are often found in translog cost functions and econometric total cost benchmarking research. A similar variable was included in the 4GIR benchmarking models.

The constant is typically included in econometric modeling and provides the intercept of the total costs. The coefficients are estimates of the cost impact of each included variable. The adjusted R-Squared is a measurement of fit that shows the ratio of the variation in the sample that is explained by the variables, relative to the total variation in the sample.

d) Please refer to Toronto Hydro’s response to interrogatory 1B-SEC-20.

e) Please see the response to 1B-SEC-20 and Chapter 3 “The Board Three Key Areas on 2015 Total Cost Benchmarking” of the PSE Report.

f) Please see the working papers PSE provided. Specifically, for THESL data, the Excel spreadsheet titled “THESLdata.xls” will be most relevant to see the underlying data. The Excel sheet “Modeling Dataset” will contain all the THESL variables included in the model.
g) PSE put together a dataset of 1,318 observations. We then estimated an econometric model that automatically estimates the coefficients for each variable. We conducted the econometric process using the software tool EViews, version 10. However, there are many other econometric software tools available for use. On a more basic and somewhat simplified level, the econometric model estimates the coefficients and identifies the best combination of coefficients that minimizes the sum of the squares of the residuals of all the observations. The estimated coefficients “explain” total costs such that the squared errors (or residuals) are minimized.

h) There are “standard” elements to the model presented and “custom” elements. The standard elements are items such as the translog cost function. Most of the variables are standard type variables. One element that could be considered “custom” in terms of model specification and variables is the congested urban variable. However, in our opinion this should become a standard variable in cost benchmarking for utilities with congested urban centers. This variable is crucial to accurately benchmarking Toronto Hydro.

i) There is only one total cost model presented, and the variables and coefficients have been provided in Table 6.

j) The two variables measure two separate items. The congested urban variable measures the percentage of the service territory designated as congested urban. The underground plant variable measures the percentage of distribution plant that is underground plant. They are somewhat related in the sense that undergrounding power lines in congested urban settings will be far costlier than in non-urban settings. Please also see a description of these variables in Section 2.3.4 of the PSE Report.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION
INTERROGATORIES

INTERROGATORY 11:

Reference(s): EB-2018-0165, Exhibit 1B, Tab 4, Schedule 2, Table 7
EB-2014-0116, Exhibit B, Tab 2 Schedule 5, Table 6

a) With reference to the Total Cost projections provided in Table 6 and Figure 3 of the 2014 Report, please provide a comparison in graphical form to Total Costs to 2018 and the projection for 2019 and then to the current historic and projection in Table 7 and Figure 5 in the 2018 Report.

b) Comment on the differences and if these relate to
i) Changes to the Peer group
ii) Performance of the peer group (industry Total Cost/productivity)
iii) or TH performance/productivity.

c) Please discuss in detail why, based on the latest model results, in 2019 TH is still 18.6% lower cost relative to the peer group, even though its costs are similar to those projected in the 2014 Report for the IRM period.

d) Please provide a discussion regarding what the models indicate regarding trends in industry Total Cost and TFP since 2010 and projections for the next 5 years.
RESPONSE (PREPARED BY PSE):

a) The requested comparison between the cost levels in the 2014 report and the current report is not a meaningful or practical exercise because the cost definitions have been modified with high voltage expenses being added, bad debt expenses subtracted, and CSI expenses subtracted. Further, there are different assumptions on items like the OEB approved rate of return which will influence the capital cost portion of total costs. So this requested cost comparison cannot be done in a way that would provide meaningful information.

A comparison can be made on the benchmarking scores between the studies. In the 2014 results, Toronto Hydro was projected to be 3% below benchmark costs in 2018 and 2% below benchmark costs in 2019. For the current results, Toronto Hydro is projected to be 12.7% below benchmark costs in 2018 and 11.6% below benchmark costs in 2019. This difference mainly reflects a more precise measurement of the congested urban cost driver.

b) The peer group in the tables referenced for the 2014 study included the combined sample of Ontario plus the U.S. utilities. The current study only includes six other Ontario distributors. However, more variables are able to be included than the previous model and a vast improvement has been made in the congested urban variable. The current research more accurately evaluates Toronto Hydro’s cost performance because of this variable improvement.

Regarding the performance of the peer group, in terms of productivity, the trend variable will serve as a proxy for the total factor productivity (TFP) estimate of the industry, with the caveat that there will be items like economies of scale that won’t make the trend variable exact. In the current research of the U.S. distributors, we
have a trend variable of -0.005. This implies that total costs are being reduced each
year by 0.5% if all other variables stayed equal. This implies 0.5% average annual
growth in the U.S. TFP trend. The performance of Toronto Hydro is similar in both
studies. The utility is below its benchmark costs, but converging to the expected or
benchmark costs.

c) The research enhancements have an impact on the benchmarking evaluation and
results. Most notably, the enhanced congested urban variable provide a more precise
measurement of the cost challenges of a utility serving a congested urban core, such
as Toronto Hydro. Other research improvements in the sample and methodology
detailed in the response to 1B-SEC-20 are also impacting the result.

d) The model does not specifically indicate trends from 2010 onwards, it produces
estimates for the entirety of the sample period, which starts in 2002. Regarding what
the models indicate over the entire term of the sample, in terms of productivity, the
trend variable will serve as a proxy for the total factor productivity (TFP) estimate of
the industry, with the caveat there will be items like economies of scale that won’t
make it exact. In the current research of the U.S. distributors, we have a trend
variable of -0.005. This implies that total costs are being reduced each year by 0.5% if
all variables stayed equal. This implies 0.5% average annual growth in the U.S. TFP
trend. The performance of Toronto Hydro is similar in both studies. The utility is
below its benchmark costs, but converging to the expected or benchmark costs.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION
INTERROGATORIES

INTERROGATORY 12:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, PSE Report p. 4 and 15/16
Exhibit 1B, Tab 4, Schedule 3, PEG Benchmarking Data

a) Please compare the Input Parameters listed and, in particular, the Ontario Sample
to those in the PEG Report. Please provide a Tabulation of the TH data set
(including 2018-2024 projections) and provide sources and explanations for each
of the values.

b) For CSI/CDM costs please provide a Table that shows for the Sample the amounts
eliminated for each and as a percentage of cost.

c) Please explain in detail why PSEs result shows TH Total Costs are 18.7% below the
PSE Benchmark moving to 6% less in 2024 compared to the PEG Benchmark
showing Toronto Hydro Cost Performance is 54% of peer group that is above.

d) Discuss which result (PEG or PSE) should ratepayers and the OEB use in setting the
CIR rate plan and the X/stretch factor and list all of the reasons why the Board
should adopt the PSE recommendation?

RESPONSE (PREPARED BY PSE):

a) Please see the response to 1B-SEC-20. For the sources and explanations of each of
the values, please see p. 17 through 21 of the PSE Report. For the data value, please

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see the working papers; most notably the file titled “Modeling Dataset.xls” will have all the variable values.

b) Please see the working papers in the file titled “Modeling Dataset.xls”. The CSI expenses for each utility in each year can be found in column X, which is labelled “ccsi”. The total costs can be found in column V, which is labelled “ctot”.

c) The differences reflect the differences in the two models and underlying datasets. The most notable include:

- PSE’s dataset includes U.S. distributors that are far more comparable in terms of size and characteristics than PEG’s Ontario-only sample,
- PSE includes adjustments for the cost challenges and realities of serving a congested urban service territory and the added costs of undergrounding lines in those territories. The PEG model has no adjustment for the congested urban realities of Toronto Hydro and the cost implications of them.
- PSE includes a capital price levelization that adjusts for the cost differences in serving higher or lower cost cities and regions. The PEG model does not adjust for these differences.
- PSE includes other added variables that provide enhanced adjustments for the specific circumstances of the sample (see the response to 1B-SEC-20 for a list of the difference variables included).

d) Our view is that PSE’s recommendation on the appropriate stretch factor for Toronto Hydro is reliable and should be adopted for a number of reasons, including those outlined in the PSE Report and the following summary. The PSE dataset includes a U.S. sample plus six Ontario distributors with congested urban characteristics. This is more appropriate and useful in benchmarking Toronto Hydro compared to the
Ontario-only sample used in the PEG model. That is because using an Ontario only
sample does not include distributors that have variable values and sizes that
encompass the values of Toronto Hydro. Toronto Hydro is an outlier in terms of size
and urban characteristics relative to an Ontario-only sample. Further, the PSE model
includes the best available measure of congested urban service territory. This variable
enables an accurate depiction of the cost challenges that Toronto Hydro faces in
serving a large urban city such as Toronto. The PEG model has no such variable and is
not adjusting for this fundamental characteristic in Toronto Hydro’s case. PSE’s other
explanatory variables, such as using GIS for the percent forestation and elevation
standard deviations, also produce a more accurate adjustment for service territory
characteristics. The PSE model also adjusts for the varying costs of constructing
capital between cities and regions whereas the PEG model has no such correction.
This adjustment is especially important for a utility serving a higher cost area like
Toronto. PSE has built on the general benchmarking approach and underlying
methodology used by PEG and improved upon it to better and more accurately apply
it to Toronto Hydro and the realities of its service territory and circumstances. This
response is without prejudice to our ability to respond or make any comment to any
report filed by PEG in this proceeding.

We believe we have adequately addressed the three key benchmarking areas
identified in the Board Decision in Toronto Hydro’s last CIR application. These were
the urban variable, CDM expenses, and the asset price inflation projection. Regarding
the urban variable, we have examined every single city in the U.S. served by a utility in
the sample over a population of 200,000 and mapped its congested urban service
territory to its entire service territory. This has produced a continuous variable, rather
than the simpler “0” or “1” binary variable approach. Rather than only four utilities
being designated as having highly urban characteristics, now over 40 utilities in the
sample have a percentage of congested urban assigned to them. This provides a more
precise and accurate estimate of the cost challenges of serving a congested urban
service territory.

Regarding CDM expenses, in Toronto Hydro’s last application a concern was raised
that some of the U.S. utilities included CDM expenses in their customer service and
information (CSI) cost category, and this would unfairly advantage Toronto Hydro,
which does not include CDM expenses in their CSI category. During the last
application, PEG addressed this issue by excluding CSI expenses for the entire sample.
PSE believes that approach is a reasonable one and has adopted it for the current
study. This should alleviate any concern that U.S. CDM costs are inflating Toronto
Hydro’s total cost benchmarks.

The third area was the asset price inflation projections for future years. In the last CIR
application, PSE used the historical growth rate of the asset prices to form the basis
for the projected asset prices in the CIR period. This produced a fairly rapid inflation
rate of 4.55% compared to general economy-wide inflation rate. PSE has modified
that assumption to follow the projections produced by the Conference Board of
Canada for “Engineering Structures, Electric power generation, transmission, and
distribution”. This produces an asset inflation assumption of 2.18% for the CIR period.
This is the same approach PEG took in their Oshawa PUC research (EB-2014-0101),
and PSE believes this should help alleviate any concern in this third area.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION
INTERROGATORIES

INTERROGATORY 13:

Reference(s): EB-2018-0165 Exhibit 1B, Tab 4 Schedule 2, p. 44 ff, Tables 2 & 3, Figures 2 and 3
EB-2014-0116 Exhibit B, Tab 2, Schedule 5, Table 15 and Figures 4&5

Preamble:
PSE States: We find that Toronto Hydro’s 2015-2017 average SAIFI is 47.2% above the benchmark value. Our research on Toronto Hydro’s 2015-2017 average CAIDI indicates that the reliability level is 63.4% below the benchmark value.

a) Please provide the full specification/details of 2018 PSE Reliability Econometric Model including the TH input values for variables and the coefficients.

b) Please provide a Comparison Summary Table with the 2014 Model.

c) Please confirm the definition(s) used for CAIDI dataset.

d) With reference to the Reliability (SAIDI/SAIFI) projections Provided in Table 15 and Figures 4 and 5 of the 2014 Report: please provide a comparison in graphical form to the current projection in the 2018 Report.

e) Please comment on the differences and if/how these relate to the Peer group or TH.
f) How does the Model provide Reliability projections for the 2018-2024 forecast period? Please explain the approach and methodology in reasonable detail. Specifically indicate if regression of historic data is used to generate the projections.

g) If the projections are provided by TH please provide a copy of these and discuss how using these data differs from a statistical projection.

h) Please provide a discussion regarding if the models show Reliability is/is not improving as shown for each indicator
   i) For the Industry Peer group sample
   ii) For TH (given the increase in TH capital investment).

RESPONSE (PREPARED BY PSE):

a) Please see the response to interrogatory 1B-Staff-37 (e). For the Toronto Hydro variable values, please see the working papers, most notably the Excel file “THESLdata.xls”.

b) It is unclear what specific comparison this question is requesting. In general, a raw comparison to the 2014 Model should not be made and would not provide meaningful information because PSE did not exclude major event days (MEDs) in the 2014 research, but has in the current research. The reason PSE did not exclude MEDs in the 2014 research was because we included all of the Ontario distributors in the dataset, and MED-excluded data was not available. Given our focus on a U.S. dataset in the current research, we were able to exclude MEDs which in our view is an improved approach.
c) The definition for CAIDI is the customer average interruption duration index. It is the average outage time per outage for an average customer on the system. The CAIDI values exclude major event days (MEDs) and include loss of supply.

d) Please see the response to part (b) of this interrogatory.

e) Please see the response to part (b) of this interrogatory.

f) The projections are based on projecting all of the explanatory variables for the future years, and then using the estimated equation that results from the regression to calculate the expected SAIFI or CAIDI given those variable projections. The regression coefficients are generated from the historical dataset.

g) The projections are provided by Toronto Hydro. They can be found in the working papers in the file titled “THESLdata.xls”. The Toronto Hydro reliability projections are what Toronto Hydro projects based on the utility’s projection methodology which can be found in Exhibit 2B, Section D3.2.1.3, Part 2. Reliability Projections. This is different from PSE’s statistical projections, which are based on what the model would expect from a hypothetical utility with the exact same variable values as Toronto Hydro.

h) The model does not reveal if reliability is or is not improving for the industry. Toronto Hydro’s SAIFI is projected to improve relative to the PSE benchmarks, and its CAIDI is projected to get worse relative to the PSE benchmarks (but to still be below benchmarks). Both are converging closer to the benchmarks during the CIR period.
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION

INTERROGATORIES

INTERROGATORY 14:

Reference(s): Exhibit 1B, Tab 2, Schedule 2, Tables 2 and 3 and Figures 2, 3, 6&7

Preamble:

PSE’s reliability benchmarking analysis indicates the following findings:
1. Historical SAIFI metrics for T H are considerably higher than the benchmark values.
2. Projected SAIFI metrics remain higher than the benchmarks.
3. Historical CAIDI metrics for TH are considerably lower than the benchmark values.
4. Projected CAIDI metrics for TH continue to be lower than the benchmark values.

a) Please confirm/clarify if the PSE historic and projected SAIFI and CAIDI chart data sets are
   i) with or without LoS
   ii) with or without MEDs
   iii) with or without scheduled maintenance
   iv) with or without sustained outage (excluding MAIFI outages<1min).

b) Please provide a data set that uses identical data as projections set out in the TH evidence without LoS and MEDs.

c) Please revise Figures 2 and 3 and 6 and 7 to be consistent the SAIDI/SAIFI charts in the DSP.

d) Confirm/amend your conclusions as appropriate.

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RESPONSE (PREPARED BY PSE):

a) Toronto Hydro provided PSE data that includes LoS and scheduled maintenance. The data excludes MED outages. The sustained outage definition is 5 minutes or greater. The U.S. sample also excludes MED outages. Although the data sources do not indicate, we believe most of the reported indexes include LoS and scheduled maintenance. However, if a few utilities exclude these, that would likely harm Toronto Hydro’s benchmarking results. A large majority of the U.S. distributors use the 5-minute sustained duration definition.

b) This data is not available.

c) We are unclear which specific charts are being referred to in the DSP, or what revisions to Figures 2, 3, 6, or 7 are being requested (or whether those would be relevant or meaningful to do).

d) Please see the response to part (c) of this interrogatory.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 1:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 3 of 34, lines 9-24

THESL uses the term “extreme weather” throughout the evidence. What is THESL definition of Extreme Weather?

RESPONSE:
The term “extreme weather” refers to weather considered to be unexpected, unusual, severe, unseasonable, or at the edges of the historical distribution (i.e. range) of weather that has been experienced. From an operational perspective, an extreme weather event is any abnormal weather that directly results in or has the potential to result in a large outage and/or a large number of outage events (high wind/gusts, high freezing rain accumulation, heavy rain accumulation, abnormally high temperatures for an extend period of time, etc.). Where the term “extreme weather” is used in the evidence, its context should be considered, as it may reference a particular environmental factor (e.g. wind, rainfall, temperature) or a combination of factors that put Toronto Hydro’s distribution system at risk.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 2:

Reference(s):  Exhibit 1B, Tab 1, Schedule 1, p. 3 of 34, lines 9-24

If it is based on wind speed, accumulated glace ice, amount of water on the ground, etc. what are the values? [sic]

RESPONSE:

Please refer to Toronto Hydro’s response to interrogatory 1B-Hann-1.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 3:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 10 of 34, line 14-16

What is impact on SAIDI and SAIFI if the feeders and interruptions for the “densely populated downtown core are removed from 2009-2017? [sic]

RESPONSE:
Feeders within Toronto Hydro’s service territory do not have specific boundary limits or categorization in regards to customer density, and it is not possible to distinguish which customers were interrupted in these specific areas based on the outage data collected by Toronto Hydro.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 4:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 11 of 34, line 3-6

What are the criteria for useful life?

RESPONSE:
Please refer to Toronto Hydro’s response to interrogatory 1B-CCC-12.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 5:

How much of the asset base is beyond Maximum Useful life?

RESPONSE:

Approximately 18 percent of Toronto Hydro’s asset base is beyond Maximum Useful life.

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 11 of 34, lines 3-6
RESPONSES TO ND HANN INTERROGATORS

INTERROGATORY 6:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, pp. 13, 14 of 34, lines 3-9 and 1

Table 1 Months of Extreme Weather (January 1 2017 through June 2018)

What are the design loads for wind in KPH and/or ice in mm including overload factors?

RESPONSE:

For overhead systems, 12.5 mm radial thickness of ice, 400 N/m² horizontal wind loading, and -20 degree Celsius temperature are used to determine loads and maximum tensions. These values are based on CSA C22.3 No. 1 “Overhead Systems” standard.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 7:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, pp. 13, 14 of 34, lines 3-9 and 1 Table 1 Months of Extreme Weather (January 1 2017 through June 2018)

Provide evidence including dates of events where the actual loads of wind and/or glace ice exceeded the design loads.

RESPONSE:

Toronto Hydro tracks customer outages due to weather events by cause codes such as Adverse Environment and Tree Contacts. However, it does not specifically track the information requested. For weather events that resulted in significant impacts to Toronto Hydro’s distribution system, please refer to Appendix C – Forensic Analysis of Weather Related Power Outage Events of Exhibit 2B, Section D, Appendix D and Exhibit 1B, Tab 1, Schedule 1, Table 1. For comparable storm data for the previous 18 months, please refer to Toronto Hydro’s response to interrogatory 1B-BOMA-6.

Toronto Hydro designs its system in line with standard utility practice. For overhead systems, the system is designed to the CSA C22.3 No. 1 “Overhead Systems” standard. For underground systems, the system is designed to the CSA C22.3 No.1 “Underground Systems” standard. These include requirements for combined loads of ice, wind, and temperature, as provided in Toronto Hydro’s response to interrogatory 1B-Hann-6.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 8:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 15 of 34, lines 9-15

Why does the system not withstand the design loads including overload factor?

RESPONSE:
Please see Toronto Hydro’s response to interrogatory 1B-Hann-7.

Due to the effects of climate change, weather events are becoming more frequent and have increased reliability risks for Toronto Hydro’s distribution system. To better understand the risks related to increases in extreme and severe weather due to climate change, Toronto Hydro completed a vulnerability assessment of its infrastructure (Exhibit 2B, Section D, Appendix D). Following this study, Toronto Hydro developed a climate change road map, along with initiatives relating to climate data validation, review of equipment specifications, and review of the load forecasting model. For further information on these initiatives and Toronto Hydro’s ongoing efforts to renew and enhance its system to changes in the weather and climate, please refer to Exhibit 2B, Section D2.1.2.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 9:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 16 of 34, lines 1-5

Why does the system not withstand the design loads including overload factor?

RESPONSE:
Please refer to Toronto Hydro’s response to interrogatory 1B-Hann-8.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 10:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 32 of 34, lines 1-4

Please refer to the evidence to support the statement “The risk to the utility’s deteriorating is compounded by increases in the frequency and magnitude of extreme weather.”?

RESPONSE:

Please refer to Exhibit 2B, Section D2.1.2 and please also refer to Exhibit 2B, Section D, Appendix D.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 11:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 15 of 34, line 1-3

Did the extreme weather events in 2017 or the aging of the urban forest and in particular invasive species such as the Norway Maple with a life span of 20-40 years, result “in a 72 percent increase in the number of customer interruptions attributed to tree contacts compared to the average of the previous five years.” [sic]

RESPONSE:
The customer interruptions referenced all occurred during weather events and weather was a primary cause of the interruptions. Toronto Hydro does not have information that would suggest the aging of the urban forest or the presence of invasive species such as the Norway Maple was a significant contributor to the “72 percent increase” in the number of customer interruptions in 2017 relative to the average of the previous five year.

Toronto Hydro does recognize that the City of Toronto’s tree canopy, along with factors such as age, invasive species, and disease, is a risk to system reliability. Toronto Hydro manages this risk through programs such as the Preventative and Predictive Overhead Line Maintenance program, and in particular the Vegetation Management segment (Exhibit 4A, Tab 2, Schedule 1, Section 7), the Overhead System Renewal program (Exhibit 2B, Section E6.5), and the Area Conversion program (Exhibit 2B, Section E6.1).
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 12:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 15 of 34, line 1-3

Is the aging urban forest the issue, since trees that were planted in “fields” in the 1960’s in Etobicoke, Scarborough and North York are now 50 years older, taller and in some cases weaker due to age, disease and infestations? If not, please explain why.

RESPONSE:

Please refer to Toronto Hydro’s response to interrogatory 1B-Hann-11.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 13:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 15 of 34, line 13-15

How many underground vaults and cable chambers are vulnerable to flooding? What has been done to:

a) Improve the design of new vaults and cable chambers?

b) Protect existing vaults and cable chambers?

RESPONSE:

Approximately 1,100 vaults and 3,400 cable chambers are in Toronto’s high water table and are vulnerable to flooding.

a) Toronto Hydro has improved the design of new cable chambers and vaults by minimizing ground water intrusion and ensuring soak-away pits and drains are installed where possible. In addition, new civil infrastructure are located away from groundwater and low points on sidewalks.

b) Toronto Hydro has addressed flooding concerns in existing vaults through continuous maintenance activities, and has improved drainage by removing debris and installing backwater valves in drains.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 14:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 15 of 34, line 13-15

Is there a predominate area in the service territory where flooding of the underground vaults and cable chambers is a chronic problem? Please identify on a map the areas where flooding is a chronic problem in underground vaults and cable chambers.

RESPONSE:

Toronto Hydro’s high water table exists predominantly south of Queen’s Quay in the downtown area. These sections have been identified to have high and medium risk. Toronto Hydro targets these locations for appropriate drainage and maintenance work accordingly. Please refer to Figures 1 and 2 below.
Figure 1: Cable chambers and associated flood risk

Figure 2: Vaults and associated flood risk
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 15:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 33 of 34, lines 11-19

What design criteria changes are being or have been made “to extract the full value out of distribution equipment through programs that perform preventative, predictive, and corrective maintenance on the deteriorating infrastructure” from 2008-2017 related to pole design, pole hardware and underground vaults? [sic]

RESPONSE:
Toronto Hydro regularly reviews its design, materials, construction and maintenance standards to ensure they are in alignment with principles such as safety, reliability, and efficiency, as well as follow industry best practices. Please refer to Exhibit 2B, Section D, Appendix B, which contains Toronto Hydro’s Standards Review – 2018 Update completed by Power System Engineering, Inc., for this discussion.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 16:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 33 of 34, lines 11-19

Please provide a list of fuse coordination studies, the feeder and station studied, when they were implemented, number of interruptions at the feeder switch in the station before and after the fuses were recoordinated? [sic]

RESPONSE:

Please see the Table 1 below. Toronto Hydro’s experience has been that fuse coordination studies have not yielded material improvements (i.e. approximately 2 percent) to reliability. Please note that fuse coordination studies are undertaken for a variety of reasons in addition to reliability performance. These reasons include, breaker equipment upgrades, feeder reconfigurations, and feeder extensions.

Table 1: 2010 -2018 Fuse Coordination Studies

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<th>Study Year</th>
<th># of Interruptions</th>
<th>Avg. Per Year</th>
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RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 17:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 9 of 34, no line numbers reference below

Reference: We emphasize the importance of including U.S. distributors into any benchmark evaluation involving Toronto Hydro (or any other extreme outlier in the Ontario dataset). While an Ontario only dataset is appropriate for the clear majority of Ontario distributors, an Ontario-only dataset will not produce reliable results for Toronto Hydro, due to its outlier status within that dataset. This outlier status is shown by the fact that Toronto Hydro has over double the number of customers than the next largest distributor (prior to Alectra Utilities being formed), except for the extremely rural Hydro One Networks. Additionally, Toronto Hydro’s “congested urban” variable is over three times as large as the next closest Ontario peer.

Please provide segregated SAIFI, SAIDI with and without MED data for the downtown congested and horseshoe.

RESPONSE:

Toronto Hydro does not track reliability down to the “congested urban” area as defined by the PSE study. Feeders run in and out of the various “congested urban” area and as such, it is not possible to distinguish which customers were interrupted in these specific areas based on the outage data collected by Toronto Hydro.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 18:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 9 of 34, no line numbers reference below

Reference: We emphasize the importance of including U.S. distributors into any benchmark evaluation involving Toronto Hydro (or any other extreme outlier in the Ontario dataset). While an Ontario only dataset is appropriate for the clear majority of Ontario distributors, an Ontario-only dataset will not produce reliable results for Toronto Hydro, due to its outlier status within that dataset. This outlier status is shown by the fact that Toronto Hydro has over double the number of customers than the next largest distributor (prior to Alectra Utilities being formed), except for the extremely rural Hydro One Networks. Additionally, Toronto Hydro’s “congested urban” variable is over three times as large as the next closest Ontario peer.

Please compare the horseshoe segregated SAIFI, SAIDI with and without MED data with appropriate Ontario LDC’s.

RESPONSE (PREPARED BY PSE):

The explanatory variable values for the horseshoe segregated areas of Toronto Hydro are not available and are not able to be disaggregated to make this comparison.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 19:
Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 19 of 29

The service territories and environments are very different in the list provided. [sic] Why are Ameren UE, Detroit Edison, Pacific Gas and Electric, SaskPower Southern California Edison and Xcel Energy comparable utilities?

RESPONSE (PREPARED BY UMS GROUP):
Please refer to the response to 1B-SEC-15 part (c), which outlines the criteria UMS Group used to create the initial list of 20 electric utilities to form the peer group. For those utilities that have larger rural areas (e.g. Ameren UE, Detroit Edison, Pacific Gas and Electric, SaskPower Southern California Edison and Xcel Energy), UMS Group narrowed the request for unit cost data to those districts within their service territories that serve the larger population centers, so that it more closely resembles Toronto Hydro’s demographics and operating environment.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 20:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, pp. 8, 9 of 21, lines 14-17, 1-5

Where are the remotely operated switches located on the system?

RESPONSE:

The remotely operated switches are installed in different parts of a feeder to form tie and sectionalizing points. These remotely operated switches are located mostly on poles and concrete foundations.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 21:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, pp. 8, 9 of 21, lines 14-17, 1-5

Are the new remotely operated switches located on the feeders or at the stations?

RESPONSE:

The new remotely operated switches are located on the feeders.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 22:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 11 of 21, Figure 12: SAIDI Cause Code 1 Breakdown (Excluding MEDs)

Since THESL “tracks the cost code as a measure of continuous improvement in the execution of its capital expenditure and maintenance plans”. [sic]

a) How many defective equipment interruptions occurred,

b) How many fuse links were replaced during unplanned interruptions?

c) How many fused switches were replaced during unplanned interruptions?

d) How many poles were replaced during unplanned interruption? From 2013-2017.

RESPONSE:

a) 2,922 outages were caused by defective equipment from 2013-2017. Please see Table 1 for a detailed breakdown.

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>Total</th>
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<tbody>
<tr>
<td>Outages Caused By Defective Equipment</td>
<td>636</td>
<td>711</td>
<td>572</td>
<td>519</td>
<td>484</td>
<td>2,922</td>
</tr>
</tbody>
</table>

b) Toronto Hydro does not track the number of fuse links replaced specifically during unplanned outages and as such, is unable to provide the requested information.
1. c) Over the 2013-2017 period, 167 overhead disconnect switches were replaced due to outages caused by defective equipment.

2. d) Over the 2013-2017 period, 48 poles were replaced due to outages caused by defective equipment.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 23:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 11 of 21, Figure 12: SAIDI Cause Code 1 Breakdown (Excluding MEDs)

What is the definition of Defective Equipment cause used by the reporting staff, was it a blown fuse or a switch operating as it should have due to a fault on the line that was attributed to defective equipment? [sic]

RESPONSE:

Defective Equipment is a cause code defined by the Ontario Energy Board’s Electricity Reporting & Record Keeping Requirements document¹ as follows:

“Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.”¹

The OEB’s requirements further specify how outages should be categorized into the various cause codes based on the cause.

RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 24:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 11 of 21, Figure 12: SAIDI Cause Code 1 Breakdown (Excluding MEDs)

Is it a Defective Equipment failure because the insulator wasn’t washed?

RESPONSE:

Toronto Hydro tracks causes of service interruptions using the ten primary cause codes as specified in the OEB’s Electricity Reporting and Record Keeping Requirements for the categorization of outages. As such, if the failure of an insulator is due to contamination, it is categorized as “Adverse Environment”, and if it is found to be defective (e.g. equipment failures due to deterioration from age, maintenance deficiencies), it is categorized as “Defective Equipment”. Please refer to Exhibit 1B, Tab 2, Schedule 4 for more details.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 25:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 11 of 21, Figure 12: SAIDI Cause Code 1 Breakdown (Excluding MEDs)

If the cause is actual defective equipment, what is the main defect that caused the majority of the interruptions and the impact on SAIFI?

RESPONSE:

Underground Cable failures are the largest contributor to Defective Equipment interruptions and the impact on SAIFI. Please refer to Exhibit 1B, Tab 2, Schedule 4, Figure 23.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 26:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 11 of 21, Figure 12: SAIDI Cause Code 1 Breakdown (Excluding MEDs)

What is the mode of failure exhibited to for poles, switches, conductor and insulators a) due to deterioration from age, b) incorrect maintenance, or c) imminent failures detected by maintenance? [sic]

RESPONSE:

Toronto Hydro follows OEB’s Electricity Reporting and Record Keeping Requirements for the categorization of outages. Defective equipment can encompass any of the above causes of interruption.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 27:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 12 of 21, lines 1-9

What was the performance of the section of the lines/feeders before and after the capital improvements? Please provide the dates, Number of interruption, number of customer interruptions, duration of interruption by line/feeder and year.

RESPONSE:

Toronto Hydro does not track the reliability impacts of specific section of lines/feeders before and after a capital project. The results of capital investments targeting performance are affected by numerous factors, including but not limited to:

- Toronto Hydro’s Outage Management System, which tracks outages at a feeder level;
- Scope/size/type of the capital project (i.e. some projects are minor, while others rebuild a large section of a feeder);
- Multiple projects carried out on the same feeder over a period of time (e.g. small projects being done year after year on a feeder);
- External factors (e.g. foreign interference or adverse weather); and
- The continuously changing size and configuration of feeders that may redistribute customers from one feeder to another.
**RESPONSES TO ND HANN INTERROGATORIES**

**INTERROGATORY 28:**

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 13 of 21, line 5-9

What is the correlation between the weather data and the associated interruptions?

a) For example, did the wind speed exceed the design standard with overload?

b) Did the accumulated glace ice exceed the design standard with overload?

**RESPONSE:**

As stated in the evidence in Exhibit 1 B, Tab 1, Schedule 1, page 15, extreme weather events in 2017 resulted in a 72 percent increase in the number of customer interruptions attributed to tree contacts compared to the average of the previous five years. Please see Table 1, in Exhibit 1B, Tab 1, Schedule 1, page 14 for a list and description of recent extreme weather events such as wind and ice storms that have affected Toronto Hydro’s customers. Please see Toronto Hydro’s response to 1B-Hann-7 for a discussion regarding dates of events where the actual loads of wind and/or glace ice exceeded the design loads.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 29:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 13 of 21, line 5-9

Since there have been improvements in distribution automation, why has the time an average customer is interrupted under weather impacts not improved except for 2014?

RESPONSE:

Weather events can vary significantly from year to year in terms of frequency and impact. As such, customers will experience a greater SAIDI impact in years in which there is a higher frequency and impact of storms. Please refer to Toronto Hydro’s response to interrogatory 1B-Hann-30.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 30:
Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 13 of 21, line 5-9

Does line 8/9 “improvements in 2014 can be attributed to relatively favorable weather conditions that year.” mean that system improvements had no impact on these indices and that SAIFI SAIDI improvement only occurs when all the days are “non storm days”?

RESPONSE:
Please see Figures 13 and 14 in Exhibit 1B, Tab 2, Schedule 4, page 13, which highlight the correlation between weather events and the impact on SAIDI and SAIFI.

Weather events can have a significant impact on system reliability as these events can vary drastically from year to year in terms of frequency and magnitude of the storms. If a major storm, or multiple major storms, occur in a specific year, its reliability impacts can counteract improvements achieved through system improvements. For example, 2013 experienced a number of storms including the December 2013 Ice Storm, which caused an increase in customer interruptions.

It should also be noted that reliability measures are lagging indicators of performance and therefore include the effects of investments made over many years. Please note that from 2013-2017, SAIFI and SAIDI have also improved as discussed in Exhibit 1B, Tab 2, Schedule 4. Please see Exhibit 1B, Tab 2, Schedule 2, Section 3 “Customer Average Interruption Duration Index” and Exhibit 1B, Tab 2, Schedule 2, Section 3 “Customer Average Interruption Duration Index”.

Panel: Distribution System Capital and Maintenance
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 31:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 19 of 21, lines 1-14

“This is mainly due to the 5 magnitude of these types of failures, which often disable large numbers of feeders.”, implies that it is an interruption, or number of interruptions that have occurred at the protective devises at the station. [sic]

a) What is being done to prevent the protective device operating at the station and have them operate near the actual fault on the line?

b) Were the poles actually replaced due to them being defective, were they replaced at all or was the switch operated? What was the defects in the poles? [sic]

c) Was the failure due to external forces being applied (e.g. a tree or tree branch)?

d) What is the failure mode of the insulators? Mechanical (e.g. breaking) or Electrical (e.g. flash over due to contamination)?

RESPONSE:

a) Toronto Hydro’s feeder design incorporates fuses on the lateral sections of feeders to minimize the need for the operation of the protective device at the station. Fuses are coordinated with station protective devices to enable this. However, if a fault occurs on the trunk of a feeder, then the station breaker will operate as designed.
Toronto Hydro’s proposed renewal investments will also introduce additional fuse locations in the system to increase the likelihood that a fuse operates near the fault on a line. An example of this may be found in the Area Conversion program, Exhibit 2B, Section E6.1, page 9, lines 12-15, through which legacy rear lot systems will be replaced with modern standards that include additional fuse locations. The System Enhancements program, Exhibit 2B, Section E7.1, also consists of investments that provide Toronto Hydro with additional operating flexibility, through the installation of switches and protective devices, and that reduce the risk of large interruptions.

b) In cases where interruptions were caused by defective poles, the poles were replaced. In cases where interruptions were caused by defective pole hardware, the pole hardware was replaced. Generally, switches were operated to isolate line segments to carry out the necessary replacements or repairs associated with the poles.

c) While external forces may have contributed to the failures, the primary cause of the failures described in the reference were determined to have been defective equipment.

d) The insulator failures referenced were determined to have been caused by defects in the insulator, either mechanical or electrical, which for insulators are often linked. In circumstances where the primary failure cause was contamination, these would not be captured under the defective equipment cause code.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 32:
Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 19 of 21, lines 1-14

What are the actual dates, numbers of interruptions, numbers of customer interruptions and durations of the interruptions caused by equipment in the conversion areas, before and after the conversions? Please provide a table with this information. Do not include interruptions outside of the conversion area that impacted the area.

RESPONSE:
Toronto Hydro is unable to provide the specific table requested due to reasons that include:

- For conversions that have been completed, Toronto Hydro’s reliability tracking tools and systems are not configured in a manner to enable comparisons of interruptions within only “the conversion area”; and

- Only a subset of all of the 4kV areas will be converted during the 2020-2024 period and the detailed scoping and design of work for those conversions has not been developed.

Despite the inability to provide the specific table, please see Exhibit 2B, Section E6.1, pages 5 to 11 for detailed reliability information related to area conversions, including lists of interruptions and comparisons of reliability performance. In addition, please see Toronto Hydro’s response to interrogatory 2B-AMPCO-54.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 33:
Reference(s): Exhibit 1B, Tab 2, Schedule 5, p. 1 of 1, OEB Appendix 2-G Service Reliability Indicators 2013 - 2017

THESL uses SAIFI as a measure of aging and deteriorating assets, please explain why SAIFI including MEDs is showing a downward trend (excluding 2013) in an environment of increasing storms and aging assets?

RESPONSE:

SAIFI is not a measure of aging and deteriorating assets, although aging and deteriorating assets may impact SAIFI. The Ontario Energy Board’s Electricity Reporting & Record Keeping Requirements document\(^1\) defines SAIFI as “an index of system reliability that expresses the number of times per reporting period that the supply to a customer is interrupted.” \(^1\)

Further, Toronto Hydro uses more than just reliability (such as the SAIFI measure) when assessing aging and deteriorating assets. Toronto Hydro must also consider the age and the condition of assets. Please refer to Exhibit 2B, Section D3 for details on Toronto Hydro’s Asset Lifecycle Optimization approach.

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\(^1\) “Electricity Reporting & Record Keeping Requirements”, p. 12, Ontario Energy Board, 2018, URL: https://www.oeb.ca/sites/default/files/RRR-Electricity-20181129-1.pdf

Panel: Distribution System Capital and Maintenance
Even though Toronto Hydro’s assets continue to age and deteriorate, and adverse weather events are unpredictable, the following factors have contributed to improved reliability:

- as described in the System Renewal Programs presented in Exhibit 2B, Section E6 as well as the System Enhancements Programs presented in Exhibit 2B, Section E7.1, Toronto Hydro invests in renewing and enhancing the existing distribution system to reduce the impacts and duration of outages due to storms; and

- through inspections and maintenance, assets that are at risk of imminent failure can be identified and replaced prior to them failing thereby preventing an unplanned outage. For more details, please refer to the Reactive and Corrective Capital program presented in Exhibit 2B, Section E6.7.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 34:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Appendix A, p. 19 of APPENDIX 1.1

Low-Volume Customer Focus Groups

What are the components that make up the delivery charge?

RESPONSE:

The Delivery Charge is made up of several components that cover the cost of getting power from generators to your home, and ensuring electricity is available when you need it. These charges cover the costs of transmission companies, as well as costs of distribution companies, such as Toronto Hydro. Our portion of your bill is invested into the local distribution grid to maintain safety and reliability of our infrastructure, help support a growing city, and enable us to plan for and respond to extreme weather.

The components of the Delivery Charge that Toronto Hydro is seeking approval of in this Application are set out in Exhibit 8, Tab 3, Schedule 2, in a series of Tariffs of Rates and Charges. The Tariffs also specify the rates that Toronto Hydro is requesting for each of those components.

In the proposed Tariffs, there are no components listed for rate riders that relate to Retail Settlement Variance Accounts. However, from time to time, the OEB orders rate riders to clear balances in those accounts. For example, see the 2018 Tariffs set out at Exhibit 8, Tab 3, Schedule 1, which provide for the clearing of the balance in a Global Adjustment account. These are examples of pass-through accounts that relate to other parts of the electricity system. In the case of Global Adjustment, it relates to the supply of the
electricity commodity (e.g. generation). These accounts ensure that any amounts charged by Toronto Hydro and any amounts paid by customers “pass-through” from each of those parties to the other parties, without any mark-up (i.e. rate of return, profit margin) charged by Toronto Hydro. Toronto Hydro is simply the billing agent so that customers only have to receive one electricity bill, instead of bills from the distributor, transmitters, generators, and other companies and organizations in the sector.

For a different view of the components of the Delivery Charge, please see Exhibit 8, Tab 6, Schedule 1. This section of the Application presents the Bill Impact tables. These tables organize the Delivery Charge into three categories: the items listed above “Sub-Total A” are the components most closely associated with the costs of distribution; the items listed next and ending at “Sub-Total B” are “pass-through” costs; and the last category for Delivery, which ends at “Sub-Total C” are for transmission rates, which are also “pass-through” in nature. Below Sub-Total C are other charges on the electricity bill that are also “pass-through” in nature, such as commodity and regulatory charges.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 35:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Appendix A, p. 19 of APPENDIX 1.1

Low-Volume Customer Focus Groups

Please provide the charges of each of these components from 2008-2017 for all 4 customer groupings. [sic]

RESPONSE:

Please see Appendix A to this response for the charges of each of these components from 2008-2017 for all customer groups. Key Accounts comprise customers from both the GS 1000-4999 kW and Large User class.
RESPONSE to 1B-HANN-35

TABLE 1 - 2008-2017 estimated bill components

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<th>2009 ($)</th>
<th>2010 ($)</th>
<th>2011 ($)</th>
<th>2012 ($)</th>
<th>2013 ($)</th>
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<th>2015 ($)</th>
<th>2016 ($)</th>
<th>2017 ($)</th>
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<td>General Service 50-999 kW - 200 kVA</td>
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</table>

Note 1: These numbers are an estimate for informational purposes only and based on multiple assumptions that will vary for specific customers within each class.
Note 2: Electricity Commodity is based on Regulated Price Plan
Note 3: Delivery (Distribution) refers to Sub-total B
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 36:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Appendix A, p. 31 of Toronto Hydro 2018 Customer Engagement Customer Feedback Portal Report Segmentation and Demographics

Why are Defective Equipment (36% of interruptions and Aging Equipment (36% of interruptions) the same values? [sic]

RESPONSE:

The value of the component labelled as “aging equipment” in the chart at the above-noted reference corresponds to the contribution of defective equipment to outages. The terminology “aging equipment” is consistent with the presentation of this chart in previous engagements with customers.¹

¹ EB-2014-0116, Exhibit 1B, Tab 2, Schedule 7, Appendix B, pg. 12 of the Residential Workbook.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 37:
Reference(s): Exhibit 1B, Tab 3, Schedule 1, Appendix A, p. 31 of Toronto Hydro 2018 Customer Engagement Customer Feedback Portal Report
Segmentation and Demographics

Does THESL not have any defective equipment and every interruption involving equipment is due to age?

RESPONSE:
Please refer to Toronto Hydro’s response to interrogatory 1B-Hann-23 for the definition of “Defective Equipment”. Age is one of the contributors to defective equipment, and defective equipment is one of the contributors to system interruptions.

Please also refer to Toronto Hydro’s response to interrogatory 1B-Hann-36.
INTERROGATORY 38:

What are the actual number of interruptions, and customer interruptions 2008-2017 for defective equipment?

RESPONSE:

Please see Table 1 below for number of interruptions and customer interruptions for defective equipment from 2008-2017.

Table 1: Reliability Impact of Defective Equipment (Outage Incidents & CI)

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of Outage Incidents</th>
<th>Total Customers Interrupted</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>803</td>
<td>582,999</td>
</tr>
<tr>
<td>2009</td>
<td>718</td>
<td>517,980</td>
</tr>
<tr>
<td>2010</td>
<td>724</td>
<td>488,566</td>
</tr>
<tr>
<td>2011</td>
<td>696</td>
<td>434,578</td>
</tr>
<tr>
<td>2012</td>
<td>557</td>
<td>453,218</td>
</tr>
<tr>
<td>2013</td>
<td>636</td>
<td>382,908</td>
</tr>
<tr>
<td>2014</td>
<td>711</td>
<td>387,519</td>
</tr>
<tr>
<td>2015</td>
<td>572</td>
<td>433,324</td>
</tr>
<tr>
<td>2016</td>
<td>519</td>
<td>370,901</td>
</tr>
<tr>
<td>2017</td>
<td>484</td>
<td>344,853</td>
</tr>
</tbody>
</table>

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Appendix A, p. 31 of Toronto Hydro 2018 Customer Engagement Customer Feedback Portal Report Segmentation and Demographics
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 39:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Appendix A, p. 48 in Appendix 2.1

In multiple locations in the evidence photos show “storms” with “trees”. How does capital replacement storm hardening eliminate these interruptions due to tree contact?

RESPONSE:

Capital replacements that harden the system against extreme weather will not eliminate interruptions due to tree contacts. Toronto Hydro does however have a number of programs that are aimed at reducing the number of tree contacts through design changes such as tree proof conductors (please refer to Exhibit 2B, Section E6.5 - Overhead System Renewal), as well as converting infrastructure that is more prone to tree contacts, or that makes it more difficult to resolve interruptions due to tree contact (please refer to Exhibit 2B, Section E6.1 - Area Conversions).
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 40:
Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 10 of 14, Table 3: Revenue Requirement Components for Determining Scap

What is the ROE if assets are run to the end of life, instead of remaining useful life 2021 – 2024?

RESPONSE:
If assets currently in service were run to the end of their lives (“EOL“), i.e. until they cease to operate as intended, as opposed to the end of the remaining useful lives (“RUL”), i.e. based on accounting policy, ROE may be greater or lesser depending on the situation.

For example (for a particular asset) if the EOL is sooner than RUL, ROE will be less. If EOL is later than RUL, ROE will be more. This is further complicated when the asset base includes a broad set of assets. Certain assets will reduce and others increase ROE. The net ROE result cannot be reasonably determined.
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 41:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 10, Figure 2 Toronto Hydro’s SAIFI Performance 2005-2024 13 of report point 3

Customer interruptions in SAIFI are dependent on a number of factors, what is the comparison of actual number of interruptions that have occurred on the assets from 2005 projected to 2024, segregated by 1-50, 51-500, 501 to 1000, 1001 to 5000 and greater than 5000 customers interrupted by a device? Please provide in table and chart format.

[sic]

RESPONSE:

Please see Table 1 and Figure 1 for 2005-2017 results. Toronto Hydro does not forecast customer interruptions. Toronto Hydro does not currently have this data finalized for 2018.

Table 1: Number of Outage Incidents (By CI of Incident)

<table>
<thead>
<tr>
<th>Year</th>
<th>1-50 CI</th>
<th>51-500 CI</th>
<th>501-1000 CI</th>
<th>1001-5000 CI</th>
<th>&gt;5000 CI</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>853</td>
<td>425</td>
<td>147</td>
<td>298</td>
<td>39</td>
</tr>
<tr>
<td>2006</td>
<td>744</td>
<td>394</td>
<td>164</td>
<td>314</td>
<td>41</td>
</tr>
<tr>
<td>2007</td>
<td>709</td>
<td>409</td>
<td>105</td>
<td>321</td>
<td>47</td>
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<tr>
<td>2008</td>
<td>665</td>
<td>397</td>
<td>127</td>
<td>304</td>
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<td>2009</td>
<td>610</td>
<td>373</td>
<td>101</td>
<td>248</td>
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<td>2010</td>
<td>618</td>
<td>334</td>
<td>101</td>
<td>255</td>
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<td>2011</td>
<td>638</td>
<td>323</td>
<td>107</td>
<td>277</td>
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<tr>
<td>2012</td>
<td>535</td>
<td>285</td>
<td>87</td>
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<td>2013</td>
<td>650</td>
<td>342</td>
<td>81</td>
<td>236</td>
<td>38</td>
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</tbody>
</table>

Panel: Distribution System Capital and Maintenance
<table>
<thead>
<tr>
<th>Year</th>
<th>1-50 CI</th>
<th>51-500 CI</th>
<th>501-1000 CI</th>
<th>1001-5000 CI</th>
<th>&gt;5000 CI</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>676</td>
<td>335</td>
<td>99</td>
<td>224</td>
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<tr>
<td>2015</td>
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<td>92</td>
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<td>2016</td>
<td>503</td>
<td>241</td>
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<td>2017</td>
<td>439</td>
<td>213</td>
<td>75</td>
<td>204</td>
<td>54</td>
</tr>
</tbody>
</table>

Figure 1: Number of Outage Incidents (By CI of Incident)
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 42:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 31 of 34, lines 6-13

How many pole top transformers fail each year listed by year of manufacture from 2008 to 2017?

RESPONSE:

Exhibit 2B, Section E6.5, Figure 7 at page 9 provides the age distribution for failed overhead transformers for the period of 2013-2017, based on the subset of pole top transformers investigated by Toronto Hydro’s Quality Program. However, as a result of information system limitations, Toronto Hydro is unable to provide the information requested going back to 2008.

Exhibit 2B, Section E6.5, Figure 4 also provides the total number of interruptions caused by pole-top transformers for the period of 2013-2017. The following table provides the same information for the prior period of 2008-2012.

Table 1: Pole Transformer Failures from 2008-2012 (Toronto Hydro ITIS Database)

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of Failures</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>72</td>
</tr>
<tr>
<td>2009</td>
<td>65</td>
</tr>
<tr>
<td>2010</td>
<td>95</td>
</tr>
<tr>
<td>2011</td>
<td>79</td>
</tr>
<tr>
<td>2012</td>
<td>55</td>
</tr>
</tbody>
</table>
RESPONSES TO ND HANN INTERROGATORIES

INTERROGATORY 43:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 31 of 34, lines 6-13

What is the difference in SAIFI by allowing to run to failure compared to a renewal approach?

RESPONSE:
Please refer to Exhibit 2B Section E2.2.2.3, page 15, and Figure 8 for the SAIFI Defective equipment impacts in a reactive scenario (which is a run to failure scenario for defective equipment). Toronto Hydro is unable to provide system-wide SAIFI projections due to the unpredictable nature of multiple factors that impact SAIFI.
RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 1:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 3, lines 4-5

"This is the second five-year plan filed by Toronto Hydro. The plan largely continues the methodology approved by the OEB for the 2015-2019 period."

a) Please identify any major differences between the methodology approved by the Board in the 2015-2019 application and the methodology that OPG has followed in the current application.

RESPONSE:

Toronto Hydro assumes that in reference to the current application, PWU intended to note “Toronto Hydro” rather than “OPG”. On that basis, there are no differences in the ratemaking methodology currently proposed by Toronto Hydro compared to the methodology approved by the Board in Toronto Hydro’s the 2015-19 application. Regarding the overall methodology of its application, Toronto Hydro has incorporated incremental guidance from the OEB in many areas, including developing an outcomes-based framework and custom measures, as well as an enhanced customer engagement process.
INTERROGATORY 2:

Reference(s):  Exhibit 1B, Tab 3, Schedule 1, Appendix A, p. 20
Exhibit 1B, Tab 5, Schedule 1, p. 1, Table 1

Exhibit 1B, Tab 3, Schedule 1, Appendix A, p. 20
"THESL's initial round of engagement occurred before the introduction of the Fair Hydro Plan and the second round occurred in the lead up to the 2018 Provincial Election campaign"

Exhibit 1B, Tab 5, Schedule 1, p. 1, Table 1

a) Did the second round of customer engagement include discussion of the Fair Hydro Plan and its impacts on customer bill?

b) Do the bill impacts in Table 1 above take the Fair Hydro Plan into consideration? If not, why not?

c) What are the drivers for the decrease in bill impacts in 2020?

RESPONSE:

a) No.

b) The bill impacts provided in Exhibit 1B, Tab 5, Schedule 1, Table 1 are based on the standard Bill Impacts defined by the OEB and filed at Exhibit 8, Tab 6, Schedule 1.
These bill impacts assume constant commodity and regulatory rates throughout the 2020-24 period, as required by the OEB's filing requirements. The Fair Hydro Plan addresses the commodity portion of the bill for Residential and GS <50 kW customers (and eligible customers not on RPP plan) and does not impact the distribution portion of the bill. The determination of the commodity rates under the Fair Hydro Plan are a function of the overall approved distribution rates (including rate riders), transmission rates, regulatory rates and the rate of inflation.

c) The primary drivers of decreasing bills in 2020 are: 1) expiration of existing rate riders at the end of 2019; 2) new proposed rate riders in 2020 which, in aggregate, result in a bill credit; and 3) a decrease in certain bill components due to proposed (lower) loss factors. These drivers and the consequential decrease in HST serve to offset the proposed increase in the base distribution charge.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2:
Reference(s): Exhibit 1B

Please provide a copy of all materials provided to the Toronto Hydro Board of Directors for approval of the proposed application and the underlying budgets.

RESPONSE:
Please refer to Toronto Hydro’s response to interrogatory 1A-CCC-1.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 3:
Reference(s): Exhibit 1B

Please provide a copy of all internal or external benchmarking reports, analysis, studies and/or similar documents undertaken by Toronto Hydro, or for Toronto Hydro, since 2015 that is not already included in the application.

RESPONSE:

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appendix B - Davies Consulting, 2016 Emergency Management Benchmark Update, December 30, 2016</td>
<td>This is an update to a benchmarking study submitted as part of Appendix B above that provides emergency management improvement opportunities for Toronto Hydro.</td>
</tr>
<tr>
<td>Appendix C - Independent Project Managers, Benchmark Report Summary of Facility Renovations, Toronto Hydro, 71 Rexdale Boulevard, 25 April, 2016</td>
<td>Benchmarking study (consisting of three independent studies) that provides an analysis of the estimated construction costs for the facility renovation at 71 Rexdale Boulevard, with industry benchmarks for projects similar in nature.</td>
</tr>
<tr>
<td>Item</td>
<td>Description</td>
</tr>
<tr>
<td>------</td>
<td>-------------</td>
</tr>
<tr>
<td><strong>Appendix E – Fleet Challenge, 2017 Comprehensive Vehicle Fleet Review, August 2017</strong></td>
<td>This report provides (i) life cycle analysis of Toronto Hydro vehicle replacement practices and (ii) recommendations with respect to long term fleet capital planning. This report also contains a benchmarking analysis of peer utilities fleet. However, as acknowledged by the author, in reviewing the peer fleet comparisons, readers must be mindful that in the Canadian marketplace Toronto Hydro’s fleet is unique in terms of fleet size and makeup as well as operational characteristics - no peer fleets with directly similar characteristics exist. Peer fleets in this analysis share few comparable data points with Toronto Hydro and are presented for information only, in that (for example) the municipal electric utility operates in a much smaller city with less underground and overhead physical plant, and the gas and telecom utility fleets are comprised mainly of vans and other light-duty vehicles and operate in a much broader geographical footprint.</td>
</tr>
<tr>
<td><strong>Appendix E - Facilities Security Internal Benchmarking [Filed Confidentially]</strong></td>
<td>The survey developed by Toronto Hydro was circulated to electrical distribution companies within the North Atlantic Mutual Assistance Group to assess security practices and infrastructure.</td>
</tr>
</tbody>
</table>
November 30, 2016

To All Participants:

Davies Consulting would like to thank you for making the inaugural Utility Emergency Management Benchmark Study a success. Your participation was vital to achieve the objectives of the effort, which were to:

- Recognize leading practices in emergency management, response, and communications;
- Acknowledge successful leadership in the field; and
- Enhance industry knowledge sharing.

After almost a year of effort working with 17 utilities through the evaluation process, we are pleased to present the results of the benchmarking study. This packet provides Davies Consulting’s assessment of your company’s emergency management capability maturity.

The results included in this packet are a culmination of our assessment process, which included: (1) a survey questionnaire completed by each participating utility; (2) site visit interviews and assessments for each utility performed by a Davies Consulting team; and (3) several internal challenge sessions with all Davies Consulting assessment teams to provide the most complete perspective on each rating.

Davies Consulting looks forward to continuing our support and advisory relationship with each utility that participated in this year’s study. We look forward to discussing your assessment in person as you evaluate your company’s potential next steps in greater detail. Also, we would welcome any insight you might have to make the next benchmarking effort an even better success.

The Davies Consulting Team
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Maturity Model and Assessment Description
Description of the Assessment Methodology

The Emergency Management Maturity Model framework is founded upon the Carnegie Mellon Capabilities Maturity Model (CMM) and incorporates: 1) Davies Consulting’s emergency management expertise, 2) a variety of industry standards and guidelines, and 3) the experience of emergency management organizations within the utility industry.

- CMM is designed to measure the maturity of process goals from a level of 1 (ad hoc) to level 3 (defined or threshold acceptable level) to level 5 (optimized)

- The CMM model focuses on process. Davies Consulting adapted the CMM approach so that the measures of emergency management maturity are more precise for each goal by incorporating process as well as considering organization and other aspects of a successful emergency management program.

- Using the CMM approach, the model separates Emergency Management Maturity into five major Program Components. Each Program Component consists of at least one Category. Program Components, Emergency Management Categories and Goals are detailed in the table on the next two pages.

- Each Category is further described by a specific set of Goals for Emergency Management Maturity. The maturity assessments are completed for each Goal using the CMM 1 through 5 scale. The numeric assessments for the Goals within each Category are aggregated and translated into overall numeric assessments for each Category.
## Emergency Management Assessment Model Description

<table>
<thead>
<tr>
<th>Program Component</th>
<th>Category</th>
<th>Category Description</th>
<th>Evaluated Emergency Management Goals</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Program Management</strong></td>
<td>Governance</td>
<td>The organization, corporate governance and processes by which the Emergency Management function is defined, lead and maintained. It is characterized by visible leadership support, endorsement and demonstrated engagement.</td>
<td>• Centralized Responsibility&lt;br&gt;• Scope&lt;br&gt;• Corporate Alignment&lt;br&gt;• Vision and Guiding Principles&lt;br&gt;• Emergency Management Culture&lt;br&gt;• Skills and Abilities&lt;br&gt;• Resources&lt;br&gt;• Program Standards and Requirements&lt;br&gt;• Performance Measurement</td>
</tr>
<tr>
<td><strong>Program Planning</strong></td>
<td>Workforce Mobilization and Care</td>
<td>The ability of an enterprise to identify and engage the necessary number of human resources (internal or external), with the required skills and expertise, and to prepare for and respond to any incident. There also should be a plan to account for and manage the welfare of the responders and, to a certain extent, their families.</td>
<td>• Roles and Responsibilities&lt;br&gt;• Qualifications&lt;br&gt;• Mutual Assistance&lt;br&gt;• External Labor Qualifications Tracking&lt;br&gt;• Resource Accountability&lt;br&gt;• Family and Employee Assistance</td>
</tr>
<tr>
<td></td>
<td>Planning</td>
<td>Emergency planning and coordination during the preparedness or mitigation phase.</td>
<td>• Hazard and Threat Analysis&lt;br&gt;• Incident Levels and Complexity Analysis&lt;br&gt;• All-Hazards Planning&lt;br&gt;• Logistics</td>
</tr>
<tr>
<td><strong>Program Implementation</strong></td>
<td>Response Organization</td>
<td>The scalable, all-hazards incident and crisis management organization that the enterprise has created and implements to manage emergencies and crises.</td>
<td>• Level 1 Crisis Management&lt;br&gt;• Level 2 Incident Support&lt;br&gt;• Level 3 Incident Management&lt;br&gt;• Incident Command System Certification&lt;br&gt;• ICS: Adoption and Use</td>
</tr>
<tr>
<td></td>
<td>Response Plans</td>
<td>The documented policies and processes in place that describe emergency response strategies and tactics for all enterprise units and all response organization levels.</td>
<td>• Plan Framework&lt;br&gt;• Plan Review and Approval&lt;br&gt;• Plan Distribution and Availability&lt;br&gt;• Plan Testing</td>
</tr>
</tbody>
</table>

---

**MATURITY ASSESSMENT OVERVIEW & SUMMARY**

*Page | 8*
<table>
<thead>
<tr>
<th>Program Component</th>
<th>Category</th>
<th>Category Description</th>
<th>Evaluated Emergency Management Goals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Program Implementation (cont’d)</td>
<td>Command and Information Systems</td>
<td>The facilities, technology and communication systems that enable command and control through redundant, efficient and effective communication and sharing of information.</td>
<td>• Command and Control Nodes  • Mobile Command Centers  • Telecommunications  • Incident Management Tools and Tech  • Operational Tools  • Analytical Tools  • Notification Tools</td>
</tr>
<tr>
<td>Training and Exercise</td>
<td>Training and Education</td>
<td>The program that ensures the people are well trained and prepared to respond to all-hazards. The training and education program is focused on the roles and responsibilities to respond across the enterprise.</td>
<td>• Exercise Program  • Periodicity  • Type  • Stakeholder Engagement  • Evaluation</td>
</tr>
<tr>
<td>Communications and Outreach</td>
<td>Communications</td>
<td>The processes, planning, and implementation of an effective communications strategy during an incident. It includes the way in which messaging is created, approved, and disseminated. More mature communications organizations follow a well-coordinated and well-integrated process that also develops hazard-specific messaging during blue-sky.</td>
<td>• Organization  • Communication Channels  • Message Consistency  • Messaging  • Preparedness Communication</td>
</tr>
<tr>
<td>Outreach and Coordination</td>
<td>Outreach and Coordination</td>
<td>The extent to which the Emergency Management effort integrates with external agencies and organizations to both improve their own skills but also to train and educate those external organizations.</td>
<td>• Planning and Coordination  • Participation in Critical Infrastructure  • First Responder Training</td>
</tr>
</tbody>
</table>
Analysis of Results for All Participants
Maturity Assessment Data Analysis and Participant Characteristics

As part of the Emergency Management Benchmark Assessment, each participating utility completed an extensive questionnaire. The information provided in that questionnaire served as key input into our site visit interviews and subsequent assessment analyses. The information collected by the questionnaire provided a baseline understanding so that the interview process was as efficient as possible; and it also, it provided reference material for the Davies Consulting team to use when completing each individual maturity assessment. Detailed information gained from your company’s completed questionnaire and interviews is reflected in the presentation of your company’s results for each Emergency Management Category and Goal. The information from the questionnaire helped guide the determination of your company’s assessment scores and supported the development of summary assessments on individual participant strengths and weaknesses. Your company’s customized, detailed assessment appears later in this report.

The following Maturity Assessment Data and Analysis and Participant Characteristic section provides a description of the participants included in this benchmarking effort and a graphical analysis and summary of a few notable items in the questionnaire as answered by the participants. In some instances, combining the questionnaire responses with the maturity assessment scores provides interesting insight about the state of the industry and its leading Emergency Management practices. Davies Consulting is confident it will be useful as you endeavor to continue to improve and build the Emergency Management capabilities in your organization.
2016 Emergency Benchmark Participants
### Summary Statistics of Participating Utilities

<table>
<thead>
<tr>
<th>Utility</th>
<th>Number of EM Personnel</th>
<th>Customers per EM Personnel</th>
<th>EM Annual Budget</th>
<th>EM $ per customer</th>
<th>Number of Commodities</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Not provided</td>
<td>Not provided</td>
<td>Not provided</td>
<td>Not provided</td>
<td>5</td>
</tr>
<tr>
<td>B</td>
<td>4</td>
<td>215,541</td>
<td>$450,000</td>
<td>$2.09</td>
<td>4</td>
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<tr>
<td>C</td>
<td>4</td>
<td>1,352,853</td>
<td>Not provided</td>
<td>Not provided</td>
<td>5</td>
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<tr>
<td>D</td>
<td>9</td>
<td>122,222</td>
<td>Not provided</td>
<td>Not provided</td>
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<td>E</td>
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<td>350,000</td>
<td>$130,000</td>
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<td>G</td>
<td>30</td>
<td>163,333</td>
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<tr>
<td>H</td>
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<td>I</td>
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<td>O</td>
<td>7</td>
<td>685,261</td>
<td>$2,000,000</td>
<td>$2.92</td>
<td>3</td>
</tr>
<tr>
<td>P</td>
<td>2</td>
<td>2,000,000</td>
<td>$300,000</td>
<td>$0.15</td>
<td>4</td>
</tr>
<tr>
<td>Q</td>
<td>2</td>
<td>415,000</td>
<td>Not provided</td>
<td>Not provided</td>
<td>3</td>
</tr>
<tr>
<td>Min</td>
<td>2</td>
<td>122,222</td>
<td>$130,000</td>
<td>$0.15</td>
<td>1</td>
</tr>
<tr>
<td>Max</td>
<td>32</td>
<td>2,000,000</td>
<td>$12,000,000</td>
<td>$32.65</td>
<td>6</td>
</tr>
<tr>
<td>Average</td>
<td>10</td>
<td>666,389</td>
<td>$2,783,750</td>
<td>$9.50</td>
<td>4</td>
</tr>
</tbody>
</table>

Customers range from nearly 800,000 to 9.7 million, with an average of 3.9 million
Commodities are divided into energy type (electric and gas) and then operation type (transmission, distribution, generation, and storage).

All participants provide electric service. Most participants (10) also provide gas service. Four utilities provide the full range of services included in the questionnaire.

For six of the participants, the entire range of Emergency Management functions are within a central Emergency Management organization. Disaster Recovery and Risk Management are the two functions most often not included.
For most participants, the leader of the Emergency Management function is either at the Manager (5 participants) or the Director (5 participants) levels. Three respondents indicated that their emergency management leadership is at an executive level. Three participants did not provide the information.

The leadership level of Emergency Management within a utility is an indicator of the ultimate maturity. Those utilities with leadership at higher levels ended with higher maturity assessment scores than those with leadership at lower levels. This could be a result of the ability to obtain the necessary resources, be considered a part of corporate strategy, be able to concentrate on one objective (Emergency Management), or a combination of these.
There is a difference in the Emergency Management maturity among the participating utilities as shown by the Governance Category.

The six utilities with the highest assessment scores in Governance were also among the higher scores in seven of the 10 categories.

Participants whose scores in Governance were outside the top third earned top-third scores in only 5 of the 10 categories, with response plans being the most common.

The chart to the left shows the utilities in the top third of maturity assessments by Category.
Participating utilities consider and plan for a wide-range of hazards.

- Snow, ice, wind, flood, workplace violence, and cyber (IT) are among the most common hazards.
- Mudslide, tsunami, physical attack, and fire are among the least common hazards planned for by the participants.
- No participant plans for all the hazards on the list.
- Two participants did not provide information.
Summary of Your Assessment Results
Summary of Your Assessment Compared to All Participants

The diagram to the left shows your assessment for each of the major Emergency Management categories. The thin blue line in the graph to the left shows the average score for all benchmark participants. For comparison purposes, the diagram to the right shows the individual results for all 17 participating utilities. A level 3 score, highlighted with a thick gray line on the left diagram, is considered to be a minimum threshold in utility Emergency Management capabilities and expectations in 2016. When undergoing your strategic planning for emergency management, please consider prioritizing improvement opportunities for any area that has been rated lower than a 3. These two diagrams allow you to compare your company’s maturity with that of the other participants. This will be useful as you plan and justify investments for improvement in pursuit of your own path to Emergency Management maturity.
Strengths

- Toronto Hydro has implemented significant change over the last two years which has moved its maturity forward.
- The company’s damage assessment process uses statistical assessment to establish a global restoration estimate followed by a wider assessment for more accurate ETRs as time passes. This is a leading practice in the industry.
- Additionally, communication processes and consistency of messaging to all stakeholders with accurate and timely information in One-Voice is a vast improvement.

Opportunities for Continuous Improvement

- Toronto Hydro has opportunity to improve in several areas. In general, we see Toronto Hydro as a developing company.
- They have recently finalized a new grid emergency plan.
- Once the grid emergency plan is fully implemented, emergency management should train staff to respond to all-hazards emergencies.
Detailed Maturity Assessment Results
How to Read and Interpret the Assessment Results

[Category] Score

The detailed report will present each participant’s rating using the number line format as shown above. The meanings of the individual number line components are:

- **[Category] Score**: For each assessed category of Emergency Management, the report provides a summary of the overall assessment for that category, which is the resulting average of the Goal scores within each Category.

- **Participant Score**: Shown by the yellow bar, the Participant Score is your company’s score placed on the number line scale of 1 through 5. For [Category] Scores, it shows the average of the individual emergency management maturity goals that make up that category. As an average of several sub-scores (related to the goals listed in each Category), the [Category] Score can be any number, with decimals, between 1 through 5. For each individual goal, the detailed assessment report shows the specific rating of that goal, indicated by an integer 1 through 5.

- **Low, High, and Average Benchmark Score**: These numbers show the low (red arrow), average (yellow arrow), and high (green arrow) score for that category and goal among all of the participants.
Governance: Description and Leading Practices

Description

The organization, corporate governance and processes by which the Emergency Management function is defined, lead and maintained. It is characterized by visible leadership support, endorsement and engagement demonstrated through the elements of its program.

Leading Practices

- Leading practice utilities often balance utility knowledge with Emergency Management certifications and skills (i.e., Disaster Recover Institute, International Association of Emergency Managers, or Incident Command System training certifications). One utility has full-time staff that are certified in Emergency Management (e.g., IAEM certification), maintain certifications in subject areas (i.e., training, exercise), and are certified in National Incident Management System (NIMS).
- A utility which has recently prioritized Emergency Management has advanced quickly. This is largely attributable to the governance of the program. A governance committee has met regularly to develop a strategy, monitor progress, and to manage roadblocks. Each member of this governance committee communicates the importance of the initiative down into their respective department so all employees recognize Emergency Management as a corporate priority. Also the governance committee has helped to create a strong connection between Emergency Management and risk management within the company, which fosters appropriate identification and prioritization of effort.
Governance: Overall Assessment

2.78

**STRENGTHS**
- Vision and guiding principles are developed and widely shared with internal and external stakeholders.
- Emergency Management has been given enough authority to drive goals across the company.

**OPPORTUNITIES FOR IMPROVEMENT**
- Improve centralization of emergency preparedness and corporate disaster organizationally.
- Develop more consistent emphasis on emergency management across the enterprise.
- Dedicate more staff to Emergency Management.
## Governance: Goals

### Centralized Responsibility

<p>| | | | | |</p>
<table>
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<td>5</td>
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</table>

**Current Level of Maturity Definition**
Dedicated resources exist throughout the enterprise to address all identified required Emergency Management functions. There is coordination of resources across some business units, but the coordination is informal and not enterprise-wide.

**Next Level of Maturity Definition**
Existence of a dedicated resource to lead Emergency Management functions. There is an identified position accountable for enterprise Emergency Management that has the authority to drive change with Emergency Management functions embedded within other business units throughout and across the enterprise.

### Scope

<p>| | | | | |</p>
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<tbody>
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<td>1</td>
<td>2</td>
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</tbody>
</table>

**Current Level of Maturity Definition**
Emergency Management is governed centrally, with less than quarterly (but regular) meetings to align with BC, DR, Cyber Security, and Physical Security.

**Next Level of Maturity Definition**
Corporate Alignment

| 1 | 2 | 3 | 4 | 5 |

**Current Level of Maturity Definition**
The enterprise Emergency Management leadership is a manager.

**Next Level of Maturity Definition**
The enterprise Emergency Management leadership is a director reporting to an executive management team member.

Vision and Guiding Principles

| 1 | 2 | 3 | 4 | 5 |

**Current Level of Maturity Definition**
Emergency Management is governed centrally, with less than quarterly (but regular) meetings to align with BC, DR, Cyber Security, and Physical Security.

**Next Level of Maturity Definition**
Continue to advance capabilities in Emergency Management according to industry, stakeholder, and customer needs.

Emergency Management Culture

| 1 | 2 | 3 | 4 | 5 |

**Current Level of Maturity Definition**
Emergency Management is governed centrally, with less than quarterly (but regular) meetings to align with BC, DR, Cyber Security, and Physical Security.

**Next Level of Maturity Definition**
A formal communications strategy is developed, implemented, and supported by all levels of the company that actively and regularly communicate the importance of and activities executed by Emergency Management personnel across the enterprise.
Skills and Abilities

Current Level of Maturity Definition
Within the Emergency Management Governance Organization, there are full time employees or contractors that have demonstrable experience in a particular function (e.g., training, exercise, planning, external stakeholder engagement, plan writing, etc.). Certifications may or may not be completed.

Next Level of Maturity Definition
Emergency Management leadership and a majority of the FTEs and contractors are certified by an Emergency Management related accreditation body or can demonstrate the skills and experience needed to obtain the accreditation. Formal plans exist that (1) are aligned with the relevant accreditation body to increase the skills and experience of all FTEs within a specified period of time; and (2) create succession plans for each key role.

Resources

Current Level of Maturity Definition
Defined Emergency Management organization structure, number and type of resources, and job profiles defined in order to achieve all objectives within the program elements using FTE or contract resources.

Next Level of Maturity Definition
Defined Emergency Management organization structure, number and type of resources, and job profiles known in order to achieve all program elements using FTEs. Contractors are used ad hoc to fill temporary needs.
Program Standards and Requirements

<table>
<thead>
<tr>
<th>Current Level of Maturity Definition</th>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corporate Emergency Management expectations are set at consistently higher levels than what is required by the regulatory agencies.</td>
<td>Business unit and enterprise is partially and intentionally compliant with external standards.</td>
</tr>
</tbody>
</table>

Performance Measurement

<table>
<thead>
<tr>
<th>Current Level of Maturity Definition</th>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Either (1) Program performance is assessed on an ad-hoc or undefined basis by an internal group; or (2) Emergency Management program has no formalized scope, goals, or performance metrics.</td>
<td>Emergency Management program is reviewed internally but there are no established metrics.</td>
</tr>
</tbody>
</table>
Workforce Mobilization and Care: Description and Leading Practices

Description

The ability of an enterprise to identify and engage the necessary number of human resources (internal or external), with the required skills and expertise, and to prepare for and respond to any incident. There also should be a plan to account for and manage the welfare of the responders and, to a certain extent, their families.

Leading Practices

- One participating utility has an employee accountability program, supported through an automated system, that communicates to employees and receives information regarding their well-being and if/when they are able to return to work. Designated representatives from each business unit are responsible for locating employees who have not checked-in and directing anyone needing help to Human Resources.
- Several utilities have representatives serving in leadership roles to develop cyber mutual assistance that will aid companies in rebuilding and recovering computer systems in the event of a regional or national cyber event. The Electricity Subsector Coordinating Council (ESCC) Cyber Mutual Assistance Task Force builds upon the electric power industry’s culture of mutual assistance to develop resource sharing relationships.
- A number of utilities implement an electronic solution to provide utility companies situational awareness, both in daily operations and in emergencies, regarding resource qualifications, resource status, and notification capabilities. The solution integrates with human resources and training systems to ensure source information is accurate and current, as well as to allow the user to create customized rosters/lists.
- Designating emergency roles for all utility employees is a leading practice. Several utilities are leading the way in this area by designating primary and secondary roles for all employees, including non-traditional emergency responders (e.g., legal or accounting business unit employees).
Workforce Mobilization and Care: Overall Assessment

STRENGTHS
- Major response roles (command and general staff) are well defined and tracked in a centralized system.
- Mutual assistance groups are utilized, and Toronto Hydro is leading the process for implementing a Canadian standard for mutual assistance within the CEA.

OPPORTUNITIES FOR IMPROVEMENT
- Development of a process to account for resources is needed. This may include tools or technology to rapidly, or in real time, account for employees during an emergency.
- Assistance for employees and their families should be considered. If employees do not feel that their families are secure, they may not be able to report for their emergency role.
Workforce Mobilization and Care: Goals

Roles and Responsibilities

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<th>1</th>
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<th>4</th>
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</table>

Current Level of Maturity Definition
All major response roles and responsibilities are defined with minimum qualification guidelines, including: Command and General Staff roles, Branch Directors and Unit Leaders, all PIO roles, all Logistics Roles, Liaison, Damage Assessment, and Forensics.

Next Level of Maturity Definition
All response roles and responsibilities are defined.

Qualifications

<table>
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<tr>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
</table>

Current Level of Maturity Definition
Emergency Management roles and qualifications are tracked in an enterprise-wide system.

Next Level of Maturity Definition
One central database or a system of integrated databases that automatically updates and provides universal access. Data captured includes (1) assigned role(s), (2) last training and certifications for Emergency Management, and (3) adjusts with change of primary responsibilities.
Mutual Assistance Program

**Current Level of Maturity Definition**
Involvement in cyber and/or non-traditional Mutual Assistance program.

**Next Level of Maturity Definition**
Continue to advance capabilities in Emergency Management according to industry, stakeholder, and customer needs.

External Labor Qualifications Tracking

**Current Level of Maturity Definition**
Internal resource gaps have been identified (number and qualifications). External resource minimum qualification and certification requirements are established.

**Next Level of Maturity Definition**
Internal resource types are defined for each hazard and operational need, with minimum qualifications and certifications for external resources.

Resource Accountability

**Current Level of Maturity Definition**
No clear guidelines exist for accounting for employees.

**Next Level of Maturity Definition**
Supervisory call trees are the only tools and process to locate key personnel.
Family and Employee Assistance

| 1 | 2 | 3 | 4 | 5 |

Current Level of Maturity Definition
Assistance is undocumented or there is no process to manage family assistance.

Next Level of Maturity Definition
An informal process exists to support all personnel families during or after an emergency.
Planning: Description and Leading Practices

Description

Emergency planning and coordination during the preparedness or mitigation phase.

Leading Practices

- Leading utilities make effective use of the time before an incident to concentrate on effective preparedness and mitigation planning. At least one participating utility actively engages the local first responders, agencies, transportation authorities, as well as local, state, and federal government agencies in planning for full, effective exercises. This utility also actively participates in the exercises of the outside organizations. This not only helps to strengthen relationships but it also assists in creating a more cohesive and successful response when needed.

- In addition to working with all outside agencies and partners to build a successful exercise effort, leading utilities will also work with local organizations that will be involved in a response. One participating utility actively serves on the board for many of the local response organizations, such as the Red Cross and YMCA. This builds relationships and helps to align response strategies.

- Effective planning goes beyond exercises, training, and communication. It also incorporates longer term vision and strategy development in identifying hazards and designing and implementing response approaches. On a three-year basis, one utility integrates their response strategy and planning with the local jurisdictions. This helps to align response efforts and share information to improve the all-hazards portfolio.
Planning: Overall Assessment

Overall Planning Score:

2.50

STRENGTHS
- Incident levels are normalized and consistent across the enterprise.

OPPORTUNITIES FOR IMPROVEMENT
- Hazard analysis should be centralized by business unit.
- Emergency Management at Toronto Hydro is focused on grid emergencies only. All hazards should be planned for in a centralized way.
Planning: Goals

Hazard and Threat Analysis

| 1 | 2 | 3 | 4 | 5 |

**Current Level of Maturity Definition**
(1) Hazard and Threat analysis is decentralized by business unit, with no common framework or approach; or (2) None or very minimally conducted.

Next Level of Maturity Definition
Business units conduct Hazard and Threat analysis based on internal assessments. These analyses are reported to the enterprise.

Incident Levels and Complexity Analysis

| 1 | 2 | 3 | 4 | 5 |

**Current Level of Maturity Definition**
Enterprise has incident levels which (1) consider worst reasonable case scenario for all hazards it may experience; and (2) measures multiple types of consequences.

Next Level of Maturity Definition
Modeling of ‘work’ or level of effort and the amount of resources are included in the incident levels and can be used to support decision making with the complexity analysis or incident levels.

All-hazards Planning

| 1 | 2 | 3 | 4 | 5 |

**Current Level of Maturity Definition**
Plans exist for multiple hazards and threats, but may lack consistency.

Next Level of Maturity Definition
Plans may not exist for each hazard but the all-hazards approach accommodates the response. Planning exists for the top hazards and threats of the enterprise.
Logistics

Current Level of Maturity Definition
Logistics planning occurs only for major ‘storms’ or other natural hazards endemic to the utility, but no other hazards. Includes proactive identification of suppliers, resources, and staging areas. Specialized agreements may not be in place.

Next Level of Maturity Definition
Contracts and agreements are in place to meet the needs for spare parts and identified staging areas during any storm response.
Response Organization: Description and Leading Practices

Description

The scalable, all-hazards incident and crisis management organization that the enterprise has created and implements to manage emergencies and crises.

Leading Practices

- A few utilities have formed teams of individuals familiar with ICS, the company's Emergency Management processes and procedures, and operations to support Incident Management Teams (IMTs) and first responders during a response. During blue sky, the teams communicate Emergency Management messages and initiatives to Operations personnel and help integrate Emergency Management culture.
- A utility with multiple operating companies spanning several states recently standardized their Emergency Management structures and response processes and procedures. To implement this approach, the company engaged a cross-functional team of representatives. This practice gave each of the operating companies ownership in the process and incorporated the diverse needs and cultures that exists across the enterprise. The standardization and centralization of incident response processes also enables the company to share resources.
- In leading practice entities, an ICS-based response organization is used for all-hazards from the executive level to the front-line personnel and consists of three levels: (1) Crisis Management Team (CMT) of executives providing policy-level direction, support and strategic leadership to protect the brand and financial interests of the company; (2) Incident Support Team (IST) that can be activated when events are not site-specific, immediately identifiable, geographically dispersed, lengthy, or dispersed across the company or geographically; and (3) Incident Management Teams (IMT) that are typically responsible for tactical response and management of the incident.
Response Organization: Overall Assessment

2.40

STRENGTHS
- Toronto Hydro has established a Crisis Management Team, a formal response organization that includes the senior most executives of a company.

OPPORTUNITIES FOR IMPROVEMENT
- The crisis management team interaction with the response team could be more clear.
- Toronto Hydro is in their first year of formal training for their new response plan. As such, they are ramping up to a regular schedule and curriculum of training for IMS/ICS. In the future, this training could be required of every emergency role.
Response Organization: Goals

**Crisis Management**

<table>
<thead>
<tr>
<th>Current Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>A crisis management team is defined with plans in place and formalized crisis roles.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>The crisis management team is evaluated in functional exercises with increasing complexity that include exercising with the incident Management Team (IMT) and Incident Support Team (IST) activation.</td>
</tr>
</tbody>
</table>

**Incident Support**

<table>
<thead>
<tr>
<th>Current Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incident support is defined with plan in place and formalized role.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incident support is (1) defined with plan in place and (2) integrated across operational and support functions.</td>
</tr>
</tbody>
</table>

**Level 3 Incident Management**

<table>
<thead>
<tr>
<th>Current Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Business unit incident plans in place with no integration across the enterprise.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incident management is defined with a plan in place and integrates other operational and support functions.</td>
</tr>
</tbody>
</table>
### Incident Command System Certification

<table>
<thead>
<tr>
<th>Current Level of Maturity Definition</th>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Command and General Staff training via independent study (or similar) is mandatory through ICS-100.</td>
<td>Command and General Staff training is aligned with ICS-400. No position-specific training exists.</td>
</tr>
</tbody>
</table>

### ICS: Adoption and Use

<table>
<thead>
<tr>
<th>Current Level of Maturity Definition</th>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incident response is based on ICS structure and used for all incidents for the 'operational' business units. Some penetration towards the front lines, but minimal use of ICS-based response for front line personnel.</td>
<td>ICS-based response is used for all hazards and all threats. Many front line personnel are familiar with or trained on ICS principles.</td>
</tr>
</tbody>
</table>
Response Plans: Description and Leading Practices

**Description**

The documented policies and processes in place that describe emergency response strategies and tactics for all enterprise units and all response organization levels.

**Leading Practices**

- Several companies have created plan frameworks in line with best practices. This includes establishing a core, all-hazards plan supported by plan annexes related to different commodities, operating companies, and/or hazards with attached supporting documents like rosters, job aids, and templates. Additionally, all plans are consistent and standardized in tone and format, and are part of the same body of documents.
- Some of these companies are additionally applying leading practices with plan distribution. It is important that employees have the most up-to-date emergency documents available at any time. At a minimum, response plans should be accessible in hard copy at Emergency Operations Centers (EOCs) and electronically via SharePoint or other solution. In order to meet and exceed this need companies are using pocket guides to the plan, secure thumb drives, and even have developed secure apps to push change notifications when the plans are updated and make content available even while offline.
- Plan review and approval at the most mature companies is happening at least annually for base, and twice annually for any annexes. Lastly, one company is using a checklist to compare their plan content against the industry to ensure that their plans are complete.
Response Plans: Overall Assessment

STRENGTHS
- There is an identified framework for plans using a central core plan supported by related annexes.

OPPORTUNITIES FOR IMPROVEMENT
- Hazard annexes need to be completed.
- Tools to distribute the plans could be considered (such as a secure app that pushes the most recent version of the plan to download and be made available offline).
Response Plans: Goals

Plan Framework

Current Level of Maturity Definition
Response plans exist for commodities, business units, or hazards, but lack common framework and consistency.

Response plans exist for commodities, business units, or hazards, but lack common framework and consistency.

Next Level of Maturity Definition
The Core Plan and framework are complete with at least one hazard or functional annex complete.

Plan Review and Approval

Current Level of Maturity Definition
Annual plan review and documented approval - for all plans, or following a conscious decision made on the periodicity based on resources and priority of plans.

Next Level of Maturity Definition
Plan review and approval is conducted at least annually and following any severe or catastrophic incident, or following a conscious decision made on the periodicity based on resources and priority of plans.
Plan Distribution and Availability

Current Level of Maturity Definition
Plan is available in hard copy at Emergency Operations Center (EOCs) and on a SharePoint site available within the LAN.

Next Level of Maturity Definition
Plan is available as a pdf (not updated automatically) via secure mobile access, mobile data terminals, and hard copy.

Plan Testing

Current Level of Maturity Definition
The plans are formally tested in the exercise process without specifically asking for players to reference the plans.

Next Level of Maturity Definition
The plans are formally tested in the exercise process. Exercise players are asked to reference the plan, and the processes documented in it support the exercise players and comport with actual process.
Command and Information Systems: Description and Leading Practices

**Description**

The facilities, technology and communication systems that enable command and control through redundant, efficient and effective communication and sharing of information.

**Leading Practices**

- Leading practices are developing quickly in command and information systems. Among the best were predictive damage assessment, state of the art emergency operations centers (EOCs), advanced mobile command centers, and a portable network system. Several utilities are using predictive modeling to drive their preparation for an incident as well as the early stages of response or pre-staging. These systems compare current conditions with historical data to predict damage to the electric system from hazards including hurricanes and earthquakes.

- The most advanced EOCs in the industry are in line with the most advanced EOCs in the public sector. These are purpose built or retrofitted facilities to withstand the hazards or threats that the company faces. They have the necessary space to fit the IMT as well as breakout rooms for meetings and public communication (i.e., press conferences). Technology and materials are designed to maximize information sharing and are maintained on a regular basis. These facilities include redundant communications technologies, power supply, HVAC and gas/water service. Additionally, mobile command centers are being used by many companies as a way to make their IMT mobile, to be visible to the public, or to promote customer outreach. A few companies have customized several best in class mobile emergency vehicles, each with a specific purpose.
Command and Information Systems: Overall Assessment

1.57

STRENGTHS
- Statistical damage assessment process allows for rapid analysis of damage to the system based on a pre-selected sample of maps to estimate the damage across the service territory.

OPPORTUNITIES FOR IMPROVEMENT
- The EOC could be larger, with added capability for more visual displays, and it could be purpose-built to meet the needs of the IMT.
- A notification tool to alert the workforce about emergencies would help to speed the company’s initial response.
- The company could consider adding a mobile command center.
Command and Information Systems: Goals

Command and Control Nodes

| 1 | 2 | 3 | 4 | 5 |

Current Level of Maturity Definition

Emergency Operations Centers exist using shared space, but are outfitted with the necessary IT, communications and projection capabilities. They have sufficient space to support work, meeting, and break out capabilities. Public Information/JIC and Press Briefing facilities are co-located.

Next Level of Maturity Definition

Emergency Operations Centers are purpose-built or use pre-defined space. Designed to maximize the sharing and communication of information within the utility.

Mobile Command Centers

| 1 | 2 | 3 | 4 | 5 |

Current Level of Maturity Definition

No Mobile Command Center

Next Level of Maturity Definition

Mobile Command Center that does not meet FEMA requirements, but available for deployment within service territory
<table>
<thead>
<tr>
<th><strong>Telecommunications</strong></th>
<th><strong>Next Level of Maturity Definition</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Three paths of independent data and voice transmission for Emergency Management data/voice needs (e.g., cellular, radio, copper, VOIP, fiber, satellite, etc.). Microwave communication (if used) can operate with any single tower offline</td>
</tr>
</tbody>
</table>

**Current Level of Maturity Definition**
Two paths of independent data and voice transmission for Emergency Management data/voice needs (e.g., cellular, radio, copper, VOIP, fiber, satellite, etc.).

<table>
<thead>
<tr>
<th><strong>Incident Management Tools and Technology</strong></th>
<th><strong>Next Level of Maturity Definition</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>A Commercial Off-The-Shelf Software (COTS) or homegrown incident management tool (e.g., WebEOC) with no integration with existing systems (EMS, OMS, paper based forms, etc.).</td>
</tr>
</tbody>
</table>

**Current Level of Maturity Definition**
Either (1) A manual incident management tool; or (2) no incident management tool

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<thead>
<tr>
<th><strong>Operational Tools</strong></th>
<th><strong>Next Level of Maturity Definition</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>All company field internal personnel have mobile capabilities (internal field, damage assessors, etc.).</td>
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</table>

**Current Level of Maturity Definition**
All company operations vehicles are equipped with access capabilities to OMS/GIS/CIS
**Analytical Tools**

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</table>

**Current Level of Maturity Definition**
Either (1) Heuristics-driven prediction based on historical information and knowledge only; or (2) no tools.

**Next Level of Maturity Definition**
Predictive and analytical tools exist that predict the number of instances of damage and resources, but do not predict the damage to systems.

---

**Notification Tools**

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</tr>
</tbody>
</table>

**Current Level of Maturity Definition**
Non-automated/other notification tools for employees (e.g., phone tree)

**Next Level of Maturity Definition**
Automated, email-based notification for employees.
Training and Education: Description and Leading Practices

Description

The program that ensures the people are well trained and prepared to respond to all-hazards. The training and education program is focused on the roles and responsibilities to respond across the enterprise.

Leading Practices

- Leading utilities directly link Emergency Management training to personal performance goals to create a partnership between the company and its employees by ensuring accountability on both of their parts. Utilities are able to track which employees have been trained so that the capabilities of the response organization can be quickly assessed.
- Many utilities are moving in the direction of adopting Incident Command System (ICS) to prepare and respond to emergencies. Leading utilities find a practical balance between ICS and utility Emergency Management practices because the two ideologies do not mix perfectly. Using ICS to influence a utility’s Emergency Management practices, rather than replace them, fosters an environment far more open to change management.
- All utilities know that, in order for their response organization to perform well during exercises and real events, their responders need adequate training and education beforehand. Leading utilities utilize online training and education to equip their responders on a regular basis. At the end of each (re)training session, they require users to take a test and pass with a certain score in order to receive credit. This practice ensures the utility that its responders are continuously equipped with the necessary knowledge to be effective responders.
Training and Education: Overall Assessment

2.50

STRENGTHS
- Training is tracked in a system integrated with HR’s employee tracking system.

OPPORTUNITIES FOR IMPROVEMENT
- Training could be included as an element of employees’ annual performance reviews.
- IMS training should be consistently applied across the enterprise.
Training and Education: Goals

Training and Education Programs

Current Level of Maturity Definition
Business units may have a formal training program within the unit itself, but no coordination.

Next Level of Maturity Definition
Training is supported by corporate training department, a central organization (EMO), or a SME organization to provide the necessary training for all response positions. Certification may exist.

System/Database Tracking

Current Level of Maturity Definition
Externally-developed database or system to track training. No integration with Human Resources.

Next Level of Maturity Definition
Integration of training tracking systems with the Human Resources systems.
Exercise and Evaluation: Description and Leading Practices

**Description**

The exercise and evaluation program is focused on the ability of the team to respond to any hazard. It identifies improvement opportunities, and measure the effectiveness of the people, the response organization, the response plans, and the supporting tools and technology.

**Leading Practices**

- Leading utilities know that their response capabilities depend on the frequency and thoroughness of their exercise program. They conduct exercises in conjunction with other first responders and stakeholder agencies in their community to ensure the response is collaborative and efficient. Conducting exercises not only allow responders to test emergency practices in a controlled environment, but also give fellow responders familiarity with the response processes of every organization involved.
- Leading utilities plan for multiple hazards and conduct exercises that include them. Though storms and other natural disasters are typical for utilities to face, when other hazards occur, utilities are expected to respond just as prudently. Because those other hazards occur so infrequently, leading utilities test them in the controlled environment of an exercise.
- Leading utilities have dedicated organizations to plan and facilitate exercises and After Action Reviews. These dedicated exercise groups focus on testing the entire response organization by incorporating different hazards, event levels, and other exercise characteristics.
- Some utilities have enterprise-wide corrective action plans dedicated to improving their many business practices. They have processes to identify improvement areas, establish action plans to remedy those improvement areas, and assign different employees with tasks to implement the action plans. Leading utilities include Emergency Management in the business practice corrective action plans by using the findings from completed After Action Reviews.
Exercise and Evaluation: Overall Assessment

2.00

STRENGTHS
- The company is working toward a functional exercise in the coming year.

OPPORTUNITIES FOR IMPROVEMENT
- Toronto Hydro is working toward having a regular schedule and curriculum, but is still in a building phase. The company should pursue full implementation of this effort.
### Exercise and Evaluation: Goals

#### Exercise Program

<table>
<thead>
<tr>
<th>Current Level of Maturity Definition</th>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Individual business units may have a developed exercise program, but there is little to no coordination with other business units, outside agencies, or the rest of the enterprise.</td>
<td>Business units align with an enterprise exercise program, which includes scope/purpose, ownership, priorities, elements of program, details about who is required to participate, tracking, and an all-hazards schedule.</td>
</tr>
</tbody>
</table>

#### Scope

<table>
<thead>
<tr>
<th>Current Level of Maturity Definition</th>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than functional exercises not including field resources, but more than table top.</td>
<td>Less than functional exercise including field resources, but more than table top.</td>
</tr>
</tbody>
</table>

#### Periodicity

<table>
<thead>
<tr>
<th>Current Level of Maturity Definition</th>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Table top at least annually.</td>
<td>One system-wide functional exercise per year, testing one single hazard.</td>
</tr>
</tbody>
</table>
### Exercise & Evaluation

#### Type

<table>
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<tr>
<th>1</th>
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</table>

**Current Level of Maturity Definition**
Table top exercises are performed with coordination across the enterprise.

**Next Level of Maturity Definition**
Table top exercises and an annual exercise less than full functional.

#### Stakeholder Engagement

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</thead>
</table>

**Current Level of Maturity Definition**
Coordination or relationship with external partners exist, but no proactive involvement in exercises. External partners may occasionally participate.

**Next Level of Maturity Definition**
External agencies participate in exercises.

#### Evaluation

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</thead>
</table>

**Current Level of Maturity Definition**
Documented after action after exercises to identify recommendations within business units and some sharing across the enterprise. Limited follow-up on action items.

**Next Level of Maturity Definition**
Emergency Management organization defines requirements for after action process and takes responsibility for facilitating after action for incident support and crisis management teams. After action responses at the business unit level are shared across the enterprise, integrating efforts where duplicates exist.
Communications: Description and Leading Practices

Description

The processes, planning, and implementation of an effective communications strategy during an incident. It includes the way in which messaging is created, approved, and disseminated. More mature communications organizations follow a well-coordinated and well-integrated process that also develops hazard-specific messaging during blue-sky.

Leading Practices

- A community portal provides real-time information to communities and emergency operating centers. Information included on the portal includes: contact and outage information, status of life support/medical customers and critical facilities, priorities identified by the community, and status of wires down. The portal can also provide users with community-specific and system-wide messaging, with access managed through the use of different levels that correspond to community role – ranging from read-only to being able to modify priorities.
- Implementation of a one-voice message development and dissemination process, including reliance on a robust database for compiling and vetting information, reflects a leading practice in the industry. One-voice processes ensure consistent messaging, but detail may vary by stakeholder type. The one-voice process includes pre-approved communications and a process to create, approve, and disseminate the message. Leading practice companies have also implemented web-based systems to manage requests and reports during an incident.
- Leading practice companies have an overarching communications plan that describes the company’s overall approach to communicating and hazard-specific plans that include pre-approved messaging and processes. Communications plans specify channels, stakeholders/target audiences, integration of one-voice messaging, the communications response organization, communication team activation, strategy development process, message development, approval, and dissemination process, and social media strategies and tactics.
Communications: Overall Assessment

**STRENGTHS**
- Consistency of messaging is attained by using a process for One Voice messaging
- A single source of information is identified to create a path for accurate information to flow to communicators in a timely manner.

**OPPORTUNITIES FOR IMPROVEMENT**
- The PIO organization could have better integration into the response organization.
## Communications: Goals

### Organization

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</table>

**Current Level of Maturity Definition**
A separate communications organization is in place and fully staffed to address all aspects of communication tracking and development during an incident.

**Next Level of Maturity Definition**
A separate communications organization dedicated to support the incident is fully integrated into response organization.

### Communication Channels

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</table>

**Current Level of Maturity Definition**
All customers and their preferred communications channels (text, email, phone) are proactively identified.

**Next Level of Maturity Definition**
Existence of robust press/satellite conference uplink capabilities with multiple mobile sites capable of activation.

### Message Consistency

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</table>

**Current Level of Maturity Definition**
Documented One Voice process that is integrated into response plans.

**Next Level of Maturity Definition**
Documented One Voice process that addresses specific stakeholder needs but remains consistent.
### One Voice

<table>
<thead>
<tr>
<th>Level</th>
<th>Current</th>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-</td>
<td>System/database to compile and track vetted data across response, requests for information/action, and other information to support communications.</td>
</tr>
<tr>
<td>2</td>
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</tbody>
</table>

### Current Level of Maturity Definition
System/database to compile and track vetted data across response, requests for information/action, and other information to support communications.

### Plans

<table>
<thead>
<tr>
<th>Level</th>
<th>Current</th>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-</td>
<td>Overarching plan with hazard specific communications plans for two or less hazards.</td>
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<tr>
<td>3</td>
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<tr>
<td>5</td>
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</tbody>
</table>

### Current Level of Maturity Definition
Overarching plan, with no hazard specific communications plans.

### Messaging

<table>
<thead>
<tr>
<th>Level</th>
<th>Current</th>
<th>Next Level of Maturity Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-</td>
<td>Pre-approved messaging templates for all-hazards/threats it may face.</td>
</tr>
<tr>
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</table>

### Current Level of Maturity Definition
Pre-approved and documented messaging for multiple, but not all hazards.
Preparedness Communication

| 1 | 2 | 3 | 4 | 5 |

Current Level of Maturity Definition
Annual campaign dedicated to customer and community preparedness broadcast year-round. Focused on storms and some other hazards that could affect customers and/or infrastructure.

Next Level of Maturity Definition
Annual campaign dedicated to customer and community preparedness broadcast year-round. Focused on all of the major hazards (e.g., earthquake, ice, floods, etc.) that could affect customers and/or infrastructure.
Outreach and Coordination: Description and Leading Practices

Description

The extent to which the emergency management effort integrates with external agencies and organizations to both improve their own skills but also to train and educate those external organizations.

Leading Practices

- Being actively engaged and involved in key community organizations can have a major positive impact on the success of a response. One leading practice utility serves on the board of directors for non-profit agencies that would be involved in a response (e.g., Red Cross). This involvement benefits the communities that they serve, supports the non-profit, and builds relationships with the response partner.
- At least two utilities are involved with the Fire Academy curricula and are involved with delivering utility (gas or electric) safety for first responders. This leads to improvements in the safety of first responders, provides awareness of electrical and gas systems for first responders, and builds a working relationship between the utility and public safety first responders.
- Several utilities have developed programs to meet the needs of local elected and professional leaders during the response. One utility has developed a program to provide a dashboard and knowledgeable personnel to staff each of the utility’s locales. This program is assigned blue-sky relationships that continue during the response to an actual incident.
Outreach and Coordination: Overall Assessment

**STRENGTHS**
- Toronto Hydro partners with local first responders or emergency managers for hazard-specific planning.

**OPPORTUNITIES FOR IMPROVEMENT**
- The company would benefit from implementing a formal or ad hoc program for training public safety agencies response to utility infrastructure incidents.
# Outreach and Coordination: Goals

## Planning and Coordination

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**Current Assessment**  
Participation with local first responders or emergency managers for specific hazard planning. Outreach not coordinated by business units.

**Next Level of Maturity Definition**  
Coordinated outreach across the enterprise with state and local emergency managers for major hazards.

## First Responder Training

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</table>

Informal/ad hoc training program that provides training on request.

**Next Level of Maturity Definition**  
Formal training program that provides training to public safety agencies on request.
2016 Emergency Management Benchmark Update
As of December 30, 2016

Prepared by:

daviesconsulting
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INTRODUCTION
Background

In 2016, Toronto Hydro participated in an industry-wide benchmarking study of emergency management (EM). Participants included 17 utilities representing 25 U.S. states and the province of Ontario, and approximately 50% of electric invested-owned utility (IOU) customers. Davies Consulting, LLC, conducted this independent assessment, using a methodology based upon the Carnegie Mellon Capabilities Maturity Model framework to assess 10 categories of emergency management capability:

- Governance
- Workforce Mobilization and Care
- Planning
- Response Organization
- Response Plans
- Command and Information System
- Training and Education
- Exercise and Evaluation
- Communications
- Outreach and Communication

The results of the 2016 benchmarking study have been provided to Toronto Hydro under separate cover. The purpose of this update is to show how Toronto Hydro potentially can improve its emergency management maturity through: 1) The implementation of improvements currently planned for 2017; and 2) The adoption of additional changes in line with maturity model criteria.
Description of the 2016 Benchmarking Methodology

The Emergency Management Maturity Model framework, used in the 2016 benchmarking assessment, is founded upon the Carnegie Mellon Capabilities Maturity Model (CMM) and incorporates: 1) Davies Consulting’s emergency management expertise, 2) a variety of industry standards and guidelines, and 3) the experience of emergency management organizations within the utility industry.

- CMM is designed to measure the maturity of *process* goals from a level of 1 (ad hoc) to level 3 (defined or threshold acceptable level) to level 5 (optimized)

- The CMM model focuses on process. Davies Consulting adapted the CMM approach so that the measures of emergency management maturity are more precise for each goal by incorporating process as well as considering organization and other aspects of a successful emergency management program.

- Using the CMM approach, the model separates Emergency Management Maturity into five major Program Components. Each Program Component consists of at least one Category. Program Components, Emergency Management Categories and Goals are detailed in the table on the next two pages.

- Each Category is further described by a specific set of Goals for Emergency Management Maturity. The maturity assessments are completed for each Goal using the CMM 1 through 5 scale. The numeric assessments for the Goals within each Category are aggregated and translated into overall numeric assessments for each Category.
Description of Methodology Used for 2016 Update

As a supplement to the 2016 Davies Consulting Emergency Management Benchmarking Report, this update shows how the Toronto Hydro Emergency Management Program is continuing to advance, using the same scoring methodology in the ten key categories of emergency management.

This assessment update includes three scores:

- **Actual** – The 2016 score based on work that was completed and implemented by the completion of the initial benchmarking assessment in August of 2016.
- **Planned** – A forecasted score for the end of 2017 based on work that has happened since the initial assessment, and/or is planned to be completed and implemented by the end of 2017.
- **Possible** – A possible score based on improvements that are not currently planned for 2017, but could have a significant impact on raising the maturity score and are reasonably achievable by the end of 2017.

The rationale for maintaining or increasing the Planned and Possible scores is detailed for each category. The Planned and Possible scores have been rounded to the nearest quarter of a point (except where a Planned score remains the same as the Actual score).

It is important to note that the scoring criteria in the Emergency Management Maturity Model may change to reflect leaning from the 2016 process and/or the increasing level of maturity across the industry and among the participants. So the Planned and Possible scores described in this document should be interpreted in this context (i.e., actual scores may differ depending upon the evaluation criteria and thresholds used in the conduct of the next benchmarking study).
## Emergency Management Assessment Model Description

<table>
<thead>
<tr>
<th>Program Component</th>
<th>Category</th>
<th>Category Description</th>
<th>Evaluated Emergency Management Goals</th>
</tr>
</thead>
</table>
| **Program Management** | Governance | The organization, corporate governance and processes by which the Emergency Management function is defined, lead and maintained. It is characterized by visible leadership support, endorsement and demonstrated engagement. | • Centralized Responsibility  
• Scope  
• Corporate Alignment  
• Vision and Guiding Principles  
• Emergency Management Culture  
• Skills and Abilities  
• Resources  
• Program Standards and Requirements  
• Performance Measurement |
| **Program Planning** | Workforce Mobilization and Care | The ability of an enterprise to identify and engage the necessary number of human resources (internal or external), with the required skills and expertise, and to prepare for and respond to any incident. There also should be a plan to account for and manage the welfare of the responders and, to a certain extent, their families. | • Roles and Responsibilities  
• Qualifications  
• Mutual Assistance  
• External Labor Qualifications Tracking  
• Resource Accountability  
• Family and Employee Assistance |
| **Program Implementation** | Planning | Emergency planning and coordination during the preparedness or mitigation phase. | • Hazard and Threat Analysis  
• Incident Levels and Complexity Analysis  
• All-Hazards Planning  
• Logistics |
| **Program Implementation** | Response Organization | The scalable, all-hazards incident and crisis management organization that the enterprise has created and implements to manage emergencies and crises. | • Level 1 Crisis Management  
• Level 2 Incident Support  
• Level 3 Incident Management  
• Incident Command System Certification  
• ICS: Adoption and Use |
| **Program Implementation** | Response Plans | The documented policies and processes in place that describe emergency response strategies and tactics for all enterprise units and all response organization levels. | • Plan Framework  
• Plan Review and Approval  
• Plan Distribution and Availability  
• Plan Testing |
<table>
<thead>
<tr>
<th>Program Component</th>
<th>Category</th>
<th>Category Description</th>
<th>Evaluated Emergency Management Goals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Program Implementation</td>
<td>Command and Information Systems</td>
<td>The facilities, technology and communication systems that enable command and control through redundant, efficient and effective communication and sharing of information.</td>
<td>• Command and Control Nodes</td>
</tr>
<tr>
<td>(cont’d)</td>
<td></td>
<td></td>
<td>• Mobile Command Centers</td>
</tr>
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<td></td>
<td></td>
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<td>• Telecommunications</td>
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<td></td>
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<td>• Incident Management Tools and Tech</td>
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<td>• Operational Tools</td>
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<td>• Analytical Tools</td>
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<td></td>
<td></td>
<td></td>
<td>• Notification Tools</td>
</tr>
<tr>
<td>Training and Education</td>
<td>Training and Education</td>
<td>The program that ensures the people are well trained and prepared to respond to all-hazards. The training and education program is focused on the roles and responsibilities to respond across the enterprise.</td>
<td>• Training Program</td>
</tr>
<tr>
<td></td>
<td>Exercise and Evaluation</td>
<td>The exercise and evaluation program is focused on the ability of the team to respond to any hazard. It identifies improvement opportunities, and measure the effectiveness of the people, the response organization, the response plans, and the supporting tools and technology.</td>
<td>• Exercise Program</td>
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<td></td>
<td></td>
<td>• Periodicity</td>
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<td></td>
<td></td>
<td></td>
<td>• Type</td>
</tr>
<tr>
<td>Communications and Outreach</td>
<td>Communications</td>
<td>The processes, planning, and implementation of an effective communications strategy during an incident. It includes the way in which messaging is created, approved, and disseminated. More mature communications organizations follow a well-coordinated and well-integrated process that also develops hazard-specific messaging during blue-sky.</td>
<td>• Organization</td>
</tr>
<tr>
<td></td>
<td>Outreach and Coordination</td>
<td>The extent to which the Emergency Management effort integrates with external agencies and organizations to both improve their own skills but also to train and educate those external organizations.</td>
<td>• Planning and Coordination</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Participation in Critical Infrastructure</td>
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<td>• First Responder Training</td>
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</tbody>
</table>
SUMMARY OF TORONTO HYDRO
EMERGENCY MANAGEMENT MATURITY SCORES
Summary of 2016 Emergency Management Benchmarking Results

Figure 1 is a “spider chart” that illustrates the collection of Toronto Hydro’s results from the 2016 benchmarking study. These scores reflect the assessment of Toronto Hydro’s maturity in each of the 10 categories reviewed, as compared to the participants’ average (indicated by the blue line), as well as the industry minimum threshold. Within a category, the minimum threshold score (shown in gray) indicates that a utility has met much of the evaluation criteria, and the achievement of higher score requires a more thorough or advanced demonstration of leading practice. The blue line indicates the average score, by category, of all participants.

Generally, the 2016 benchmarking results indicate that Toronto Hydro is an emerging company in terms of emergency management maturity. At the time of the assessment, the Company’s emergency management improvement program had been in place for less than two years -- but already demonstrated results, particularly in the categories of Communications and Training and Communication. As expected, there remain significant opportunities for improvement. Please see the Toronto Hydro 2016 Emergency Management Benchmark Report for additional details.

Figure 1: Summary of 2016 Benchmarking Maturity Scores
Figure 2 illustrates the maturity scores, by category, that Toronto Hydro is expected to achieve by the end of 2017. These reflect improvements made since August 2016 as well as ones planned for 2017. The single activity that will have the most impact on the 2017 scores is the completion of the functional exercise that is planned for Spring of 2017. The functional exercise can lead to increases in scores in several categories: Exercise and Evaluation, Governance, Planning and Response Organization.

A comparison of the 2017 Planned scores to the 2016 benchmarking study scores, indicates that, with these Planned improvements, Toronto Hydro could achieve or maintain a score of 3 in four of the ten categories, a notable advancement. The yellow circle represents the minimum threshold.
Summary of 2017 Possible Emergency Management Maturity Scores

Figure 3 illustrates possible increases to 2017 to the Planned scores from the implementation of one or more recommended improvements (see the following section of this Report for details). These additional advancements could result in scores that meet or exceed the minimal threshold (shown in yellow) in nearly all categories.

Suggested actions that could lead to an increase in a category score of one-half to a full point include:

- Training and Education: Improve the tracking of emergency management training across the Company.
- Response Organization: Complete advanced training (above IMS 100) for all Command and General staff.
EM MATURITY ASSESSMENT UPDATE RESULTS
Governance

Description
The organization, corporate governance and processes by which the Emergency Management function is defined, lead and maintained. It is characterized by visible leadership support, endorsement and engagement demonstrated through the elements of its program.

Scores
Toronto Hydro Actual 2016 Governance: 2.75
Toronto Hydro Planned 2017 Governance: 3.00
Toronto Hydro Possible 2017 Governance: 3.75

Rationale
As of our assessment in August of 2016, Toronto Hydro achieved a score of 2.75.
We expect that the Governance score will increase to 3.00 by the end of 2017 based on the following planned or completed work since the initial assessment:

- Ramp up Grid Emergency Management staffing.

If these suggested changes are implemented in addition to the planned improvement, we could expect the score to rise to 3.75:

- Develop a multi-year strategic plan for implementing and improving emergency management, including a resource plan.
- Establish metrics to measure progress/results of the emergency management program.
- Ensure that the Grid Emergency Management Manager has authority to drive the advancement of emergency management capabilities across the Company.
- Tie emergency management objectives to individual performance incentive goals.
- Centralize all emergency management functions under one responsible executive (e.g., Business Continuity, Disaster Recovery, Cyber Security and Physical Security).
Workforce Mobilization and Care

Description

The ability of an enterprise to identify and engage the necessary number of human resources (internal or external), with the required skills and expertise, and to prepare for and respond to any incident. There also should be a plan to account for and manage the welfare of the responders and, to a certain extent, their families.

Scores

Toronto Hydro 2016 Workforce Mobilization and Care: 2.83
Toronto Hydro Planned 2017 Workforce Mobilization and Care: 2.83
Toronto Hydro Possible 2017 Workforce Mobilization and Care: 3.25

Rationale

As of our assessment in August of 2016, Toronto Hydro achieved a score of 2.83 for Workforce Mobilization and Care. We expect that the Workforce Mobilization and Care score will remain at 2.83 by the end of 2017 based on the following planned or completed work since the initial assessment:

- No work is planned that will affect the score.

If these suggested changes are implemented, we could expect the score to increase to 3.25:

- Formalize call trees and the process to locate personnel during or in advance of an incident.
  Or
- Implement tools or technology to rapidly account for employees following a major incident.
- Implement a process to support (or decide to support) employee families during or after an incident.
Planning

Description
Emergency planning and coordination during the preparedness or mitigation phase.

Scores

<table>
<thead>
<tr>
<th>Description</th>
<th>Score</th>
</tr>
</thead>
<tbody>
<tr>
<td>Toronto Hydro 2016 Planning:</td>
<td>2.50</td>
</tr>
<tr>
<td>Toronto Hydro Planned 2017 Planning:</td>
<td>2.75</td>
</tr>
<tr>
<td>Toronto Hydro Possible 2017 Planning:</td>
<td>3.00</td>
</tr>
</tbody>
</table>

Rationale
As of our assessment in August of 2016, Toronto Hydro achieved a score of 2.50 for Planning.
We expect that the Planning score will increase to 2.75 by the end of 2017 based on the following planned or completed work since the initial assessment:
- Put contracts in place in Logistics to meet the needs of an incident response.
- Identify staging areas and make ready for use.

If these suggested changes are implemented in addition to the planned improvements, we could expect the score to rise to 3.00:
- Develop and train Response Plans for all top hazards and threats.
Response Organization

Description
The scalable, all-hazards incident and crisis management organization that the enterprise has created and implements to manage emergencies and crises.

Scores

<table>
<thead>
<tr>
<th>Description</th>
<th>Score</th>
</tr>
</thead>
<tbody>
<tr>
<td>Toronto Hydro 2016 Response Organization:</td>
<td>2.40</td>
</tr>
<tr>
<td>Toronto Hydro Planned 2017 Response Organization:</td>
<td>2.50</td>
</tr>
<tr>
<td>Toronto Hydro Possible 2017 Response Organization:</td>
<td>3.00</td>
</tr>
</tbody>
</table>

Rationale
As of our assessment in August of 2016, Toronto Hydro achieved a score of 2.40 for Response Organization.
We expect that the Response Organization score will increase to 2.50 by the end of 2017 based on the following planned or completed work since the initial assessment:

- Involved the crisis management team in a functional exercise.

If these suggested changes are implemented in addition to the planned improvement, we could expect the score to increase to 3.00:

- Complete advanced training for all Command and General staff have advanced (higher than 100 level course) IMS/ICS training.
- Train all staff rostered in response roles in IMS/ICS to respond to all hazards.
Response Plans

Description

The documented policies and processes in place that describe emergency response strategies and tactics for all enterprise units and all response organization levels.

Scores

<table>
<thead>
<tr>
<th>Description</th>
<th>Score</th>
</tr>
</thead>
<tbody>
<tr>
<td>Toronto Hydro 2016 Response Plans:</td>
<td>2.75</td>
</tr>
<tr>
<td>Toronto Hydro Planned 2017 Response Plans:</td>
<td>3.00</td>
</tr>
<tr>
<td>Toronto Hydro Possible 2017 Response Plans:</td>
<td>3.75</td>
</tr>
</tbody>
</table>

Rationale

As of our assessment in August of 2016, Toronto Hydro achieved a score of 2.75 for Response Plans.

We expect that the Response Organization score will increase to 3.00 by the end of 2017 based on the following planned or completed work since the initial assessment:

- Complete the framework of plans supporting the core plan and complete at least one hazard or functional annex.

If these suggested changes are implemented in addition to the planned improvements, we could expect the score to rise to 3.75:

- Put a formal process in place to update all plans annually and as needed after any incident Level 3 and above.
- Make response plans available as PDFs via secure mobile access.
- Formally test plans through tabletop and functional exercises where players are asked to reference the plans.
Command and Information Systems

Description
The facilities, technology and communication systems that enable command and control through redundant, efficient and effective communication and sharing of information.

Scores
- Toronto Hydro 2016 Command and Information Systems: 1.57
- Toronto Hydro Planned 2017 Command and Information Systems: 1.75
- Toronto Hydro Possible 2017 Command and Information Systems: 2.25

Rationale
As of our assessment in August of 2016, Toronto Hydro achieved a score of 1.57 for Command and Information Systems.
We expect that the Command and Information Systems score will increase to 1.75 by the end of 2017 based on planned work:
- Train the damage assessment statistical prediction process.

If these suggested changes are implemented in addition to the planned improvement, we could expect the score to rise to 1.75:
- Create an automated email process to notify employees when an incident has been declared.
- Acquire a Mobile Command vehicle (score could be higher depending on the capabilities of the vehicle).
Training and Education

Description

The program that ensures the people are well trained and prepared to respond to all-hazards. The training and education program is focused on the roles and responsibilities to respond across the enterprise.

Scores

Toronto Hydro 2016 Training and Education: 3.00
Toronto Hydro Planned 2017 Training and Education: 3.00
Toronto Hydro Possible 2017 Training and Education: 4.00

Rationale

As of our assessment in August of 2016, Toronto Hydro achieved a score of 3.00 for Training and Education.

We expect that the Training and Education score will remain at 3.00 by the end of the year based on the following planned or completed work since the initial assessment:

- No work is planned that will affect the score.

If these suggested changes are implemented, we could expect the score to increase to 4.00:

- Centralize EM training under a single unit (including emergency management, business continuity and disaster response)
- Track all EM-related training through a single system, in coordination with Human Resources.
Exercise and Evaluation

Description

The exercise and evaluation program is focused on the ability of the team to respond to any hazard. It identifies improvement opportunities, and measure the effectiveness of the people, the response organization, the response plans, and the supporting tools and technology.

Scores

Toronto Hydro 2016 Exercise and Evaluation: 2.00
Toronto Hydro Planned 2017 Exercise and Evaluation: 2.50
Toronto Hydro Possible 2017 Exercise and Evaluation: 3.25

Rationale

As of our assessment in August of 2016, Toronto Hydro achieved a score of 2.00 for Exercise and Evaluation.

We expect that the Exercise and Evaluation score will increase to 2.50 by the end of 2017 based on the following planned or completed work since the initial assessment:

- Include All-hazards exercises as part of an enterprise exercise program, in coordination with all business units.
- Hold a full functional exercise using a master scenario events list (MSEL).

If these suggested changes are implemented in addition to the planned improvements, we could expect the score to rise to 3.25:

- Hold one functional exercise per year (2017 will be the first functional exercise; “credit” for the 2018 annual exercise could be given if planning begins in 2017).
- Include external agencies in exercises.
- Institute an after action process to be led by the Grid Emergency Management organization.
Communications

Description

The processes, planning, and implementation of an effective communications strategy during an incident. It includes the way in which messaging is created, approved, and disseminated. More mature communications organizations follow a well-coordinated and well-integrated process that also develops hazard-specific messaging during blue-sky.

Scores

<table>
<thead>
<tr>
<th>Description</th>
<th>Score</th>
</tr>
</thead>
<tbody>
<tr>
<td>Toronto Hydro 2016 Communications</td>
<td>3.86</td>
</tr>
<tr>
<td>Toronto Hydro Planned 2017 Communications</td>
<td>3.86</td>
</tr>
<tr>
<td>Toronto Hydro Possible 2017 Communications</td>
<td>4.00</td>
</tr>
</tbody>
</table>

Rationale

As of our assessment in August of 2016, Toronto Hydro achieved a score of 2.00 for Communications.

We expect that the Communications score will remain at 3.86 by the end of the year based on the following planned or completed work since the initial assessment:

- No work is planned that will affect the score (Note: The score may improve through practice of existing processes through exercises and application in real events.)

If these additional suggested changes are implemented, we could expect the score to rise to: 4.00

- Create hazard-specific communications annexes to support the existing Emergency Communications Plan.
- Add all hazards messaging to customer and community messaging (currently the messaging is storm-focused).
Outreach and Coordination

Description

The extent to which the emergency management effort integrates with external agencies and organizations to both improve their own skills but also to train and educate those external organizations.

Scores

Toronto Hydro 2016 Outreach and Coordination: 2.00
Toronto Hydro Planned 2017 Outreach and Coordination: 2.00
Toronto Hydro Possible 2017 Outreach and Coordination: 3.00

Rationale

As of our assessment in August of 2016, Toronto Hydro achieved a score of 2.00 for Outreach and Coordination. We expect that the Outreach and Coordination score will remain at 2.00 by the end of 2017 based on the following planned or completed work since the initial assessment:

- No work is planned that will affect the score (Note: The score may improve through practice of existing processes through exercises and application in real events.)

If these suggested changes are implemented, we could expect the score to rise to: 3.50

- Coordinate outreach across the Company with external emergency managers or officials (e.g., between Emergency Management, Business Continuity and Government Affairs).
- Provide formal training to public safety agencies upon request (informal training currently is provided).
April 25, 2016

Toronto Hydro-Electric System Limited
500 Commissioners Street
Toronto, Ontario  M4M 3N7

Attention: Mr. Kees-Jan Homsma

Re: BENCHMARK REPORT SUMMARY
Facility Renovations, Toronto Hydro, 71 Rexdale Boulevard, Toronto
Project No. 13013

Sir:

Independent Project Managers has carried out a review of the benchmark reports for the above noted project and our findings are outlined below.

At the request of Toronto Hydro, Independent Project Managers commissioned three (3) independent cost consulting firms to perform an analysis of the current estimated construction costs for the facility renovation at 71 Rexdale Boulevard, with industry benchmarks for projects similar in nature.

The enclosed benchmark reports issued by A.W. Hooker Quantity Surveyors, Altus Group Limited and Marshall Murray, reflect independent professional analysis and opinion in accordance with data collected from projects within their historical portfolios. Due to the uniqueness of the project, comparative elemental reviews have been provided with multiple reference projects to provide the basis for the conclusions within each report. To the best of our knowledge, the reports provided have been completed in conformity to the requested analysis and information as commissioned.

The summary of hard costs are demonstrated in Table 1.1 (attached). An average and median of each cost consultant’s report is shown as well to reflect the variance in reference projects provided.

The summary of soft costs are demonstrated in Table 1.2 (attached). Due to the nature of soft costs and the variations to be considered, such as design/project durations, owner supplied equipment/furnishings and project execution methods, an industry percentage range against the hard costs was provided by each consultant in lieu of actual soft costs from the reference projects. A.W. Hooker provides a range of 20% to 40% and used 25% of hard costs in their report to calculate soft costs of the reference projects. Altus Group Limited provided an industry range for soft cost to be 15% to 35% of hard costs, an average soft cost value of 25% was calculated and applied to the average and median of their reference projects. Marshall Murray has provided an industry range for soft cost to be 15% to 35% of hard costs, an average soft cost value of 25% was calculated and applied to the average and median of their reference projects.
The combined totals for hard and soft costs are summarized on Table 1.3 (attached). Our review of the benchmark reports reveal that the estimated square footage cost of 71 Rexdale Boulevard of $234.31/sf is lower that the average of $392.31/sf and median of $378.32/sf. The analysis shows that utilizing the existing building structural elements and efficient design has been cost effective in comparison to similar projects.

The following tables summarize the report results.

Yours very truly,

Rob Ward
Project Manager

RW/Ip
### TABLE 1.1 IPM Benchmark summary: Hard Cost

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>A.W. Hooker</td>
<td>$185</td>
<td>$266</td>
<td>$267</td>
</tr>
<tr>
<td>Altus Group</td>
<td>$184</td>
<td>$434</td>
<td>$417</td>
</tr>
<tr>
<td>Marshall Murray</td>
<td>$184</td>
<td>$242</td>
<td>$224</td>
</tr>
<tr>
<td>IPM (Average of reports)</td>
<td>$184</td>
<td>$314</td>
<td>$303</td>
</tr>
</tbody>
</table>

![Bar chart showing the cost comparison between consultants and the IPM average reports. The chart uses different colors to represent hard cost 71 Rexdale, average of reference projects, and median of reference projects.](chart.png)
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>A.W. Hooker</td>
<td>$49.93</td>
<td>$66.40</td>
<td>$66.69</td>
</tr>
<tr>
<td>Altus Group</td>
<td>$50.00</td>
<td>$108.50</td>
<td>$104.25</td>
</tr>
<tr>
<td>Marshall Murray</td>
<td>$50.00</td>
<td>$60.49</td>
<td>$56.05</td>
</tr>
<tr>
<td>IPM (Average of reports)</td>
<td>$49.98</td>
<td>$78.46</td>
<td>$75.66</td>
</tr>
</tbody>
</table>

![Bar chart showing soft cost comparison](image)
## TABLE 1.3 IPM Benchmark summary, Total Sum

<table>
<thead>
<tr>
<th>Consultant</th>
<th>Sum of 71 Rezto $/SF</th>
<th>Sum of Average of reference</th>
<th>Sum of Median of reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>A.W. Hooker</td>
<td>$235.23</td>
<td>$332.01</td>
<td>$333.45</td>
</tr>
<tr>
<td>Altus Group</td>
<td>$234.00</td>
<td>$542.50</td>
<td>$521.25</td>
</tr>
<tr>
<td>Marshall Murray</td>
<td>$234.00</td>
<td>$302.43</td>
<td>$280.25</td>
</tr>
<tr>
<td>IPM (Average of reports)</td>
<td>$234.41</td>
<td>$392.31</td>
<td>$378.32</td>
</tr>
</tbody>
</table>

![Bar chart showing total sums for each consultant]

- **Green**: Sum of 71 Rezto $/SF
- **Red**: Sum of Average of reference projects
- **Orange**: Sum of Median of reference projects
Dear Mr. Chris Baylis,

We understand that Toronto Hydro has requested an analysis for costs associated with the subject project. Further, we understand that Independent Project Managers (IPM) has solicited benchmark cost reports from three independent cost consultants to compare cost data for similar projects within the Greater Toronto Area.

Barry Bryan Associates (BBA) has drafted this report to provide an overall background associated with the project direction as well as a supplement of value received by Toronto Hydro which extends beyond the benchmark cost reports.

At the time the 71 Rexdale property was obtained by Toronto Hydro, it was requested that the design team provide a schematic review of the existing building in order to confirm possible opportunity for reuse and modification to suit the overall program needs and to achieve Toronto Hydro’s overall consolidation goals. Through the design process, the design and management team completed several feasibility studies, and ended up with the following to provide the best proposed overall project value:

- Selective demolition to remove end-of-life and poor quality materials as well as structure which could not be salvaged for reuse as part of the future use.
- Lifting of an existing portion of roof to insert a second floor structure for the proposed front office area.
- Installation of new Mechanical and Electrical Services.
- Refinishing of space including new professional office, warehouse and fleet garage.
- Site work to support the proposed Toronto Hydro operational requirements.
- Removal and replacement of the majority of the existing building envelope.
- Implementation of a new security program to mitigate the Toronto Hydro risk assessment concerns as a vital City Service.

The benefits obtained by implementing the above design include the following:

- A major portion of the building cost was removed from the budget as the team was able to reuse much of the existing structure including foundations, steel building framing, metal deck, portions of existing concrete slab and site sanitary services.
- The renovation design incorporating the existing building allowed for much of the same footprint to remain unchanged. Therefore the team was able to prevent a City of Toronto site plan approval process which would have been a substantial cost to both the schedule and financials for the project.
- By keeping much of the existing building footprint, City of Toronto Development Fees have not been requested nor collected by the City of Toronto.
- Existing building mezzanine area has been left unfinished for future expansion should it be required. There is value of this space with relatively little or no cost to the project as it was existing and has not been substantially improved.
- The existing building has been renovated while implementing the Toronto Hydro Standard.
- Conservatively, more than 2,500 tonnes of concrete and 400 tonnes of structural steel were salvaged, reused and diverted from landfill as part of this project. This design allowed Toronto Hydro to achieve environmental goals associated with this project.
The project included the replacement of the majority of roofing, cladding and windows allowing for a modern and energy efficient envelope which meets current code standards, provides an overall reduced energy consumption and increased life cycle.

Fast track methods were utilized allowing for maximum value to be achieved from a phased approach and compressed schedule by the Construction Management team.

Should you have any questions regarding the above, or require any additional information, please do not hesitate to call our office.

Yours very truly,

Barry Bryan Associates
Architects, Engineers, Project Managers

David Bovill, P.E., P. Eng.

DB/ah
Benchmark Report (Rev.0)

Toronto Hydro, 71 Rexdale Boulevard Facility

Prepared for:
IPM Project Managers

Prepared by:
A.W. HOOKER
QUANTITY SURVEYORS

April 6, 2016
April 5, 2016

Independent Project Managers
286 King Street West, Suite 201
Oshawa, Ontario  L1J 2J9

Attn: Rob Ward, Project Manager

Re: Benchmark Report for 71 Rexdale Facility Estimated Project Cost

Dear Rob,

Please find enclosed our Benchmark Report for the above project. The benchmark report is based on the data collected from the similar projects in nature and the cost estimate for 71 Rexdale Facility which was issued by A. W. Hooker on February 4, 2016.

This independent review has been commissioned by Independent Project Managers for Toronto Hydro to examine the value of design and procurement for 71 Rexdale Facility by benchmarking the estimated project cost to help them understand if the estimated cost of project is within the reasonable cost range in GTA current market.

This benchmark report is meant to reflect our independent professional opinion, as per analysis in accordance with data collected from the similar projects (reference projects) that are available at A.W. Hooker Associates Ltd. office. Due to uniqueness of the 71 Rexdale Facility project, it is not intended to compare 71 Rexdale Facility (investigated project) with multiple similar renovation projects. In addition, the nature of renovation works for the facility involves with major substructure and superstructure upgrades such as replacement of slab on grade, partial raising existing roof framing, addition of second floor structure and replacement of building enclosures such as cladding and roofing. Therefore, the reference projects mentioned in this report represent new project costs.

We have conducted a unit cost comparison for square foot cost of building (Type 1) and square foot cost of group elements (Type 2) to benchmark the cost performance of the investigated project. Group elements are investigated under five major groups such as Substructure, Superstructure, Finishes, Fitting and Furnishing and M&E Services. Site Works, Demolition Works and Project Soft Cost are benchmarked separately due to difficulties of finding resembling projects. For demolition and soft costs, a variety of sites, building ratios and projects varying in nature were used.

We recommend that the owner and/or the design team carefully review the report, including preamble, comparison tables and graphs, clarifications, exclusions, inclusions and assumptions. This is to ensure that the expected benchmark is captured within the content of the report.

116188, Benchmark Report for 71 Rexdale Estimated Construction Cost
We trust our work will assist in the decision making process and look forward to our continued involvement in this important project.

Sincerely,
A.W. Hooker Associates Ltd.

Tanju Celen, PQS
Partner

Encl. (71 Rexdale Facility Estimated Project Cost Benchmark, April 5, 2016)
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8. Benchmark Report Analysis (Tables and Graphs)
1. Executive Summary

A.W. Hooker Associates Ltd. has been commissioned to review the estimated construction cost of 71 Rexdale Facility project. This report primarily examines the estimated square foot cost of the overall building and grouped building elements; and benchmarks their estimated costs against eight (8) new reference projects gathered from our database. Major resemblance of the Reference Projects has been identified as function of the buildings which consists of administration/office storage/vehicle storage areas. In addition, our benchmark report utilizes the mentioned eight reference projects for site works cost benchmarking. Due to uniqueness of Rexdale project and difficulties for finding similar reference project for demolition cost benchmarking, we selected six (6) separate reference projects to review demolition cost of Rexdale facility.

1.1 Building Cost Benchmark

The overall building and grouped elements square foot costs of 71 Rexdale Facility and Average and Median of Reference Projects are highlighted in Table 1.1, Chart 1.1 and 1.2.

Our analysis for this Benchmark Report reveals that estimated square foot cost of 71 Rexdale Facility building ($150.26/SF) is lower than both average and median unit rates of reference projects (average*: $189.26, median*: $200.78). (*) Refer to Section 5.2 of this report for further clarification about “average” and “median”.

In regards to grouped elemental unit rate cost, 71 Rexdale Facility’s grouped elemental unit rates are lower than average and median of reference project with the exception of grouped M&E unit rate benchmark for average cost. Grouped M&E unit rate of 71 Rexdale Facility is 3% higher than average benchmark but it is 4.3% lower than median benchmark rate.

As per attached detailed analysis of the Benchmark Report, A.W. Hooker Associates Ltd. concludes that 71 Rexdale Facility estimated overall building unit rate and grouped elemental unit rates are reasonable among the selected reference projects (peer projects).

Table 1.1: Executive Benchmark Report for Building Hard Construction Cost

<table>
<thead>
<tr>
<th>Description</th>
<th>71 Rexdale Facility</th>
<th>Average Reference Projects</th>
<th>Median of Reference Projects</th>
<th>Comparison to Average of Reference Projects</th>
<th>Comparison to Median of Reference Projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Floor Area, Overall Estimated Unit Rate ($/SF), excluding site and demolition works</td>
<td>$150.26</td>
<td>$189.26</td>
<td>$200.78</td>
<td>20.6% Lower</td>
<td>25.2% Lower</td>
</tr>
<tr>
<td>1-Substructure Unit Rate ($/SF)</td>
<td>$29.35</td>
<td>$44.59</td>
<td>$43.63</td>
<td>35.8% Lower</td>
<td>35.4% Lower</td>
</tr>
<tr>
<td>2-Super Structure Unit Rate ($/SF)</td>
<td>$29.35</td>
<td>$40.60</td>
<td>$50.26</td>
<td>40.6% Lower</td>
<td>41.9% Lower</td>
</tr>
<tr>
<td>3-Finishes Unit Rate ($/SF)</td>
<td>$21.43</td>
<td>$24.30</td>
<td>$23.04</td>
<td>11.6% Lower</td>
<td>7% Lower</td>
</tr>
<tr>
<td>4-Fitting and Equipment Unit Rate ($/SF)</td>
<td>$8.17</td>
<td>$9.47</td>
<td>$9.52</td>
<td>13.8% Lower</td>
<td>16.8% Lower</td>
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<tr>
<td>5-M&amp;E Service Unit Rate ($/SF)</td>
<td>$63.13</td>
<td>$61.30</td>
<td>$55.91</td>
<td>-3% Higher</td>
<td>4.2% Lower</td>
</tr>
<tr>
<td>3-Trade work Unit Rate ($/SF)</td>
<td>Included elsewhere</td>
<td>Included elsewhere</td>
<td>Included elsewhere</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>7-Demolition Unit Rate ($/SF)</td>
<td>Included elsewhere</td>
<td>NA</td>
<td>NA</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
</tbody>
</table>
1.2 Site Works Cost Benchmark

The overall site works square foot costs of 71 Rexdale Facility and Average and Median of Reference Projects is highlighted below in Table 1.2, Chart 1.3 and 1.4.

The same reference projects for building hard construction cost benchmarking have been utilized for site work cost benchmarking. It should be noted that the ratio of site area / building gross floor area varies significantly. For this reason, site work cost impact on building cost gross floor area unit rate will not provide proper benchmarking. Therefore, we have provided two different benchmarks for site work cost unit rates. The first one is based on Net Site Work area (excluding building footprint) and the second one is based on building gross floor area. Although reasonableness of site work unit rate (as per net site work area) is 26.3% higher than the median of reference projects, overall cost impact of site work on each square foot of the building is 64.3% lower than the median of reference project due to smaller “site area/building area” ratio. This result can be seen in Table 1.2, Chart 1.3 and 1.4.
Table 1.2: Executive Benchmark Report for Site Works Hard Construction Cost

<table>
<thead>
<tr>
<th>Description</th>
<th>71 Rexdale Facility</th>
<th>Average of Reference Projects</th>
<th>Median of Reference Projects</th>
<th>Comparison to Average of Reference Projects</th>
<th>Comparison to Median of Reference Projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit Rate as per Site Area (Factorized for Economy of Scale for 365,675 SF Site Work GFA), $/SF</td>
<td>$12.01</td>
<td>$10.24</td>
<td>$9.51</td>
<td>-17.2% Higher</td>
<td>-26.3% Higher</td>
</tr>
<tr>
<td>Unit Rate as per Building GFA (Addition Cost Impact on Building Unit Rate for 190,401 SF), $/SF</td>
<td>$23.05</td>
<td>$68.00</td>
<td>$54.49</td>
<td>65.1% Lower</td>
<td>64.3% Lower</td>
</tr>
</tbody>
</table>

Chart 1.3: Overall Site Works square foot cost benchmark chart, as per net site work area

Chart 1.4: Overall Site Works square foot cost benchmark chart, as per building gross floor area

1.3 Demolition Cost Benchmark

Due to difficulties for finding similar reference project for demolition cost benchmarking, we selected six (6) separate reference projects out of which none of them has close resemblance to Rexdale project. However, all reference projects include selective interior and structural demolition works. Reference projects for demolition cost benchmarking consist of hospital, church, parking garage, food manufacturing facility, government office building and retail store.
warehouse. As per our analysis, demolition cost unit rate is 24.9% higher than median of reference projects. This result can be seen in Table 1.3 and Chart 1.5.

**Table 1.3: Executive Benchmark Report for Demolition Work Hard Construction Cost**

<table>
<thead>
<tr>
<th>Description</th>
<th>71 Rexdale Facility</th>
<th>Average of Reference Projects</th>
<th>Median of Reference Projects</th>
<th>Comparison to Average of Reference Projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demolition Unit Rate ($/SF)</td>
<td>$12.61</td>
<td>$10.35</td>
<td>$8.61</td>
<td>-16% Higher -24.9% Higher</td>
</tr>
</tbody>
</table>

*Chart 1.5: Overall Demolition Works square foot cost benchmark chart, as per building gross floor area*

**1.4 Soft Costs**

Soft costs items are traditionally funded by the owner and are separate from the hard construction costs which would be applicable to the contractor. The soft costs include items such as consultant fees; disbursements; project management fees; independent inspection and testing; third party commissioning; legal fees; permits and development charges; operational and moving expenses; financing and loan fees; owner supplied furnishings, fixtures, and equipment; land acquisition costs; and Harmonized Sales Tax.

Project soft cost varies significantly between 20% and 40% of hard construction cost. For the purpose of this benchmark report, soft costs have been incorporated as 25% of hard construction cost in average and median of reference project, while 71 Rexdale Soft Cost has been carried as estimated unit rate. Assumed soft cost (25% of hard construction) excludes Land Acquisition Costs, Financing and Loan Fees and HST.

Soft cost of average and median reference projects can be seen in Table 1.4, Item 8.

**1.5 Project Cost Benchmark and Conclusions**

A.W. Hooker Associates Ltd. has conducted an analysis to benchmark 71 Rexdale Facility building hard construction cost unit rates against eight selected reference projects (peers as per resemblances). The cost data for each selected reference project was normalized to provide a meaningful comparison across the selected reference projects. Normalization
process has been described in details in Section 4. Data Comparison. These eight projects are also used for site work cost benchmarking. In addition, 6 (six) separate reference projects have been selected and processed for demolition cost benchmarking. Soft cost is also considered in this benchmark report.

We also noted that 71 Rexdale Facility project has the following challenges:

a. Design is not finalized or in flux while construction is in progress
b. Expedited construction schedule.

c. Construction Management contract. Although, construction management Procurement may result in premium cost, this may have been the ideal approach for this project as the design was changing constantly.
d. Existing conditions or equipment that could have been reused but the replacement option was taken to achieve longevity

b) Upgrades to meet energy efficiency (roof with reflective aggregate and increased insulation, exterior walls, foundation insulation, reflective coatings on glazing, etc.)

Although above listed challenges contributes the cost of 71 Rexdale Facility project, we found that existing building elements (foundation, upper floor structure, roof structural steel framing) were utilized in a cost effective manner. Building enclosure, finishes, fittings and equipment, mechanical and electrical service have been fully upgraded. Although selective demolition cost increase the project cost, overall impact of demolition cost is not major. The ratio of Site Area/Building Area reduced the cost impact of site works to building cost. Soft cost of Rexdale project is 26.7% of hard construction cost. It is slightly higher than 25%. However, overall estimated project cost is still lower than average and median cost of peers in GTA. Also refer to attached Benchmark Report Analysis (Page A1-4) for details.

Table 1.4: Executive Benchmark Report for Project Cost

<table>
<thead>
<tr>
<th>Description</th>
<th>71 Rexdale Facility</th>
<th>Comparison to Average of Reference Projects</th>
<th>Comparison to Median of Reference Projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Floor Area, Overall Estimated Unit Rate ($/SF), excluding Site and Demolition works</td>
<td>$150.25</td>
<td>$180.26</td>
<td>$200.78</td>
</tr>
<tr>
<td>1-Substructure Unit Rate ($/SF)</td>
<td>$38.17</td>
<td>$44.59</td>
<td>$40.63</td>
</tr>
<tr>
<td>2-Super Structure Unit Rate ($/SF)</td>
<td>$29.35</td>
<td>$46.60</td>
<td>$50.26</td>
</tr>
<tr>
<td>3-Finishes Unit Rate ($/SF)</td>
<td>$21.43</td>
<td>$45.50</td>
<td>$33.04</td>
</tr>
<tr>
<td>4-Fitting and Equipment Unit Rate ($/SF)</td>
<td>$8.17</td>
<td>$9.47</td>
<td>$9.62</td>
</tr>
<tr>
<td>5-ME Service Unit Rate ($/SF)</td>
<td>$6.13</td>
<td>$6.13</td>
<td>$6.91</td>
</tr>
<tr>
<td>6-Site work Unit Rate ($/SF)</td>
<td>$23.05</td>
<td>$66.00</td>
<td>$64.49</td>
</tr>
<tr>
<td>7-Demolition Unit Rate ($/SF)</td>
<td>$12.01</td>
<td>$10.35</td>
<td>$9.61</td>
</tr>
<tr>
<td>8-Soft Cost (ranges between from 20% to 40% of hard construction cost), assumed 25%</td>
<td>$49.92</td>
<td>$60.40</td>
<td>$56.69</td>
</tr>
<tr>
<td>TOTAL PROJECT COST BENCHMARK (including Hard and Soft Cost)</td>
<td>$236.23</td>
<td>$332.01</td>
<td>$333.45</td>
</tr>
</tbody>
</table>

A.W. HOOKER
QUANTITY SURVEYORS

116188, Benchmark Report for 71 Rexdale Facility Estimated Construction Cost
2. Introduction

Benchmarking is a process by which the estimated performance (often cost) of a project is compared to other similar projects. This can highlight areas of design that are not offering good value for money and can help in the assessment of tenders from suppliers and contractors. Our Benchmark Report incorporates a process of comparing the cost of investigated construction cost against others which are similar in nature, magnitude, functions, etc.

The key consideration is to note that when comparing cost analysis benchmarking costs between different projects in different regions it is essential that systems of elemental breakdown, rules or method of measurement and stage plan of work are equalised through establishment of a defined baseline and set of assumptions and that these are consistently applied.

Where reference projects include significant components, features or systems which differ from the investigated project, it is recommended that where feasible, these anomalies be eliminated so the reference projects are more comparable on a like for like basis. Compensation of differentiations for the investigated project and reference projects are clarified in Section 3.

2.1 Confidentiality

As per Royal Institution of Chartered Surveyors' (RICS) recommendation, published benchmarking results should not identify the data source by reference to project name.

A.W. Hooker Associates Ltd. makes every possible effort to ensure that the information related with data source is kept secure in accordance with executed confidentiality agreements with its clients. Therefore, reference projects listed as data in section 3.3 are defined with generic names such as Reference project 1, 2, ..., i.

2.2 Taxes

Harmonized Sales Tax (HST) is excluded from our Benchmark Report.
3. Keys of Benchmark Report

3.1 Location Cost Base

The location for the investigated and reference projects is Greater Toronto Area (GTA), Ontario. Therefore, no adjustment to reference projects is required for localization cost factor. When the data source is based on various locations, the reference projects which are to be used to establish a baseline for benchmarking should be considered for localization cost factor.

3.2 Data Collection, Gathering Information, Resemblance between investigated projects and references

Resemblance between investigated project and reference projects contributes respectable baseline cost(s). Resemblances of buildings are depending on multiple criteria. Major criteria for high level resemblance are building classification, function of building, program areas, geometry and dimensions of the building. For the purpose of this report, we have identified two major program areas: Office and Vehicle Storage areas. These program areas allow us to collect data from the similar buildings that we prepared cost estimates in the past. Based on our assessment, we believe that there are resemblances between 71 Rexdale Facility and municipal operation centres and bus garages. All projects consist of office/administration areas and storage areas. Some of the selected reference projects may include heavy material storage area instead of vehicle storage. However, both storage areas require similar design. Therefore, we omitted such detail in our report.

We have collected 8 similar projects from our historical database as reference project. The reference projects consist of 6 municipal operation centres and 2 bus garages. The common building property of the selected 8 reference projects is having office and storage (either vehicle or heavy material storage) areas. Due to lack of resemblance between Rexdale Facility and demolition reference projects, they have not been remarked in detail in Section 3.2 and 3.3.

3.3 Descriptions of Reference Projects

Reference Projects from #1 to #6 can be classified as Multi-Purpose Facility - Municipal Operation Centres while #7 to #8 are Multi-Purpose Facility - Transit Bus Garage Operation Facilities. Refer to the Table 3.3 for description and detailed properties of the reference projects.
Table 3.3

<table>
<thead>
<tr>
<th>Name</th>
<th>Building Classification</th>
<th>Location</th>
<th>GFA (SF)</th>
<th>Construction Type</th>
<th>Building Description</th>
<th>Office / Storage areas %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference Project 1</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>8,245</td>
<td>New</td>
<td>Operation centre, Single storey office and vehicle garage</td>
<td>Office: 51%; Storage: 39%</td>
</tr>
<tr>
<td>Reference Project 2</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>89,051</td>
<td>New</td>
<td>Operation centre, Two storey storey office and single storey storage</td>
<td>Office: 33%; Storage: 67%</td>
</tr>
<tr>
<td>Reference Project 3</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>83,852</td>
<td>New</td>
<td>Operation centre, two storey office and single storey vehicle garage</td>
<td>Office: 82%; Storage: 18%</td>
</tr>
<tr>
<td>Reference Project 4</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>72,173</td>
<td>New</td>
<td>Operation centre, Two storey office and single storey vehicle storage</td>
<td>Office: 69%; Storage: 31%</td>
</tr>
<tr>
<td>Reference Project 5</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>70,655</td>
<td>New</td>
<td>Operation centre, Single storey office and vehicle storage</td>
<td>Office: 46%; Storage: 54%</td>
</tr>
<tr>
<td>Reference Project 6</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>54,377</td>
<td>New</td>
<td>Operation centre, Single storey office and vehicle storage, plus partial mezzanine</td>
<td>Office: 50%; Storage: 50%</td>
</tr>
<tr>
<td>Reference Project 7</td>
<td>Multi-Purpose Facility - Transit Bus Garage Operation Facility</td>
<td>GTA</td>
<td>82,324</td>
<td>New</td>
<td>Bus Garage, Two storey + mezzanine, office and vehicle garage</td>
<td>Office: 46%; Storage: 54%</td>
</tr>
<tr>
<td>Reference Project 8</td>
<td>Multi-Purpose Facility - Transit Bus Garage Operation Facility</td>
<td>GTA</td>
<td>81,720</td>
<td>New</td>
<td>Bus Garage, Two storey office and single storey vehicle garage</td>
<td>Office: 20%; Storage: 80%</td>
</tr>
</tbody>
</table>

3.4 Description of Investigated Project

This project consists of the alteration and interior retrofit of the existing meat processing plant to be integrated office space, vehicle storage and warehouse space for Toronto Hydro at 71 Rexdale Boulevard in Toronto, Ontario. The scope of work also includes new addition to existing building to house Fleet Maintenance Area, Lubrication, Parts and Office rooms at southwest corner of the building. Alteration to existing plant includes, fully demolition of single storey administration building, partial building demolition of processing plant. Selective demolition includes demolition of cladding, second floor, plenum space as well as interior finishes. The retrofit of a portion of the northerly plant to a 2 storey office building includes raising of the 26'-0" roof structure to 33'-0" and construction of second floor within the existing plant where roof elevation heightened. All existing mechanical and electrical services will be removed to facilitate the proposed systems. The approximate gross floor area of renovation is 190,461 square feet (17,694 square meters).

Refer to the Table 3.4 for description and detailed properties of the investigated project.

Table 3.4

<table>
<thead>
<tr>
<th>Name</th>
<th>Building Classification</th>
<th>Location</th>
<th>GFA (SF)</th>
<th>Construction</th>
<th>Building Description</th>
<th>Office / Storage areas %</th>
</tr>
</thead>
<tbody>
<tr>
<td>71 Rexdale Facility</td>
<td>Multi-Purpose Facility - Toronto</td>
<td>GTA</td>
<td>190,461</td>
<td>Renovation</td>
<td>Toronto Hydro Facility, two storey office and single storey vehicle storage</td>
<td>Office: 44%; Storage: 56%</td>
</tr>
</tbody>
</table>
3.5 Cost escalation to reference projects

The dates of selected reference projects vary from 2008 to 2015. The investigated building cost is based on the estimate issued on February 4, 2016. All costs for reference projects are escalated properly to bring up to date of investigated building cost. Therefore, all compared costs in this report (either unit cost for gross floor area or unit costs for grouped elements) are based on current market condition.

Cost Indexes for Non-Residential Building Construction for Toronto area from Statistic Canada web site have been utilized to escalate the cost of reference projects. Refer to link below for further details.


3.6 Economy of scale

Economies of scale are the cost advantages that a business can exploit by expanding their scale of production. The effect of economies of scale is to reduce the average (unit) costs of production. Economy of scale is a term that refers to the reduction of per-unit costs through an increase in production volume. This idea is also referred to as diminishing marginal cost. Same principal is applicable to construction cost. It means that construction square foot costs rise or fall less than proportionately to building size in terms of the economy of scale in construction industry.

Our report incorporates economy of scale factor in accordance with industry acceptable standards.

Economy of scale factors are to be used for each reference project by equating the gross floor area of the reference project to investigated project. By doing so, it is aimed that compensation of differentiations in size of the buildings are to be achieved.

3.7 Types of Benchmarking

We identified two types of benchmarking approach for the purpose of this report.

a) Type 1 Benchmark (Spatial Measures): Encompasses square foot cost benchmarking.

b) Type 2 Benchmark (Grouped Elements): Encompasses square foot cost of group elements benchmarking such as substructure, superstructure, finishes, fitting and furnishing and M&E services. Separate benchmarking for site works, demolition works and soft cost are also benchmarked in Type 2 and they have been incorporated for Type 1 benchmarking in Table 1.4.
4. Data Comparison

Data comparison process incorporates following steps:

a) Identification of reference projects. This process involves selection of reference projects as per resemblance with investigated project. To be able to establish a credible benchmark cost, resemblance of the selected projects is very important. Major resemblance points for the purpose of this benchmark report are based on administration/office and material/vehicle storage areas and the functioning of the buildings.

Identified reference projects in this report are consist of Multi-Purpose Facility - Municipal Operation Centre and Multi-Purpose Facility - Transit Bus Garage Operation buildings.

b) Localization Factor: When the selected reference projects for benchmarking are gathered from different region of the country, localization factor should be identified and incorporated in the reference project cost. Depending on the purpose of benchmark report, localization factor can be selected as per region, province or country.

Since all selected reference projects are in GTA, Ontario; localization process has been excluded from this report.

c) Elimination of the dissimilarities: Major dissimilarities among the reference projects should be eliminated during the establishment of benchmark cost. To be able to increase the similarities, reference projects may be subject to further cost adjustments.

Some of the selected reference projects included vehicle maintenance bays. All costs associated with vehicle maintenance bay in three (3) reference projects have been deleted.

d) Escalation to reference projects costs: Clarified in Section 3.5 above.

e) Economy of scale factor to reference projects costs: Clarified in Section 3.6 above.

5. Scope Clarifications

5.1 List of Exclusions

a) Harmonized Sales Tax (HST)
b) Security, Communication any other specially equipment cost
c) Localization factor (N/A)
d) Construction Contingency
5.2 What is the median and how is it different from the average?

Median vs. Average to Describe Normal.

Although average is a commonly-used and well understood statistic, median is also a common descriptor used to express a “middle” value in a set of data. This “middle” value is also known as the central tendency. Median is determined by ranking the data from largest to smallest, and then identifying the middle so that there are an equal number of data values larger and smaller than it is. While the average and median can be the same or nearly the same, they are different if more of the data values are clustered toward one end of their range and/or if there are a few extreme values. In statistical terminology, this is called skewness. In this case, the average can be significantly influenced by the few values, making it not very representative of the majority of the values in the data set. Under these circumstances, median gives a better representation of central tendency than average.

6. Disclaimer

This report has been prepared solely by A.W. Hooker Associates Ltd. (HOOKER). Opinions from HOOKER may deviate from opinions presented by other parties. This may typically be the result of differing methodologies, contexts, reference projects, data or other factors. HOOKER assumes no liability as regards to taken by the Owner, Design Consultants, Project Manager or any other parties involved with project subject to this report.
<table>
<thead>
<tr>
<th>Description</th>
<th>71 Roxdale Facility</th>
<th>Reference Project 1</th>
<th>Reference Project 2</th>
<th>Reference Project 3</th>
<th>Reference Project 4</th>
<th>Reference Project 5</th>
<th>Reference Project 6</th>
<th>Reference Project 7</th>
<th>Reference Project 8</th>
<th>Average of References</th>
<th>Median of References</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Floor Area, Overall Estimated Unit Rate ($/SF)</td>
<td>$150.25</td>
<td>$169.79</td>
<td>$155.49</td>
<td>$203.95</td>
<td>$198.58</td>
<td>$203.85</td>
<td>$202.98</td>
<td>$211.95</td>
<td>$167.48</td>
<td>$189.26</td>
<td>$200.78</td>
</tr>
<tr>
<td>1-Substructure Unit Rate ($/SF)</td>
<td>$28.17</td>
<td>$56.72</td>
<td>$37.07</td>
<td>$40.64</td>
<td>$39.37</td>
<td>$51.79</td>
<td>$46.62</td>
<td>$49.63</td>
<td>$34.89</td>
<td>$44.59</td>
<td>$43.63</td>
</tr>
<tr>
<td>2-Super Structure Unit Rate ($/SF)</td>
<td>$29.35</td>
<td>$48.75</td>
<td>$45.57</td>
<td>$51.76</td>
<td>$55.82</td>
<td>$56.62</td>
<td>$59.93</td>
<td>$40.14</td>
<td>$39.18</td>
<td>$49.60</td>
<td>$50.26</td>
</tr>
<tr>
<td>3-Finishes Unit Rate ($/SF)</td>
<td>$21.43</td>
<td>$18.87</td>
<td>$14.19</td>
<td>$22.49</td>
<td>$28.20</td>
<td>$30.21</td>
<td>$21.56</td>
<td>$35.30</td>
<td>$23.56</td>
<td>$24.30</td>
<td>$23.04</td>
</tr>
<tr>
<td>4-Fitting and Equipment Unit Rate ($/SF)</td>
<td>$8.17</td>
<td>$5.10</td>
<td>$11.87</td>
<td>$16.03</td>
<td>$8.37</td>
<td>$11.48</td>
<td>$10.56</td>
<td>$9.08</td>
<td>$3.32</td>
<td>$9.47</td>
<td>$9.82</td>
</tr>
<tr>
<td>5-M&amp;E Service Unit Rate ($/SF)</td>
<td>$63.13</td>
<td>$40.35</td>
<td>$46.79</td>
<td>$73.02</td>
<td>$66.82</td>
<td>$53.78</td>
<td>$65.32</td>
<td>$77.81</td>
<td>$66.51</td>
<td>$61.30</td>
<td>$65.91</td>
</tr>
<tr>
<td>6-Site work Unit Rate ($/SF)</td>
<td>Included else where</td>
<td>Included else where</td>
<td>Included else where</td>
<td>Included else where</td>
<td>Included else where</td>
<td>Included else where</td>
<td>Included else where</td>
<td>Included else where</td>
<td>Included else where</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>7-Demolition Unit Rate ($/SF)</td>
<td>Included else where</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>
# Detailed Building Benchmark Report

**April 5, 2016**

<table>
<thead>
<tr>
<th>Rate</th>
<th>Name</th>
<th>Building Classification</th>
<th>Location</th>
<th>GFA (SF) of Building</th>
<th>Unit Rate (based on Economic of Costs for 190,461 SF building GFA)</th>
<th>1-Substructure</th>
<th>2-Super Structure</th>
<th>3-Finishes</th>
<th>4-Fitting and Equipment</th>
<th>5-ME (Service)</th>
<th>6-lab work</th>
<th>7-Demolition</th>
<th>Construction Type</th>
<th>Building Description</th>
<th>Office / Storage area percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>11492</td>
<td>Rate 1</td>
<td>Multi-Purpose Facility - Toronto Hydro</td>
<td>DTA</td>
<td>150,461</td>
<td>$150.25</td>
<td>$118.12</td>
<td>$102.25</td>
<td>$25.17</td>
<td>$24.35</td>
<td>$31.43</td>
<td>$81.71</td>
<td>$132.13</td>
<td>Included</td>
<td>Included</td>
<td>Included</td>
</tr>
<tr>
<td>11492</td>
<td>Rate 2</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>DTA</td>
<td>250,931</td>
<td>$220.93</td>
<td>$199.70</td>
<td>$130.72</td>
<td>$41.70</td>
<td>$11.87</td>
<td>$59.13</td>
<td>$90.00</td>
<td>Included</td>
<td>Included</td>
<td>Included</td>
<td>New</td>
</tr>
<tr>
<td>11492</td>
<td>Rate 3</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>DTA</td>
<td>250,931</td>
<td>$220.93</td>
<td>$199.70</td>
<td>$130.72</td>
<td>$41.70</td>
<td>$11.87</td>
<td>$59.13</td>
<td>$90.00</td>
<td>Included</td>
<td>Included</td>
<td>Included</td>
<td>New</td>
</tr>
<tr>
<td>11492</td>
<td>Rate 4</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>DTA</td>
<td>250,931</td>
<td>$220.93</td>
<td>$199.70</td>
<td>$130.72</td>
<td>$41.70</td>
<td>$11.87</td>
<td>$59.13</td>
<td>$90.00</td>
<td>Included</td>
<td>Included</td>
<td>Included</td>
<td>New</td>
</tr>
<tr>
<td>11492</td>
<td>Rate 5</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>DTA</td>
<td>250,931</td>
<td>$220.93</td>
<td>$199.70</td>
<td>$130.72</td>
<td>$41.70</td>
<td>$11.87</td>
<td>$59.13</td>
<td>$90.00</td>
<td>Included</td>
<td>Included</td>
<td>Included</td>
<td>New</td>
</tr>
<tr>
<td>11492</td>
<td>Rate 6</td>
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<td>DTA</td>
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<td>$199.70</td>
<td>$130.72</td>
<td>$41.70</td>
<td>$11.87</td>
<td>$59.13</td>
<td>$90.00</td>
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<td>$11.87</td>
<td>$59.13</td>
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<td>$130.72</td>
<td>$41.70</td>
<td>$11.87</td>
<td>$59.13</td>
<td>$90.00</td>
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<td>Included</td>
<td>New</td>
</tr>
<tr>
<td>11492</td>
<td>Rate 9</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>DTA</td>
<td>250,931</td>
<td>$220.93</td>
<td>$199.70</td>
<td>$130.72</td>
<td>$41.70</td>
<td>$11.87</td>
<td>$59.13</td>
<td>$90.00</td>
<td>Included</td>
<td>Included</td>
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<td>New</td>
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<tr>
<td>11492</td>
<td>Rate 10</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>DTA</td>
<td>250,931</td>
<td>$220.93</td>
<td>$199.70</td>
<td>$130.72</td>
<td>$41.70</td>
<td>$11.87</td>
<td>$59.13</td>
<td>$90.00</td>
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<tr>
<td>11492</td>
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<td>DTA</td>
<td>250,931</td>
<td>$220.93</td>
<td>$199.70</td>
<td>$130.72</td>
<td>$41.70</td>
<td>$11.87</td>
<td>$59.13</td>
<td>$90.00</td>
<td>Included</td>
<td>Included</td>
<td>Included</td>
<td>New</td>
</tr>
</tbody>
</table>

---

**Gross Floor Area Cost Benchmark**

- **Building Hard Construction Cost Unit Rates ($/SF)**
  - Residential
  - Industrial
  - Commercial
  - Retail
  - Hotel
  - Office
  - Storage
  - Average
  - Minimum
  - Maximum
# Detailed Site Works Benchmark Report

**April 6, 2016**

<table>
<thead>
<tr>
<th>Ref#</th>
<th>Name</th>
<th>Site Works Classification</th>
<th>Location</th>
<th>GFA (SP) of Building</th>
<th>GFA (SF) of Site Works</th>
<th>Unit Rate as per net site area (excluded)</th>
<th>Unit Rate as per Site Area (Factored for Economy of Scale for 500,000 to 600,000 Site Work GFA)</th>
<th>Total Site Work Amount</th>
<th>Unit Rate as per Building GFA (Additional Cost Impact on Building Unit Rate)</th>
<th>Construction Type</th>
<th>Building Description</th>
<th>Office / Net Site area percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>11433</td>
<td>11433-1</td>
<td>Multi-Purpose Facility - Toronto Hydro</td>
<td>GTA</td>
<td>994,451</td>
<td>568,757</td>
<td>$12.01</td>
<td>$12.01</td>
<td>$4,389,204.34</td>
<td>$22.25</td>
<td>Renovation</td>
<td>Toronto Hydro Facility, two story office and single story vehicle storage</td>
<td>Office: 34% Site: 59%</td>
</tr>
<tr>
<td>11549</td>
<td>11549</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>92,245</td>
<td>53,747</td>
<td>$18.71</td>
<td>$13.78</td>
<td>$492,045.33</td>
<td>$59.65</td>
<td>New</td>
<td>Operation centre, single story office and vehicle garage</td>
<td>Office: 19% Site: 81%</td>
</tr>
<tr>
<td>11622</td>
<td>11622</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>39,051</td>
<td>239,468</td>
<td>$10.71</td>
<td>$12.74</td>
<td>$3,846,527.20</td>
<td>$40.93</td>
<td>New</td>
<td>Operation centre, two story office and single story vehicle storage</td>
<td>Office: 21% Site: 79%</td>
</tr>
<tr>
<td>11630</td>
<td>11630</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>83,862</td>
<td>611,200</td>
<td>$8.20</td>
<td>$8.79</td>
<td>$5,812,343.97</td>
<td>$62.37</td>
<td>New</td>
<td>Operation centre, two story office and single story vehicle storage</td>
<td>Office: 11% Site: 89%</td>
</tr>
<tr>
<td>11731</td>
<td>11731</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>72,173</td>
<td>627,328</td>
<td>$8.46</td>
<td>$9.26</td>
<td>$5,967,417.32</td>
<td>$78.26</td>
<td>New</td>
<td>Operation centre, two story office and single story vehicle storage</td>
<td>Office: 10% Site: 90%</td>
</tr>
<tr>
<td>10703</td>
<td>10703</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>70,655</td>
<td>432,382</td>
<td>$9.42</td>
<td>$9.89</td>
<td>$3,718,364.01</td>
<td>$52.84</td>
<td>New</td>
<td>Operation centre, single story office and vehicle storage</td>
<td>Office: 14% Site: 86%</td>
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<tr>
<td>10723</td>
<td>10723</td>
<td>Multi-Purpose Facility - Municipal Operation Centre</td>
<td>GTA</td>
<td>54,377</td>
<td>370,343</td>
<td>$9.45</td>
<td>$9.85</td>
<td>$3,785,063.98</td>
<td>$58.44</td>
<td>New</td>
<td>Operation centre, single story office and vehicle storage</td>
<td>Office: 9% Site: 91%</td>
</tr>
<tr>
<td>11452</td>
<td>11452</td>
<td>Multi-Purpose Facility - Transit Bus Garage Operation</td>
<td>GTA</td>
<td>67,324</td>
<td>332,365</td>
<td>$13.92</td>
<td>$13.92</td>
<td>$4,020,732.02</td>
<td>$74.24</td>
<td>New</td>
<td>Bus Garage, two story - mezzanine, office and vehicle garage</td>
<td>Office: 16% Site: 84%</td>
</tr>
<tr>
<td>11121</td>
<td>11121</td>
<td>Multi-Purpose Facility - Transit Bus Garage Operation</td>
<td>GTA</td>
<td>81,720</td>
<td>532,450</td>
<td>$8.76</td>
<td>$7.12</td>
<td>$5,788,390.83</td>
<td>$48.36</td>
<td>New</td>
<td>Bus Garage, Two story office and single story vehicle garage</td>
<td>Office: 13% Site: 87%</td>
</tr>
</tbody>
</table>

### Average (Mean of References)
- **Average**
  - GFA GTA: 65,301
  - GFA Site Works: 442,462
  - Unit Rate: $18.71
  - Total Site Work Amount: $8,162,324
  - Unit Rate as per Building GFA: $58.06

### Median of References
- **Median**
  - GFA GTA: 75,414
  - GFA Site Works: 482,356
  - Unit Rate: $8.42
  - Total Site Work Amount: $8,041,872
  - Unit Rate as per Building GFA: $56.45

---

**Site Works Hard Construction Cost Unit Rates ($/SF) as per Net Site Works Area**

**Site Works Hard Construction Cost Unit Rates ($/SF) as per Building Gross Floor Area**
# Detailed Demolition Work Benchmark Report

**A.W. Hooker**

**Quantity Surveyors**

**April 5, 2016**

<table>
<thead>
<tr>
<th>Ref#</th>
<th>Name</th>
<th>Building Classification</th>
<th>Location</th>
<th>GFA (SF) of Building</th>
<th>Unit Rate as per building GFA (escalated)</th>
<th>Unit Rate (Factored for Economy of Scale for 190,461 SF Building GFA)</th>
<th>Construction Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>114333</td>
<td>71 Resolute Facility</td>
<td>Multi-Purpose Facility - Toronto Hydro</td>
<td>GTA</td>
<td>190,461</td>
<td>$12.01</td>
<td>$12.01</td>
<td>Renovation</td>
</tr>
<tr>
<td>112194</td>
<td>Reference Project 1</td>
<td>Hospital Building</td>
<td>GTA</td>
<td>188,790</td>
<td>$21.20</td>
<td>$21.20</td>
<td>Renovation</td>
</tr>
<tr>
<td>112157</td>
<td>Reference Project 2</td>
<td>Religious Building</td>
<td>GTA</td>
<td>12,100</td>
<td>$21.02</td>
<td>$16.53</td>
<td>Renovation</td>
</tr>
<tr>
<td>112573</td>
<td>Reference Project 3</td>
<td>Parking Garage</td>
<td>GTA</td>
<td>275,085</td>
<td>$3.78</td>
<td>$3.97</td>
<td>Renovation</td>
</tr>
<tr>
<td>112594</td>
<td>Reference Project 4</td>
<td>Food Manufacturing Facility</td>
<td>GTA</td>
<td>18,417</td>
<td>$18.97</td>
<td>$15.13</td>
<td>Renovation</td>
</tr>
<tr>
<td>113548</td>
<td>Reference Project 5</td>
<td>Government Office Building</td>
<td>GTA</td>
<td>12,271</td>
<td>$5.35</td>
<td>$4.10</td>
<td>Renovation</td>
</tr>
<tr>
<td>114133</td>
<td>Reference Project 6</td>
<td>Retail Store Warehouse</td>
<td>GTA</td>
<td>97,983</td>
<td>$1.21</td>
<td>$1.15</td>
<td>Renovation</td>
</tr>
<tr>
<td>Average of References</td>
<td>Average</td>
<td>GTA</td>
<td></td>
<td>100,771</td>
<td>$12.00</td>
<td>$10.35</td>
<td></td>
</tr>
<tr>
<td>Median of References</td>
<td>Median</td>
<td>GTA</td>
<td></td>
<td>58,190</td>
<td>$12.16</td>
<td>$9.61</td>
<td></td>
</tr>
</tbody>
</table>

### Demolition Works Hard Construction Cost Unit Rates ($/SF) as per Building Area (GFA)

![Bar chart showing unit rates per SF for each project and average and median values.](chart.png)
TORONTO HYDRO OPERATIONS CENTRE
71 Rexdale Blvd. Etobicoke, Ontario

ELEMENTAL BENCHMARKING COST EXERCISE

Prepared for:
IPM PROJECT MANAGERS & TORONTO HYDRO

Prepared by:
ALTUS GROUP LIMITED

Issued: April 14, 2016
Job No. P7274

Unpublished Work © 2016 Altus Group Limited
April 14, 2016

IPM Project Managers
286 King Street West, Suite 201
Oshawa, Ontario, L1J 2J9

Attn: Rob Ward, Project Manager

Re: Toronto Hydro Operations Centre – Elemental Benchmarking Cost Exercise

Dear Rob,


The benchmarking exercise includes a detailed analysis of the elemental unit rates in the hard construction cost estimate for the Rexdale Operation Centre, as well as the Reference Projects selected for the exercise. Not all of the reference projects selected for the exercise include a demolition and site work scope of work, so the analysis includes these elements only where data was available. We have also included our comments on the latest demolition and site work estimates prepared for the Rexdale project. We have also included our high level review of the soft costs being reported for the project.

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Should you have questions related to this report please do not hesitate to contact the undersigned.

Yours truly,

ALTUS GROUP LIMITED

Mel Yungblut, PQS(F)
Director, Cost Planning & Project Management
Executive Summary

The overall average per square meter (m2) or per square foot (SF) unit rate of the Rexdale Project at $2,530/m2 or $235/SF (including Soft Costs) is considerably less than the selected Reference Projects at an average of $4,670/m2 ($434/SF) and median unit rate of $4,488/m2 or $417/SF. The lower unit rate for the Rexdale Project reflects the reuse of the existing structural elements of the existing building and the savings in not having to build foundations for a large portion of the building.

We conclude that the elemental unit rates included in the latest estimate for Rexdale Project reflect the savings for the reuse of the structural elements of the existing building and represent below average rates for similar projects. The overall mechanical and electrical unit rates indicate the design of these buildings systems is very efficient for the Rexdale project.

<table>
<thead>
<tr>
<th>MAJOR ELEMENT</th>
<th>Total Value</th>
<th>$/SF GFA</th>
<th>Average of Reference Projects $/SF GFA</th>
<th>Variance from Benchmark (Average)</th>
<th>Median of Reference Projects $/SF GFA</th>
<th>Variance from Benchmark (Median)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HARD CONSTRUCTION TOTAL</td>
<td>$44,757,565</td>
<td>$235/SF</td>
<td>$434/SF</td>
<td>-46%</td>
<td>$417/SF</td>
<td>-44%</td>
</tr>
<tr>
<td>1 - SUBSTRUCTURE</td>
<td>$496,270</td>
<td>$3/SF</td>
<td>$21/SF</td>
<td>-87%</td>
<td>$22/SF</td>
<td>-88%</td>
</tr>
<tr>
<td>2 - SUPER STRUCTURE</td>
<td>$10,750,448</td>
<td>$56/SF</td>
<td>$158/SF</td>
<td>-64%</td>
<td>$158/SF</td>
<td>-64%</td>
</tr>
<tr>
<td>3 - FINISHES</td>
<td>$4,038,774</td>
<td>$21/SF</td>
<td>$23/SF</td>
<td>-6%</td>
<td>$24/SF</td>
<td>-13%</td>
</tr>
<tr>
<td>4 - FITTINGS &amp; EQUIPMENT</td>
<td>$1,839,792</td>
<td>$8/SF</td>
<td>$7/SF</td>
<td>24%</td>
<td>$5/SF</td>
<td>58%</td>
</tr>
<tr>
<td>5 - M&amp;E SERVICES</td>
<td>$11,898,387</td>
<td>$62/SF</td>
<td>$138/SF</td>
<td>-55%</td>
<td>$117/SF</td>
<td>-47%</td>
</tr>
<tr>
<td>6 - SITEWORK</td>
<td>$4,343,819</td>
<td>$23/SF</td>
<td>$75/SF</td>
<td>-70%</td>
<td>$19/SF</td>
<td>20%</td>
</tr>
<tr>
<td>7 - DEMOLITION</td>
<td>$2,189,575</td>
<td>$11/SF</td>
<td>$13/SF</td>
<td>-8%</td>
<td>$14/SF</td>
<td>-16%</td>
</tr>
<tr>
<td>8 - SOFT COST</td>
<td>$9,510,000</td>
<td>$50/SF</td>
<td>$0/SF</td>
<td>Excluded</td>
<td>$0/SF</td>
<td>Excluded</td>
</tr>
</tbody>
</table>

71 Rexdale Boulevard $235/SF

Average of Reference Projects $434/SF

Median of Reference Projects $417/SF

Hard Construction Total - Dollars per Square foot of Gross Floor Area
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1 Introduction
   1.1 Scope of Services

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   2.2 Location Factor
   2.3 Selection of Comparable Projects (Reference Projects)
   2.4 Summary of the Adjustments to the Reference Projects
   2.5 Site Work Estimate Review
   2.6 Escalation for the Reference Projects
   2.7 Contingencies & Allowances
   2.8 Taxes
   2.9 Soft Cost Review

3 Observations and Conclusions
   3.1 General Observations
   3.2 Summary of the Elemental Unit Rates
   3.3 Detailed Observations & Conclusion

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   Appendix A – Executive Summary – Elemental Unit Rates
   Appendix B – Summary of Detailed Elemental Unit Rates
1 Introduction

1.1 Scope of Services

This exercise includes an analysis of the estimated hard and soft construction costs for the Rexdale Operation Centre project for Toronto Hydro operations. The analysis includes a comparison of the costs of the Rexdale project with other similar projects on an elemental basis. The format of the exercise follows the Elemental Cost Analysis Format - Method of Measurement - Pricing & Measurement of Buildings by Area & Volume (4th Edition, 2006) produced by the Canadian Institute of Quantity Surveyors (CIQS). This elemental estimate format is commonly used by the cost consulting profession for cost reporting during the design phase of the project.

The benchmarking exercise includes comparable projects (with the exception of Reference Project 2) with similar program functions and overall size to the Rexdale Operation Centre project. In all cases, the elemental cost data for the comparable projects has been adjusted for escalation to closer align the timeframe of the latest estimate for the Rexdale project.

The baseline reference for the hard construction costs of the Rexdale project is the latest Class B Cost Estimate prepared by the Altus Group in September 2015. The baseline reference for the soft cost of the project has been provided by IPM Project Managers.

2 Project Details

2.1 Project Description - Toronto Hydro Rexdale Operations Centre (Control Project)

The Control Project of the benchmarking exercise is the Rexdale Operation Centre project. This project consists of a major redevelopment of an existing meat production facility into a new regional operations centre for Toronto Hydro. The project scope includes a small addition to the southwest corner of the existing building for the maintenance bay, office and storage areas, and major renovations to provide administration offices, warehouse storage, maintenance areas, and indoor vehicle storage. Alterations to the existing building include the complete demolition of an existing two-storey office area and select demolition to portions of the existing processing plant. Alterations to the existing processing plant conversion include the raising of the existing roof structure and complete replacement of the building mechanical and electrical systems.

The total gross floor area of the project is approximately 17,694 square meters or 190,461 square feet. The breakdown of the gross floor area between addition and renovation is as follows:

<table>
<thead>
<tr>
<th></th>
<th>Addition (m²)</th>
<th>Addition (SF)</th>
<th>Renovation (m²)</th>
<th>Renovation (SF)</th>
<th>Total (m²)</th>
<th>Total (SF)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ground Floor</td>
<td>597</td>
<td>6,426</td>
<td>11,851</td>
<td>127,564</td>
<td>12,448</td>
<td>133,991</td>
</tr>
<tr>
<td>Second Floor</td>
<td>0</td>
<td>0</td>
<td>5,246</td>
<td>56,470</td>
<td>5,246</td>
<td>56,470</td>
</tr>
<tr>
<td>Combined Total</td>
<td>597</td>
<td>6,426</td>
<td>17,097</td>
<td>184,034</td>
<td>17,694</td>
<td>190,461</td>
</tr>
<tr>
<td>% of the Total</td>
<td>3.4%</td>
<td>3.4%</td>
<td>96.6%</td>
<td>96.6%</td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>
The total site development area is 46,337 square meters (498,771 SF) or 11.5 acres. The area of the site impacted by the redevelopment is approximately 33,963 m² (365,575 SF) 8.4 acres.

2.2 Location Factor

The location cost base for the estimates and the reference projects used in the benchmarking exercise is the Greater Toronto Area (GTA).

2.3 Selection of Comparable Reference Projects

The selection of comparable projects includes seven (7) projects that contain similar space program areas and are of a comparable size in gross floor area (with the exception of Reference Project 2). The name and location of the reference projects have been kept generic to protect any confidentiality agreements in effect as part of any service agreements on the individual projects. In addition to the 7 reference projects, the analysis incorporates the elemental unit rates employed in an estimate for this project prepared by the Altus Group in September 2015 (Reference Project # 1). The scope of work on the latest design drawings may not exactly match the current design drawings and documentation; however, we believe this previously completed estimate is a good reference for the benchmarking exercise.

A summary of the Reference Projects used in the benchmarking exercise are as follows.

<table>
<thead>
<tr>
<th>Ref #</th>
<th>Building Description</th>
<th>Location</th>
<th>GFA (m²)</th>
<th>GFA (SF)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Class B Elemental Estimate prepared by Altus Group Limited in September 2015 for the Control project at that time</td>
<td>GTA</td>
<td>17,694</td>
<td>190,461</td>
</tr>
<tr>
<td>2</td>
<td>Fire Services Operations Centre, 2 storey with vehicle storage</td>
<td>GTA</td>
<td>1,790</td>
<td>19,268</td>
</tr>
<tr>
<td>3</td>
<td>Rail Maintenance Facility, with partial 2nd Floor Office, including shop maintenance, warehouse and storage</td>
<td>GTA</td>
<td>20,044</td>
<td>215,753</td>
</tr>
<tr>
<td>4</td>
<td>Rail Maintenance Facility, with partial 2nd Floor Office, including shop maintenance, warehouse and storage</td>
<td>GTA</td>
<td>15,812</td>
<td>170,200</td>
</tr>
<tr>
<td>5</td>
<td>Bus Operations &amp; Maintenance, with partial 2nd Floor Office, including shop maintenance and vehicle storage</td>
<td>GTA</td>
<td>10,324</td>
<td>111,128</td>
</tr>
<tr>
<td>6</td>
<td>Bus Operations &amp; Maintenance, with partial 2nd Floor Office, including shop maintenance and vehicle storage</td>
<td>GTA</td>
<td>10,261</td>
<td>100,449</td>
</tr>
<tr>
<td>7</td>
<td>Transit Operations Centre, including shops, warehouse and storage</td>
<td>GTA</td>
<td>13,081</td>
<td>140,804</td>
</tr>
<tr>
<td>8</td>
<td>Transit Operations Centre, including shops, warehouse and storage</td>
<td>GTA</td>
<td>10,781</td>
<td>116,047</td>
</tr>
</tbody>
</table>
2.4 Summary of Adjustments to the Reference Projects

All of the elemental unit rates for the Reference Projects have been factored to include an allowance for escalation between the time of the estimate and the date being used for the Rexdale Project as Q1 2016. The escalation allowance is based on the cost indices provided by Statistics Canada for Non Residential Building Construction for the Toronto (GTA) Ontario region. The cost index being used for the Rexdale Project is 157.7, which is actually the reported cost index for Q4 2015 in the Stats Canada data. No cost index is available for Q1 of 2016 as yet.

No adjustments have been made to the elemental unit rates for the economy of scale to account for the difference in the gross floor area (the size) between the Reference Project and the Rexdale Project. This adjustment is considered subjective when dealing with the elemental unit rates of estimates for two different projects of a different size. The elemental unit rates already contain an element of the economy of the size of the project because they are a product of the estimated cost of a particular element divided by the elemental area or gross floor area. In theory, the elemental area for larger projects will be higher than elemental areas for smaller projects. The magnitude of the elemental unit rate is more apt to be a product of the specifications of the work included in the element. For example, more expensive cladding would produce a higher elemental unit rate than less expensive cladding on two buildings with exactly the same gross floor area.

2.4 Escalation for the Reference Projects

The dates of the estimates for the Reference Projects vary from 2010 to 2015. Refer to the attached Appendix “A” Summary of Elemental Unit Rates for the dates of the Reference Projects. The elemental unit rates for the reference projects have been adjusted utilizing cost indices for Non Residential Building Construction for the GTA from Statistics Canada. The cost indices for each of the reference projects have been identified within Appendix A along with the conversion of the indices into the total and annual escalation rates and shown as a percentage adjustment. The cost index used for the latest cost estimate prepared for the Rexdale project is 157.7, which is the Stats Canada index for Q4 2015. Statistics Canada has not published the cost indices for Q1 2016 at this time.

The elemental unit rates for the Control Project (Rexdale project) are based on the most recent estimate completed in February 2016 (Q1 2016) by A.W. Hooker Associates Ltd. (Quantity Surveyors/Cost Consultants).

2.5 Contingencies

For comparison purposes, the elemental unit rates employed in the projects included in the benchmarking exercise exclude all allowances and contingencies. The estimate for the Control Project also excludes these contingencies, as well as a premium time allowance, winter heat allowance, and any additional design savings being considered post the date of the latest estimate for the Rexdale Operations Centre project.
2.6 Taxes

The estimates and cost data for the Reference Projects and the Control Project exclude any applicable Harmonized Sales Tax (HST).

2.7 Demolition

The latest estimate prepared by A.W. Hooker Associates Ltd. for the Rexdale Operations Centre includes a tendered value for the building demolition scope of work in the value of $1,973,460. Demolition for the Reference Projects has been included in the benchmarking exercise where available. Not all of the reference projects included a demolition scope of work.

2.8 Review of the Site Work Estimate

The statistics of the latest site work estimate for the Rexdale Operations Centre are reported as follows:

<table>
<thead>
<tr>
<th></th>
<th>Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total site area</td>
<td>33,962 m2 or 365,575 SF (8.4 acres)</td>
</tr>
<tr>
<td>Site development including demolition</td>
<td>$2,402,938</td>
</tr>
<tr>
<td>Mechanical Site Services</td>
<td>$445,487</td>
</tr>
<tr>
<td>Electrical Site Services</td>
<td>$1,066,650</td>
</tr>
<tr>
<td>Total Site Work Estimate</td>
<td>$3,915,075</td>
</tr>
<tr>
<td>Average $ per m2</td>
<td>$115.27/m2</td>
</tr>
<tr>
<td>Average $ per SF</td>
<td>$10.71/SF</td>
</tr>
<tr>
<td>Average $ per acre</td>
<td>$466,080</td>
</tr>
</tbody>
</table>

The following is a summary of our comments on the Site Development Estimate for the Rexdale Operations Centre project:

<table>
<thead>
<tr>
<th>Elem</th>
<th>Element Description &amp; Scope</th>
<th>Estimate</th>
<th>Review Comments/Recommendations</th>
</tr>
</thead>
<tbody>
<tr>
<td>D1.11</td>
<td>Site Preparation</td>
<td>$168,688</td>
<td>Total for Site Prep Element</td>
</tr>
<tr>
<td></td>
<td>Site preparation</td>
<td>$33,674</td>
<td>Appears adequate</td>
</tr>
<tr>
<td></td>
<td>Site demolition</td>
<td>$100,014</td>
<td>Appears adequate</td>
</tr>
<tr>
<td></td>
<td>Allowance for the removal of existing site services</td>
<td>$15,000</td>
<td>This allowance appears low.</td>
</tr>
<tr>
<td>D1.12</td>
<td>Hard Surfaces</td>
<td>$1,049,119</td>
<td>Total for this Element</td>
</tr>
<tr>
<td></td>
<td>New asphalt paving</td>
<td>$406,805</td>
<td>Unit rates are okay</td>
</tr>
<tr>
<td></td>
<td>Allowance to patch existing paving</td>
<td>$360,977</td>
<td>Allowance appears adequate for the rather large area of existing paving to remain</td>
</tr>
<tr>
<td></td>
<td>Other hard surfaces, curbs, etc</td>
<td>$281,337</td>
<td>Unit rates appear okay</td>
</tr>
</tbody>
</table>
### TORONTO HYDRO OPERATIONS CENTRE
Elemental Benchmarking Cost Exercise
April 14, 2016

<table>
<thead>
<tr>
<th>Elem</th>
<th>Element Description &amp; Scope</th>
<th>Estimate</th>
<th>Review Comments/Recommendations</th>
</tr>
</thead>
<tbody>
<tr>
<td>D1.13</td>
<td>Site Improvements</td>
<td>$1,092,918</td>
<td>Total for this Element</td>
</tr>
<tr>
<td></td>
<td>Security fence</td>
<td>$193,415</td>
<td>Unit rates okay</td>
</tr>
<tr>
<td></td>
<td>Controlled access gates</td>
<td>$120,000</td>
<td>Unit rates okay</td>
</tr>
<tr>
<td>D1.13</td>
<td>Vehicle canopy (allowance)</td>
<td>$400,120</td>
<td>The allowance is based on an assumed area of 10,000 SF at $40/SF. Allowance should be adequate for a simple canopy design.</td>
</tr>
<tr>
<td></td>
<td>Balance of the site improvements</td>
<td>$379,383</td>
<td>Unit rates appear okay</td>
</tr>
<tr>
<td>D1.14</td>
<td>Landscaping</td>
<td>$92,213</td>
<td>Overall estimate total for landscaping is low however, the scope for this work is limited.</td>
</tr>
<tr>
<td>D1.2</td>
<td>Mechanical Site Services</td>
<td>$445,487</td>
<td>Estimate includes the domestic water, sanitary and storm water requirements for the site. Estimate appears adequate.</td>
</tr>
<tr>
<td>D1.3</td>
<td>Electrical Site Services</td>
<td>$1,066,650</td>
<td>Estimate includes the tendered value for the incoming hydro service. Balance of the estimate appears adequate.</td>
</tr>
</tbody>
</table>

| Total Site Work Estimate | $3,915,075 |

### 2.9 Review of the Site Work Estimate, cont’d

We find the total estimate for the Site Work in the amount of $3,915,075 to be an accurate reflection of the scope of the site work including the assumptions and allowances.

### 2.10 Review of the Soft Cost Estimate

The soft costs reported in the Benchmarking Exercise for the Control Project were provided by IFM Project Managers. Soft Costs for the Reference Projects were not available to the Altus Group as part of their involvement in the projects.

The soft costs for operations type projects can vary significantly depending on the magnitude of the Owner Supplied Equipment for such areas as the maintenance shops, paint shops, detailing area and wash bays. In some cases, the operations centre can include a control centre and dispatch component in the overall program with a higher than normal technology and communications (IT) requirement. These requirements can have a significant impact on the soft cost requirements in the overall project budget for these types of facilities.

The soft cost component of the overall project can also be impacted by the requirement for municipal development charges and any requirements for “offsite” infrastructure to service the proposed site.
In the case of the Rexdale Operations Centre for Toronto Hydro, we note that the soft costs being reported exclude development charges and any offsite infrastructure requirements.

The soft costs being reported in the total project budget is $9,842,850 including a soft cost contingency of $332,850. These costs represent 21.3% of the total project budget of $46,117,139. Soft costs typically range from as lower at 15% up to 35% depending on the variables outlined above. Without the review of a breakdown of the reported soft cost of $9.5M, we find the overall magnitude of the soft costs to be within the typically range for this type of project.

3 Conclusions & Observations

3.1 General Comments

You will note in Appendix A – Summary of Major Elemental Unit Rates, the elemental unit rates for the structural elements including A1 Substructure, A2 Structure, and A3 Exterior Enclosure for the Reference Projects are all higher than the Rexdale Project. The Rexdale Project takes advantage of the existing structure with only modifications (raising the roof, recladding, etc) as part of the overall renovations. The elemental unit rates for Rexdale Project reflect this difference in the scope of work in the structural elements. The structural elemental rates for the Reference Projects are based on new construction with minor alterations of the existing buildings.

The elemental unit rates for the mechanical and electrical elements of the Rexdale Project are considerably less than the average or median unit rates for the Reference Project. This difference would be subject to a detailed analysis of the scope of work for both of these building systems to determine where the major difference was in the overall system design. The difference in the mechanical and electrical unit rates could also be a product of a very efficient design for the M&E systems for the Rexdale Project.

The elemental unit rates for the B3 Fittings & Equipment element are slightly higher for the Rexdale Project. The scope of work included in this element is heavily dependent on the amount of fittings and equipment included in the building, which is primarily driven by the program spaces or uses of the building. Without a detailed analysis of the scope of work in this element in each of the Reference Projects, we speculate that the difference in this elemental unit rate is a product of a difference the amount of fittings and equipment.

3.2 Summary of Elemental Unit Rates

Included below in Table 1 is a summary of the elemental unit rates for the major elements in both cost per square meter (m²) and cost per square foot (SF) for both the Rexdale Operations Centre (Control Project) and the Reference Projects. Both the “Average” and the “Median” unit rates for the Reference Projects have been included in the summary. Variance between the elemental unit rates for the Reference Projects and the Rexdale Project are shown in the two columns in the right of Table 1.
You will note that with the exception of the elemental unit rates for the “B3. Fittings & Equipment” element, the elemental unit rates for the Rexdale Project range from 2% to 89% less than the unit rates for the Reference Projects. The average cost per m² of the Rexdale Project at $2,530/m² ($235/SF) including soft costs is also considerably less than the average cost per m² of the Reference Projects at $4,671/m² or $434/SF and the median unit rate of $4,488/m² or $417/SF including demolition and site work.

Table 1 – Appendix “A” Executive Summary – Elemental Unit Rates

<table>
<thead>
<tr>
<th>MAJOR ELEMENT</th>
<th>71 Rexdale Boulevard</th>
<th>Average of Reference Projects</th>
<th>Variance from Benchmark (Average)</th>
<th>Median of Reference Projects</th>
<th>Variance from Benchmark (Median)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HARD CONSTRUCTION TOTAL</td>
<td>$84,025,354</td>
<td>$222/SF</td>
<td>-46%</td>
<td>$417/SF</td>
<td>-44%</td>
</tr>
<tr>
<td>1 - SUBSTRUCTURE</td>
<td>$496,770</td>
<td>$3/SF</td>
<td>-87%</td>
<td>$22/SF</td>
<td>-88%</td>
</tr>
<tr>
<td>2 - SUPER STRUCTURE</td>
<td>$10,750,148</td>
<td>$56/SF</td>
<td>-64%</td>
<td>$158/SF</td>
<td>-64%</td>
</tr>
<tr>
<td>3 - FINISHES</td>
<td>$4,038,774</td>
<td>$21/SF</td>
<td>-6%</td>
<td>$24/SF</td>
<td>-13%</td>
</tr>
<tr>
<td>4 - FITTINGS &amp; EQUIPMENT</td>
<td>$1,539,792</td>
<td>$8/SF</td>
<td>24%</td>
<td>$5/SF</td>
<td>58%</td>
</tr>
<tr>
<td>5 - M&amp;E SERVICES</td>
<td>$11,896,387</td>
<td>$62/SF</td>
<td>-55%</td>
<td>$117/SF</td>
<td>-47%</td>
</tr>
<tr>
<td>6 - SHEWORK</td>
<td>$1,343,819</td>
<td>$23/SF</td>
<td>-70%</td>
<td>$19/SF</td>
<td>20%</td>
</tr>
<tr>
<td>7 - DEMOLITION</td>
<td>$2,189,575</td>
<td>$11/SF</td>
<td>-8%</td>
<td>$14/SF</td>
<td>-16%</td>
</tr>
<tr>
<td>8 - SOFT COST</td>
<td>$9,510,000</td>
<td>$50/SF</td>
<td>Excluded</td>
<td>$0/SF</td>
<td>Excluded</td>
</tr>
</tbody>
</table>

3.3 Conclusions and Observations

At the conclusion of the benchmarking exercise, we provide the following observations and recommendation for your consideration.

1. The overall average per square meter (m²) or per square foot (SF) unit rate of the Rexdale Project at $2,530/m² ($235/SF) including soft costs is considerably less than the average unit rate of the selected Reference Projects at $4,671/m² or $434/SF and median unit rate of $4,488/m² or $417/SF including demolition and site work. The lower unit rate for Rexdale Project reflects the reuse of the existing structural elements of the existing building.

2. The elemental unit rates for the interiors of the buildings B1 Partitions & Doors and B2 Finishes are very close for both the Reference Projects and the Rexdale Project.

3. The elemental unit rates for the B3 Fittings & Equipment element are slightly higher for the Rexdale Project. The scope of work included in this element is heavily dependent on the amount of fittings and equipment included in the building, which is primarily driven by the program spaces or uses of the building. Without a detailed analysis of the scope of work in this element in each of the Reference Projects, we speculate that the difference in this elemental unit rate is a product of a difference the amount of fittings and equipment.
4. The elemental unit rates for the mechanical and electrical elements of the Rexdale Project are considerably less than the average or median unit rates for the Reference Project. This difference would be subject to a detailed analysis of the scope of work for both of these building systems to determine where the major difference was in the overall system design. The difference in the mechanical and electrical unit rates could also be a product of a very efficient design for the M&E systems for the Rexdale Project.

5. Refer to Section 2.8 Demolition and Section 2.9 Site Work above for specific comments related to the demolition and site work elements of the exercise.

We conclude that the elemental unit rates included in the latest estimate for Rexdale Project reflect the savings for the reuse of the structural elements of the existing building and represent below average rates for similar projects. The overall mechanical and electrical unit rates indicate the design of these buildings systems is very efficient for the Rexdale project.

**List of Appendices**

The following appendices are enclosed:

- Appendix A – Executive Summary – Elemental Unit Rates
- Appendix B – Summary of Detailed Elemental Unit Rates (for the Control Project & Reference Projects)
<table>
<thead>
<tr>
<th>MAJOR ELEMENT</th>
<th>71 Rexdale Boulevard</th>
<th>Average of Reference Projects</th>
<th>Variance from Benchmark (Average)</th>
<th>Median of Reference Projects</th>
<th>Variance from Benchmark (Median)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>190,461 SF Total Value</td>
<td>$44,767,565/$235/SF</td>
<td>$434/SF</td>
<td>-46%</td>
<td>$417/SF</td>
</tr>
<tr>
<td>HARD CONSTRUCTION TOTAL</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 - SUBSTRUCTURE</td>
<td>$4,936,770</td>
<td>$3/SF</td>
<td>$21/SF</td>
<td>-87%</td>
<td>$22/SF</td>
</tr>
<tr>
<td>2 - SUPER STRUCTURE</td>
<td>$10,750,443</td>
<td>$56/SF</td>
<td>$158/SF</td>
<td>-64%</td>
<td>$158/SF</td>
</tr>
<tr>
<td>3 - FINISHES</td>
<td>$4,038,774</td>
<td>$21/SF</td>
<td>$23/SF</td>
<td>-6%</td>
<td>$24/SF</td>
</tr>
<tr>
<td>4 - FITTINGS &amp; EQUIPMENT</td>
<td>$1,539,792</td>
<td>$8/SF</td>
<td>$7/SF</td>
<td>24%</td>
<td>$5/SF</td>
</tr>
<tr>
<td>5 - M&amp;E SERVICES</td>
<td>$11,898,387</td>
<td>$62/SF</td>
<td>$138/SF</td>
<td>-55%</td>
<td>$117/SF</td>
</tr>
<tr>
<td>6 - SITWORK</td>
<td>$4,343,819</td>
<td>$23/SF</td>
<td>$17/SF</td>
<td>-70%</td>
<td>$19/SF</td>
</tr>
<tr>
<td>7 - DEMOLITION</td>
<td>$2,159,575</td>
<td>$11/SF</td>
<td>$13/SF</td>
<td>-8%</td>
<td>$14/SF</td>
</tr>
<tr>
<td>8 - SOFT COST</td>
<td>$9,510,000</td>
<td>$50/SF</td>
<td>$0/SF</td>
<td>Excluded</td>
<td>$0/SF</td>
</tr>
</tbody>
</table>

71 Rexdale Boulevard $235/SF

Average of Reference Projects $434/SF

Median of Reference Projects $417/SF

Hard Construction Total - Dollars per Square foot of Gross Floor Area
##控制项目 - 通货膨胀数据与参考项目 - 通货膨胀数据

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<th>参考项目日期</th>
<th>Q1 2016</th>
<th>Q3 2015</th>
<th>Q3 2012</th>
<th>Q1 2016</th>
<th>Q1 2015</th>
<th>Q1 2015</th>
<th>Q1 2016</th>
<th>Q1 2015</th>
<th>Q1 2015</th>
<th>Q1 2015</th>
<th>Q1 2015</th>
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</thead>
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<tr>
<td>年度到当前</td>
<td>0.00</td>
<td>0.25</td>
<td>3.25</td>
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<td>CANSIM 327-0043 Index (见注1)</td>
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<td>157.2</td>
<td>151.7</td>
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<td>141.1</td>
<td>145.9</td>
<td>142.9</td>
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<td>通货膨胀总和 (%)</td>
<td>0.0%</td>
<td>0.3%</td>
<td>4.0%</td>
<td>0.0%</td>
<td>0.0%</td>
<td>6.9%</td>
<td>6.9%</td>
<td>8.1%</td>
<td>10.4%</td>
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<tr>
<td>通货膨胀年率 (%)</td>
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<td>1.2%</td>
<td>1.2%</td>
<td>0.0%</td>
<td>0.0%</td>
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<td>1.7%</td>
<td>1.6%</td>
<td>1.9%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

###参考项目

<table>
<thead>
<tr>
<th>参考项目</th>
<th>71 Rexdale Boulevard</th>
</tr>
</thead>
<tbody>
<tr>
<td>毛面积</td>
<td>190,461 SF</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>硬件施工总和</td>
<td>$44,767,565</td>
<td>$225/SF</td>
<td>$186/SF</td>
<td>$471/SF</td>
<td>$290/SF</td>
<td>$317/SF</td>
<td>$414/SF</td>
<td>$420/SF</td>
<td>$851/SF</td>
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<tr>
<td>2 - 超级结构</td>
<td>$11,750,048</td>
<td>$56/SF</td>
<td>$42/SF</td>
<td>$107/SF</td>
<td>$107/SF</td>
<td>$209/SF</td>
<td>$24/SF</td>
<td>$24/SF</td>
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<tr>
<td>3 - 完成</td>
<td>$4,036,774</td>
<td>$23/SF</td>
<td>$24/SF</td>
<td>$32/SF</td>
<td>$31/SF</td>
<td>$102/SF</td>
<td>$11/SF</td>
<td>$22/SF</td>
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<tr>
<td>4 - 完善设备</td>
<td>$1,530,000</td>
<td>$3/SF</td>
<td>$3/SF</td>
<td>$11/SF</td>
<td>$11/SF</td>
<td>$33/SF</td>
<td>$5/SF</td>
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<td>5 - M&amp;E服务</td>
<td>$11,899,387</td>
<td>$26/SF</td>
<td>$42/SF</td>
<td>$80/SF</td>
<td>$81/SF</td>
<td>$152/SF</td>
<td>$152/SF</td>
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<td>$12/SF</td>
<td>$12/SF</td>
<td>$12/SF</td>
</tr>
<tr>
<td>8 - 软件</td>
<td>$9,510,000</td>
<td>$20/SF</td>
<td>$20/SF</td>
<td>$20/SF</td>
<td>$20/SF</td>
<td>$20/SF</td>
<td>$20/SF</td>
<td>$20/SF</td>
<td>$20/SF</td>
</tr>
</tbody>
</table>

###注
1. 通货膨胀数据参考Statistics Canada "Price indexes of non-residential building construction, by class of structure"表327-0043，针对Toronto, Ontario地区。非住宅建筑施工总和
2. 上述项目以Q4 2015年为基准，非住宅建筑施工（157.7）作为Q1 2016年指数未在本时期公布。
IPM PROJECT MANAGERS & TORONTO HYDRO
TORONTO HYDRO OPERATION CENTRE
RENOVATIONS & NEW ADDITIONS
TORONTO, ONTARIO

ELEMENTAL BENCHMARK COST EXERCISE

FINAL REPORT

REVISION 01

prepared for:
IPM PROJECT MANAGERS & TORONTO HYDRO
286 King Street West
Toronto, Ontario
L1J 2J9

prepared by:
MARSHALL & MURRAY INCORPORATED
120 Carlton Street - Suite 414
Toronto, Ontario
M5A 4K2

April 25, 2016

Quantity Surveyors and Development Consultants
625 Wellington Street, London, Ontario N6A 3R8 Tel: (519) 433-3908 Fax: (519) 433-9453
Suite 414, 120 Carlton Street, Toronto, Ontario M5A 4K2 Tel: (416) 928-1993 Fax: (416) 928-0895
1379 Bank Street, Suite 301, Ottawa, Ontario K1H 8N3 Tel: (613) 230-3115 Fax: (613) 230-4091
E-mail: main@marshallmurray.com Website: www.marshallmurray.com
EMAILED!

April 25, 2016

Independent Project Managers
286 King Street West
Toronto, Ontario
L1J 2J9

Attention: Rob Ward

Re: TORONTO HYDRO OPERATION CENTRE
RENOVATIONS & NEW ADDITIONS

Dear Rob Ward

Please find enclosed a copy of our Elemental Benchmarking Cost Report for the above noted project.

If any further information or assistance is required, please do not hesitate to contact our office.

Yours truly,

MARSHALL & MURRAY INC.

Anil Ramjee
Anil Ramjee, PQS, MRICS, CCE
Principal

Cc:
<table>
<thead>
<tr>
<th>SECTION</th>
<th>CONTENTS PAGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>EXECUTIVE SUMMARY</td>
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<td>2</td>
<td>BENCHMARK REFERENCE PROJECTS</td>
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<td></td>
<td>SUMMARY</td>
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<tr>
<td></td>
<td>REFERENCE PROJECT 1</td>
</tr>
<tr>
<td></td>
<td>REFERENCE PROJECT 2</td>
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<tr>
<td></td>
<td>REFERENCE PROJECT 4</td>
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<tr>
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</tr>
<tr>
<td></td>
<td>REFERENCE PROJECT 6</td>
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</table>
1.00 ASSIGNMENT OVERVIEW

Marshall & Murray Inc. have been commissioned by Independent Project Managers to provide an elemental benchmark cost report to compare the average and median market cost of a warehouse type project constructed in the Greater Toronto Area to the estimated project cost for the Toronto Hydro Operations Centre at 71 Rexdale Boulevard.

The format of the exercise follows the Elemental Cost Analysis Format - Method of Measurement - Pricing & Measurement of Buildings by Area & Volume produced by the Canadian Institute of Quantity Surveyors (CIQS).

The baseline reference cost estimate for the hard construction cost of the Rexdale project has been prepared by AW Hooker and Associates.

Marshall & Murray Inc. have not been privy to the detailed elemental estimate prepared by AW Hooker and Associates, nor has Marshall & Murray Inc. been commissioned to prepare an independent elemental cost estimate for the Toronto Hydro Rexdale project.

A description of the scope of works for the Toronto Hydro Rexdale project has been provided by Independent Project Managers through telephone conference meetings, emails and previous benchmarking reports prepared by both Altus Group and AW Hooker and Associates.

2.00 UNDERSTANDING THE PROJECT SCOPE OF WORKS

Marshall & Murray Inc. understands that the Toronto Hydro Rexdale Facility project comprises of an existing 190,461 square foot warehouse building, located at 71 Redale Boulevard in Toronto.

We understand that the scope of works for this project includes major renovation works to the estimate building, including:
- Demolition of existing interior finishes
- Demolitions and removal of all existing M&E Installations
- Alterations to increase the height of the building perimeter façade and roof.
- Removal and disposal of the existing building façade, including doors and glazing.
- The construction of a 6426 square foot addition
- New building façade, new roofing, finishes, M&E Installation and site works.

3.00 COMPARABLE REFERENCE PROJECTS

The selection of the comparable projects includes six (6) projects that contain similar space program areas and construction scope of works.

The reference projects differ in size and the cost base dates for the reference projects differ as well. Marshall & Murray Inc. have accommodated for both escalation and economies of scale for all reference projects.

The names of the reference projects have been kept generic to protect any confidentiality agreements in effect as part of any service agreements on the individual projects.

It is understood that the latest estimate prepared by A.W. Hooker and Associates for the Rexdale Operations Centre includes a tendered value for the building demolition scope of works. Demolition for the reference projects have been included in the benchmarking exercise where available. Not all of the reference projects includes for demolition scope of work. It should also be noted that demolition works varies significantly between the various projects.
4.00 PROJECT SOFT COSTS

The reference projects included in the benchmarking report do not include for any Soft Costs. For this reason no evaluation of the soft costs for the project has been undertaken within this report.

The soft cost being reported in the total project budget amounts to $9,510,000.00, which represents 26.973% of the total hard construction cost totaling $35,257,565.

Project soft costs typically range from 15% on the low range to 35% on the high range. This percentage range varies depending on project variables and professional design agreements. Without the review of the breakdown of the reported soft costs of $9.5 million, we find the overall magnitude of the soft costs to be within the typical range for this type of project.

5.00 COMPARISON REVIEW

<table>
<thead>
<tr>
<th>MAJOR ELEMENT</th>
<th>71 Rexdale</th>
<th>Average Rate</th>
<th>Variance</th>
<th>Median Rate</th>
<th>Variance</th>
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<tbody>
<tr>
<td>1 - SUBSTRUCTURE</td>
<td>$3.00</td>
<td>$12.84</td>
<td>-76.63%</td>
<td>$9.35</td>
<td>-67.91%</td>
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<tr>
<td>2 - SUPERSTRUCTURE</td>
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<td>$71.70</td>
<td>-21.90%</td>
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<td>3 - FINISHES</td>
<td>$21.00</td>
<td>$22.54</td>
<td>-6.85%</td>
<td>$14.04</td>
<td>49.54%</td>
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<tr>
<td>4 - FITTINGS &amp; EQUIPMENT</td>
<td>$8.00</td>
<td>$6.46</td>
<td>23.90%</td>
<td>$8.64</td>
<td>64.50%</td>
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<tr>
<td>5 - M&amp;E INSTALLATION</td>
<td>$62.00</td>
<td>$93.52</td>
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<tr>
<td>6 - SITE DEVELOPMENT</td>
<td>$23.00</td>
<td>$17.60</td>
<td>30.66%</td>
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<td>11.35%</td>
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<tr>
<td>7 - DEMOLITIONS</td>
<td>$11.00</td>
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<td>2774.81%</td>
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<tr>
<td>8 - SOFT COST</td>
<td>Excluded</td>
<td>Excluded</td>
<td>Excluded</td>
<td>Excluded</td>
<td>Excluded</td>
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<tr>
<td><strong>HARD CONSTRUCTION TOTAL</strong></td>
<td><strong>$184.00</strong></td>
<td><strong>$241.94</strong></td>
<td><strong>-23.95%</strong></td>
<td><strong>$224.62</strong></td>
<td><strong>-18.08%</strong></td>
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6.00 CONCLUSION

Our analysis for this benchmark report reveals that estimated square foot cost for the 71 Rexdale Facility building at $184.00 per square foot is lower than both the average and median unit rates of the reference projects.

7.00 EXCLUSIONS

Project Soft Costs
Harmonized Sales Tax (HST)
Construction Contingency Allowances
Escalation Allowances beyond April 2016
Loose Furniture
Legal Fees and Expenses
Hazardous material abatement
Acceleration premiums
Permits and Development Charges
Moving and Relocation Costs
LEED Premiums

Disclaimer
This report is not intended for general circulation, publication or reproduction for any other person or purpose without the express written consent by Marshall & Murray Inc. Furthermore, this report was produced for the exclusive use of IPM Project Managers and Toronto Hydro.
<table>
<thead>
<tr>
<th>Item No.</th>
<th>Description</th>
<th>Reference Projects</th>
<th>Average</th>
<th>Median</th>
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<tr>
<td></td>
<td></td>
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<td>Project 2</td>
<td>Project 3</td>
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<td>Finishes</td>
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<td>Fittings, Fixtures &amp; Equipment</td>
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<td>5.00</td>
<td>Mechanical &amp; Electrical Installation</td>
<td>$134.12</td>
<td>$134.58</td>
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<td>6.00</td>
<td>Site Development</td>
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<td>Demolitions</td>
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<td>$9.22</td>
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<td>8.00</td>
<td>Soft Costs</td>
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<td>$0.00</td>
<td>$0.00</td>
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</tbody>
</table>

HARD CONSTRUCTION TOTAL ESCALATED TO APRIL 2016

$401.09 | $288.30 | $159.92 | $165.47 | $302.75 | $166.68 | $247.37 | $227.49
The project comprises the construction of a new rail maintenance facility, complete, including standard strip footing foundations, structural steel building frame, with composite steel suspended floor slabs, a steel roof structure with 2 ply built-up roof coverings and a precast concrete exterior facade. Site development costs have been excluded as the site works for this project is significant and includes bulk earthworks, soil remediation, roads and parking, reservoir construction, rail track installation and specialist train installations. The project also included a basement construction, which has been excluded.

**Project Description:**

**Procurement:** Construction Management with GMP

**Construction Type:** New Build

**Project Location:** Greater Toronto Area

**GFA (SQFT):** 387,899

**Cost Base Date:** June 2014

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<td>7.00</td>
<td>Demolitions</td>
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<tr>
<td>8.00</td>
<td>Soft Costs</td>
<td>$0</td>
<td>$0.00</td>
<td>Excluded</td>
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</table>

**HARD CONSTRUCTION TOTAL ESCALATED TO APRIL 2016** $155,580,667 $401.09
### Project Description:
The project comprises the construction of a new maintenance garage and storage facility, including administration office. The building construction comprises standard cast-in-place concrete strip footings and pad footings, structural steel building frame and composite steel framed suspended floor slab. Special foundations included on this project includes caisson piles. The building superstructure comprises of a concrete block facade with face brick finish, curtain wall, structural steel roof frame with a two ply mod-bit built-up roof. Specialist equipment installation includes a 9000kg crane as well as wash bay equipment and a 900kg hydraulic elevator. Demolitions of a portion of the existing building has been included in this cost evaluation.

### Procurement:
Lump Sum Fixed Price Tender Procurement

### Construction Type:
Renovation & Addition

### Project Location:
Greater Toronto Area

### GFA (SQFT):
29,924

### Cost Base Date:
April 2011

### Item Description
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<td>8.00</td>
<td>Soft Costs</td>
<td>$0</td>
<td>$0.00</td>
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</table>

**HARD CONSTRUCTION TOTAL ESCALATED TO APRIL 2016**

$8,627,048  $288.30
**Project Description:** The project comprises the construction of a new warehouse sorting facility, including storage building. The building foundation includes concrete cast-in-place strip footings with reinforced concrete pads and stub columns. The building superstructure comprises a structural steel frame, with composite suspended steel floor slab, steel roof structure with a EPDM fully adhered roof covering. The building facade comprises of pre-finished metal cladding with overhead roller shutter doors and four panel sliding doors. Site development includes asphalt parking and roads as well as soft landscaping and site fixtures.

**Procurement:** Lump Sum Fixed Price Tender Procurement

**Construction Type:** Renovation & Addition

**Project Location:** Greater Toronto Area

**GFA (SQFT):** 15,177

**Cost Base Date:** July 2011

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**HARD CONSTRUCTION TOTAL ESCALATED TO APRIL 2016:** $2,427,175 $159.92
REFERENCE PROJECT NUMBER 4

Project Description: The project comprises the construction of a new warehouse sorting facility, including storage building. The building foundation includes concrete cast-in-place strip footings with reinforced concrete pads and stub columns. The building superstructure comprises a structural steel frame, with composite suspended steel floor slab, steel roof structure with an EPDM fully adhered roof covering. The building facade comprises pre-finished metal cladding with overhead roller shutter doors and four panel sliding doors. Site development includes asphalt parking and roads as well as soft landscaping and site fixtures.

Procurement: Lump Sum Fixed Price Tender Procurement

Construction Type: New Construction

Project Location: Greater Toronto Area

GFA (SQFT): 19,601

Cost Base Date: August 2011

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HARD CONSTRUCTION TOTAL ESCALATED TO APRIL 2016 $3,243,391 $165.47
**Project Description:** The project comprises of the construction of new warehouse type facility. The buildings foundations, comprises reinforced concrete strip footings with concrete pad foundations and stub columns. The buildings superstructure comprises of a steel framed building structure, with OWSJ suspended floor slab and composite floor structure. The building facade comprises of composite walls with corrugated pre-finished metal sidings, glazed curtain walls and punched windows. The buildings roof comprises of a structural steel OWSJ frame and a high reflective membrane roof covering.

**Procurement:** Lump Sum Fixed Price Tender Procurement

**Construction Type:** New Construction

**Project Location:** Greater Toronto Area

**GFA (SQFT):** 112,215

**Cost Base Date:** December 2012

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<tr>
<td>8.00</td>
<td>Soft Costs</td>
<td>$0</td>
<td>$0.00</td>
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**HARD CONSTRUCTION TOTAL ESCALATED TO APRIL 2016:** $33,973,300 $302.75
The project comprises the construction of new Bus Storage Facility. The buildings foundation comprises reinforced concrete strip footings and pad footings for columns. The building superstructure comprises of a structural steel frame, steel OWSI roof structure and two ply mod-bit roof coverings. The building facade comprises of a combination of metal siding, concrete block and curtain wall glazing.

**Procurement:** Lump Sum Fixed Price Tender Procurement

**Construction Type:** New Construction

**Project Location:** Greater Toronto Area

**GFA (SQFT):** 42,184

**Cost Base Date:** March 2012

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<td>Soft Costs</td>
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**HARD CONSTRUCTION TOTAL ESCALATED TO APRIL 2016**  $7,031,127  $166.68
TORONTO HYDRO CORPORATION
SENIOR EXECUTIVE COMPENSATION POLICIES & PRACTICES

October 31, 2017

DISCUSSION DRAFT
STRICTLY PRIVATE & CONFIDENTIAL

The information included in this report is strictly confidential and is proprietary to Mercer. Any unauthorized use and/or distribution of this material are strictly prohibited unless explicitly agreed to in advance and in writing by Mercer.
INTRODUCTION

BACKGROUND

- Toronto Hydro Corporation ("THC") has engaged Mercer (Canada) Limited ("Mercer") to conduct an assessment of compensation for eight (8) senior executive positions relative to market. Specifically as a part of this mandate, Mercer has completed the following work to date:
  - Held discussions with THC to better understand the responsibilities of each in-scope position and the markets in which THC competes for executive talent
  - Reviewed THC documentation to gain an understanding of current compensation practices
  - Analyzed market compensation levels and practices in comparable organizations and summarized key findings in this report
- Compensation levels in this report have been benchmarked in respect of:
  - Base Salary;
  - Target Total Cash Compensation (i.e., salary plus target annual incentive);
  - Target Total Direct Compensation (i.e., target total cash compensation plus expected value of long-term incentives); and,
  - Total Remuneration (i.e., target total direct compensation plus expected value of pension, benefits and perquisites)
- Following review of this draft report with THC, we will refine our analysis as appropriate
INTRODUCTION

PEER GROUP (PROXY AND AIF)

- The table below provides an overview of the organizations included in THC’s Peer Group for NEO equivalent roles:

<table>
<thead>
<tr>
<th>Organization</th>
<th>Assets (M CAD)</th>
<th>Revenue (M CAD)</th>
<th>Distribution Revenue</th>
<th>’000s of Customers</th>
<th>Private / Public Sector</th>
</tr>
</thead>
<tbody>
<tr>
<td>SaskPower¹</td>
<td>$10,434</td>
<td>$2,296</td>
<td>$1,046</td>
<td>520</td>
<td>Public Sector</td>
</tr>
<tr>
<td>Epcor²</td>
<td>$6,161</td>
<td>$1,946</td>
<td>$634</td>
<td>379</td>
<td>Public Sector</td>
</tr>
<tr>
<td>Enmax</td>
<td>$5,926</td>
<td>$2,604</td>
<td>$537</td>
<td>946</td>
<td>Public Sector</td>
</tr>
<tr>
<td>Hydro One Ltd ⁴</td>
<td>$25,351</td>
<td>$6,552</td>
<td>$3,125</td>
<td>1,365</td>
<td>Public Sector</td>
</tr>
<tr>
<td>ATCO</td>
<td>$19,724</td>
<td>$4,045</td>
<td>$360</td>
<td>2,000</td>
<td>Private Sector</td>
</tr>
<tr>
<td>TransAlta Corp.</td>
<td>$10,996</td>
<td>$2,397</td>
<td>$1,434</td>
<td>--</td>
<td>Private Sector</td>
</tr>
<tr>
<td>Northland Power Inc.</td>
<td>$8,663</td>
<td>$1,099</td>
<td>--</td>
<td>--</td>
<td>Private Sector</td>
</tr>
<tr>
<td>FortisBC Inc. ⁵</td>
<td>$8,443</td>
<td>$1,512</td>
<td>$1,032</td>
<td>1,163</td>
<td>Private Sector</td>
</tr>
<tr>
<td>Algonquin Power</td>
<td>$9,250</td>
<td>$1,096</td>
<td>$816</td>
<td>763</td>
<td>Private Sector</td>
</tr>
<tr>
<td>Capital Power</td>
<td>$6,062</td>
<td>$1,214</td>
<td>$794</td>
<td>--</td>
<td>Private Sector</td>
</tr>
<tr>
<td>Nova Scotia Power</td>
<td>$4,800</td>
<td>$1,327</td>
<td>--</td>
<td>511</td>
<td>Private Sector</td>
</tr>
<tr>
<td>FortisAlberta Inc.</td>
<td>$4,059</td>
<td>$672</td>
<td>$383</td>
<td>--</td>
<td>Private Sector</td>
</tr>
<tr>
<td>Capstone Infrastructure</td>
<td>$1,148</td>
<td>$173</td>
<td>--</td>
<td>--</td>
<td>Private Sector</td>
</tr>
</tbody>
</table>

**Comparator Averages**

| Comparator Averages | |
|---------------------| |
| Public Sector Energy (excluding Hydro One) | |
| Public Sector Energy (including Hydro One) | |
| Private & Public Sector Energy (excluding Hydro One) | |
| Private & Public Sector Energy (including Hydro One) | |

**Toronto Hydro²**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$4,954</td>
<td>$4,030</td>
<td>$648</td>
</tr>
</tbody>
</table>

Sources: Annual information forms, annual reports and corporate websites

¹ Revenues are for the year ended December 30, 2014 (the most recently reported 12 month period). Assets figures are effective March 31, 2016. SaskPower switched to a March 31st year end, resulting in revenue disclosure for a 15-month period in 2016.

² Approximate electricity customers only.

³ Hydro One is in the process of partially privatizing and has sold an approximately 50.1% stake on the open market in the past two years.

⁴ Figures presented for FortisBC Inc. represent the sum of the disclosed financials for FortisBC (gas) and FortisBC (electric).

⁵ Includes the approximately 761,000 customers who are part of bulk metering arrangements.

- For THC Executives matched to survey data (i.e. non NEO equivalents), we have selected market refinements which most closely mirror the organizations included in the peer group detailed above. For a list of organizations included in each sample please refer to Appendix B.

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EXECUTIVE SUMMARY
RECOMMENDATIONS

- Subject to review and discussion, the table below presents potential compensation adjustments for select THC executives to more closely align with comparator organizations:

<table>
<thead>
<tr>
<th>THC Position Title</th>
<th>Data Source</th>
<th>Benchmark Position Title</th>
<th>Base Salary THC</th>
<th>P50</th>
<th>Proposed</th>
</tr>
</thead>
<tbody>
<tr>
<td>President &amp; Chief Executive Officer</td>
<td>Peer Group</td>
<td>Chief Executive Officer</td>
<td>$549</td>
<td></td>
<td>$575</td>
</tr>
<tr>
<td>EVP &amp; Chief Financial Officer</td>
<td>Peer Group</td>
<td>Chief Financial Officer</td>
<td>$375</td>
<td></td>
<td>$400</td>
</tr>
<tr>
<td>EVP &amp; Chief Engineering and Construction Officer</td>
<td>Peer Group</td>
<td>Top Division Executive</td>
<td>$338</td>
<td></td>
<td>$360</td>
</tr>
<tr>
<td>EVP &amp; Chief Electric Operations and Procurement Officer</td>
<td>Peer Group</td>
<td>Top Division Executive</td>
<td>$298</td>
<td></td>
<td>$320</td>
</tr>
<tr>
<td>EVP &amp; Chief Human Resources and Safety Officer</td>
<td>2016 CA MBD</td>
<td>Top Human Resources Executive</td>
<td>$266</td>
<td></td>
<td>$266</td>
</tr>
</tbody>
</table>

* Figures in CAD$ 000’s

1 Represents the median of the Public Sector Utility Peers (excluding Hydro One) market refinement

<table>
<thead>
<tr>
<th>THCs Position Title</th>
<th>Data Source</th>
<th>Benchmark Position Title</th>
<th>Target Short-term Incentives (% of Base) THC</th>
<th>P50</th>
<th>Proposed</th>
</tr>
</thead>
<tbody>
<tr>
<td>EVP &amp; Chief Financial Officer</td>
<td>Peer Group</td>
<td>Chief Financial Officer</td>
<td>65%</td>
<td></td>
<td>65%</td>
</tr>
<tr>
<td>EVP &amp; Chief Engineering and Construction Officer</td>
<td>Peer Group</td>
<td>Top Division Executive</td>
<td>40%</td>
<td></td>
<td>40%</td>
</tr>
<tr>
<td>EVP &amp; Chief Electric Operations and Procurement Officer</td>
<td>Peer Group</td>
<td>Top Division Executive</td>
<td>40%</td>
<td></td>
<td>40%</td>
</tr>
<tr>
<td>EVP &amp; Chief Human Resources and Safety Officer</td>
<td>2016 CA MBD</td>
<td>Top Human Resources Executive</td>
<td>40%</td>
<td></td>
<td>40%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Target Total Cash Compensation</th>
<th>THCs</th>
<th>P50</th>
<th>Proposed</th>
<th>% Var. (P50)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EVP &amp; Chief Financial Officer</td>
<td>$906</td>
<td></td>
<td>$949</td>
<td></td>
</tr>
<tr>
<td>EVP &amp; Chief Engineering and Construction Officer</td>
<td>$526</td>
<td></td>
<td>$560</td>
<td></td>
</tr>
<tr>
<td>EVP &amp; Chief Electric Operations and Procurement Officer</td>
<td>$474</td>
<td></td>
<td>$504</td>
<td></td>
</tr>
<tr>
<td>EVP &amp; Chief Human Resources and Safety Officer</td>
<td>$418</td>
<td></td>
<td>$448</td>
<td></td>
</tr>
</tbody>
</table>

The proposed compensation levels presented above more closely align THC’s Executive cash compensation levels with those observed among peer organizations, by making modest increases where cash compensation is materially below market levels.

- Consistent with THC’s current pay practice, we have maintained the current compensation structure (e.g., short-term incentive levels unchanged, no long-term incentives).

- The proposed compensation levels are intended to serve as a guideline for potential pay adjustments after consideration of the market data and factors such as internal relativity, tenure, job complexity, and the individual contribution of each incumbent.

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**EXECUTIVE SUMMARY**  
**POTENTIAL RANGES AND COMPA RATIOS**

<table>
<thead>
<tr>
<th>THC Title</th>
<th>Benchmark Scope</th>
<th>Base Salary</th>
<th>Compa Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>THC (Current)</td>
<td>THC (Proposed)</td>
</tr>
<tr>
<td>President &amp; Chief Executive Officer</td>
<td>Proxy Peer Group: Public Sector Utility Peers</td>
<td>$549</td>
<td>$575</td>
</tr>
<tr>
<td>EVP &amp; Chief Financial Officer</td>
<td>Proxy Peer Group: Public Sector Utility Peers</td>
<td>$375</td>
<td>$400</td>
</tr>
<tr>
<td>EVP &amp; Chief Engineering and Construction Officer</td>
<td>Proxy Peer Group: Public Sector Utility Peers</td>
<td>$338</td>
<td>$360</td>
</tr>
<tr>
<td>EVP &amp; Chief Electric Operations and Procurement Officer</td>
<td>Proxy Peer Group: Public Sector Utility Peers</td>
<td>$298</td>
<td>$320</td>
</tr>
<tr>
<td>EVP &amp; Chief Human Resources and Safety Officer</td>
<td>Survey Data (CA MBD): Public Sector Utility Orgs, Comparable Size</td>
<td>$286</td>
<td>$286</td>
</tr>
<tr>
<td>[Redacted]</td>
<td>Survey Data (CA MBD): Public Sector Utility Orgs, Comparable Size</td>
<td>$[Redacted]</td>
<td>$[Redacted]</td>
</tr>
<tr>
<td>[Redacted]</td>
<td>Survey Data (CA MBD): Public Sector Utility Orgs, Comparable Size</td>
<td>$[Redacted]</td>
<td>$[Redacted]</td>
</tr>
</tbody>
</table>

- Benchmarks in the above table conform to the City of Toronto benchmarking comparator requirements of like-size, publicly owned electrical utilities.
- "Compa ratio" is the ratio of current base salary to the midpoint of the compensation range. Per the City of Toronto’s requirements, the midpoint of the range is the median of the above benchmark, and the range is set to +/-15% of that median (“P50”), per Attachment 1 of the Guiding Principles.
## Executive Summary

### Observations

<table>
<thead>
<tr>
<th>Element of Pay</th>
<th>Market Alignment</th>
<th>Key Findings and Observations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Salary</td>
<td></td>
<td>*<em>NEOs</em>: Relative to both Public Sector Utilities and a combination of Private &amp; Public Sector Utilities, THC’s base salaries are generally positioned between the market P25 and P50 for NEO equivalent roles. THC is generally positioned closer to the market median when Private Sector Utilities are included.</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Other Executives</strong>: For THC’s other executives, positioning relative to market varies by role. The EVP &amp; Chief HR and Safety Officer is generally aligned with market, the EVP &amp; Chief Customer Care &amp; Conservation Officer and EVP &amp; Chief Information Officer are positioned above market, and the EVP, Regulatory Affairs &amp; General Counsel is positioned below market.</td>
</tr>
<tr>
<td>Short-term Incentives (% of salary)</td>
<td></td>
<td>*<em>NEOs</em>: Relative to both Public Sector Utilities and a combination of Private &amp; Public Sector Utilities, THC’s target and maximum short-term incentive opportunity is positioned below market. This is particularly pronounced when Private Sector Utilities are included as these organizations often provide higher incentive opportunities and may also have a larger degree of upside leverage.</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Other Executives</strong>: For THC’s other executives, positioning relative to market varies by role, however THC’s short-term incentives are generally positioned above the market. This implies greater differentiation in short-term incentives between NEOs and Other executives in the market than is present in THC.</td>
</tr>
<tr>
<td>Target Total Cash Compensation (Base + STI)</td>
<td></td>
<td>*<em>NEOs</em>: Consistent with base salary positioning, relative to both Public Sector Utilities and a combination of Private &amp; Public Sector Utilities, THC’s total cash compensation is generally positioned between the market P25 and P50 for NEO equivalent roles.</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Other Executives</strong>: For THC’s other executives, positioning remains consistent with that observed for base salary, and varies for each executive position reviewed.</td>
</tr>
</tbody>
</table>

*For the purposes of this review THC’s President & Chief Executive Officer, EVP & Chief Financial Officer, EVP & Chief Engineering & Construction Officer and EVP & Chief Electric Operations & Procurement Officer were considered Named Executive Officer ("NEO") equivalents*
## Executive Summary

### Observations

<table>
<thead>
<tr>
<th>Element of Pay</th>
<th>Market Alignment</th>
<th>Key Findings and Observations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-term Incentives (% of salary)</td>
<td></td>
<td><strong>NEOs</strong>: The majority of utilities comparators (private and public sector) provide some form of long-term incentives to NEO equivalent positions. THC’s practice of not offering any form of long-term incentives is not aligned with comparator practices observed.</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Other Executives</strong>: Below the NEO level the prevalence of long-term incentives for Public Sector Utilities organizations drops significantly (however long-term incentives remain prevalent in the private sector at this level). THC is aligned with Public Sector Utility practice in not offering long-term incentives awards to executives below the NEO level.</td>
</tr>
<tr>
<td>Target Total Direct Compensation</td>
<td></td>
<td><strong>NEOs</strong>: Due to THC’s lack of long-term incentive awards, target total direct compensation positioning generally weakens relative to market, though in some cases, the differences are small.</td>
</tr>
<tr>
<td>(Base + STI + LTI)</td>
<td></td>
<td><strong>Other Executives</strong>: Positioning deteriorates relative to the Public &amp; Private Sector market refinement due to the higher prevalence of long-term incentives within private utilities, though in some cases, the differences are small.</td>
</tr>
<tr>
<td>Pension, Benefits &amp; Perquisites</td>
<td></td>
<td>• Overall, THC’s Pension, Benefits and Perquisites appear to be positioned below market on a dollar value basis. A primary driver of this difference is lower compensation levels (i.e. more comparable on a percentage basis)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• In general, Public Sector Utilities offer more generous Pension and Benefit provisions to executives, while perquisites are higher in Private Sector Utilities. In general, due to the lower relative value of perquisites (compared to pension and benefits), the aggregate value of Pension, Benefits &amp; Perquisites was generally higher for Public Sector comparators.</td>
</tr>
</tbody>
</table>

*For the purposes of this review THC’s President & Chief Executive Officer, EVP & Chief Financial Officer, EVP & Chief Engineering & Construction Officer and EVP & Chief Electric Operations & Procurement Officer were considered Named Executive Officer ("NEO") equivalents*

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## Benchmark Results:
**President & Chief Executive Officer**

<table>
<thead>
<tr>
<th>Salary Rank</th>
<th>STI Range ¹</th>
<th>Thr.</th>
<th>Tar.</th>
<th>Max</th>
<th>% of Target Paid ²</th>
<th>Target Total Cash Comp. ³</th>
<th>LTI Award ⁴</th>
<th>Target Total Direct Comp. ⁵</th>
<th>Total Pension/Benefits /Perqs ⁶</th>
<th>Target Total Rem ⁷</th>
</tr>
</thead>
<tbody>
<tr>
<td>THC</td>
<td>$549K</td>
<td>THC</td>
<td>0%</td>
<td>65%</td>
<td>97.5%</td>
<td>THC</td>
<td>THC</td>
<td>THC</td>
<td>THC</td>
<td>THC</td>
</tr>
</tbody>
</table>

### Proxy Peer Group

**Public Sector Utility Peers (excluding Hydro One) – n = 4**

<table>
<thead>
<tr>
<th>THC ²</th>
<th>THC ³ (max)</th>
<th>P22</th>
<th>THC ³</th>
<th>THC ³</th>
<th>P27</th>
</tr>
</thead>
</table>

**Public Sector Utility Peers (including Hydro One) – n = 5**

<table>
<thead>
<tr>
<th>THC ²</th>
<th>THC ³ (max)</th>
<th>P22</th>
<th>THC ³</th>
<th>THC ³</th>
<th>P27</th>
</tr>
</thead>
</table>

**Public & Private Sector Utility Peers (excluding Hydro One) – n = 13**

<table>
<thead>
<tr>
<th>THC ²</th>
<th>THC ³ (max)</th>
<th>P45</th>
<th>THC ³</th>
<th>THC ³</th>
<th>P15</th>
</tr>
</thead>
</table>

**Public & Private Sector Utility Peers (including Hydro One) – n = 14**

<table>
<thead>
<tr>
<th>THC ²</th>
<th>THC ³ (max)</th>
<th>P42</th>
<th>THC ³</th>
<th>THC ³</th>
<th>P13</th>
</tr>
</thead>
</table>

### All Group

**All Peer Group – n = 17**

<table>
<thead>
<tr>
<th>THC ²</th>
<th>THC ³ (max)</th>
<th>P41</th>
<th>THC ³</th>
<th>THC ³</th>
<th>P18</th>
</tr>
</thead>
</table>

### Canadian Industry Group

**Best Comparators Orgs in Revenue Range – n = 32**

<table>
<thead>
<tr>
<th>THC ²</th>
<th>THC ³ (max)</th>
<th>P62</th>
<th>THC ³</th>
<th>THC ³</th>
<th>P25</th>
</tr>
</thead>
</table>

*Please see footnotes on next page.*

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**Benchmark Results: President & Chief Executive Officer (Cont’d)**

*Percentiles for previous page:
1. Represents the threshold, target and maximum short-term incentive for THC expressed as a percentage of base salary. For market statistics, the data presented represents the average maximum short-term incentive opportunity.
2. Represents the most recent actual short-term incentive award expressed as a percentage of the target award. For THC these percentages were based on the 2016 effective employee salary.
3. Target total cash compensation represents base salary plus the target short-term incentive opportunity.
4. Represents the estimated value of long-term incentive awards at grant, expressed as a percentage of base salary, if any.
5. Target total direct compensation represents target total cash plus the long-term incentive opportunity.
6. Total pension/benefits/perks represent the total annual value of pension, benefits and perquisites received.
7. For Mr. Halio, the pension value presented above represents the pension maximum and annual incremental increase in the existing and second retirement allowances ($125,000 and $225,000 respectively).
8. Target total remuneration represents target total direct compensation plus total pension, benefits and perquisites.
9. Represents THC’s percentile rank relative to the market.*

<table>
<thead>
<tr>
<th>Detailed Public Sector Proxy / AIF matches</th>
<th>Target Total Cash Comp.</th>
<th>Target Total Direct Comp.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salary Rank</td>
<td>Salary</td>
<td>Salary</td>
</tr>
<tr>
<td>SaskPower</td>
<td>$1,051K</td>
<td>$1,945K</td>
</tr>
<tr>
<td>Hydro One Ltd</td>
<td>$650K</td>
<td>$1,615K</td>
</tr>
<tr>
<td>Emaxx Corp.</td>
<td>$863K</td>
<td>$1,194K</td>
</tr>
<tr>
<td>EPCOR Utilities Inc.</td>
<td>$600K</td>
<td>$1,050K</td>
</tr>
<tr>
<td>Toronto Hydro</td>
<td>$549K</td>
<td>$906K</td>
</tr>
</tbody>
</table>

**Public Sector Organizations Offering LTI**

- Proxy Peer Group Public Sector Utility Peers (excluding Hydro One) 3 of 3
- Proxy Peer Group Public Sector Utility Peers (including Hydro One) 4 of 4

---

*Target total cash compensation represents base salary plus the target short-term incentive opportunity.

*Target total direct compensation represents target total cash plus the long-term incentive opportunity.

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### Benchmark Results: EVP & Chief Financial Officer

<table>
<thead>
<tr>
<th>Salary Rank</th>
<th>STI Range¹</th>
<th>Thr.</th>
<th>Tar.</th>
<th>Max</th>
<th>% of Target Paid ²</th>
<th>Target Total Comp. ³</th>
<th>LTI Award ⁴</th>
<th>Target Total Direct Comp. ⁵</th>
<th>Total Pension/Benefits /Perqs ⁶</th>
<th>Target Total Rem ⁷</th>
</tr>
</thead>
<tbody>
<tr>
<td>THC</td>
<td>$375K</td>
<td>THC</td>
<td>0%</td>
<td>40%</td>
<td>60%</td>
<td>THC</td>
<td>N/A</td>
<td>THC</td>
<td>THC</td>
<td>THC</td>
</tr>
<tr>
<td>Proxy Peer Group</td>
<td>Public Sector Utility Peers (excluding Hydro One) – n = 4</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>THC²</td>
<td>P38</td>
<td>THCU</td>
<td>N/A</td>
<td>THC³</td>
<td>N/A</td>
<td>THCU</td>
<td>N/A</td>
<td>THC³</td>
<td>THC³</td>
<td>THC³</td>
</tr>
<tr>
<td>Proxy Peer Group</td>
<td>Public Sector Utility Peers (including Hydro One) – n = 5</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>THC²</td>
<td>P31</td>
<td>THCU</td>
<td>N/A</td>
<td>THC³</td>
<td>N/A</td>
<td>THCU</td>
<td>N/A</td>
<td>THC³</td>
<td>THC³</td>
<td>THC³</td>
</tr>
<tr>
<td>Proxy Peer Group</td>
<td>Public &amp; Private Sector Utility Peers (excluding Hydro One) – n = 13</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>THC²</td>
<td>P42</td>
<td>THCU</td>
<td>N/A</td>
<td>THC³</td>
<td>N/A</td>
<td>THCU</td>
<td>N/A</td>
<td>THC³</td>
<td>THC³</td>
<td>THC³</td>
</tr>
<tr>
<td>Proxy Peer Group</td>
<td>Public &amp; Private Sector Utility Peers (including Hydro One) – n = 14</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>THC²</td>
<td>P39</td>
<td>THCU</td>
<td>N/A</td>
<td>THC³</td>
<td>N/A</td>
<td>THCU</td>
<td>N/A</td>
<td>THC³</td>
<td>THC³</td>
<td>THC³</td>
</tr>
<tr>
<td>Canadian Industry Group</td>
<td>Best Comparators Orgs in Revenue Range – n = 21</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>THC²</td>
<td>P36</td>
<td>THCU</td>
<td>N/A</td>
<td>THC³</td>
<td>N/A</td>
<td>THCU</td>
<td>N/A</td>
<td>THC³</td>
<td>THC³</td>
<td>THC³</td>
</tr>
</tbody>
</table>

¹ Represents the threshold, target and maximum short-term incentive for THC expressed as a percentage of base salary. For market statistics, the data presented represents the average maximum short-term incentive opportunity.
² Represents the most recent actual short-term incentive award expressed as a percentage of the target award. It is our understanding that Mr. Bowington joined the organization in 2017 and as a result no % of Target paid has been presented.
³ Target total cash compensation represents base salary plus the target short-term incentive opportunity.
⁴ Represents the estimated value of long-term incentive awards at grant, expressed as a percentage of base salary, if any.
⁵ Target total direct compensation represents target total cash plus the long-term incentive opportunity.
⁶ Total pension/benefits/perqs represent the total annual value of pension, benefits and perquisites received.
⁷ Target total remuneration represents target total direct compensation plus total pension, benefits and perquisites.
⁸ Represents THC’s percentile rank relative to the market.
**Benchmark Results:**
**EVP & Chief Financial Officer (Cont'd)**

<table>
<thead>
<tr>
<th>Detailed Public Sector Proxy / AIF matches</th>
<th>Target Total Cash Comp.</th>
<th>Target Total Direct Comp.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salary Rank</td>
<td>SaskPower</td>
<td>$1.324K</td>
</tr>
<tr>
<td>Saskatchewan Power</td>
<td>$779K</td>
<td></td>
</tr>
<tr>
<td>Hydro One Ltd</td>
<td>$500K</td>
<td></td>
</tr>
<tr>
<td>Enmax Corp.</td>
<td>$430K</td>
<td></td>
</tr>
<tr>
<td>Toronto Hydro</td>
<td>$375K</td>
<td></td>
</tr>
<tr>
<td>EPCOR Utilities Inc.</td>
<td>$371K</td>
<td></td>
</tr>
<tr>
<td></td>
<td>SaskPower</td>
<td>$2.537K</td>
</tr>
<tr>
<td></td>
<td>Hydro One Ltd</td>
<td>$1.399K</td>
</tr>
<tr>
<td></td>
<td>Enmax Corp.</td>
<td>$640K</td>
</tr>
<tr>
<td></td>
<td>EPCOR Utilities Inc.</td>
<td>$820K</td>
</tr>
<tr>
<td></td>
<td>Toronto Hydro</td>
<td>$525K</td>
</tr>
</tbody>
</table>

Note: Target total cash compensation represents base salary plus the target short-term incentive opportunity.

Note: Target total direct compensation represents target total cash plus the long-term incentive opportunity.

---

**Public Sector Organizations Offering LTIP**

- **Proxy Peer Group**
  - Public Sector Utility Peers (excluding Hydro One)
    - 3 of 3
  - Public Sector Utility Peers (including Hydro One)
    - 4 of 4
# Benchmark Results:

**EVP & Chief Engineering and Construction Officer**

<table>
<thead>
<tr>
<th>Salary Rank</th>
<th>STI Range</th>
<th>Thr.</th>
<th>Tar.</th>
<th>Max</th>
<th>% of Target Paid</th>
<th>Target Total Cash Comp.</th>
<th>LTI Award</th>
<th>Target Total Direct Comp.</th>
<th>Total Pension/Benefits /Perqs</th>
<th>Target Total Rem.</th>
</tr>
</thead>
<tbody>
<tr>
<td>THC</td>
<td>$338K</td>
<td>THC</td>
<td>0%</td>
<td>40%</td>
<td>60%</td>
<td>THC</td>
<td>THC</td>
<td>$474K</td>
<td>THC $80K</td>
<td>THC $554K</td>
</tr>
</tbody>
</table>

Proxy Peer Group

**Public Sector Utility Peers (excluding Hydro One)** – n = 7

| THC3 | P33 | THC6 (max) | P33 | THC8 | P100 | THC8 | P32 | THC8 | N/A | THC8 | P30 | THC8 | N/A | THC8 | P25 – P50 | THC8 | P25 – P50 |

Proxy Peer Group

**Public & Private Sector Utility Peers (excluding Hydro One)** – n = 10

| THC3 | P33 | THC6 (max) | P29 | THC8 | P100 | THC8 | P32 | THC8 | N/A | THC8 | P30 | THC8 | P25 – P50 | THC8 | P25 – P50 |

Canadian Industry Group

**Best Comparators Ours in Revenue Range** – n = 40

| THC5 | P97 | THC6 (max) | P40 | THC8 | N/A  | THC8 | N/A | THC8 | N/A | THC8 | N/A  | THC8 | N/A  | THC8 | N/A  | THC8 |

---

*As Hydro One did not disclose a top division executive, separate market statistics including Hydro One have not been presented.

1. Represents the threshold, target, and maximum short-term incentive for THC expressed as a percentage of base salary. For market statistics, the data presented represents the average maximum short-term incentive opportunity.

2. Represents the most recent actual short-term incentive award expressed as a percentage of the target award. For THC these percentages were based on the 2016 effective employee salary.

3. Target total cash compensation represents base salary plus the target short-term incentive opportunity.

4. Represents the estimated value of long-term incentive awards at grant, expressed as a percentage of base salary, if any.

5. Target total direct compensation represents target total cash, plus the long-term incentive opportunity.

6. Total pensions/benefits/perqs represent the total annual value of pension, benefits and perks received.

7. Target total remuneration represents target total direct compensation plus total pension, benefits and perks.

8. Represents THC’s percentile rank relative to the market.
### Benchmark Results: EVP & Chief Engineering and Construction Officer (Cont’d)

<table>
<thead>
<tr>
<th>Salary Rank</th>
<th>Target Total Cash Comp. 2</th>
<th>Target Total Direct Comp. 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>SaskPower</td>
<td>$57K</td>
<td>SaskPower</td>
</tr>
<tr>
<td>Enmax Corp¹</td>
<td>$442K</td>
<td>Enmax Corp¹</td>
</tr>
<tr>
<td>EPCOR Utilities Inc</td>
<td>$430K</td>
<td>EPCOR Utilities Inc</td>
</tr>
<tr>
<td>Enmax Corp¹</td>
<td>$422K</td>
<td></td>
</tr>
<tr>
<td>Toronto Hydro</td>
<td>$338K</td>
<td>Toronto Hydro</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Proxy Peer Group</th>
<th>Public Sector Utility Peers (excluding Hydro One)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enmax Corp¹</td>
<td>Enmax Corp¹</td>
</tr>
<tr>
<td>EPCOR Utilities Inc</td>
<td>EPCOR Utilities Inc</td>
</tr>
<tr>
<td>Toronto Hydro</td>
<td>Toronto Hydro</td>
</tr>
</tbody>
</table>

¹ Target total cash compensation represents base salary plus the target short-term incentive opportunity
² Target total direct compensation represents target total cash plus the long-term incentive opportunity
³ Represents the data for items, D, EVP – Competitive Energy at Enmax Corp.
⁴ Represents the data for McMaster, D, EVP – Power Delivery

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**Benchmark Results: EVP & Chief Electric Operations and Procurement Officer**

<table>
<thead>
<tr>
<th>Salary Rank</th>
<th>STI Range</th>
<th>Thr.</th>
<th>Tar.</th>
<th>Max</th>
<th>% of Target Paid</th>
<th>Target Total Cash Comp.</th>
<th>LTI Award</th>
<th>Target Total Direct Comp.</th>
<th>Total Pension/Benefits/Perqs</th>
<th>Target Total Rem.</th>
</tr>
</thead>
<tbody>
<tr>
<td>THC</td>
<td>$218K</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>THC</td>
<td>$418K</td>
<td>THC</td>
<td>THC</td>
<td>THC</td>
</tr>
</tbody>
</table>

Proxy Peer Group
Public Sector Utility Peers (excluding Hydro One)* – n = 7

| THC³ | P30 | THC³ (max) | P33 | THC³ | P100 |

Proxy Peer Group
Public & Private Sector Utility Peers (excluding Hydro One)* – n = 10

| THC³ | P31 | THC³ (max) | P29 | THC³ | P100 |

Canadian Industry Group
Best Comparators Orgs in Revenue Range – n = 40

| THC³ | P76 | THC³ (max) | P40 | THC³ | N/A  |

* As Hydro One did not disclose a top division executive, separate market statistics including Hydro One have not been presented.

1 Represents the threshold, target and maximum short-term incentive for THC expressed as a percentage of base salary. For market statistics, the data presented represents the average maximum short-term incentive opportunity.

2 Represents the most recent actual short-term incentive award expressed as a percentage of the target award. For THC these percentages were based on the 2016 effective employee salary.

3 Target total cash compensation represents base salary plus the target short-term incentive opportunity.

4 Represents the estimated value of long-term incentive awards at grant, expressed as a percentage of base salary, if any.

5 Target total direct compensation represents target total cash plus the long-term incentive opportunity.

6 Total pension/benefits/perqs represent the total annual value, or pension, benefits, and perquisites received.

7 Target total remuneration represents target total direct compensation plus total pension, benefits and perquisites.

8 Represents THC's percentile rank relative to the market.
### Detailed Public Sector Proxy / AIF matches

<table>
<thead>
<tr>
<th>Salary Rank</th>
<th>Target Total Cash Comp.</th>
<th>Target Total Direct Comp.</th>
</tr>
</thead>
<tbody>
<tr>
<td>SaskPower</td>
<td>$577K</td>
<td></td>
</tr>
<tr>
<td>Enmax Corp(^3)</td>
<td>$442K</td>
<td></td>
</tr>
<tr>
<td>EPCOR Utilities Inc</td>
<td>$430K</td>
<td></td>
</tr>
<tr>
<td>Enmax Corp(^4)</td>
<td>$422K</td>
<td></td>
</tr>
<tr>
<td>Toronto Hydro</td>
<td>$298K</td>
<td></td>
</tr>
</tbody>
</table>

\(^1\) Target total cash compensation represents base salary plus the target short-term incentive opportunity

\(^2\) Target total direct compensation represents target total cash plus the long-term incentive opportunity

\(^3\) Represents the data for Rehn, D., EVP – Competitive Energy at Enmax Corp.

\(^4\) Represents the data for McMaster, D., EVP – Power Delivery

### Public Sector Organizations Offering LTC

<table>
<thead>
<tr>
<th>Proxy Peer Group</th>
<th>Public Sector Utility Peers (excluding Hydro One)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

4 of 4
**Benchmark Results:**
**EVP & Chief Human Resources and Safety Officer**

<table>
<thead>
<tr>
<th>Salary Rank</th>
<th>STI Range</th>
<th>Thr.</th>
<th>Tar.</th>
<th>Max</th>
<th>% of Target Paid</th>
<th>Target Total Cash Comp.</th>
<th>LTI Award</th>
<th>Target Total Direct Comp.</th>
<th>Total Pension/Benefits /Perqs</th>
<th>Target Total Rem</th>
</tr>
</thead>
<tbody>
<tr>
<td>THC</td>
<td>$266K</td>
<td>THC</td>
<td>0%</td>
<td>40%</td>
<td>60%</td>
<td>THC</td>
<td>149%</td>
<td>THC</td>
<td>N/A</td>
<td>THC</td>
</tr>
</tbody>
</table>

**Survey Data (CA MBD)**
Public Sector Utility Orgs, Comparable Size (excluding Hydro One) – n = 5

<table>
<thead>
<tr>
<th>THC^5</th>
<th>P37</th>
<th>THCC^6 (max)</th>
<th>P58</th>
<th>THC^6</th>
<th>N/A</th>
</tr>
</thead>
</table>

Public Sector Utility Orgs, Comparable Size (including Hydro One) – n = 6

<table>
<thead>
<tr>
<th>THC^5</th>
<th>P46</th>
<th>THCC^6 (max)</th>
<th>P58</th>
<th>THC^6</th>
<th>N/A</th>
</tr>
</thead>
</table>

Public & Private Sector Utility Orgs, Comparable Size (excluding Hydro One) – n = 22

<table>
<thead>
<tr>
<th>THC^5</th>
<th>P50</th>
<th>THCC^6 (max)</th>
<th>P27</th>
<th>THC^6</th>
<th>P100</th>
</tr>
</thead>
</table>

Public & Private Sector Utility Orgs, Comparable Size (including Hydro One) – n = 23

<table>
<thead>
<tr>
<th>THC^5</th>
<th>P52</th>
<th>THCC^6 (max)</th>
<th>P27</th>
<th>THC^6</th>
<th>P0</th>
</tr>
</thead>
</table>

Canadian Industry Group
Best Comparators Orgs in Revenue Range – n = 22

<table>
<thead>
<tr>
<th>THC^5</th>
<th>P83</th>
<th>THCC^6 (max)</th>
<th>P33</th>
<th>THC^6</th>
<th>N/A</th>
</tr>
</thead>
</table>

---

1. Represents the threshold, target and maximum short-term incentive for THC expressed as a percentage of base salary. For market statistics, the data presented represents the average maximum short-term incentive opportunity.
2. Represents the most recent actual short-term incentive award expressed as a percentage of the target award. For THC these percentages were based on the 2016 effective employee salary.
3. Target total cash compensation represents base salary plus the target short-term incentive opportunity.
4. Represents the estimated value of long-term incentive awards at grant, expressed as a percentage of base salary, if any.
5. Target total direct compensation represents target total cash plus the long-term incentive opportunity.
6. Total pension/benefits/perqs represent the total annual value of pension, benefits and perquisites.
7. Target total remuneration represents target total direct compensation plus total pension, benefits and perquisites.
8. Represents THC’s percentile rank relative to the market.
APPENDIX A:
BENCHMARKING METHODOLOGY
APPENDIX A
METHODOLOGY: DATA SOURCES

Data Sources

• Compensation data for the peer companies was determined by reviewing publicly disclosed management information circulars ("proxies") and annual information forms ("AIFs"). The most recent publications were generally released in 2017 in respect of fiscal 2016 compensation levels.
  – Unless otherwise noted, all compensation information detailed in this review is presented in Canadian dollars (CAD).

Proxy Data for NEO equivalent positions

• Consistent with Mercer’s typical benchmarking approach, THC’s most senior executives have been matched to the Named Executive Officers (“NEOs”) of peer organizations based on their functional responsibilities.
  – The use of proxy disclosure is limited to the most senior executive officers as organizations typically only disclose compensation practices for the five (5) highest paid officers.

Survey Data for non-NEO equivalent positions

• Mercer has benchmarked non-NEO positions at THC to data from the Mercer Benchmark Database, our premier proprietary general industry survey. To provide a consistent benchmarking approach we have selected market refinements which closely mirror the constituents of the proxy peer group:

<table>
<thead>
<tr>
<th>Market Refinement</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Public Sector, Utility Orgs. (excluding Hydro One)</td>
<td>Includes Canadian Public Sector Utilities organizations of a comparable size/complexity to THC (excluding Hydro One)</td>
</tr>
<tr>
<td>2. Public Sector, Utility Orgs. (including Hydro One)</td>
<td>Includes Canadian Public Sector Utilities organizations of a comparable size/complexity to THC (including Hydro One)</td>
</tr>
<tr>
<td>3. Public &amp; Private Sector, Utility Orgs. (excluding Hydro One)</td>
<td>Includes Canadian Public &amp; Private Sector Utilities organizations of a comparable size/complexity to THC (excluding Hydro One)</td>
</tr>
<tr>
<td>4. Public &amp; Private Sector, Utility Orgs. (including Hydro One)</td>
<td>Includes Canadian Public &amp; Private Sector Utilities organizations of a comparable size/complexity to THC (including Hydro One)</td>
</tr>
</tbody>
</table>

• We note that compensation figures for Hydro One have been sourced from the Ontario “Sunshine List” and adjusted to approximate base salary and target total direct compensation levels (based on the pay mix for disclosed executives)
APPENDIX A

METHODOLOGY: BENCHMARK MATCHES

- Mercer’s typical benchmarking practice is to match executives to positions of similar responsibility within comparable companies.

- The table below outlines the benchmark matches and data sources that have been utilized in conducting this review:

<table>
<thead>
<tr>
<th>Incumbent</th>
<th>Title</th>
<th>Data Source</th>
<th>Match Title</th>
</tr>
</thead>
<tbody>
<tr>
<td>A. Haines</td>
<td>President &amp; Chief Executive Officer</td>
<td>Peer Group (Proxy/AIF)</td>
<td>Chief Executive Officer</td>
</tr>
<tr>
<td>S. Bovingdon</td>
<td>EVP &amp; Chief Financial Officer</td>
<td>Peer Group (Proxy/AIF)</td>
<td>Chief Financial Officer</td>
</tr>
<tr>
<td>D. Priore</td>
<td>EVP &amp; Chief Engineering and Construction Officer</td>
<td>Peer Group (Proxy/AIF)</td>
<td>Top Division Executive</td>
</tr>
<tr>
<td>B. La Planta</td>
<td>EVP &amp; Chief Electric Operations and Procurement Officer</td>
<td>Peer Group (Proxy/AIF)</td>
<td>Top Division Executive</td>
</tr>
</tbody>
</table>
# Appendix A

**Methodology: Current Compensation**

- The following table outlines Mercer’s understanding of THC’s current target total remuneration opportunity for each of the executive positions reviewed:

<table>
<thead>
<tr>
<th>Incumbent</th>
<th>Title</th>
<th>Base Salary</th>
<th>Target Short-term Incentives (value / % of base)</th>
<th>Target Total Cash Compensation</th>
<th>Pension &amp; Retirement Entitlements</th>
<th>Benefits &amp; Perquisites</th>
<th>Total Remuneration</th>
</tr>
</thead>
<tbody>
<tr>
<td>A. Haines</td>
<td>President &amp; Chief Executive Officer</td>
<td>$549.0</td>
<td>$356.9 (65%)</td>
<td>$905.9</td>
<td>$467.1</td>
<td>$16.7</td>
<td>$1,389.7</td>
</tr>
<tr>
<td>S. Bovingdon</td>
<td>EVP &amp; Chief Financial Officer</td>
<td>$375.0</td>
<td>$150.0 (40%)</td>
<td>$525.0</td>
<td>$79.0</td>
<td>$9.4</td>
<td>$613.4</td>
</tr>
<tr>
<td>D. Priore</td>
<td>EVP &amp; Chief Engineering and Construction Officer</td>
<td>$338.3</td>
<td>$135.3 (40%)</td>
<td>$473.6</td>
<td>$71.0</td>
<td>$9.4</td>
<td>$553.9</td>
</tr>
<tr>
<td>B. La Pianta</td>
<td>EVP &amp; Chief Electric Operations and Procurement Officer</td>
<td>$298.3</td>
<td>$119.3 (40%)</td>
<td>$417.6</td>
<td>$62.2</td>
<td>$9.4</td>
<td>$489.3</td>
</tr>
</tbody>
</table>

1) Represents base salary plus target short-term incentive
2) Target total direct compensation for THC is equal to target total cash compensation, due to the organization’s lack of a long-term incentive plan
3) Includes the values of the flexible wellness benefit, executive medicals and club membership as provided by THC
4) Represents target total direct compensation plus pension, benefits and perquisites
5) For Mr. Haines, the pension value presented above represents the pension maximum and annual incremental increase in the existing and second retirement allowances ($125,000 and $225,000 respectively)
APPENDIX A
METHODOLOGY: DATA SOURCES (CONT’D)

Data Confidentiality

• In order to preserve the confidentiality of our survey participants and ensure robust data sets, Mercer requires a minimum of:
  – 3 data points to report an average
  – 4 data points to report a median
  – In the case where there is insufficient data to report, “--” will appear

Statistical Terms

• P25 / Market 25th percentile:
  – The data point that is higher than 25% of all other data in the sample when ranked from low to high. Also known as the first quartile.

• P50 / Market 50th percentile / Median:
  – The data point that is higher than 50% of all other data in the sample when ranked from low to high. Also known as the median.

• P75 / Market 75th percentile:
  – The data point that is higher than 75% of all other data in the sample when ranked from low to high.

• Mean / Average:
  – The sum of all data reported divided by the number of observations in the sample.
APPENDIX A
METHODOLOGY: PENSION

- Pension values for the market were estimated based on Mercer’s proprietary database and publicly available information using the following set of actuarial assumptions and methods

<table>
<thead>
<tr>
<th>Economic Assumptions</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Discount Rate</td>
<td>5.0% per annum</td>
</tr>
<tr>
<td>Salary Increases</td>
<td>3.0% per annum</td>
</tr>
<tr>
<td>Inflation rate</td>
<td>2.0% per annum</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Demographic Assumptions</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Mortality</td>
<td>100% of CPM 2014 Private Sector Mortality projected with CPM-B Scale</td>
</tr>
<tr>
<td>Termination</td>
<td>Ontario light termination scale</td>
</tr>
<tr>
<td>Retirement</td>
<td>25% at 55</td>
</tr>
<tr>
<td></td>
<td>50% at 60</td>
</tr>
<tr>
<td></td>
<td>100% at 65</td>
</tr>
</tbody>
</table>

- These pension values were then used (in combination with benefits and perquisite data) to develop a view of market total remuneration for each position analyzed
- We note that the pension values are based on a large number of utilities organizations, which have significant overlap with the peer group and include a variety of plan types (e.g. Public and Private Sector Defined Benefit and Defined Contribution plans)
A P P E N D I X  A
M E T H O D O L O G Y :  B E N E F I T S

• Benefit values for the market were estimated based on Mercer’s Plan Design Database for organizations in the Utilities Industry. To align with the approach taken to benchmark compensation levels, the following two comparator groups were selected from the database:
  1. Public Sector Utilities Organizations of a Comparable Size to THC
  2. Public & Private Sector Utilities Organizations of a Comparable Size to THC
• The employer-provided values, while not based on THC’s employee demographics or claims utilization patterns, provide an indication of the relative richness of the various plans by benefit, and the overall ranking of the benefit plans offered by each company.
  – The values calculated are estimates and should not be interpreted as a cost comparison. As an example, if two companies offer the same benefit plan, they would be assigned the exact same relative value, even though their costs would be different, due to several factors such as different claims experience, premium rates, and employee demographics.
• These benefit values were then used (in combination with pension and perquisite data) to develop a view of market total remuneration for each position analyzed.
APPENDIX A
METHODOLOGY: PERQUISITES

- Summarized below are the most prevalent and valuable perquisites typically offered to executives of Canadian-based employers:
  - This data is sourced from Mercer’s 2016/2017 Canadian Policies & Practices Survey

<table>
<thead>
<tr>
<th>Type of Perquisite</th>
<th>Executive Level Positions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Energy/Utilities Organizations</td>
</tr>
<tr>
<td>Company Match for Charity Donations</td>
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<tr>
<td>Discounted Cell Phone Plans</td>
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<tr>
<td>Discounted Entertainment Tickets</td>
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<tr>
<td>External Training / Professional Development</td>
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<tr>
<td>Flexible Spending Account*</td>
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<tr>
<td>Paid / Subsidized Parking</td>
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<tr>
<td>Reimbursement for Development Coursework</td>
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</tr>
<tr>
<td>Car Allowance**</td>
<td></td>
</tr>
</tbody>
</table>

Note: Figures presented above are in $CAD 000’s
* Annual maximum per employee
** Annual allowance per employee
APPENDIX B: MARKET COMPARATORS
## Appendix B

### Market Comparators

- This section outlines the comparator organizations included in each market sample presented in the body of this report:
  - We note that in certain cases (e.g., top division executive) there may be multiple benchmark matches from a single organization listed.

<table>
<thead>
<tr>
<th>THC Position</th>
<th>Market Refinement</th>
<th>Comparators</th>
</tr>
</thead>
<tbody>
<tr>
<td>President &amp; Chief Executive Officer</td>
<td>Proxy Peer Group: Public Sector Utility Peers</td>
<td>SaskPower&lt;br&gt;ENMAX Corporation&lt;br&gt;Hydro One Ltd.&lt;br&gt;Enegy Utilities Inc.&lt;br&gt;ATCO Ltd&lt;br&gt;Northland Power Inc.&lt;br&gt;FortisAlberta Inc.&lt;br&gt;FortisBC Inc.&lt;br&gt;Capstone Infrastructure Corp.&lt;br&gt;Algonquin Power &amp; Utilities Corp&lt;br&gt;Hydro One Ltd.</td>
</tr>
<tr>
<td>EVP &amp; Chief Financial Officer</td>
<td>Proxy Peer Group: Public Sector Utility Peers</td>
<td>SaskPower&lt;br&gt;ENMAX Corporation&lt;br&gt;Hydro One Ltd.&lt;br&gt;Enegy Utilities Inc.&lt;br&gt;ATCO Ltd&lt;br&gt;Northland Power Inc.&lt;br&gt;FortisAlberta Inc.&lt;br&gt;FortisBC Inc.&lt;br&gt;Capstone Infrastructure Corp.&lt;br&gt;Algonquin Power &amp; Utilities Corp&lt;br&gt;Hydro One Ltd.</td>
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</table>
### APPENDIX B

**MARKET COMPARATORS (CONT'D)**

<table>
<thead>
<tr>
<th>THC Position</th>
<th>Market Refinement</th>
<th>Comparators</th>
</tr>
</thead>
<tbody>
<tr>
<td>EVP &amp; Chief Engineering and Construction Officer*</td>
<td>Proxy Peer Group: Public Sector Utility Peers*</td>
<td>SaskPower</td>
</tr>
<tr>
<td></td>
<td>Proxy Peer Group: Public &amp; Private Sector Utility Peers*</td>
<td>ENMAX Corporation</td>
</tr>
<tr>
<td></td>
<td>Survey Data (CA MBD): Public Sector Utility Orgs, Comparable Size</td>
<td>Capstone Infrastructure Corp.</td>
</tr>
<tr>
<td>EVP &amp; Chief Electric Operations and Procurement Officer*</td>
<td>Proxy Peer Group: Public Sector Utility Peers*</td>
<td>SaskPower</td>
</tr>
<tr>
<td></td>
<td>Proxy Peer Group: Public &amp; Private Sector Utility Peers*</td>
<td>ENMAX Corporation</td>
</tr>
<tr>
<td></td>
<td>Survey Data (CA MBD): Public Sector Utility Orgs, Comparable Size</td>
<td>Capstone Infrastructure Corp.</td>
</tr>
<tr>
<td>EVP &amp; Chief Human Resources and Safety Officer</td>
<td>Survey Data (CA MBD): Public &amp; Private Sector Utility Orgs, Comparable Size</td>
<td>SaskPower</td>
</tr>
<tr>
<td></td>
<td>Survey Data (CA MBD): Public Sector Utility Orgs, Comparable Size</td>
<td>ENMAX Corporation</td>
</tr>
<tr>
<td></td>
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</table>

*As Hydro One did not disclose a top division executive, separate market statistics including Hydro One have not been presented.*
## Appendix B

**Market Comparators (Cont’d)**

<table>
<thead>
<tr>
<th>THC Position</th>
<th>Market Refinement</th>
<th>Comparators</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Survey Data (CA MBD): Public Sector Utility Orgs, Comparable Size</td>
<td>SaskPower, ENMAX Corporation, Epcor Utilities Inc.</td>
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<tr>
<td></td>
<td>Survey Data (CA MBD): Public Sector Utility Orgs, Comparable Size</td>
<td>SaskPower, ENMAX Corporation, Hydro One Ltd.</td>
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### APPENDIX B
MARKET COMPARATORS (CONT'D)

<table>
<thead>
<tr>
<th>Canadian Industry Group Companies</th>
<th>AIF Companies</th>
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<tr>
<td>BC Hydro Power &amp; Authority</td>
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<td>Emera, Inc.</td>
<td></td>
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<tr>
<td>TransAlta Corporation</td>
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<tr>
<td>Ontario Power Generation</td>
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</tr>
<tr>
<td>Capital Power Corporation</td>
<td></td>
</tr>
<tr>
<td>SaskPower</td>
<td></td>
</tr>
<tr>
<td>AltaGas, Ltd.</td>
<td></td>
</tr>
<tr>
<td>ENMAX Corporation</td>
<td></td>
</tr>
<tr>
<td>EPCOR Utilities, Inc.</td>
<td></td>
</tr>
<tr>
<td>Hydro One</td>
<td></td>
</tr>
<tr>
<td>ATCO</td>
<td></td>
</tr>
<tr>
<td>Hydro Ottawa Ltd.</td>
<td></td>
</tr>
<tr>
<td>Hydro-Quebec</td>
<td></td>
</tr>
<tr>
<td>Independent Electricity System Operator</td>
<td></td>
</tr>
<tr>
<td>Manitoba Hydro (2015)</td>
<td></td>
</tr>
<tr>
<td>NB Power</td>
<td></td>
</tr>
<tr>
<td>Ontario Energy Board</td>
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</tr>
</tbody>
</table>
2017 Comprehensive Vehicle Fleet Review

FINAL REPORT

Prepared for:

Toronto Hydro-Electric Services Ltd.

Fleet & Equipment Services Division

Prepared by:

Fleet Challenge

A program of Richmond Sustainability Initiatives

August 2017
EXECUTIVE SUMMARY

Toronto Hydro-Electric System (“THES” or “Toronto Hydro”) operates a vehicle fleet of ~550 units. The fleet is made up of light, medium and heavy-duty vehicles as well as the equipment necessary to delivering the operational requirements of one of Canada’s largest municipal electricity distribution companies.

As part of Toronto Hydro’s upcoming rate filing application process, the Fleet & Equipment Services Department (“Fleet Services”) is seeking to refine its fleet capital replacement program to account for vehicle historical/operational performance. Specifically, Fleet Services wishes to apply Life Cycle Analysis (“LCA”) methodology to inform, support and justify vehicle replacement practices and to facilitate the analysis and communication of future replacement costs.

In general, as commercial vehicle fleets age they incur higher operating expenses due to increasing levels of reactive repairs (unplanned, breakdowns). As well, downtime costs for spare/loaner vehicles increase as does the cost of loss of productivity for the drivers who depend on vehicles to perform their daily work routines. Therefore, capital re-investment in the fleet is critical to any organization that depends on a fleet of vehicles to achieve its objectives and mission.

Richmond Sustainability Initiatives’ Fleet Challenge team (“RSI-FC”) was commissioned to review the on-road vehicle fleet, apply Life Cycle and related analysis, and provide recommendations. Fleet Challenge completed LCA for Toronto Hydro in 2013 using historical data for a multi-year period (10+ years) leading up to 2013. This report is a ‘refresh’ and update of the 2013 LCA using data from the period of 2013 to 2016 LCA.

The following components have been prepared in keeping with Toronto Hydro’s statement of work; a summary of the results are provided herein.

1. Fleet Baseline Data Review & Data Compilation – A ‘Business as Usual’ view that reviews productivity, fuel, downtime, depreciation, usage, maintenance, and repairs.
2. Life Cycle Analysis & Peer Fleet Comparison, Long-Term Capital Planning
4. Final Report

1 “Business as Usual” is a snapshot of data for the existing fleet, using historical costs and fuel consumption, kilometers travelled during the review period with vehicle replacement schedules based on 2013 LCA optimal lifecycles.
In the preceding table, it is shown that, on average, Toronto Hydro's vehicles:

- Travelled just under 6,000 km a year;
- Had approximately 3.3 days of downtime;
- Used, on average 39.6 liters/fuel per 100km (due to the number of intense fuel users like cable, crane and line trucks, single and double bucket trucks, digger derricks, and single bucket-van mounts); and,
- Cost approximately $2.17/km, although this varied by unit.

Initial Results: Life Cycle Analysis & Peer Fleet Utility Comparison

Peer fleet values\(^2\) were used derived from a southern Ontario municipal electric utility ("MEU"), an Ontario gas utility, a telecom utility and additional benchmark data from 12 urban municipal fleets. This comparison highlights that:

- The age of Toronto Hydro’s fleet is in the mid-range of the peer fleets for the entire

---

\(^2\) In reviewing the peer fleet comparisons, readers must be mindful that in the Canadian marketplace Toronto Hydro’s fleet is unique in terms of fleet size and makeup as well as operational characteristics - no peer fleets with directly similar characteristics exist. Peer fleets in this analysis share few comparable data points with TH and are presented for information only, in that (for example) the MEU operates in a much smaller city with less underground and overhead physical plant, and the gas and telecom utility fleets are comprised mainly of vans and other light-duty vehicles and operate in a much broader geographical footprint.
fleet as well as for each major vehicle grouping;

- The **book value** of the Toronto Hydro vehicle fleet is higher than the MEU, gas utility and telecom fleets (due to the large size, complexity and acquisition cost of Toronto Hydro’s vehicles);
- The **total vehicle-kilometers-travelled** for the Toronto Hydro fleet is lower than the peer fleets (due to the size and density of the city);
- Average **preventative maintenance** is in line with peer fleets;
- **Repair costs** tend towards the higher end compared to peer fleets (also due to the size, complexity and number of large trucks in the Toronto Hydro fleet);
- The fleet has the second highest **cost of capital** after the gas utility (due to the number of large, specialized and costly trucks);
- **Total controllable costs** are higher than peer fleets (due to the number of large, specialized and costly trucks);
- The **cost per km** is the second highest of the peer fleets after the telecom (due to the number of large, specialized and costly trucks and lower average km);
- The fleet on average **travels** significantly less km than peer fleets (due to the geographical size of each fleet’s service area);
- Availability (uptime) is above average; and,
- Based on **2013 optimal replacement cycles**, the capital required for vehicle and equipment replacement is $11,205,766. Toronto Hydro’s rate of re-investment\(^3\) based on current-day replacement practices is therefore 36.9% of net present value (NPV) for on-road vehicles, compared to 28.8% for the Ontario MEU, 23.7% for the gas utility, 23.4% for the telecom utility and 34.5% for the municipal group.

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\(^3\) Investing capital in the fleet at the rate of depreciation is a best-in-class fleet management best practice.
## Toronto Hydro - Peer Fleet Comparisons

<table>
<thead>
<tr>
<th>Key Performance Indicator (KPI)</th>
<th>Metric</th>
<th>Toronto Hydro</th>
<th>Peer Fleet &quot;A&quot; (Ontario MEU)</th>
<th>Peer Fleet &quot;B&quot; (Ontario Gas Utility)</th>
<th>Peer Fleet &quot;C&quot; (Telecom Utility)</th>
<th>Benchmark Data - 12 Urban Municipal Fleets</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vehicles in Review</td>
<td>On-Road Vehicles</td>
<td>No. of Units</td>
<td>488</td>
<td>136</td>
<td>762</td>
<td>11,598</td>
</tr>
<tr>
<td>Equipment / Trailers</td>
<td></td>
<td>No. of Units</td>
<td>51</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Age</td>
<td>On-Road Vehicles (all)</td>
<td>Years</td>
<td>6.5</td>
<td>7.8</td>
<td>4.1</td>
<td>6.3</td>
</tr>
<tr>
<td>Average Age</td>
<td>Light-Duty (Car, Pickup, Full- or Mini-Van, SUV’s)</td>
<td>Years</td>
<td>5.8</td>
<td>7.6</td>
<td>3.9</td>
<td>6.3</td>
</tr>
<tr>
<td>Average Age</td>
<td>Medium-Duty (Cube Van, Single Bucket Van Mount)</td>
<td>Years</td>
<td>6.1</td>
<td>5.8</td>
<td>13.8</td>
<td>6.6</td>
</tr>
<tr>
<td>Average Age</td>
<td>Heavy-Duty Trucks (Cable- Crane- Dump- Line-Truck, Single- Double-Bucket, Digger Derrick)</td>
<td>Years</td>
<td>7.6</td>
<td>7.1</td>
<td>5.6</td>
<td>7.4</td>
</tr>
<tr>
<td>Average Age</td>
<td>Trailers</td>
<td>Years</td>
<td>11.8</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NPV / Book Value of Fleet</td>
<td>On-Road Capable Vehicles</td>
<td></td>
<td>$ 29,359,167</td>
<td>$2,624,843</td>
<td>$11,844,214</td>
<td>$23,424,600</td>
</tr>
<tr>
<td>NPV / Book Value of Fleet</td>
<td>Trailers</td>
<td></td>
<td>$ 1,570,888</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Vehicle Kilometers</td>
<td>On-Road Vehicles</td>
<td>Kilometers</td>
<td>2,985,069</td>
<td>1,483,408</td>
<td>15,836,561</td>
<td>254,968,297</td>
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<tr>
<td>Total Fuel Consumed</td>
<td>On-Road Vehicles</td>
<td>Liters</td>
<td>1,099,199</td>
<td>445,217</td>
<td>3,383,338</td>
<td>42,583,753</td>
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<tr>
<td>Total Fuel Consumed</td>
<td>Trailers</td>
<td>Liters</td>
<td>2,165</td>
<td></td>
<td></td>
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<tr>
<td>Corporate Average Fuel Economy (CAFE)</td>
<td>On-Road Vehicles</td>
<td>L/100 KM</td>
<td>33.6</td>
<td>23.7</td>
<td>16.5</td>
<td>17.4</td>
</tr>
<tr>
<td>Average Fuel Consumption</td>
<td>Trailers</td>
<td>L/100 KM</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Downtime</td>
<td>On-Road Vehicles</td>
<td>Days</td>
<td>1,615</td>
<td>694</td>
<td></td>
<td>90,517</td>
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<tr>
<td>Total Downtime</td>
<td>Trailers</td>
<td>Days</td>
<td>199</td>
<td></td>
<td></td>
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<tr>
<td>Average Downtime</td>
<td>On-Road Vehicles</td>
<td>Days/Vehicle</td>
<td>3.3</td>
<td>5.1</td>
<td></td>
<td>7.4</td>
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<tr>
<td>Average Downtime</td>
<td>Trailers</td>
<td>Days/Vehicle</td>
<td>3.7</td>
<td></td>
<td></td>
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<tr>
<td>Total Downtime Cost</td>
<td>On-Road Vehicles</td>
<td></td>
<td>$ 584,400</td>
<td>$29,619</td>
<td></td>
<td>$22,103,831</td>
</tr>
<tr>
<td>Total Downtime Cost</td>
<td>Trailers</td>
<td></td>
<td>$ 56,700</td>
<td></td>
<td></td>
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<tr>
<td>Key Performance Indicator (KPI)</td>
<td>Metric</td>
<td>Toronto Hydro</td>
<td>Peer Fleet “A” (Ontario MEU)</td>
<td>Peer Fleet “B” (Ontario Gas Utility)</td>
<td>Peer Fleet “C” (Telecom Utility)</td>
<td>Benchmark Data 12 Urban Municipal Fleets</td>
</tr>
<tr>
<td>--------------------------------</td>
<td>--------</td>
<td>---------------</td>
<td>-----------------</td>
<td>-----------------</td>
<td>-----------------</td>
<td>--------------------------</td>
</tr>
<tr>
<td>Average PM Cost</td>
<td>On-Road Vehicles</td>
<td>$1,382</td>
<td>$1,118</td>
<td>$758</td>
<td>$1,897</td>
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<tr>
<td>Average PM Cost</td>
<td>Trailers</td>
<td>$812</td>
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<td>Average Repair Cost</td>
<td>On-Road Vehicles</td>
<td>$5,112</td>
<td>$4,082</td>
<td>$2,647</td>
<td>$4,513</td>
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<tr>
<td>Average Repair Cost</td>
<td>Trailers</td>
<td>$2,555</td>
<td></td>
<td></td>
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<tr>
<td>Average Fuel Cost</td>
<td>On-Road Vehicles</td>
<td>$2,047</td>
<td>$3,042</td>
<td>$3,212</td>
<td>$4,471</td>
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<td>Average Fuel Cost</td>
<td>Trailers</td>
<td>$413</td>
<td></td>
<td></td>
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<tr>
<td>Cost per Kilometer</td>
<td>Total Fleet</td>
<td>$2.17</td>
<td>$0.89</td>
<td>$0.44</td>
<td>$2.96</td>
<td>$0.97</td>
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<td>Cost per Kilometer</td>
<td>Light-Duty On-Road Capable (Car, Pickup, Full- or Mini-Van, SUV’s)</td>
<td>$0.87</td>
<td>$0.45</td>
<td>$0.72</td>
<td>$0.62</td>
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<tr>
<td>Cost per Kilometer</td>
<td>Medium-Duty On-Road Capable (Cube Van, Single Bucket Van Mount)</td>
<td>$2.24</td>
<td>$1.06</td>
<td>$2.15</td>
<td>$3.05</td>
<td></td>
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<tr>
<td>Cost per Kilometer</td>
<td>Heavy-Duty Trucks On-Road Capable (Cable-Crane, Dump, Line-Truck, Single-Bucket, Digger Derrick)</td>
<td>$7.01</td>
<td>$4.23</td>
<td>$2.95</td>
<td>$3.41</td>
<td></td>
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<tr>
<td>Average Vehicle Kilometers Traveled (VKT)</td>
<td>On-Road Vehicles</td>
<td>Kilometers</td>
<td>6,119</td>
<td>10,907</td>
<td>20,783</td>
<td>21,984</td>
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<tr>
<td>Average Vehicle Kilometers Traveled (VKT)</td>
<td>Light-Duty On-Road Capable (Car, Pickup, Full- or Mini-Van, SUV’s)</td>
<td>Kilometers</td>
<td>6,217</td>
<td>10,593</td>
<td>22,488</td>
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<tr>
<td>Average Vehicle Kilometers Traveled (VKT)</td>
<td>Medium-Duty On-Road Capable (Cube Van, Single Bucket Van Mount)</td>
<td>Kilometers</td>
<td>4,271</td>
<td>14,714</td>
<td>12,523</td>
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<tr>
<td>Average Vehicle Kilometers Traveled (VKT)</td>
<td>Heavy-Duty Trucks On-Road Capable (Cable-Crane, Dump, Line-Truck, Single-Bucket, Digger Derrick)</td>
<td>Kilometers</td>
<td>4,623</td>
<td>6,287</td>
<td>19,523</td>
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<tr>
<td>Average Availability</td>
<td>On-Road Vehicles</td>
<td>%</td>
<td>98.7</td>
<td>98.0</td>
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<td>97.6</td>
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<tr>
<td>Average Availability</td>
<td>Trailers</td>
<td>%</td>
<td>99.5</td>
<td></td>
<td></td>
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<tr>
<td>GHG Baseline</td>
<td>Total Fleet</td>
<td>Metric tons CO2 eq. (carbon equivalent)</td>
<td>2,489</td>
<td>1,140</td>
<td>7,671</td>
<td>96,804</td>
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<tr>
<td>Maintenance Ratio</td>
<td>On-Road Vehicles</td>
<td>% of total parts &amp; labour</td>
<td>0.28</td>
<td>0.27</td>
<td>0.27</td>
<td>0.57</td>
</tr>
<tr>
<td>Maintenance Ratio</td>
<td>Trailers</td>
<td>% of total parts &amp; labour</td>
<td>0.51</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Capital Required for Vehicle Replacement</td>
<td>On-Road Vehicles</td>
<td>(note: for TH amount is net)</td>
<td>$10,845,266</td>
<td>$5,691,757</td>
<td>$7,830,432</td>
<td>$131,217,400</td>
</tr>
<tr>
<td>Capital (net) Required for Equipment Replacement</td>
<td>Trailers</td>
<td>$366,500</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Capital Replacement Ratio</td>
<td>On-Road Vehicles</td>
<td>Capital Required as Percentage of Vehicle Replacement Cost</td>
<td>36.9%</td>
<td>20.8%</td>
<td>23.7%</td>
<td>23.4%</td>
</tr>
<tr>
<td>Capital Replacement Ratio</td>
<td>Trailers</td>
<td>Capital Required as Percentage of Vehicle Replacement Cost</td>
<td>22.9%</td>
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</table>
## Life Cycle Analysis for 2017

<table>
<thead>
<tr>
<th>Vehicle Type</th>
<th>Current Planned Life Cycle</th>
<th>Optimal AEC (lowest annual equivalent cost) 2013 LCA</th>
<th>Optimal AEC (lowest annual equivalent cost) 2017 LCA</th>
<th>Recommended Tactic (See Section 4.2 for detail)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Car</td>
<td>6 years / 120,000 km</td>
<td>6 years</td>
<td>9 years</td>
<td>Increase LC+3</td>
</tr>
<tr>
<td>Cargo Minivan</td>
<td>7 years / 140,000 km</td>
<td>7 years</td>
<td>7 years</td>
<td>No change</td>
</tr>
<tr>
<td>Passenger Minivan</td>
<td>6 years / 120,000 km</td>
<td>6 years</td>
<td>9 years</td>
<td>Increase LC+3</td>
</tr>
<tr>
<td>Full Size Van</td>
<td>9 years / 135,000 km</td>
<td>9 years</td>
<td>10 years</td>
<td>Increase LC+1</td>
</tr>
<tr>
<td>Pick-up</td>
<td>9 years / 180,000 km</td>
<td>9 years</td>
<td>9 years</td>
<td>No change</td>
</tr>
<tr>
<td>SUV</td>
<td>6 years / 120,000 km</td>
<td>6 years</td>
<td>8 years</td>
<td>Increase LC+2</td>
</tr>
<tr>
<td>Cube Van</td>
<td>12 years / 180,000 km</td>
<td>12 years</td>
<td>12-15 years</td>
<td>Assess case by case at Y12. Consider increasing LC+3</td>
</tr>
<tr>
<td>Single Bucket Aerial Device</td>
<td>14 years / 210,000 km</td>
<td>14 years</td>
<td>12-16 years</td>
<td>Assess case by case at Y12. Consider increasing LC+2</td>
</tr>
<tr>
<td>Single-bucket Van Mount Aerial Device</td>
<td>8 years / 120,000 km</td>
<td>8 years</td>
<td>11 years</td>
<td>Increase LC+3</td>
</tr>
<tr>
<td>Cable Truck</td>
<td>16 years / 240,000 km</td>
<td>16 years</td>
<td>11 – 14 years</td>
<td>Assess case by case at Y11 – consider Y14. Decrease LC-5 (re-assess at Y11).</td>
</tr>
<tr>
<td>Crane Truck</td>
<td>14 or 16 years / 210,000 km or 240,000 km</td>
<td>14 years</td>
<td>10 -14 years</td>
<td>Assess case by case at Y10 – consider increase to Y14. Decrease LC – 4 (re-assess at Y10).</td>
</tr>
<tr>
<td>Dump Truck</td>
<td>14 years / 210,000 km</td>
<td>14 years</td>
<td>8 -12 years</td>
<td>Assess case by case at Y8 – consider increase to Y12. Decrease LC – 6 (re-assess at Y8)</td>
</tr>
<tr>
<td>Line Truck</td>
<td>13 years / 195,000 km</td>
<td>13 years</td>
<td>13 Years</td>
<td>No change</td>
</tr>
<tr>
<td>Double Bucket Aerial Device</td>
<td>14 years / 210,000 km</td>
<td>14 years</td>
<td>14 years</td>
<td>No change</td>
</tr>
</tbody>
</table>
In general, the recommended LCA for 2017 differs in several cases from the 2013 recommendations. This is due to changes in the fleet resulting from vehicle replacements and disposals, as well as changes in operating costs and ages of the units being analyzed.

Overall it is recommended to:

- **Increase** the planned life cycle for many of the vehicles in the light duty vehicle category, including cars, passenger minivans, full size vans, and SUVs;
- **Increase** the planned life cycle for all the medium duty vehicles (the cube vans, single bucket aerial device, and the single-bucket van mount aerial device); and,
- **Decrease** some of the planned life cycles for the heavy-duty vehicle category, specifically the cable trucks, crane trucks and dump trucks.

It is important to consider these recommendations in light of specific data gaps that exist for some categories – these considerations are noted in Section 4.2.

**Initial Results: Long Term Capital Planning**

- In the Business-As-Usual ("BAU") scenario, which employs the 2013 optimized vehicle replacement practices\(^4\), more than $11M would be required in 2018 for vehicle replacements.

- Using the 2017 optimized LCA practices, $7,803,925 would be required in 2018. This approach is forecasted to yield a potential Opex reduction of ~$65k in 2018 (considering the increased cost of capital, minus the decreased cost of repairs, fuel and downtime\(^5\); downtime reduction of 210 person/days and GHG reduction of 50 MT).

- Using the approved Capex budgets for 2018 and 2019 of $3.2m each year, it is predicted that an Opex increase of ~$17k will result. Also, the number of deferred replacements will increase exponentially in ensuing years, as will the amount of capital required each year (per the table below). For example, more than 100 vehicles, or ~20% of the fleet, will be due for replacement in 2020 including deferrals from previous years and based on optimal economic life cycle analysis.

---

\(^4\) Calculated with optimal economic lifecycles determined in 2013

\(^5\) Assumes that (although not possible) all vehicle replacements were made on day one in 2018 - full benefits would not accrue until 2019.
## Capital Budget Impacts FY 2018-2023

<table>
<thead>
<tr>
<th>Budget Year</th>
<th>Capital Required</th>
<th>Total Capital Budget</th>
<th>No of Vehicles</th>
</tr>
</thead>
<tbody>
<tr>
<td>FY 2018</td>
<td>$11,214,000</td>
<td>$3,085,000(^6)</td>
<td>20</td>
</tr>
<tr>
<td>FY 2019</td>
<td>$4,176,450</td>
<td>$2,876,400(^7)</td>
<td>23</td>
</tr>
<tr>
<td>FY 2020</td>
<td>$7,483,133</td>
<td>$7,387,051</td>
<td>101</td>
</tr>
<tr>
<td>FY 2021</td>
<td>$10,098,260</td>
<td>$10,098,260</td>
<td>54</td>
</tr>
<tr>
<td>FY 2022</td>
<td>$4,993,200</td>
<td>$4,993,200</td>
<td>40</td>
</tr>
<tr>
<td>FY 2023</td>
<td>$10,632,450</td>
<td>$10,632,450</td>
<td>42</td>
</tr>
<tr>
<td>FY 2024</td>
<td>$8,283,675</td>
<td>$8,283,675</td>
<td>33</td>
</tr>
</tbody>
</table>

---

\(^6\) Net estimated amount – does not include upfitting and 'make-ready' costs or vendor prices increases.

\(^7\) Net estimated amount – includes estimated inflation but not upfitting and 'make-ready' costs or vendor prices increases.
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1.0 Introduction & Context

Toronto Hydro-Electric System Limited (“Toronto Hydro” or “THES”) is the electricity distributor licensed by the Ontario Energy Board (“OEB”) to serve the City of Toronto. As the largest municipal electricity distributor in Canada, the company distributes nearly 20% of Ontario’s electricity resources and services over 750,000 people in the City of Toronto.8

THES delivers electricity to residential and industrial customers through a complex network of overhead and underground wiring, which is in turn supported by transformer stations, underground vaults, cable chambers, and associated switching facilities and structures.9 The day-to-day operation of this distribution infrastructure requires a 24/7 dedicated, high-performance and specialized vehicle fleet. Toronto Hydro’s supporting fleet comprises approximately 550 vehicle and equipment units currently in service, ranging from standard light-duty (i.e. compact cars) to highly specialized heavy duty vehicles (i.e. cable trucks, single/double buckets, etc.).

As part of the upcoming rate filing application process to the OEB (whereby the fleet budget is presented and approved), Toronto Hydro’s Fleet & Equipment Services Division (“Fleet Services”) is seeking to update the fleet capital replacement program to account for vehicle historical/operational performance; and specifically optimize replacement cycle strategies by re-applying Life Cycle Analysis (“LCA”) methodology. This LCA will provide Fleet Services with the necessary information to support and justify either existing or new replacement practices as well as insight into future replacement costs and operating expenses.

In Spring 2017, Toronto Hydro sought to engage an independent external consultant to provide the following key project elements and deliverables:

1. **Fleet Data Review & Data Compilation** to review productivity, fuel, downtime, depreciation, usage, maintenance, and repairs;
2. **Life Cycle Analysis, Peer Fleet Utility Comparison** and **Long-Term Capital Planning** for 2018 to 2022;
3. Draft Report & Presentation to Management; and
4. **A Final Report.**10

---

8 In 2010, THESL distributed 24.7 terawatt-hours of 19 electricity representing approximately 19 percent of the electricity consumed in the province of Ontario, and served a peak demand of 4,786 megawatts.


10 To be issued no later than three months following Purchase Order issuance.
On April 17, 2017, Richmond Sustainability Initiatives – Fleet Challenge ("RSI-FC") was commissioned by Fleet Services to review the on-road vehicle fleet and provide concomitant recommendations in keeping with the organizational objectives outlined. As fulfillment of work and deliverables outlined, the following elements for delivery were proposed by RSI and approved by THES in an April 17/2017 Purchase Order:

- Module (1) Fleet Analytics Review ("FAR")
- Module (2) Life Cycle Analysis ("LCA")
- Module (3) Long Term Capital Planning ("LTCP")

The approach and initial results of this exploration are detailed in subsequent sections, as fulfillment of Deliverable (4), the Final Report.

N.B. This work builds on prior work completed by the consultant on behalf of Toronto Hydro in 2013. In early 2013, Toronto Hydro met with RSI-FC to discuss the current context around its vehicle fleet and associated data management. At this meeting, various opportunities to provide fleet consulting services to address Toronto Hydro’s needs were discussed, with primary focus on data review and the development of a Life Cycle Analysis for the fleet. This work was presented in Fall of 2013 and assisted in refining the fleet capital replacement program by (1) accounting more specifically for operating performance exhibited to date; and (2) using this data to inform business planning going forward. RSI has since modified and further refined its LCA approach; this new model is described and has been applied herein.

1.2 Fleet Profile, Toronto Hydro

The fleet is owned by Toronto Hydro and comprises of approximately 550 units currently in service; which include diesel, gasoline and electric powered vehicles. Of these, 539 units were included in the 2017 review, including 488 vehicles (defined as on-road) and 51 pieces of equipment and/or trailer units.

The vehicle fleet included in the review consists of the following numbers and types of vehicles and averages 6.5 years (ranging from less than one to nearly 16 years old) (Table 1.1).\(^{11}\)

---

\(^{11}\) In 2013, the Fleet average age was 4.8 years. Note that with the addition of trailers the average age is 7 years (2016).
Table 1.1: Toronto Hydro Fleet Profile

<table>
<thead>
<tr>
<th>Vehicle Type</th>
<th>Number of Units</th>
<th>Average Age</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Light duty: 5.8 years on average</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Car</td>
<td>17</td>
<td>6.9 years</td>
</tr>
<tr>
<td>Cargo Minivan</td>
<td>58</td>
<td>4.6 years</td>
</tr>
<tr>
<td>Passenger Minivan</td>
<td>15</td>
<td>2.5 years</td>
</tr>
<tr>
<td>Full-size Van</td>
<td>43</td>
<td>7.1 years</td>
</tr>
<tr>
<td>Pick-up</td>
<td>93</td>
<td>5.7 years</td>
</tr>
<tr>
<td>SUV</td>
<td>35</td>
<td>6.9 years</td>
</tr>
<tr>
<td><strong>Medium duty: 6.1 years on average</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cube Van</td>
<td>49</td>
<td>4.9 years</td>
</tr>
<tr>
<td>Single Bucket Aerial Device</td>
<td>71</td>
<td>9.1 years</td>
</tr>
<tr>
<td>Single Bucket-Van Mount</td>
<td>7</td>
<td>7.3 years</td>
</tr>
<tr>
<td><strong>Heavy duty: 7.6 years on average</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cable Truck</td>
<td>6</td>
<td>7.8 years</td>
</tr>
<tr>
<td>Crane Truck</td>
<td>19</td>
<td>7.5 years</td>
</tr>
<tr>
<td>Dump Truck</td>
<td>9</td>
<td>7.7 years</td>
</tr>
<tr>
<td>Line Truck</td>
<td>5</td>
<td>6.9 years</td>
</tr>
<tr>
<td>Double Bucket Aerial Device</td>
<td>45</td>
<td>7.7 years</td>
</tr>
<tr>
<td>Digger Derrick</td>
<td>16</td>
<td>6.5 years</td>
</tr>
<tr>
<td><strong>Total Vehicles Reviewed</strong></td>
<td>488 units</td>
<td>6.5 years</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(average age, vehicles only)</td>
</tr>
<tr>
<td><strong>Trailers</strong></td>
<td>51 units</td>
<td>11.8 years on average</td>
</tr>
</tbody>
</table>

The fuels consumed by the fleet are primarily gasoline and diesel/biodiesel. And one electric vehicle, the Nissan Leaf.

The total vehicle kilometres travelled by the fleet in 2016 is calculated to be **2,980,698 km** with a commensurate **1,004,031 litres of fuel** consumed. The total kilometres travelled by vehicles in 2016 ranged from 0 to 30,000+ km, with associated fuel use of 0 to 9,820 litres documented annually per vehicle.
In addition to the on-road fleet and as mentioned, Toronto Hydro also owns and operates 51 trailers, also contained in this review.

2.0 Methodology

The following activities were performed by RSI-FC and required several supporting activities, as detailed in subsequent sections. Business assumptions employed are noted in Section 3.0.

- **Module 1**: Fleet Analytics Review (“FAR”)
- **Module 2**: Life Cycle Analysis (“LCA”)
- **Module 3**: Long Term Capital Plan (“LTCP”)

### 2.1 Data Compilation and FAR Analysis

Fleet Analytics Review (“FAR”) is a proprietary and unique software tool developed by RSI-FC to analyze a fleet’s baseline performance based on historical data metrics. From this baseline, and with the use of actual peer fleet data, go-forward projections are made to provide fleet management with a factual and well-informed path to continuous improvement. FAR review allows for determining:

- Fleet baseline costs, service levels, and emissions
- Future Opex impacts of Capex investment
- The business case for capital spending on a vehicle-by-vehicle basis
- Various (and infinite) “what-if” scenarios
- Performance metrics/KPI’s
- Targets for improvement
- Peer fleet comparisons

As such factors – among others – figure into successful fleet management, FAR is an important tool as it allows fleet managers to build and explore various scenarios using their fleet’s historical operating data. This allows fleet management to credibly predict the outcomes of changes being contemplated in advance of implementation.

In general, reduced capital investment will result in increased operating expenses due to

---

13 Data that RSI-FC has compiled from reviewing almost 200 Canadian and U.S. fleets – some 50,000 vehicles in the private and public sectors.
reactive repairs (breakdowns) and the resultant costs of downtime. FAR can predict the impacts on Opex of Capex decisions using performance metrics from RSI-FC’s fleet database, compiled over the past ten+ years for fleets across Canada. Thus, FAR can foster continuous improvements in fleet performance and service levels, including utilization, availability, financial performance, fuel use, and/or emission levels.

**Approach:** Toronto Hydro fleet staff provided FC team with actual historical operating data (costs and consumption, vehicle acquisition costs, dates in service, etc.). From this bulk data set, Toronto Hydro staff extracted 2016 data to populate a standard FAR Input Form.

Historical data was then synthesized to produce a FAR analysis of baseline performance, costs and emissions.

Internal benchmarking was completed by comparing each fleet unit to similar vehicles in the fleet and identifying outliers. External benchmarking was performed by comparing Toronto Hydro’s 2016 KPIS to equivalent peer fleets from the RSI database.\(^{14}\)

The FAR model was also used to assess the impacts of vehicles due for replacement on the next year’s capital budget, accomplished through accounting the historical operating data of the fleet and the actual units that will be due for replacement in 2018.

### 2.2 Life Cycle Analysis

Life Cycle Analysis (“LCA”) illustrates the total life cycle cost of fleet vehicle types/categories. LCA can help determine:

- What age units should be considered for replacement

\(^{14}\) The Fleet Challenge peer fleet database used in the Toronto Hydro project is comprised of actual historical data from Canadian municipally operated fleets – 12,500 vehicles in total. Peer fleet values used were derived from an Ontario MEU, an Ontario gas utility, a telecom utility and benchmark data from the urban municipal fleets.

Toronto Hydro’s fleet is unique in terms of fleet size and makeup as well as operational characteristics - no peer fleets with directly similar characteristics exist. Peer fleets in this analysis share few comparable data points with TH and are presented for information only, in that (for example) the MEU operates in a much smaller city with less underground and overhead physical plant; the gas and telecom utility fleets are comprised mainly of vans and other light-duty vehicles, and operate in a much broader geographical footprint.
• When replacement should occur (ideally before costs rise and reliability/safety reduced, and before major capital expenditure or refurbishment is necessary)

As LCA identifies capital strategies that will optimize vehicle life cycles and return on investment, it should be the first step in long-term capital planning.

**Approach:** Using the FAR baseline data, a new LCA was completed for each of Toronto Hydro’s primary vehicle categories. Data was compiled for vehicles up to ten model years of age, in many cases longer where data was available. A FAR model was then prepared using the vehicle replacement schedules input by Toronto Hydro’s staff – these were determined in 2013 through LCA completed at that time. The result was a “business-as-usual” (BAU) look at the fleet’s Capex requirements for years 2018 through to 2022.

New, updated Life Cycle Analysis models were then completed by RSI-FC using historical cost data provided by Toronto Hydro from the years 2013 to 2016. With the LCAs refreshed with the new data, the FAR analysis was then re-run using the new 2017 LCA optimized replacement cycles. A revised Capex forecast was prepared using optimized life cycles for FY 2018 to FY 2022, with an eye toward creating a balanced long-term Capex plan for Toronto Hydro fleet.

The initial FAR report and 2018-2022 Capex plan was reviewed with Toronto Hydro fleet staff on July 28, 2017. Fleet staff expressed interest in extending the analysis by two additional years (to 2024) to align with budget cycles. It was agreed that RSI-FC would extend FAR and LTCP analyses for purposes of longer-term planning: this modification is accounted for in the supporting .xls and herein.

For each vehicle due/past due for replacement, cost savings (or losses) that would result from replacement was plotted by comparing costs to similar vehicles – one year older - in the peer fleet database.

---

15 **Note on Revised Timelines:** In projecting budgets this far into the future many uncertainties are involved such as the cost of capital and inflationary increases, as well as future replacement vehicle costs and market values of surplus vehicles.
2.3 Long-Term Capital Planning - Five-Year Capital Planning

The Long-Term Capital Planning ("LTCP") tool uses FAR input data to calculate:

- Five-year (or longer) fleet capital replacement plans
- Financial, service level and GHG impacts of capital investment choices

The LTCP tool enables balancing go-forward budgets based on business case rationale and thereby helps fleet management avoid year-to-year cost spikes. The tool’s ‘dashboard’ guides and empowers fleet management to make decisions to “replace”, “defer” or “dispose” of units due for replacement, based on their personal knowledge around the condition and repair history each vehicle due for replacement, and any future business plans. FAR can be dynamically linked to a fleet management program to provide real-time data.

**Approach:** Using baseline data and current-day retention practices, go-forward capital budgets were determined for FY 2018-2024. The amount of capital required to make all due/past-due replacements was calculated for the period of FY 2018 to FY 2024.

Baseline data, WACC, inflation, and other assumptions (see Section 3.0) were used to forecast 2018 Opex and business implications if vehicles were replaced based on current-day replacement cycles. These operating impacts included fuel, repair and maintenance costs, cost of capital, inflation and downtime as well as service levels (% uptime) and GHG emissions.\(^{16}\)

The result is a long-term Capex plan and an actionable roadmap for cost reduction and service level improvement at the unit level. This approach provides a nuanced and the first steps toward a balanced long-term Capex plan that eliminates fluctuations or yearly spikes in costs.

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\(^{16}\) Downtime is defined as time when a vehicle is out of service during prime business hours, such as when reactive (unplanned) repairs are being completed.
3.0 Business Assumptions

Business assumptions employed in the analysis included assumptions on new vehicle replacement costs, salvage values, market values, WACC, inflationary increases, labour rates (per applicable collective agreement), fuel costs, and emissions factors.

Specifically:

- End of cycle salvage values were assessed as 7% of original value;
- Resale values were determined via www.fastline.com and/or www.rbauction.com;
- Emissions estimates based on the use of E10 gasoline and ultra-low sulfur diesel (ULSD), using GHGenius V 3.1.1 values published by Natural Resources Canada (Table 3.1).

Table 3.1: Emission Factors

A number of values used in the FAR were calculated based on historical data. Such values included residual value, downtime, and the estimated cost of new vehicles.

Forecasts based on units with mounted equipment (i.e., cranes, plows, etc.), are based on the assumption that these units are replaced in their entirety.
Standard North American vehicles categorization protocol was applied for categorization and for benchmarking purposes (Table 3.2). The American Public Works Association, the American Trucking Association, Original Equipment Manufacturers, and government bodies such as the Ontario Ministry of Transportation also employ this approach.

Table 3.2 Vehicle Categorization Protocol

<table>
<thead>
<tr>
<th>Type of Vehicle</th>
<th>APWA Category</th>
<th>GVW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Passenger cars: mini</td>
<td>PC/Mi</td>
<td>1,500–1,999 lb. (680–907 kg)</td>
</tr>
<tr>
<td>Passenger cars: light</td>
<td>PC/L</td>
<td>2,000–2,499 lb. (907–1,134 kg)</td>
</tr>
<tr>
<td>Passenger cars: compact</td>
<td>PC/C</td>
<td>2,500–2,999 lb. (1,134–1,360 kg)</td>
</tr>
<tr>
<td>Passenger cars: medium</td>
<td>PC/Me</td>
<td>3,000–3,499 lb. (1,361–1,587 kg)</td>
</tr>
<tr>
<td>Passenger cars: heavy</td>
<td>PC/H</td>
<td>3,500 lb. (1,588 kg) and over</td>
</tr>
<tr>
<td>Sport utility vehicles</td>
<td>SUV</td>
<td></td>
</tr>
<tr>
<td>Pickup trucks</td>
<td>PU</td>
<td></td>
</tr>
<tr>
<td>Vans</td>
<td>VAN</td>
<td></td>
</tr>
<tr>
<td>Bus</td>
<td>Bus</td>
<td></td>
</tr>
<tr>
<td>Light Duty Trucks</td>
<td>Class 1</td>
<td>0–6000 lb. (0–2722 kg)</td>
</tr>
<tr>
<td></td>
<td>Class 2</td>
<td>6001–10000 lb. (2722–4536 kg)</td>
</tr>
<tr>
<td></td>
<td>Class 3</td>
<td>10001–14000 lb. (4536–6350 kg)</td>
</tr>
<tr>
<td>Medium Duty Trucks</td>
<td>Class 4</td>
<td>14001–16000 lb. (6351–7257 kg)</td>
</tr>
<tr>
<td></td>
<td>Class 5</td>
<td>16001–19500 lb. (7258–8845 kg)</td>
</tr>
<tr>
<td></td>
<td>Class 6</td>
<td>19501–26000 lb. (8846–11793 kg)</td>
</tr>
<tr>
<td>Heavy Duty Trucks</td>
<td>Class 7</td>
<td>26001–33000 lb. (11794–14969 kg)</td>
</tr>
<tr>
<td></td>
<td>Class 8</td>
<td>33000 lb. and up (14969 kg)</td>
</tr>
</tbody>
</table>

The current life cycles – for new and end of cycle – for each vehicle category are listed in Table 3.3. Vehicle categories that have exceeded the recommended replacement on the current strategy are highlighted blue (cars and SUVs).
Table 3.3  Current Vehicle Life Cycle Practices

<table>
<thead>
<tr>
<th>Vehicle Type</th>
<th>Planned Life Cycle (mth)</th>
<th>Planned Life Cycle (yr)</th>
<th>Average Age</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Light duty: 5.8 years on average</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Car</td>
<td>72 months</td>
<td>6 years</td>
<td>6.9 years</td>
</tr>
<tr>
<td>Cargo Minivan</td>
<td>84 months</td>
<td>7 years</td>
<td>4.6 years</td>
</tr>
<tr>
<td>Passenger Minivan</td>
<td>72 months</td>
<td>6 years</td>
<td>2.5 years</td>
</tr>
<tr>
<td>Full-size Van</td>
<td>108 months</td>
<td>9 years</td>
<td>7.1 years</td>
</tr>
<tr>
<td>Pick-up</td>
<td>108 months</td>
<td>9 years</td>
<td>5.7 years</td>
</tr>
<tr>
<td>SUV</td>
<td>72 months</td>
<td>6 years</td>
<td>6.9 years</td>
</tr>
<tr>
<td><strong>Medium duty: 6.1 years on average</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cube Van</td>
<td>144 months</td>
<td>12 years</td>
<td>4.9 years</td>
</tr>
<tr>
<td>Single Bucket Aerial Device</td>
<td>168 months</td>
<td>14 years</td>
<td>9.1 years</td>
</tr>
<tr>
<td>Single Bucket Van-Mount</td>
<td>96 months</td>
<td>8 years</td>
<td>7.3 years</td>
</tr>
<tr>
<td><strong>Heavy duty: 7.6 years on average</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cable Truck</td>
<td>192 months</td>
<td>16 years</td>
<td>7.8 years</td>
</tr>
<tr>
<td>Crane Truck</td>
<td>168 or 192 months (by vehicle size)</td>
<td>14 or 16 years</td>
<td>7.5 years</td>
</tr>
<tr>
<td>Dump Truck</td>
<td>168 months</td>
<td>14 years</td>
<td>7.7 years</td>
</tr>
<tr>
<td>Line Truck</td>
<td>156 months</td>
<td>13 years</td>
<td>6.9 years</td>
</tr>
<tr>
<td>Double Bucket Aerial Device</td>
<td>168 months</td>
<td>14 years</td>
<td>7.7 years</td>
</tr>
<tr>
<td>Digger Derrick</td>
<td>156 or 168 months (depending on vehicle size)</td>
<td>13 or 14</td>
<td>6.5 years</td>
</tr>
<tr>
<td><strong>Trailers</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Trailers</td>
<td>240 months</td>
<td>20 years</td>
<td>11.8 years</td>
</tr>
</tbody>
</table>
4.0 Results

4.1 Fleet Analytics Review

Category Baselines, Internal Benchmarking

All operating statistics determined in FAR were calculated to find median/average performance levels for each vehicle category. Data was excerpted and averaged for VKT, availability, reactive (or unplanned) repair costs, PM costs, total costs, fuel use, GHGs, and several other metrics.

These performance levels are identified by category and listed in Table 4.1. In this table, it can be seen that, on average, vehicles:

- Travelled just under 6,000km a year;
- Had approximately 3.3 days of downtime; and,
- Used 39.6 litres/fuel per 100km (largely due to the presence of intense fuel users like cable trucks, single and double bucket trucks, digger derricks, and single bucket-van mounts).

On average the cost per vehicle was approximately $2.17/km, although this varied by unit (i.e. cable trucks exhibited the highest per km cost at $13+ per km and conversely the hybrid cars the lowest, at $0.41/km. This latter cost is despite the average age of that vehicle type, 6.6 years. Hybrid SUVs also exhibit a lower per km cost at $0.51 than non-hybrid SUV’s at $0.61, despite a higher average age of two years more (for the hybrids). Hybrid single bucket trucks had average annual total controllable operating costs almost $5k more than non-hybrids, although their average costs per km were lower ($3.68/km for hybrids versus $4.15/km for non-hybrid single bucket trucks).
Table 4.1 Vehicle Performance

<table>
<thead>
<tr>
<th>Category</th>
<th>Review Period - Average Annual KMs Travelled</th>
<th>Review Period - Quantity of Fuel Used (liters of fuel consumed in review period)</th>
<th>Review Period - Downtime Days</th>
<th>Review Period - Preventive Maintenance (PM) costs for review period (PM includes all changes and inspections)</th>
<th>Review Period - Repair Costs (planned, unplanned repair costs for period)</th>
<th>Review Period - Annual GHGs produced (tones, combustion)</th>
<th>Review Period - GHO Intensity</th>
<th>Review Period - L/100 km</th>
</tr>
</thead>
<tbody>
<tr>
<td>CABLE TRUCK</td>
<td>2,801</td>
<td>3,387</td>
<td>7.2</td>
<td>$2,686</td>
<td>$13,834.84</td>
<td>9.1</td>
<td>3.2</td>
<td>119.1</td>
</tr>
<tr>
<td>CAR</td>
<td>3,700</td>
<td>247</td>
<td>8.8</td>
<td>$778</td>
<td>$2,434.58</td>
<td>0.5</td>
<td>0.1</td>
<td>6.8</td>
</tr>
<tr>
<td>CARGO MINIVAN</td>
<td>7,298</td>
<td>1,145</td>
<td>2.9</td>
<td>$498</td>
<td>$1,784.99</td>
<td>2.4</td>
<td>0.3</td>
<td>15.7</td>
</tr>
<tr>
<td>CRANE TRUCK</td>
<td>2,507</td>
<td>1,879</td>
<td>3.4</td>
<td>$2,647</td>
<td>$6,826.13</td>
<td>4.8</td>
<td>1.6</td>
<td>68.4</td>
</tr>
<tr>
<td>CUBE VAN</td>
<td>4,328</td>
<td>1,762</td>
<td>4.7</td>
<td>$1,129</td>
<td>$5,214.30</td>
<td>4.8</td>
<td>1.3</td>
<td>41.3</td>
</tr>
<tr>
<td>DIGGER DERRICK</td>
<td>2,741</td>
<td>2,318</td>
<td>1.8</td>
<td>$2,022</td>
<td>$8,946.29</td>
<td>6.3</td>
<td>2.2</td>
<td>83.1</td>
</tr>
<tr>
<td>DOUBLE BUCKET</td>
<td>4,603</td>
<td>3,508</td>
<td>6.2</td>
<td>$3,198</td>
<td>$11,379.00</td>
<td>9.5</td>
<td>2.2</td>
<td>82.1</td>
</tr>
<tr>
<td>DUMP TRUCK</td>
<td>2,158</td>
<td>1,013</td>
<td>1.1</td>
<td>$1,212</td>
<td>$2,876.13</td>
<td>2.7</td>
<td>1.3</td>
<td>49.7</td>
</tr>
<tr>
<td>FULL SIZE VAN</td>
<td>6,081</td>
<td>1,770</td>
<td>1.9</td>
<td>$486</td>
<td>$2,772.14</td>
<td>3.7</td>
<td>0.7</td>
<td>31.7</td>
</tr>
<tr>
<td>HYBRID CAR</td>
<td>6,482</td>
<td>360</td>
<td>3.2</td>
<td>$548</td>
<td>$1,256.84</td>
<td>0.8</td>
<td>0.1</td>
<td>5.1</td>
</tr>
<tr>
<td>HYBRID PICK-UP</td>
<td>13,452</td>
<td>2,330</td>
<td>1.5</td>
<td>$473</td>
<td>$3,750.19</td>
<td>4.9</td>
<td>0.4</td>
<td>17.0</td>
</tr>
<tr>
<td>HYBRID SINGLE BUCKET</td>
<td>8,386</td>
<td>3,010</td>
<td>4.5</td>
<td>$2,733</td>
<td>$12,009.51</td>
<td>8.1</td>
<td>1.0</td>
<td>37.0</td>
</tr>
<tr>
<td>HYBRID SUV</td>
<td>6,843</td>
<td>674</td>
<td>2.9</td>
<td>$609</td>
<td>$1,842.88</td>
<td>1.4</td>
<td>0.2</td>
<td>10.2</td>
</tr>
<tr>
<td>LINE TRUCK</td>
<td>10,883</td>
<td>3,567</td>
<td>6.0</td>
<td>$1,246</td>
<td>$8,900.25</td>
<td>9.6</td>
<td>0.8</td>
<td>30.7</td>
</tr>
<tr>
<td>PASSENGER MINIVAN</td>
<td>8,231</td>
<td>1,403</td>
<td>0.3</td>
<td>$377</td>
<td>$773.43</td>
<td>2.9</td>
<td>0.4</td>
<td>17.7</td>
</tr>
<tr>
<td>PICK-UP</td>
<td>6,987</td>
<td>1,069</td>
<td>1.6</td>
<td>$407</td>
<td>$2,036.57</td>
<td>4.1</td>
<td>0.6</td>
<td>29.5</td>
</tr>
<tr>
<td>SINGLE BUCKET</td>
<td>6,259</td>
<td>3,549</td>
<td>4.4</td>
<td>$3,004</td>
<td>$10,388.08</td>
<td>9.6</td>
<td>1.6</td>
<td>59.9</td>
</tr>
<tr>
<td>SINGLE BUCKET-VAN MOL</td>
<td>4,415</td>
<td>1,647</td>
<td>0.3</td>
<td>$1,314</td>
<td>$2,270.75</td>
<td>3.5</td>
<td>0.9</td>
<td>43.5</td>
</tr>
<tr>
<td>SUV</td>
<td>6,804</td>
<td>901</td>
<td>5.4</td>
<td>$370</td>
<td>$1,919.39</td>
<td>1.9</td>
<td>0.3</td>
<td>12.9</td>
</tr>
<tr>
<td>TRAILER</td>
<td>646</td>
<td>42</td>
<td>3.7</td>
<td>$812</td>
<td>$2,555.15</td>
<td>0.1</td>
<td>0.6</td>
<td>21.7</td>
</tr>
<tr>
<td>ALL Units</td>
<td>5,693</td>
<td>1,076</td>
<td>3.3</td>
<td>$1,328</td>
<td>$4,870.51</td>
<td>4.6</td>
<td>1.0</td>
<td>39.6</td>
</tr>
</tbody>
</table>
Table 4.1 Vehicle Performance (cont’d)

<table>
<thead>
<tr>
<th>Category</th>
<th>Review Period - Direct Cost per Day</th>
<th>Review Period - Direct Cost per Unit</th>
<th>Review Period - Direct Cost per Unit</th>
<th>Review Period - Total Unit Cost</th>
<th>Review Period - Total Unit Cost</th>
<th>Review Period - Total Unit Cost</th>
<th>Review Period - Total Unit Cost</th>
<th>Review Period - Total Unit Cost</th>
<th>Review Period - Total Unit Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>CABLE TRUCK</td>
<td>$ 600.00</td>
<td>$ 4,300</td>
<td>17%</td>
<td>$ 3,426.62</td>
<td>$ 13,716.64</td>
<td>$ 37,958.05</td>
<td>$ 13.55</td>
<td>97.2</td>
<td>93.4</td>
</tr>
<tr>
<td>CAR</td>
<td>$ 100.00</td>
<td>$ 875</td>
<td>26%</td>
<td>$ 236.65</td>
<td>$ 171.46</td>
<td>$ 4,495.83</td>
<td>1.21</td>
<td>86.6</td>
<td>85.0</td>
</tr>
<tr>
<td>CARGO MINIVAN</td>
<td>$ 120.00</td>
<td>$ 246</td>
<td>27%</td>
<td>$ 1,099.22</td>
<td>$ 1,099.22</td>
<td>$ 6,724.84</td>
<td>0.65</td>
<td>98.9</td>
<td>54.8</td>
</tr>
<tr>
<td>CRANE TRUCK</td>
<td>$ 600.00</td>
<td>$ 2,021</td>
<td>38%</td>
<td>$ 1,879.32</td>
<td>$ 7,435.18</td>
<td>$ 20,805.81</td>
<td>7.16</td>
<td>98.7</td>
<td>89.8</td>
</tr>
<tr>
<td>CUBE VAN</td>
<td>$ 200.00</td>
<td>$ 931</td>
<td>21%</td>
<td>$ 1,779.43</td>
<td>$ 4,208.57</td>
<td>$ 13,259.45</td>
<td>3.06</td>
<td>98.2</td>
<td>59.3</td>
</tr>
<tr>
<td>DIGGER DERRICK</td>
<td>$ 600.00</td>
<td>$ 1,088</td>
<td>32%</td>
<td>$ 2,341.58</td>
<td>$ 11,615.95</td>
<td>$ 26,913.08</td>
<td>9.82</td>
<td>99.3</td>
<td>78.2</td>
</tr>
<tr>
<td>DOUBLE BUCKET</td>
<td>$ 600.00</td>
<td>$ 3,747</td>
<td>26%</td>
<td>$ 3,543.23</td>
<td>$ 9,826.34</td>
<td>$ 31,693.36</td>
<td>6.69</td>
<td>97.6</td>
<td>92.4</td>
</tr>
<tr>
<td>DUMP TRUCK</td>
<td>$ 600.00</td>
<td>$ 667</td>
<td>52%</td>
<td>$ 1,021.13</td>
<td>$ 6,099.59</td>
<td>$ 11,847.67</td>
<td>5.49</td>
<td>95.6</td>
<td>92.3</td>
</tr>
<tr>
<td>FULLSIZE VAN</td>
<td>$ 130.00</td>
<td>$ 248</td>
<td>21%</td>
<td>$ 1,698.81</td>
<td>$ 631.49</td>
<td>$ 5,843.67</td>
<td>0.96</td>
<td>99.3</td>
<td>85.0</td>
</tr>
<tr>
<td>HYBRID CAR</td>
<td>$ 100.00</td>
<td>$ 323</td>
<td>35%</td>
<td>$ 345.43</td>
<td>$ 182.28</td>
<td>$ 2,665.81</td>
<td>0.41</td>
<td>98.8</td>
<td>78.7</td>
</tr>
<tr>
<td>HYBRID PICK-UP</td>
<td>$ 120.00</td>
<td>$ 224</td>
<td>13%</td>
<td>$ 2,236.95</td>
<td>$ 569.29</td>
<td>$ 7,244.82</td>
<td>0.54</td>
<td>99.2</td>
<td>80.2</td>
</tr>
<tr>
<td>HYBRID SINGLE BUCKET</td>
<td>$ 600.00</td>
<td>$ 2,700</td>
<td>27%</td>
<td>$ 2,048.02</td>
<td>$ 10,407.34</td>
<td>$ 30,889.93</td>
<td>3.68</td>
<td>98.3</td>
<td>75.5</td>
</tr>
<tr>
<td>HYBRID SSV</td>
<td>$ 130.00</td>
<td>$ 374</td>
<td>28%</td>
<td>$ 646.69</td>
<td>$ 178.21</td>
<td>$ 2,651.50</td>
<td>0.53</td>
<td>98.9</td>
<td>89.4</td>
</tr>
<tr>
<td>LIE TRUCK</td>
<td>$ 600.00</td>
<td>$ 3,600</td>
<td>28%</td>
<td>$ 3,602.84</td>
<td>$ 4,456.52</td>
<td>$ 21,854.94</td>
<td>2.00</td>
<td>97.7</td>
<td>83.0</td>
</tr>
<tr>
<td>PASSENGER MINIVAN</td>
<td>$ 180.00</td>
<td>$ 60</td>
<td>47%</td>
<td>$ 1,347.13</td>
<td>$ 1,391.33</td>
<td>$ 3,948.52</td>
<td>0.48</td>
<td>99.0</td>
<td>50.5</td>
</tr>
<tr>
<td>PICK-UP</td>
<td>$ 120.00</td>
<td>$ 197</td>
<td>25%</td>
<td>$ 1,896.82</td>
<td>$ 1,049.92</td>
<td>$ 5,579.91</td>
<td>0.80</td>
<td>95.4</td>
<td>66.2</td>
</tr>
<tr>
<td>SINGLE BUCKET</td>
<td>$ 600.00</td>
<td>$ 2,640</td>
<td>26%</td>
<td>$ 3,584.20</td>
<td>$ 6,335.99</td>
<td>$ 25,970.74</td>
<td>4.15</td>
<td>98.3</td>
<td>111.6</td>
</tr>
<tr>
<td>SINGLE BUCKET-VAN MO</td>
<td>$ 600.00</td>
<td>$ 171</td>
<td>40%</td>
<td>$ 1,581.04</td>
<td>$ 897.93</td>
<td>$ 6,335.99</td>
<td>1.41</td>
<td>99.9</td>
<td>87.5</td>
</tr>
<tr>
<td>SUV</td>
<td>$ 130.00</td>
<td>$ 782</td>
<td>16%</td>
<td>$ 864.66</td>
<td>$ 268.76</td>
<td>$ 4,125.10</td>
<td>0.61</td>
<td>97.9</td>
<td>64.5</td>
</tr>
<tr>
<td>TRAILER</td>
<td>$ 300.00</td>
<td>$ 1,112</td>
<td>51%</td>
<td>$ 42.87</td>
<td>$ 1,909.48</td>
<td>$ 6,421.90</td>
<td>9.94</td>
<td>98.6</td>
<td>141.3</td>
</tr>
<tr>
<td>ALL UNITS</td>
<td>$ 305.31</td>
<td>$ 1,189</td>
<td>30%</td>
<td>$ 1,857.70</td>
<td>$ 3,545.18</td>
<td>$ 12,796.74</td>
<td>2.17</td>
<td>98.7</td>
<td>84.2</td>
</tr>
</tbody>
</table>

Benchmarking the Fleet (Peer Fleet Comparison)

Key performance indicators in Toronto Hydro’s fleet were compiled and compared to peer fleet statistics (Table 4.2). Peer fleet values were derived from a southern Ontario MEU, an Ontario gas utility, a telecom utility and benchmark data from 12 Canadian urban municipal fleets.

17 The Fleet Challenge peer fleet database is comprised of actual historical data from several dozen Ontario municipally operated fleets.

18 In reviewing the peer fleet comparisons, readers must be mindful that in the Canadian marketplace Toronto Hydro’s fleet is unique in terms of fleet size and makeup as well as operational characteristics - no peer fleets with directly similar characteristics exist. Peer fleets in this analysis share few comparable data points with TH and are presented for information only, in that (for example) the MEU operates in a much smaller city with less underground and overhead physical plant, and the gas and telecom utility fleets are comprised mainly of vans and other light-duty vehicles and operate in a much broader geographical footprint.
This comparison highlights the following:

- The age of Toronto Hydro’s fleet is in the mid-range of the peer fleets for the entire fleet as well as for each major vehicle grouping;
- The book value of the Toronto Hydro vehicle fleet is higher than the MEU, gas utility and telecom fleets (due to the large size, complexity and acquisition cost of Toronto Hydro’s vehicles);
- The total vehicle-kilometers-travelled for the Toronto Hydro fleet is lower than the peer fleets (due to the size and density of the city);
- Average preventative maintenance is in line with peer fleets;
- Repair costs tend towards the higher end compared to peer fleets (also due to the size and complexity and number of large trucks in the Toronto Hydro fleet);
- The fleet has the second highest cost of capital after the gas utility (due to the number of large, specialized and costly trucks);
- The total controllable costs are higher than peer fleets (due to the number of large, specialized and costly trucks);
- The cost per km is the second highest of the peer fleets after the telecom (due to the number of large, specialized and costly trucks and lower average km);
- The fleet on average travels significantly less km than peer fleets (due to the geographical size of each fleet’s service area);
- Availability (uptime) is above average; and,
- Based on 2013 optimal vehicle replacement cycles, the capital required for replacement is $11,205,766. Toronto Hydro’s rate of re-investment based on current-day replacement practices is therefore 36.9% of net present value (NPV) (for on-road vehicles) compared to 28.8% for the Ontario MEU, 23.7% for the gas utility, 23.4% for the telecom utility and 34.5% for the municipal group.

---

Investing capital in the fleet at the rate of depreciation is a best-in-class fleet management best practice.
## Table 4.2  Comparison to Peer Fleets, KPIs

<table>
<thead>
<tr>
<th>Key Performance Indicator (KPI)</th>
<th>Metric</th>
<th>Toronto Hydro</th>
<th>Peer Fleet “A” (Ontario MEU)</th>
<th>Peer Fleet “B” (Ontario Gas Utility)</th>
<th>Peer Fleet “C” (Telecom Utility)</th>
<th>Benchmark Data - 12 Urban Municipal Fleets</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vehicles in Review</td>
<td>On-Road Vehicles</td>
<td>No. of Units</td>
<td>488</td>
<td>130</td>
<td>762</td>
<td>11,598</td>
</tr>
<tr>
<td>Units in Review</td>
<td>Equipment /Trailers</td>
<td>No. of Units</td>
<td>51</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Age</td>
<td>On-Road Vehicles (all)</td>
<td>Years</td>
<td>6.5</td>
<td>7.8</td>
<td>4.1</td>
<td>6.3</td>
</tr>
<tr>
<td>Average Age</td>
<td>Light-Duty (Car, Pickup, Full- or Mini-Van, SUV’s)</td>
<td>Years</td>
<td>5.8</td>
<td>7.6</td>
<td>3.9</td>
<td>6.6</td>
</tr>
<tr>
<td>Average Age</td>
<td>Medium-Duty (Cube Van, Single Bucket Van Mount)</td>
<td>Years</td>
<td>6.1</td>
<td>5.8</td>
<td>12.8</td>
<td>6.6</td>
</tr>
<tr>
<td>Average Age</td>
<td>Heavy-Duty Trucks (Cable Crane- Dump-Liner-Truck, Single- Double-Bucket, Digger Derrick)</td>
<td>Years</td>
<td>7.6</td>
<td>7.1</td>
<td>5.6</td>
<td>7.4</td>
</tr>
<tr>
<td>Average Age</td>
<td>Trailers</td>
<td>Years</td>
<td>11.8</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NPV / Book Value of Fleet</td>
<td>On-Road Capable Vehicles</td>
<td>$</td>
<td>$ 29,399,167</td>
<td>$2,824,843</td>
<td>$11,844,214</td>
<td>$ 23,424,690</td>
</tr>
<tr>
<td>NPV / Book Value of Fleet</td>
<td>Trailers</td>
<td>$</td>
<td>$ 1,570,898</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Vehicle Kilometers Traveled (VKT)</td>
<td>On-Road Vehicles</td>
<td>Kilometers</td>
<td>2,985,969</td>
<td>1,483,408</td>
<td>55,836,551</td>
<td>254,968,297</td>
</tr>
<tr>
<td>Total Fuel Consumed</td>
<td>On-Road Vehicles</td>
<td>Liters</td>
<td>1,009,199</td>
<td>445,217</td>
<td>3,383,328</td>
<td>42,583,753</td>
</tr>
<tr>
<td>Total Fuel Consumed</td>
<td>Trailers</td>
<td>Liters</td>
<td>2,165</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Corporate Average Fuel Economy (CAFE)</td>
<td>On-Road Vehicles</td>
<td>L/100 KM</td>
<td>33.6</td>
<td>23.7</td>
<td>16.5</td>
<td>17.4</td>
</tr>
<tr>
<td>Average Fuel Consumption</td>
<td>Trailers</td>
<td>L/100 KM</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Downtime</td>
<td>On-Road Vehicles</td>
<td>Days</td>
<td>1,815</td>
<td>694</td>
<td></td>
<td>90,537</td>
</tr>
<tr>
<td>Total Downtime</td>
<td>Trailers</td>
<td>Days</td>
<td>189</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Downtime</td>
<td>On-Road Vehicles</td>
<td>Days/Vehicles</td>
<td>3.3</td>
<td>5.1</td>
<td></td>
<td>7.4</td>
</tr>
<tr>
<td>Average Downtime</td>
<td>Trailers</td>
<td>Days/Vehicles</td>
<td>3.7</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Downtime Cost</td>
<td>On-Road Vehicles</td>
<td>$</td>
<td>$384,400</td>
<td>$29,419</td>
<td></td>
<td>$23,103,831</td>
</tr>
<tr>
<td>Total Downtime Cost</td>
<td>Trailers</td>
<td>$</td>
<td>$56,700</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Key Performance Indicator (KPI)</td>
<td>Metric</td>
<td>Toronto Hydro</td>
<td>Peer Fleet “A” (Ontario MTO)</td>
<td>Peer Fleet “B” (Ontario Gas Utility)</td>
<td>Peer Fleet “C” (Telecom Utility)</td>
<td>Benchmark Data 12 Urban Municipal Fleets</td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>Average PM Cost</td>
<td>On-Road Vehicles</td>
<td>$</td>
<td>$1,382</td>
<td>$1,118</td>
<td>$758</td>
<td>$1,897</td>
</tr>
<tr>
<td>Average PM Cost</td>
<td>Trailers</td>
<td>$</td>
<td>$912</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Repair Cost</td>
<td>On-Road Vehicles</td>
<td>$</td>
<td>$5,112</td>
<td>$4,082</td>
<td>$2,647</td>
<td>$4,513</td>
</tr>
<tr>
<td>Average Repair Cost</td>
<td>Trailers</td>
<td>$</td>
<td>$2,555</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Fuel Cost</td>
<td>On-Road Vehicles</td>
<td>$</td>
<td>$2,047</td>
<td>$3,042</td>
<td>$3,212</td>
<td>$4,471</td>
</tr>
<tr>
<td>Average Fuel Cost</td>
<td>Trailers</td>
<td>$</td>
<td>$43</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost per Kilometer</td>
<td>Total Fleet</td>
<td>$ per KM</td>
<td>$2.17</td>
<td>$0.89</td>
<td>$0.44</td>
<td>$2.96</td>
</tr>
<tr>
<td>Cost per Kilometer</td>
<td>Light-Duty On-Road Capable (Car, Pickup, Full- or Min Van, SUV’s)</td>
<td>$ per KM</td>
<td>$0.87</td>
<td>$0.45</td>
<td>$0.72</td>
<td>$0.62</td>
</tr>
<tr>
<td>Cost per Kilometer</td>
<td>Medium-Duty On-Road Capable (Cube Van, Single Bucket Van Mount)</td>
<td>$ per KM</td>
<td>$2.24</td>
<td>$1.06</td>
<td>$1.15</td>
<td>$3.05</td>
</tr>
<tr>
<td>Cost per Kilometer</td>
<td>Heavy-Duty Trucks On-Road Capable (Cable- Crane- Dump- Line-Truck, Single-Double Bucket, Dipper Demck)</td>
<td>$ per KM</td>
<td>$7.01</td>
<td>$4.13</td>
<td>$1.55</td>
<td>$3.41</td>
</tr>
<tr>
<td>Average Vehicle Kilometers Traveled (VKT)</td>
<td>On-Road Vehicles</td>
<td>Kilometers</td>
<td>6,119</td>
<td>10,907</td>
<td>20,782</td>
<td>21,994</td>
</tr>
<tr>
<td>Average Vehicle Kilometers Traveled (VKT)</td>
<td>Light-Duty On-Road Capable (Car, Pickup, Full- or Min Van, SUV’s)</td>
<td>Kilometers</td>
<td>6,217</td>
<td>10,593</td>
<td>22,488</td>
<td></td>
</tr>
<tr>
<td>Average Vehicle Kilometers Traveled (VKT)</td>
<td>Medium-Duty On-Road Capable (Cube Van, Single Bucket Van Mount)</td>
<td>Kilometers</td>
<td>4,371</td>
<td>14,714</td>
<td>12,523</td>
<td></td>
</tr>
<tr>
<td>Average Vehicle Kilometers Traveled (VKT)</td>
<td>Heavy-Duty Trucks On-Road Capable (Cable- Crane- Dump- Line-Truck, Single-Double Bucket, Dipper Demck)</td>
<td>Kilometers</td>
<td>4,623</td>
<td>6,287</td>
<td>19,523</td>
<td></td>
</tr>
<tr>
<td>Average Availability</td>
<td>On-Road Vehicles</td>
<td>%</td>
<td>98.7</td>
<td>98.0</td>
<td></td>
<td>97.6</td>
</tr>
<tr>
<td>Average Availability</td>
<td>Trailers</td>
<td>%</td>
<td>98.6</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GHG Baseline</td>
<td>Total Fleet</td>
<td>Emission factors (CO2 kg, hydrogen equivalent)</td>
<td>2,489</td>
<td>1,140</td>
<td>7,671</td>
<td>96,804</td>
</tr>
<tr>
<td>Maintenance Ratio</td>
<td>On-Road Vehicles</td>
<td>% of total parts &amp; labour</td>
<td>0.28</td>
<td>0.27</td>
<td>0.27</td>
<td>0.57</td>
</tr>
<tr>
<td>Maintenance Ratio</td>
<td>Trailers</td>
<td>% of total parts &amp; labour</td>
<td>0.51</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capital Required for Vehicle Replacement</td>
<td>On-Road Vehicles (net of TH amount is net)</td>
<td>$</td>
<td>$10,845,366</td>
<td></td>
<td>$816,085</td>
<td></td>
</tr>
<tr>
<td>Capital (net) Required for Equipment Replacement</td>
<td>Trailers</td>
<td>$</td>
<td>366,580</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capital Replacement Ratio</td>
<td>On-Road Vehicles</td>
<td>Capital Required on Percentage of GPH</td>
<td>36.9%</td>
<td>28.8%</td>
<td>23.7%</td>
<td>23.4%</td>
</tr>
<tr>
<td>Capital Replacement Ratio</td>
<td>Trailers</td>
<td>Capital Required on Percentage of GPH</td>
<td>22.9%</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Internal Benchmarking - Exception Management

To complete internal benchmarking, outliers were identified for each category of vehicles. Outliers are defined as “vehicles performing sub-par or out-of-threshold” (relative to comparable vehicles in Toronto Hydro’s fleet).

These vehicles are highlighted for management’s case-by-case review and action in the FAR detailed data reports, provided under separate cover. This exception management process creates a defined path to continuous improvement, and builds on fleet management expertise as well as accounts for the unique performance attributes of each vehicle under review.

This information is also used in the process of Capex budgeting, and can be employed as a KPI for any subsequent performance management program.

**Table 4.3: Sample**, internal benchmarking exception management (units highlighted in FAR are “exceptions”, or units performing sub-par / out-of-threshold to the average for comparable vehicles)

- A summary profile of the exception units has been detailed in the FAR.xls reports, provided under separate cover to this report.
4.2 Life Cycle Analysis

Life Cycle Analysis ("LCA") was calculated for each category of vehicles in the fleet. The LCA findings presented are based on actual historical data compiled by units and by ages for the period FY 2013 to FY 2016.

Table 4.4: Life Cycle Analysis Results (Summary)

<table>
<thead>
<tr>
<th>Vehicle Type</th>
<th>Current Planned Life Cycle</th>
<th>Optimal AEC (lowest annual equivalent cost) 2013 LCA</th>
<th>Optimal AEC (lowest annual equivalent cost) 2017 LCA</th>
<th>Recommended Tactic (See Section 4.2 for detail)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Car</td>
<td>6 years / 120,000 km</td>
<td>6 years</td>
<td>9 years</td>
<td>Increase LC+3</td>
</tr>
<tr>
<td>Cargo Minivan</td>
<td>7 years / 140,000 km</td>
<td>7 years</td>
<td>7 years</td>
<td>No change</td>
</tr>
<tr>
<td>Passenger Minivan</td>
<td>6 years / 135,000 km</td>
<td>6 years</td>
<td>9 years</td>
<td>Increase LC+3</td>
</tr>
<tr>
<td>Full Size Van</td>
<td>9 years / 135,000 km</td>
<td>9 years</td>
<td>10 years</td>
<td>Increase LC+1</td>
</tr>
<tr>
<td>Pick-up</td>
<td>9 years / 180,000 km</td>
<td>9 years</td>
<td>9 years</td>
<td>No change</td>
</tr>
<tr>
<td>SUV</td>
<td>6 years / 120,000 km</td>
<td>6 years</td>
<td>8 years</td>
<td>Increase LC+2</td>
</tr>
<tr>
<td>Cube Van</td>
<td>12 years / 180,000 km</td>
<td>12 years</td>
<td>12-15 years</td>
<td>Assess case by case at Y12. Consider increasing LC+3</td>
</tr>
<tr>
<td>Single Bucket Aerial Device</td>
<td>14 years / 210,000 km</td>
<td>14 years</td>
<td>12-16 years</td>
<td>Assess case by case at Y12. Consider increasing LC+2</td>
</tr>
<tr>
<td>Single-bucket Van Mount Aerial Device</td>
<td>8 years / 120,000 km</td>
<td>8 years</td>
<td>11 years</td>
<td>Increase LC+3</td>
</tr>
<tr>
<td>Cable Truck</td>
<td>16 years /240,000 km</td>
<td>16 years</td>
<td>11 – 14 years</td>
<td>Assess case by case at Y11 – consider Y14. Decrease LC 2-5 (re-assess at Y11).</td>
</tr>
<tr>
<td>Crane Truck</td>
<td>14 or 16 years / 210,000 km or 240,000 km</td>
<td>14 years</td>
<td>10 -14 years</td>
<td>Assess case by case at Y10 – consider increase to Y14. Decrease LC 2-4 (re-assess at Y10).</td>
</tr>
<tr>
<td>Dump Truck</td>
<td>14 years / 210,000 km</td>
<td>14 years</td>
<td>8-12 years</td>
<td>Assess case by case at Y8 – consider increase to Y12. Decrease LC 2-6</td>
</tr>
</tbody>
</table>
The LCA took into consideration the cost of downtime (as caused by reduced reliability). LCA also considered WACC, inflation, worker cost/hour, salvage and market values, and average KMT data. The results are summarized as follows (Table 4.4). Further supporting information for each result is provided under separate cover (see FAR BAU .xls).

**Note regarding Downtime:** Although a minimum cost was placed on downtime in the analysis, the true cost of reduced worker productivity caused by vehicle downtime is significant and should not be underestimated. Downtime for the baseline period was calculated to be 1,804 person/days. When accounting for burdened wages (~$85/hr.) at 7.5 hrs./day per week, this loss of worker productivity is estimated to have cost Toronto Hydro $1,150,050 in the 2016 baseline period. This is in addition to the costs of spare vehicles/loaners, towing, service calls, rental vehicles, loss/disruption of business etc.

This situation can be exponentially exacerbated if more than one person (which is often the case) is dependent on a single vehicle.

### 4.3 Long Term (Seven-Year) Capital Planning

We have developed the following three scenarios to illustrate the potential impacts of capital budget planning:

1) ‘Business as Usual’ Forecast – calculated using 2013 LCA optimal replacement cycles
2) Optimized LCA Capital Forecast – calculated using 2017 LCA refresh

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Life Span</th>
<th>Replacement Mileage</th>
<th>Replacement Cycle</th>
<th>Conclusion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line Truck</td>
<td>13 years</td>
<td>/ 195,000 km</td>
<td>13 years</td>
<td>No change</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>13 Years</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>No change</td>
<td></td>
</tr>
<tr>
<td>Double Bucket Aerial Device</td>
<td>14 years</td>
<td>/ 210,000 km</td>
<td>14 years</td>
<td>No change</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>14 years</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>No change</td>
<td></td>
</tr>
<tr>
<td>Digger-Derrick</td>
<td>13-14 years / 195,000 or 210,000 km</td>
<td>13 - 14 years</td>
<td>13 years</td>
<td>No change</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>13 years</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>No change</td>
<td></td>
</tr>
<tr>
<td>Trailers</td>
<td>20 years</td>
<td></td>
<td>20 years</td>
<td>No change</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>20 years</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>No change</td>
<td></td>
</tr>
</tbody>
</table>

Replace cable trailers with cable trucks.
Scenario 1. 2018 Forecast – Business as Usual (2013 LCA)

Table 4.5 below illustrates long-term (7-year) Capex requirements based on current vehicle and equipment retention practices (based on 2013 LCA). The Capex forecast for FY 2018 is particularly high because of units that are past due for replacement, in addition to those that are due in the year.

Table 4.5: Long-Term Capex Requirements – ‘Business as Usual’ Retention Practices

<table>
<thead>
<tr>
<th>Budget Year</th>
<th>Capital Required</th>
<th>Deferred Spending</th>
<th>Total Capital Budget</th>
<th>Number of Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>FY 2018</td>
<td>$11,205,766</td>
<td>$0</td>
<td>$11,205,766</td>
<td>22</td>
</tr>
<tr>
<td>FY 2019</td>
<td>$3,216,838</td>
<td>$0</td>
<td>$3,216,838</td>
<td>48</td>
</tr>
<tr>
<td>FY 2020</td>
<td>$4,141,935</td>
<td>$0</td>
<td>$4,141,935</td>
<td>60</td>
</tr>
<tr>
<td>FY 2021</td>
<td>$9,547,497</td>
<td>$0</td>
<td>$9,547,497</td>
<td>59</td>
</tr>
<tr>
<td>FY 2022</td>
<td>$2,879,416</td>
<td>$0</td>
<td>$2,879,416</td>
<td>38</td>
</tr>
<tr>
<td>FY 2023</td>
<td>$7,394,698</td>
<td>$0</td>
<td>$7,394,698</td>
<td>40</td>
</tr>
<tr>
<td>FY 2024</td>
<td>$5,470,392</td>
<td>$0</td>
<td>$5,470,392</td>
<td>28</td>
</tr>
</tbody>
</table>

Ref: FAR V210.0 BAU 2013 LCA

The forecast shows that in the Business-As-Usual (“BAU”) scenario, more than $11M would be required to replace all vehicles following current retention practices in 2018. In the unlikely event this level of spending was possible, this investment would:

- Potentially decrease 2018 Opex by almost $98k\(^{20}\)
- Significantly increase uptime: (.3%, or 372 person/days);
- Reduce GHG emissions by almost 50 MT.

\(^{20}\) Calculated from the increased cost of capital, minus the decreased cost of repairs, fuel and downtime assuming, (although not possible), that all replacements were made on day one 2018 and went into service immediately (full benefits would not be attained until 2019).
**Figure 4.1:** BAU LCA (2013), 7yr. Capex Forecast

![7-Yr. Capex Plan - Dashboard](image)

**Scenario 2. Optimized LCA’s – Capex Forecast**

The following chart demonstrates 2018 to 2024 Capex using optimized 2017 LCA. In this scenario, $7,803,925 would be required in 2018.

**Table 4.6:** Long-Term Capex Requirements – Optimize 2017 LCA Practices

<table>
<thead>
<tr>
<th>Budget Year</th>
<th>Capital Required</th>
<th>Deferred Spending</th>
<th>Total Capital Budget</th>
<th>Number of Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>FY 2018</td>
<td>$7,803,925</td>
<td>$0</td>
<td>$7,803,925</td>
<td>23</td>
</tr>
<tr>
<td>FY 2019</td>
<td>$7,359,855</td>
<td>$0</td>
<td>$7,359,855</td>
<td>76</td>
</tr>
<tr>
<td>FY 2020</td>
<td>$2,985,077</td>
<td>$0</td>
<td>$2,985,077</td>
<td>48</td>
</tr>
<tr>
<td>FY 2021</td>
<td>$4,113,462</td>
<td>$0</td>
<td>$7,963,754</td>
<td>79</td>
</tr>
<tr>
<td>FY 2022</td>
<td>$4,113,462</td>
<td>$0</td>
<td>$4,113,462</td>
<td>32</td>
</tr>
<tr>
<td>FY 2023</td>
<td>$9,265,306</td>
<td>$0</td>
<td>$9,265,306</td>
<td>43</td>
</tr>
<tr>
<td>FY 2024</td>
<td>$3,862,246</td>
<td>$0</td>
<td>$3,862,246</td>
<td>19</td>
</tr>
</tbody>
</table>

*Ref: FAR V20.0 Optimized 2017 LCA*

Using 2017 optimized LCA practices $7,803,925 would be required in 2018. This approach is forecasted to yield a potential Opex reduction of ~$65k in 2018, a downtime reduction of 397 person/days and GHG reduction of 49.5 MT.
Figure 4.2: Optimized LCA (2017), 7yr. Capex Forecast

Scenario 3. Capex Forecast - Actual 2018 and 2019 Capex

In the following table is shown the actual planned capital spending for 2018 and 2019, with years 2020 to 2024 calculated on LCA optimized vehicle replacements along with deferred Capex for previous years.

Note: the budget figures shown for 2018 and 2019 are estimated and net of upfitting and 'make-ready' costs, vendor price increases, and other costs associated with new vehicle acquisition.

Table 4.7: Long-Term Capex Requirements – Actual 2018 and 2019 Capex

<table>
<thead>
<tr>
<th>Budget Year</th>
<th>Capital Required</th>
<th>Total Capital Budget</th>
<th>Number of Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>FY 2018</td>
<td>$11,214,000</td>
<td>$3,085,000</td>
<td>20</td>
</tr>
<tr>
<td>FY 2019</td>
<td>$4,176,450</td>
<td>$2,876,400</td>
<td>23</td>
</tr>
<tr>
<td>FY 2020</td>
<td>$7,483,133</td>
<td>$7,387,051</td>
<td>101</td>
</tr>
<tr>
<td>FY 2021</td>
<td>$10,098,260</td>
<td>$10,098,260</td>
<td>54</td>
</tr>
<tr>
<td>FY 2022</td>
<td>$4,993,200</td>
<td>$4,993,200</td>
<td>40</td>
</tr>
<tr>
<td>FY 2023</td>
<td>$10,632,450</td>
<td>$10,632,450</td>
<td>42</td>
</tr>
<tr>
<td>FY 2024</td>
<td>$8,283,675</td>
<td>$8,283,675</td>
<td>33</td>
</tr>
</tbody>
</table>
REF: FAR V 22.0 Actual 2018 and 2019 TH Capex Plan

Given the approved Capex budgets for 2018 and 2019 of $3.2m each year, it is forecasted that a small Opex increase will result of ~$17k in 2018. The number of deferred replacements will increase exponentially in ensuing years starting in 2020, as will the amount of capital required each year (per the table below). More than 100 vehicles will be due for replacement in 2020 including deferrals from previous years and based on optimal economic life cycle analysis.

Figure 4.3: Capital Budget Impacts FY 2018-2023 – Actual Capex for 2018-19

Next Steps

RSI-FC encourages Toronto Hydro fleet management to allot sufficient time to carefully review all units identified as being due for replacement in the FAR 7-year Capex plans as presented by RSI-FC and make deferrals of any/all units based on their personal knowledge of each unit’s mechanical condition. In this way, by combining the advanced analytical assessments of FAR and staff’s knowledge of the fleet and each unit’s physical condition, the best possible outcomes, and value for money-spent will be attained for Toronto Hydro.
Appendices – LCA Charts

![Life Cycle Analysis Chart](chart.png)

<table>
<thead>
<tr>
<th>Replacement Cycle</th>
<th>Ownership $</th>
<th>Maintenance $</th>
<th>Driver Prod $</th>
<th>Fuel $</th>
<th>Total $</th>
<th>Cost vs Next Year $</th>
<th>3-year Average $</th>
<th>Savings $/Veh</th>
<th>Savings $/All Veh</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>N/D</td>
<td>N/D</td>
<td>N/D</td>
<td>N/D</td>
<td>N/D</td>
<td>N/D</td>
<td>N/D</td>
<td>N/D</td>
<td>N/D</td>
</tr>
<tr>
<td>2</td>
<td>$7,753</td>
<td>$436</td>
<td>$44</td>
<td>$294</td>
<td>$8,693</td>
<td>$892</td>
<td>$2,721</td>
<td>$46,012</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>$6,889</td>
<td>$543</td>
<td>$56</td>
<td>$297</td>
<td>$7,696</td>
<td>$487</td>
<td>$7,720</td>
<td>$1,721</td>
<td>$26,267</td>
</tr>
<tr>
<td>4</td>
<td>$6,039</td>
<td>$636</td>
<td>$65</td>
<td>$299</td>
<td>$7,988</td>
<td>$337</td>
<td>$7,119</td>
<td>$1,234</td>
<td>$20,984</td>
</tr>
<tr>
<td>5</td>
<td>$5,554</td>
<td>$796</td>
<td>$82</td>
<td>$301</td>
<td>$6,732</td>
<td>$626</td>
<td>$6,732</td>
<td>$827</td>
<td>$15,256</td>
</tr>
<tr>
<td>6</td>
<td>$5,150</td>
<td>$885</td>
<td>$89</td>
<td>$303</td>
<td>$6,438</td>
<td>$185</td>
<td>$6,438</td>
<td>$871</td>
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TH Cargo Mini Vans - Life Cycle Analysis

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Legend:
- Ownership $
- Maintenance $
- Driver Prod $
- Fuel $
- Total $
- Cost vs Next Year $
- 3-year Average $
- Savings $/Veh $
- Savings $/All Veh $

Optimal - Total $
Optimal - vs Next Yr
Optimal - 3 Yr Avg
# TH Passenger Mini Vans - Life Cycle Analysis

![Life Cycle Analysis Chart](image)

## Annual Equivalent Cost

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<th>3-year Average $</th>
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*Note: Data for years 10 to 20 are not available.*
Toronto Hydro - Pickups - Life Cycle Analysis

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¹ Average of Ownership, Maintenance, Driver Prod, and Fuel costs for the last year of each replacement cycle.
² Savings per vehicle and total savings for all vehicles.
## TH Full-Size Vans - Life Cycle Analysis

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*Note: The table above represents the annual equivalent cost for different replacement cycles, including ownership, maintenance, driver production, fuel, total costs, cost vs next year, 3-year average, and savings for each vehicle.*
## Toronto Hydro SUV - Life Cycle Analysis

### Annual Equivalent Cost

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<th>3-year Average $</th>
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Note: The table includes columns for ownership, maintenance, driver productivity, fuel, total costs, cost vs next year, 3-year average cost, savings per vehicle, and savings per all vehicles. The data is presented for different replacement cycles, with specific costs and savings calculated for each scenario.
### Toronto Hydro Cube Vans - Life Cycle Analysis

#### Annual Equivalent Cost

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<th>Total $</th>
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<th>Average $</th>
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*Note: Assumes 3-year cycle with replacement at the end of each cycle.*
## TH Crane Trunks - Life Cycle Analysis

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### TH Digger-Derricks - Life Cycle Analysis

#### Annual Equivalent Cost

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<th>3-year Average $</th>
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### TH Single Bucket A/D - Life Cycle Analysis

![Graph showing life cycle analysis](image)

### Annual Equivalent Cost

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# Single Bucket Van Mount - Life Cycle Analysis

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## TH Double Bucket A/D - Life Cycle Analysis

![Graph showing life cycle analysis with cost breakdowns over time.](image)

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# TH - Dump Truck - Maintenance $ & Reliability used for LCA

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<th>3-year Average $</th>
<th>Savings $/Veh</th>
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[Diagram of TH - Dump Truck - Maintenance $ & Reliability used for LCA]

- **Maintenance Cost $/Yr**: 0.0 0.0 0.0 0.0 3.6 5.5 5.2 5.1 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0
- **# Work Order/Yr**: 0.0 0.0 0.0 0.0 2.7 4.1 4.0 3.9 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0

13
Toronto Hydro - Trailer - Life Cycle Analysis

Replacement Cycle (yrs.)

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<th>Ownership</th>
<th>Maintenance</th>
<th>Driver Prod</th>
<th>Fuel</th>
<th>Total</th>
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Please note that Appendix F to this response has been filed confidentially.

(9 pages)
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 4:
Reference(s): Exhibit 1B

Please provide a copy of all material provided to Toronto Hydro’s Board of Directors approving the annual budget each year between 2016 and 2019.

RESPONSE:
Toronto Hydro declines to provide the requested information on the basis that it does not have probative value to the application. The relevant financial information has been provided throughout the pre-filed evidence, in accordance with the OEB’s Filing Requirements. In addition, Toronto Hydro filed in the response to interrogatory 1A-CCC-1, a copy of the Business Plan that underpins this application. Toronto Hydro believes that the evidence (including the IR responses) provides comprehensive and sufficient financial information about the historical and bridge years for the OEB to decide the issues in this proceeding.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 5:
Reference(s): Exhibit 1B

Please provide a step-by-step explanation of the Toronto Hydro budgeting process that led to the 2020-2024 plan, as well as the annual budgeting process after a subsequent Board decision on the plan. Please explain how these processes have changed since its last Custom IR application.

RESPONSE:
The budgeting process that led to the 2020-2024 plan presented in this Application is the operational and financial component of the broader business planning process detailed in Toronto Hydro’s response to interrogatory 1B-CCC-9. The below provides further details regarding step 3 in the process set out in 1B-CCC-9.

In general, this process has matured since the utility’s last Custom IR application in tandem with the evolution of the OEB’s customer engagement requirements under the Renewed Regulatory Framework.

As noted in evidence at Exhibit 1B, Tab 1, Schedule 1 and in the response to interrogatory 2B-SEC-47, the utility initiated the budgeting process by setting the strategic parameters, including budgetary limits and performance objectives, with regard to the feedback received from customers. Toronto Hydro set the strategic parameters in order to be responsive to: the utility’s legal requirements including safety, customer feedback, and

Panel: General Plant, Operations, and Administration
business input through expert analysis and professional judgment to develop construction
and operations programs that address technical and operational requirements.
The annual budgeting process is an iterative one and began with setting the strategic
direction for the development of the operational and capital plans and budgets to be
executed over the planning horizon.

As discussed in Exhibit 1B, Tab 3, Schedule 1, customers expressed that limiting price
increases and specific performance outcomes were important to them. Both of these
were also important to Toronto Hydro. To help operationalize these parameters for
budgeting purposes, Toronto Hydro also expressed the price increase in approximate
OM&A and CapEx terms as a third strategic parameter.

Toronto Hydro developed bottom-up capital and operational budgets to address the
needs of the utility and meet the objectives, being guided by considerations such as
customer feedback, legal and regulatory requirements, subject matter expertise, business
judgment, benchmarking, third party analysis, and analytics of various types.

As the capital and operational plans and budgets matured through the process, the needs
and cost pressures of the business pressed against the budgetary limits that were set at
the outset of the process. The budgeting process involved calibration to strike a balance
between these two elements.

The ultimate budget fed into the Business Plan, presented to Toronto Hydro’s Board of
Directors for final approval. A copy of the Business Plan that underlies this application is
filed as Appendix A to interrogatory 1B-CCC-9.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 6:
Reference(s): Exhibit 1B

Please provide a copy of Toronto Hydro’s most recent Board of Directors approved business plan and/or strategic plan.

RESPONSE:
Toronto Hydro declines to provide this information on the basis that it is not relevant to this application. The relevant information is the Business Plan that underpins this application, which has been filed in the response to interrogatory 1A-CCC-1.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 7:
Reference(s): Exhibit 1B

Please provide a copy of all budget guidance documents that were issued regarding the 2020-2024 budgets that underlie the application.

RESPONSE:
Please refer to Toronto Hydro’s response to interrogatory 1B-CCC-27.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 8:
Reference(s): Exhibit 1B

Please provide a copy of Toronto Hydro’s 2015 to 2019 corporate scorecards.

RESPONSE:
Please see Tables 1-5 below. Please note that Toronto Hydro’s performance metric definitions and scope may differ from those outlined in regulatory and/or legislative reporting, and that 2018 results are not available at this time and will be provided as part of Toronto Hydro’s planned evidence update.

Table 1: 2015 Corporate Scorecard

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<th>Key Performance Indicator</th>
<th>2015 Target</th>
<th>2015 Result</th>
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<tbody>
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<td>Enhanced Customer Engagement (# of Transactions)</td>
<td>245,000</td>
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<td>81%</td>
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<td>Total Recordable Injury Frequency (TRIF)</td>
<td>1.80</td>
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<tr>
<td>Attendance (# of Days)</td>
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<td>SAIFI (#)</td>
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<td>SAIDI (Minutes)</td>
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<td>Key Accounts - Worst Performing Feeders</td>
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<td>Operating Expenses ($M)</td>
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<td>Consolidated Net Income ($M)</td>
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## Table 2: 2016 Corporate Scorecard

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<th>2016 Target</th>
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<td>First Call Resolution</td>
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<td>10.00%</td>
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<td>Key Accounts - Worst Performing Feeders 6</td>
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<td>THESL Regulated Capital ($M)</td>
<td>Lower Target</td>
<td>Upper Target</td>
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## Table 3: 2017 Corporate Scorecard

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<td>First Call Resolution</td>
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Table 4: 2018 Corporate Scorecard

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Note 1: 2018 Results not yet available.

Table 5: 2019 Corporate Scorecard

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<tr>
<td>New Services Connected on Time</td>
<td>97.7%</td>
</tr>
<tr>
<td>Bill Accuracy</td>
<td>99.0%</td>
</tr>
<tr>
<td>First Contact Resolution</td>
<td>86%</td>
</tr>
<tr>
<td>Total Recordable Injury Frequency (TRIF)</td>
<td>1.4</td>
</tr>
<tr>
<td>Employee Engagement</td>
<td>6.5</td>
</tr>
<tr>
<td>SAIFI (# - Defective Equipment Only)</td>
<td>0.52</td>
</tr>
<tr>
<td>SAIDI (Minutes - Defective Equipment Only)</td>
<td>27.71</td>
</tr>
<tr>
<td>5-Year CIR Distribution System Plan Investment ($M)</td>
<td></td>
</tr>
<tr>
<td><strong>Lower Target</strong></td>
<td><strong>Upper Target</strong></td>
</tr>
<tr>
<td>2341.2</td>
<td>2370.6</td>
</tr>
<tr>
<td>Net Income ($M)</td>
<td>160.6</td>
</tr>
</tbody>
</table>
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 9:
Reference(s): Exhibit 1B

Please provide summaries of all internal audit reports conducted since 2015, their findings, recommendations, and the status of any actions that are to be taken.

RESPONSE:
Attached as Appendices A-o to this response are summaries of internal audit quarterly reports conducted since 2015. Please note that some parts of these documents have been redacted for confidentiality purposes. Also, certain information in these documents is subject to solicitor-client privilege. Toronto Hydro refuses to provide this information, and has redacted the documents accordingly.
Internal Audit Department
Audit Committee Report

Q1, 2015, Internal Audit Report Summary
Executive Summary

Internal Audit continues to be actively engaged in assurance and consulting assignments throughout Toronto Hydro in the first quarter of 2015. The results of our work indicate that Management’s control over business activities remain effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Quarterly Audit Activities</td>
<td>Five audit reports were issued for the Program Support Office – all with Adequate ratings. One Review Consultation Memorandum was issued for the Wholesale Settlement Function, with positive results.</td>
</tr>
<tr>
<td></td>
<td>Management’s Remediation Plan Progress</td>
<td>Two management action plans were remediated in Q1. Only two low risk management action plans remain open.</td>
</tr>
<tr>
<td></td>
<td>Internal Audit Initiatives</td>
<td>Internal Audit has expanded its City Auditor General monitoring program to include all Accountability Officer reporting. A comprehensive review is underway to include all reports issued after January 1, 2014.</td>
</tr>
<tr>
<td></td>
<td>Audit Plan Progress and Changes to the Audit Plan</td>
<td>Some changes in timing have been agreed to with management to accommodate workflow. Requests for additional review consultations have been received.</td>
</tr>
<tr>
<td></td>
<td>Internal Audit Group Management</td>
<td>Team is engaged and working collaboratively with other departments and external consultants.</td>
</tr>
</tbody>
</table>

= Critical items requiring Audit Committee attention  
= Important issues that warrant discussion  
= Operating as expected
Wholesale Settlement Review Consultation
The purpose of this Review Consultation was to provide an initial assessment of potential risk exposures specific to the Wholesale Settlement – Metering area. The Wholesale Settlement process can be divided into two main streams: Metering and Rates. This review focused on the Metering stream of Wholesale Settlement, specifically, the metering controls over the reconciliation of IESO metering data to Toronto Hydro read data, the meter collection, validating, estimating and editing controls, the co-ordination/hand-offs between the Metering and Rates Departments as well as the controls over the resolution of the meter trouble reports from the IESO. Based on our review, no further audit work is recommended on the Metering function as it relates to Wholesale Settlement. However, we anticipate as part of the end-to-end Customer Services audit scheduled for Q3 2015, certain metering functions and controls will be revisited.
Management’s Remediation Plan Progress

HIGHLIGHTS

Internal Audit continues to be pleased with the depth of Management’s analysis and monitoring of their remediation projects.

- No new audit observations were added this quarter as the only issue raised attributable to Toronto Hydro management was resolved prior to the issue of the audit report.

- The Active Directory Project in IT was completed in Q1 and the last outstanding item from the 2012 ITGC internal audit has been closed.

- Significant progress has been made this quarter on the remediation of the gap identified in the Entity Level Control audit which highlighted the need for a consistent framework to monitor and report on Policy non-conformance.

- Legal has met with all Board-approved Policy owners and communicated the need for consistent capture and reporting of instances of policy non-conformance. Key Performance Indicators (KPIs) have been developed for each specific policy, as required. An annual attestation strategy is also being developed for roll-out in 2015.

- Further to the Entity Level Audit report presented at the Corporate Governance Committee, there was discussion and agreement that the Audit Committee would be responsible for the primary oversight for the remediation plan.

Outstanding Open Issues: Q1 2014 – Q1 2015*

* Cut off for remediation evaluation for Q1, 2015 was April 17, 2015
Management’s Remediation Plan Progress (continued)

HIGHLIGHTS

The average age of outstanding issues improved to 11 months as a result of the successful remediation of the Active Directory Clean-Up Project (the IT observation that was over 2 years old) in Q1, 2015. Internal Audit will test the enhanced functionality of this program in May.

None of the observations made to our Design Build or Audit Verification Contractors will be monitored or reported on here as they are the responsibility of Management Teams external to Toronto Hydro. All observations are being monitored by the Program Support Office (PSO) managers are part of their ongoing relationship management with these external providers.

Management is fully aware of the status of the above project and is taking appropriate action to close it.

Aging of Issues*

* Aging as at March 31, 2015
Internal Audit Department
Audit Committee Report

Q2, 2015, Internal Audit Report Summary
Executive Summary

Internal Audit continues to be actively engaged in assurance and consulting assignments throughout Toronto Hydro in the second quarter of 2015. The results of our work indicate that Management’s control over business activities remain effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quarterly Audit Activities</td>
<td></td>
<td>Three audit reports were issued this quarter - Miscellaneous Accounts Receivable and Inventory Procurement and Warehouse Management. One Review Consultation Memorandum was issued for Unbilled Revenue with positive results.</td>
</tr>
<tr>
<td>Management’s Remediation Plan Progress</td>
<td></td>
<td>Eight new observations were added and three management action plans were remediated in the second quarter. Aging of outstanding management action plans is three months.</td>
</tr>
<tr>
<td>Internal Audit Initiatives</td>
<td></td>
<td>Internal Audit is currently involved in the ERP implementation as part of the extended implementation team and is also involved in reviewing the process surrounding the RRR Filing.</td>
</tr>
<tr>
<td>Audit Plan Progress and Changes to the Audit Plan</td>
<td></td>
<td>Some changes in timing have been agreed to with management to accommodate workflow. Q1 2016 audit plan has been provided for comment.</td>
</tr>
<tr>
<td>Internal Audit Group Management</td>
<td></td>
<td>Team is engaged and working collaboratively with other departments and external consultants.</td>
</tr>
</tbody>
</table>

= Critical items requiring Audit Committee attention  = Important issues that warrant discussion  = Operating as expected
SUMMARY OF AUDIT ACTIVITIES

Internal Audit issued three Audit reports and one Consultation Review memorandum since our last report to the Audit Committee.
SUMMARY OF AUDIT ACTIVITIES (continued)

Miscellaneous Accounts Receivable
The Miscellaneous Accounts Receivable department is responsible for processing over $100 million of non-electrical billing each year that consists primarily of demand billable work (work conducted for customers which they are required to pay for) and contributed capital projects fees. Additionally, the unit manages both refund and collection processes of approximately $7 million outstanding invoices on a monthly basis.

Management recently reengineered the billing process, resulting in the implementation of several new procedures which enhance operating effectiveness. Our audit confirmed that these new processes and procedures have been successfully implemented and are working as designed.

Two low risk issues were identified. The first is a result of communication delays between the various departments providing service and the Miscellaneous Accounts Receivable group which results in invoices being issued after the work has been completed. Management is implementing a process to monitor time lags by way of short interval control reporting to address this issue.

The second issue was closed during the audit and addresses that existing lack of functionality in Ellipse to automate billing functions such as late payment charges. These functionality gaps will be addressed as part of the business requirements for this area as part of the new ERP.

Miscellaneous Accounts Receivable – Satisfactory

<table>
<thead>
<tr>
<th>Impact/Severity</th>
<th># Audit Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>0</td>
</tr>
<tr>
<td>Medium</td>
<td>0</td>
</tr>
<tr>
<td>Low</td>
<td>2</td>
</tr>
<tr>
<td>Total Issues</td>
<td>2</td>
</tr>
</tbody>
</table>

ICFR Controls Tested

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>No exceptions noted</td>
<td>0</td>
</tr>
<tr>
<td>Exceptions noted</td>
<td>0</td>
</tr>
<tr>
<td>Total ICFR Controls</td>
<td>0</td>
</tr>
</tbody>
</table>

Controls Tested (Includes ICFR)

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>No exceptions noted</td>
<td>6</td>
</tr>
<tr>
<td>Exceptions noted (including design gaps)</td>
<td>2</td>
</tr>
<tr>
<td>Total Controls</td>
<td>8</td>
</tr>
</tbody>
</table>

Controls implemented by management over the billing process are adequately designed, implemented and operated effectively during the assessment period. Neither observation poses a significant negative impact for Toronto Hydro nor do they impact internal controls over financial reporting.
Summary of Audit Activities (continued)

Inventory Procurement & Warehouse Audit
The scope of this audit focused on the end-to-end processes surrounding the initial procurement of the capital assets/inventory, the warehouse management in relation to these assets, as well as regulatory compliance of the processes used in warehouse management and financial treatment of the materials. It included a review of policies and procedures, detailed testing and analysis of key components of the processes as well as observations and discussions with management. We assessed key controls to ensure:

- An inventory/capital assets strategy and procurement process is in place to effectively support planned, reactive and emergency work
- Assets and materials are accounted for per appropriate accounting policies
- Assets and materials are acquired, stored, safeguarded, repaired and refurbished in accordance with the appropriate standards
- The warehousing and procurement control environment has adequate mechanisms to detect and prevent fraud

We observed only one low risk issue whereby physical inventory count control procedures could be circumvented by the employee’s ability to electronically query expected unit quantities during the count thus nullifying the “blind count” concept.

Management has re-communicated the procedures for the physical count process and has introduced independent sampling by Supervisors to ensure adherence to the physical count procedures.

Inventory Procurement & Warehouse - Satisfactory

<table>
<thead>
<tr>
<th>Impact/Severity</th>
<th># Audit Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>0</td>
</tr>
<tr>
<td>Medium</td>
<td>0</td>
</tr>
<tr>
<td>Low</td>
<td>1</td>
</tr>
<tr>
<td>Total Issues</td>
<td>1</td>
</tr>
</tbody>
</table>

ICFR Controls Tested

| No exceptions noted | 0 |
| Exceptions noted    | 0 |
| Total ICFR Controls | 0 |

Controls Tested (includes ICFR)

| No exceptions noted | 17 |
| Exceptions noted    | 1  |
| Total Controls      | 18 |

Toronto Hydro’s Procurement and Warehousing controls are well designed and working effectively
SUMMARY OF AUDIT ACTIVITIES (continued)

Unbilled Revenue Model Development – Proration “B”

The purpose of this Review Consultation was to provide a review of the development of the Proration “B” model which Finance utilizes to estimate the unbilled revenue (UBR) amounts. The Proration “B” model was used to generate the Q1 2015 unbilled revenue amount with additional verification and completeness procedures.

The Proration “B” model is the evolution and refinement of the Proration “A” model which was used to estimate both December 31, 2013 and 2014 unbilled revenue amounts (see refinements to the right). Internal Audit reviewed the conceptual model logic, unit testing, code and end user outputs (including reports). We reviewed management’s calculation and independently recalculated balances. We previously provided proactive consulting advice and rapid development review of the Proration “A” model.

The Proration “B” model developed by the Project Team was well designed to incorporate the complexities of the revenue cycle. Adequate management testing was executed to confirm model functionality and this testing was appropriately documented. Potential considerations for improvements communicated to the Project Team during Proration “A” model review were incorporated where appropriate.
Management’s Remediation Plan Progress

HIGHLIGHTS

Internal Audit continues to be pleased with the depth of Management’s analysis and monitoring of their remediation projects.

- Eight new audit observations were added this quarter attributable to Street Lighting (1 High, 2 Medium, 2 Low), Miscellaneous Accounts Receivable (2 Low) and Inventory Procurement & Warehouse (1 Low) audits and 3 were closed as follows:
  - The Entity Level Control Audit (14-ELC-01) observation concerning a lack of centralized policy compliance has been remediated. Seventeen policy compliance metrics covering seven board approved, or otherwise key, policies have been established and monitoring processes implemented.
  - The Procurement & Warehouse Audit (15-INV-01) observation concerning the potential to circumvent physical inventory count procedures has been remediated. Management has re-trained Warehouse staff on the correct procedures and supervisors are proactively ensuring compliance.
  - One Miscellaneous Accounts Receivable (15-MAR-02) issue closed during the audit as Management has identified current functionality gaps in Ellipse which will be documented as business requirements for the new ERP.

Outstanding Open Issues: Q2 2014 – Q2 2015*

* Cut off for remediation evaluation for Q2, 2015 was July 31, 2015
HIGHLIGHTS
The average age of outstanding issues improved to three months as a result of the new observations added this quarter.

Management is fully aware of the status of the above project and is taking appropriate action to close it.

Aging of Issues*

* Aging as at July 31, 2015
Executive Summary

Internal Audit continues to be actively engaged in assurance and consulting assignments throughout Toronto Hydro in the third quarter of 2015. The results of our work indicate that Management’s control over business activities remain effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Quarterly Audit Activities</td>
<td>Two ICFR memos were issued this quarter covering controls in the Conservation Demand Management, Finance, and Human Resource areas. No issues came to our attention to indicate any material weakness nor were any opportunities for improvement noted.</td>
</tr>
<tr>
<td></td>
<td>Management’s Remediation Plan Progress</td>
<td>Aging of outstanding management action plans is six months. No new additions or closures occurred this quarter.</td>
</tr>
<tr>
<td></td>
<td>Internal Audit Initiatives</td>
<td>Internal Audit staff have been supporting management with the OEB audit.</td>
</tr>
<tr>
<td></td>
<td>Audit Plan Progress and Changes to the Audit Plan</td>
<td>The End to End Customer Care audit has been rescheduled to February 2016 as requested by management to allow them to focus on regulatory priorities. Other audits have been delayed due to the staff time devoted to the OEB audit and the delayed OEB decision.</td>
</tr>
<tr>
<td></td>
<td>Internal Audit Group Management</td>
<td>A new Director of Internal Audit will be announced shortly. Abbas Lakha, Senior Internal Auditor resigned effective November 20.</td>
</tr>
</tbody>
</table>

Legend:
- Critical items requiring Audit Committee attention
- Important issues that warrant discussion
- Operating as expected

Toronto Hydro-Electric System Limited
SUMMARY OF AUDIT ACTIVITIES

Internal Audit issued two Internal Controls over Financial Reporting (ICFR) Review Consultation Memos since our last meeting. The scope of the first review reflected in Q2, in the chart on the right encompasses ICFR controls in Engineering & Construction, Conservation Demand Management and Human Resources.

The scope of the second memo, reflected in Q3 on the chart, includes all 49 Finance and Accounting ICFR. In both these memos, no exceptions were noted in the testing completed and **all ICFRs were operating as designed**. Additionally, no process improvements were suggested.

ICFR testing in Customer Services and Information Technology are currently underway. As in past years, we include KPMG in the scoping and planning of this work to allow for leveraging of testing where possible and coordination of independent KPMG testing with business units to minimize disruption in their daily activities.

The ICFR population decreased this year as we continue to refine our program to ensure that we have identified the most appropriate controls to address audit assertions and that new processes or systems have been appropriately captured, risk assessed and tested where appropriate.

No other Review Consultations or Audit Reports were issued in Q3 due primarily to our on-going work on special projects.

Both the *Grid Response* and *Payroll and Disbursements* audits are in the final stages of review and reporting and will be issued in early December.
Management’s Remediation Plan Progress

HIGHLIGHTS

Internal Audit continues to be pleased with the depth of Management’s analysis and monitoring of their remediation projects.

- In accordance with Management’s previously communicated action plans, no audit gaps were closed this quarter. No extensions in time lines were requested this quarter as management believes there is sufficient traction on remediation plans underway.

- No new observations were added by Internal Audit.

Outstanding Open Issues: Q3 2014 – Q3 2015*

* Cut off for remediation evaluation for Q3, 2015 was October 30, 2015
HIGHLIGHTS

The average age of outstanding issues is six months and distribution remains static quarter over quarter reflecting that no management action plans were closed nor were any audit observations added.

Management is fully aware of the status of the above project and is taking appropriate action to close it.

Aging of Issues*

* Aging as at October 30, 2015
2015 Fourth Quarter Internal Audit Report
Executive Summary

Internal Audit continues to be actively engaged in assurance and consulting assignments throughout Toronto Hydro in the fourth quarter of 2015. The results of the work indicate that Management’s control over business activities remain effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quarterly Audit Activities</td>
<td></td>
<td>Two ICFR memos were issued this quarter covering controls in the Customer Care and Information Technology Divisions. No issues came to our attention to indicate any material weakness. One audit report, Payroll &amp; Disbursements was also issued.</td>
</tr>
<tr>
<td>Management’s Remediation</td>
<td></td>
<td>Aging of outstanding management action plans is 6 months. Two issues were closed and 4 new issues were added from the Payroll &amp; Disbursements.</td>
</tr>
<tr>
<td>Plan Progress</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Internal Audit Initiatives</td>
<td></td>
<td>Internal Audit staff have been supporting management with the OEB audit as well as the external Financial Statement audit.</td>
</tr>
<tr>
<td>Audit Plan Progress and</td>
<td></td>
<td>Meetings were held in February with the executives to confirm divisional risk assessments and confirm audit priorities. Changes were made to the audit plan to support priorities.</td>
</tr>
<tr>
<td>Changes to the Audit Plan</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Internal Audit Group</td>
<td></td>
<td>A new interim Director of Internal Audit and Senior Internal Auditor were announced. Actively searching for a third Senior Internal Auditor.</td>
</tr>
<tr>
<td>Management</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

= Critical items requiring Audit Committee attention

= Important issues that warrant discussion

= Operating as expected
SUMMARY OF AUDIT ACTIVITIES

Internal Audit issued one Audit Report and two Internal Controls over Financial Reporting (ICFR) Review Consultation Memos since the last meeting.

Payroll & Disbursements Audit

The disbursement function has been outsourced to a third party supplier, EXL since 2013. Toronto Hydro still retains a small in-house team predominantly accountable for resolving issues. The Payroll department currently processes payroll in partnership with ADP, a 3rd party service provider. The responsibility of financial reporting for these areas reside within the Corporate Accounting and External Reporting team.

As part of our Payroll and Disbursements audit, Internal Audit focussed on the following:

- The degree to which the Department complied with the established policies and procedures, including accuracy and confidentiality of sensitive payroll records.
- The appropriateness of logical access controls over applications (i.e. tools and protocols used for identification, authentication, authorization, and accountability).
- Management of key outsourced services.
- Opportunities to streamline operational processes.

Payroll and Disbursement Audit - Satisfactory

Controls implemented by management over the payroll and disbursement processes are adequately designed, implemented and operated effectively during the assessment period. The weaknesses identified do not pose a significant negative impact for Toronto Hydro.

<table>
<thead>
<tr>
<th>Impact/Severity</th>
<th># Audit Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>0</td>
</tr>
<tr>
<td>Medium</td>
<td>2</td>
</tr>
<tr>
<td>Low</td>
<td>2</td>
</tr>
<tr>
<td>Total Issues</td>
<td>4</td>
</tr>
</tbody>
</table>

ICFR Controls Tested

| No exceptions noted | 13 |
| Exceptions noted    | 0  |
| Total ICFR Controls | 13 |

Controls Tested (includes ICFR)

| No exceptions noted | 17 |
| Exceptions noted    | 3  |
| Total Controls      | 20 |
SUMMARY OF AUDIT ACTIVITIES - continued

Since the last meeting, Internal Audit has since issued two ICFR Review Consultation Memos. The quarterly testing cycle for the entire ICFR inventory is now complete. Throughout these quarterly reviews, the testing validates the ICFRs and ensure that the controls are appropriately designed and operating effectively. A continual assessment of the ICFR inventory for completeness is conducted as audits progress.

Review Consultation Memos Issued:
Customer Care – The controls within the Customer Care division were completed in Q4. The work was coordinated with KPMG so that the testing could be leveraged by KPMG, where appropriated.

One isolated weakness was found in the Deposit and Billing adjustment procedure. With this noted exception, all ICFRs were operating as designed.

Information Technology – Similar to Customer Care, coordinated audit work with KPMG over the Information Technology General Controls (ITGCs) was completed in Q4.

One isolated weakness was found with the inter-company transfer of staff process. The exception noted is not considered material as it is an isolated weakness and would not increase risk exposure in the various IT areas due to compensating controls and the overall organizational structure and control environment. With this noted exception, all ICFRs were operating as designed.
HIGHLIGHTS

Internal Audit continues to be pleased with the depth of Management’s analysis and monitoring of their remediation projects.

- Two management action plans were remediated this quarter. One extension was requested this quarter for an outstanding issue with Asset Attachment and Leases. Management is currently exploring the potential of engaging the third party into long term occupancy agreements/Memorandum of Understanding (MOU). As a result, additional time was required for these discussions.

- Four new observations from the Payroll and Disbursements audit were added.

Management is currently in negotiations with the City to increase levels of funding to meet the capital needs of the system.

* Cut off for remediation evaluation for Q4, 2015 was February 2016
Management's Remediation Plan Progress (continued)

HIGHLIGHTS

The average age of outstanding issues improved to six months as a result of the four new observations added from the Payroll and Disbursements report as well as two observations closed since the last audit committee meeting.

Management is fully aware of the status of the above project and is taking appropriate action to close it.

Aging of Issues*

* Aging as at February 2016

Legend

- Green: Less than 6 months
- Yellow: 6 Months to 1 Year
- Red: More than 1 year
2016 First Quarter
Internal Audit Report
Executive Summary

Internal Audit continues to be actively engaged in assurance and consulting assignments throughout Toronto Hydro in the first quarter of 2016. The results of our work indicate that Management’s control over business activities remain effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
</table>
|      | Quarterly Audit Activities                                                      | • Dispatch and Grid Response Internal Audit report was issued April 6th, with an overall rating of Satisfactory  
|      |                                                                                 | • Sole Source and Vendor Performance audits are underway with an expectant report issuance in Q2     |
|      | Management’s Remediation Plan Progress                                          | • 10 issues currently outstanding                                                                 |
|      |                                                                                 | • Average aging of outstanding issues is six months                                               |
|      |                                                                                 | • High – one outstanding                                                                          |
|      |                                                                                 | • Medium – two outstanding                                                                        |
|      |                                                                                 | • Low – seven outstanding                                                                         |
|      | Internal Audit Initiatives                                                       | Collaborated in the areas of: OEB Audit, Fraud & Theft Investigation Review, [Redacted] Data      |
|      |                                                                                 | Analytics and Accountability Officer Report Review                                                 |
|      | Audit Plan Progress and Changes to the Audit Plan                               | • No changes were made in Q1 to the Audit Plan                                                    |
|      |                                                                                 | • All planned audits are underway with good traction                                               |
|      | Internal Audit Group Management                                                  | • A new Senior Internal Auditor was announced                                                    |
|      |                                                                                 | • Thomas Fu started effective April 25th                                                           |

= Critical items requiring Audit Committee attention  
= Important issues that warrant discussion  
= Operating as expected
Quarterly Audit Activities

Dispatch and Grid Response Audit - Satisfactory

Report Issued: April 6th, 2016
Key Systems: OMS/DMS, Ellipse
Final Management Resolution Date: December 31, 2016

Controls Tested (includes ICFR)

<table>
<thead>
<tr>
<th>Category</th>
<th>Count</th>
</tr>
</thead>
<tbody>
<tr>
<td>No exceptions noted</td>
<td>8</td>
</tr>
<tr>
<td>Exceptions noted (including design gaps)</td>
<td>3</td>
</tr>
<tr>
<td>Total Controls</td>
<td>11</td>
</tr>
</tbody>
</table>

Audit Focus:

Design and operating effectiveness of key internal controls over the dispatch and grid response process to ensure that Toronto Hydro restores power as safely and as quickly as possible in the event of an outage, incident or emergency.

Risks Evaluated:

1. The capture, prioritization, dispatch and resolution of events, including customer relationship management;
2. The coordination/hand-offs between departments involved in power restoration;
3. IT general and application controls over the supporting information systems utilized by the groups;
4. Records and work order management updated completely and accurately, including assets removed.

Summary of Observations: (all observations have adequate resolution action plans to address gaps observed)

1. Four controls designed to mitigate operational and financial risks were not performed:
   a) monthly supervisor evaluation of dispatcher calls not completed;
   b) OMS/DMS table not regularly updated for customer address data;
   c) Work Request Desk work orders not reviewed by supervisor for classification appropriateness;
   d) periodic review of super access for the e-SRR (MPW) not performed as required;
2. No structured training program in place;
3. Aging OMS/DMS system prevented implementation of an AIX operating system upgrade.

Note: This audit explored a similar scope expected to be completed by the City Ombudsman for an ice storm compliant. The case was dropped by the City Ombudsman in late 2015. Internal Audit supports this action taken given the controls tested in this area were considered satisfactory and does not warrant further investigation.
Management’s Remediation Plan Progress

Outstanding Open Issues: Q1 2015 – Q1 2016

Action Plans Closed in Q1:

<table>
<thead>
<tr>
<th>Process</th>
<th>Risk Level</th>
<th>Remediation Completed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Distribution Revenues</td>
<td>Low</td>
<td>Metrics/KPIs developed to monitor exceptions to invoicing &amp; collection process</td>
</tr>
</tbody>
</table>
### Open Action Plans Carried Forward:

<table>
<thead>
<tr>
<th>Process</th>
<th>Risk Level</th>
<th>Observation (O) &amp; Remediation Plan (RP)</th>
<th>Due Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution of Paystubs</td>
<td>Low</td>
<td>O: Manual distribution of paystubs&lt;br&gt;RP: Considering implementation of 'e-stubs'</td>
<td>Q4 2016</td>
</tr>
<tr>
<td>Payroll Administrator Contract</td>
<td>Medium</td>
<td>O: No formal contract with ADP&lt;br&gt;RP: Contract to be drafted and formalized by end of year</td>
<td>Q4 2016</td>
</tr>
<tr>
<td>Procure to Pay Control Environment</td>
<td>Medium</td>
<td>O: Controls to monitor proper purchase requisitioning and goods/service receipting not proactively instituted&lt;br&gt;RP: Increase engagement and communication to heighten visibility to exceptions and to improve behaviour</td>
<td>Q4 2016</td>
</tr>
<tr>
<td>Disbursement Discounts</td>
<td>Low</td>
<td>O: Forfeiting of some early payment discounts&lt;br&gt;RP: Collaborate with Procurement and vendors to include payment terms on invoices, to maximize early payment discounts</td>
<td>Q4 2016</td>
</tr>
</tbody>
</table>
## Management’s Remediation Plan Progress (continued)

<table>
<thead>
<tr>
<th>Process</th>
<th>Risk Level</th>
<th>Observation (O) &amp; Remediation Plan (RP)</th>
<th>Due Date</th>
</tr>
</thead>
</table>

### Aging of Issues

* Aging as at April 2016

- **Less than 6 months**
- **6 months to 1 Year**
- **More than 1 year**
2016 Second Quarter Internal Audit Report
# Executive Summary

Internal Audit continues to be actively engaged in assurance and consulting assignments throughout Toronto Hydro in the second quarter of 2016. The results of our work indicate that Management’s control over business activities remain effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Quarterly Audit Activities</td>
<td>• Sole Source and Vendor Performance audits were issued on July 5th. The Sole Source audit was issued with a Satisfactory rating. Vendor Performance audit was issued with a Needs Improvement rating. • Meter to Cash audit is currently underway.</td>
</tr>
<tr>
<td></td>
<td>Management’s Remediation Plan Progress</td>
<td>• 17 issues currently open, with an average of six months outstanding: • High – one outstanding • Medium – four outstanding • Low – twelve outstanding</td>
</tr>
<tr>
<td></td>
<td>Internal Audit Initiatives</td>
<td>Collaborated in the areas of: Fraud &amp; Theft Investigation Review, Data Analytics and Accountability Officer Report Review.</td>
</tr>
<tr>
<td></td>
<td>Audit Plan Progress and Changes to the Audit Plan</td>
<td>• All planned audits are underway with good traction. • Additional audits were scheduled into the 4-quarter rolling Audit Plan.</td>
</tr>
<tr>
<td></td>
<td>Internal Audit Group Management</td>
<td>Team is engaged and working collaboratively with other departments.</td>
</tr>
</tbody>
</table>

= Critical items requiring Audit Committee attention

= Important issues that warrant discussion

= Operating as expected
Quarterly Audit Activities

**Sole Source and Vendor Performance - Satisfactory**

Report Issued: July 5, 2016  
Key Systems: Ellipse, EXL (Invoice Repository)  
Final Management Resolution Date: June 30, 2017

**Controls Tested (includes ICFR)**

<table>
<thead>
<tr>
<th>Category</th>
<th>Count</th>
</tr>
</thead>
<tbody>
<tr>
<td>No exceptions noted</td>
<td>7</td>
</tr>
<tr>
<td>Exceptions noted (including design gaps)</td>
<td>7</td>
</tr>
<tr>
<td>Total Controls</td>
<td>14</td>
</tr>
</tbody>
</table>

**Audit Focus:**

The degree to which Toronto Hydro complied with the established policies and procedures for sole source purchases. Processes around vendor setup and maintenance, services/goods receipting and monitoring of vendor performance were also reviewed.

**Risks Evaluated:**

1. Sole source contracts and vendors are adequately approved and authorized.  
2. Sole source contracts are only approved in the specific instances as defined per the procurement policy.  
3. Compliance with the procurement policy (specifically around sole sourcing and vendor performance) is effectively monitored.

**Summary of Observations: (all observations have adequate resolution action plans to address gaps observed)**

1. Lack of adherence to the sole source procure to pay process. Some non-conformances to policy were found during the audit.  
2. Strengthening of sole source supporting documentation and completeness of Sole Source Justification Report required. The Sole Source Justification Report was not always filled out completely and the justification for sole sourcing was not always adequately supported.  
3. Corporate-wide framework for monitoring vendor performance does not exist. Although business units initiated their own form of vendor performance, a standardized framework increased efficiencies and effectiveness.  
4. Vendor setup and vendor modification need improvement.
Facilities Management Office – Needs Improvement
Report Issued: July 5, 2016
Key Systems: Ellipse, FMO Database (Facilities Invoice Repository)
Final Management Resolution Date: December 31, 2016

Audit Focus:

In 2014, Toronto Hydro began the transition to a comprehensive, professional facilities maintenance model and awarded a vast majority of the facilities maintenance and operational services to an outsourced provider. The audit evaluated the degree to which Toronto Hydro’s Supply Chain and Facilities Management Office (FMO) manages this service and the outsourced provider. It also evaluated the degree to which the outsourced provider complied with aspects of the Term Contract for facilities management services (the ‘contract’). The initial term of the contract is for five years from January 1, 2014 to December 31, 2018 with an estimated cost of $35M. Toronto Hydro has an option to extend the contract for another five years at a cost of $39M.

Risks Evaluated:

Vendor management oversight/external resource management. An analysis of key processes from service maintenance initiation and planning to execution of services and payment approval was performed.

Summary of Observations: (all observations have adequate resolution action plans to address gaps observed)

1. The management and control of change orders was identified as a weakness in the vendor management oversight of the outsourced provider which consequently increased costs for facilities management services.
2. Opportunities to improve overall analysis and management of costs of should be explored through standardized framework.
3. Non-integrated systems used in the provision of Facilities Management Services.
Management’s Remediation Plan Progress


Action Plans Extended in Q2:

<table>
<thead>
<tr>
<th>Process</th>
<th>Risk Level</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

No Action Plans were closed in Q2
## Management’s Remediation Plan Progress (continued)

<table>
<thead>
<tr>
<th>Process</th>
<th>Risk Level</th>
<th>Observation (O) &amp; Remediation Plan (RP)</th>
<th>Due Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Payroll Administrator Contract</td>
<td>Medium</td>
<td>O: No formal contract with ADP. RP: Contract to be drafted and formalized by end of year. Remediation is on schedule.</td>
<td>Q4 2016</td>
</tr>
<tr>
<td>Procure to Pay Control Environment</td>
<td>Medium</td>
<td>O: Controls to monitor proper purchase requisitioning and goods/service receipting not proactively instituted. RP: Increase engagement and communication to heighten visibility to exceptions and to improve behaviour. Remediation is on schedule.</td>
<td>Q4 2016</td>
</tr>
<tr>
<td>Disbursement Discounts</td>
<td>Low</td>
<td>O: Forfeiting of some early payment discounts. RP: Collaborate with Procurement and vendors to include payment terms on invoices to maximize early payment discounts. Remediation is on schedule.</td>
<td>Q4 2016</td>
</tr>
</tbody>
</table>
Management’s Remediation Plan Progress (continued)

- Total numbers of outstanding issues – 17.
- Increase of total issues due to recent release of Sole Source and Vendor Performance audit reports.
- Issues greater than one year relates to and as discussed in previous slide.

Aging of Issues

- Q3 '15
- Q4 '15
- Q1 '16
- Q2 '16

Legend:
- Less than 6 months
- 6 months to 1 year
- More than 1 year
* Aging as at July 2016
2016 Third Quarter Internal Audit Report
**Executive Summary**

Internal Audit continues to be actively engaged in assurance and consulting assignments throughout Toronto Hydro in the third quarter of 2016. The results of our work indicate that Management’s control over business activities remains effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
</table>
| Quarterly Audit Activities    | • Phase One Meter to Cash report was issued November 2016  
• Wave One for ICFR was completed and report issued October 2016  
• Phase Two Meter to Cash audit, Wave Two & Three ICFR testing are currently underway |
| Management’s Remediation Plan Progress | 35 issues currently open, with an average of nine months outstanding:  
• High – two outstanding  
• Medium – 15 outstanding  
• Low – 18 outstanding  
Meter to Cash reported 20 new observations effective November 2016. |
| Internal Audit Initiatives    | Collaborated in the areas of: Accountability Officer Report Review, Fraud & Theft Investigation Review, Executive Expense Review, ERP Engagement |
| Audit Plan Progress and Changes to the Audit Plan | All planned audits are underway with good traction. |
| Internal Audit Group Management | Team is engaged and working collaboratively with other departments. |
Quarterly Audit Activities

Meter to Cash Audit (Phase One) – Needs Improvement

Assessment Period: May 1, 2015 to April 30, 2016
Key Systems: MAS, PrimeRead, ODS, MV90, MVSTAR, CC&B, Ellipse
Final Management Resolution Date: June 30, 2019

<table>
<thead>
<tr>
<th>Controls Tested (includes ICFR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No exceptions noted</td>
</tr>
<tr>
<td>Exceptions noted (including design gaps)</td>
</tr>
<tr>
<td>Total Controls</td>
</tr>
</tbody>
</table>

Audit Focus:

The objective of Phase One of the audit was to evaluate the design and operating effectiveness of key controls in the meter-to-cash processes to ensure:

1. Master information is setup accurately and timely in the billing system
2. Meter reads are complete, accurate and timely for billing
3. Estimated reads are in compliance with regulatory requirements and are reasonable
4. Billing is complete, accurate and timely
5. Payments are processed completely, accurately and timely
6. Collections of outstanding receivables are performed in accordance with Toronto Hydro policies and procedures
7. Deposits are in accordance with Toronto Hydro policies and procedures
8. IT controls over the meter-to-cash process are adequate

Internal Audit excluded the following processes from the audit: wholesale meters, IESO settlements, support programs settlements, meter asset value, claims and Call Centre operations.

Risks Evaluated:

1. Financial risks within the meter-to-cash process which can affect revenue recognition
2. Brand and reputation risks which can affect the customer and stakeholder perception of Toronto Hydro
3. Specific regulatory and compliance risk within operational areas
Quarterly Audit Activities (continued)

Background:

Toronto Hydro issues 5.6 million bills annually to approximately 750,000 customers. Customer Care is challenged to maintain the integral meter data network that supports meter reads for customer billing.

Customer Care continuously enhances its automatic meter data collection, through the expansion of the smart meter program. Meter data is retrieved by one of three major data collection systems and is then validated, estimated and edited for billing purposes.

<table>
<thead>
<tr>
<th>Customer Type</th>
<th>Meter Data Collection System</th>
<th>~ # of Accounts</th>
<th>~ % of Revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential (single)</td>
<td>MAS</td>
<td>610,000</td>
<td>22%</td>
</tr>
<tr>
<td>Residential (multiple)</td>
<td>PrimeRead</td>
<td>65,000</td>
<td>1%</td>
</tr>
<tr>
<td>Commercial (small)</td>
<td>MAS</td>
<td>77,000</td>
<td>30%</td>
</tr>
<tr>
<td>Commercial (large)</td>
<td>MV90</td>
<td>4,000</td>
<td>47%</td>
</tr>
</tbody>
</table>

Toronto Hydro utilizes a Billing and Collections system – Customer Care & Billing (CC&B) to maintain the records of customer activities and payments. Beyond the typical electricity customers, Customer Care devised a number of customized processes to enable the billing and administration of conservation programs.

With the significant volume of transactions, there are over 100 billing cycles executed for the customer base. Toronto Hydro offers both standard paper-based bills and e-bills as options for billing delivery method.

During the assessment period, Customer Care worked on many significant initiatives including monthly billing, Ontario Energy Support Program, Billing Accuracy Reporting, and MVSTAR system upgrade.
Summary of Observations:

<table>
<thead>
<tr>
<th>Process</th>
<th>High</th>
<th>Medium</th>
<th>Low</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Metering</td>
<td>0</td>
<td>4</td>
<td>3</td>
<td>7</td>
</tr>
<tr>
<td>Billing</td>
<td>0</td>
<td>2</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>Collections</td>
<td>1</td>
<td>5</td>
<td>2</td>
<td>8</td>
</tr>
<tr>
<td>Other</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Overall</td>
<td>1</td>
<td>12</td>
<td>7</td>
<td>20</td>
</tr>
</tbody>
</table>

Conclusion: Needs Improvement

While many internal controls are in place within the meter-to-cash processes, there are weaknesses and process improvement opportunities. Due to the complexity and cross-functional involvement in this end-to-end process, transparent handoffs between departments are critical to the success of effective decision making, elimination of redundancy and proper meter data management. These findings could potentially have a negative impact to Toronto Hydro.
## Summary of Observations (Metering):

<table>
<thead>
<tr>
<th>Observation</th>
<th>Risk Level</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inaccurate CC&amp;B meter master records related to meter reverification process</td>
<td>M</td>
<td>Internal Audit noted incomplete/inconsistent meter seal date in CC&amp;B master data. The implementation of a new automated process is expected to improve the accuracy of meter seal data in CC&amp;B.</td>
</tr>
<tr>
<td>Inter-divisional handoff issues in new customer setup process cause inefficiencies</td>
<td>M</td>
<td>Operational processes are inconsistently executed in the new meter install process, negatively impacting the timeliness and accuracy of meter data records. Furthermore, when a meter order is completed in CC&amp;B, there is no standard business practice to determine the Service Agreement start date when the energization date is prior to the meter installation date.</td>
</tr>
<tr>
<td>PrimeRead read meters may be out of sync with Toronto Hydro system time</td>
<td>L</td>
<td>All meters read by PrimeRead are not synced with Toronto Hydro system time which could impact the accuracy of Time of Use billing. As a compensating control, meters not synced can be identified through a review of consumption reports to compare bulk meter reads to the aggregate suite and common meter reads.</td>
</tr>
<tr>
<td>Non-compliance with OEB on large commercial (polyphase) metering installation inspections</td>
<td>M</td>
<td>Toronto Hydro currently does not have a comprehensive and well documented inspection program for complex (polyphase) meters. As such, Toronto Hydro is offside from the OEB requirement for a distributor to have an inspection program for complex (polyphase) metering installations with documentation of the inspection and results.</td>
</tr>
<tr>
<td>Ineffective MV90 energy tolerance validation rules</td>
<td>M</td>
<td>Current energy tolerance validation rules for MV90 meters are too lenient to effectively identify recorded meter read errors which could lead to inaccurate billing.</td>
</tr>
<tr>
<td>Inefficient and redundant MVSTAR Quality Reports</td>
<td>L</td>
<td>Select MVSTAR Quality Reports do not provide the correct information needed to resolve exceptions. Inefficiencies exist since multiple reports are reviewed that serve the same purpose.</td>
</tr>
</tbody>
</table>
## Quarterly Audit Activities (continued)

### Summary of Observations (Billing):

<table>
<thead>
<tr>
<th>Observation</th>
<th>Risk Level</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-compliance to OEB requirement to limit estimated billing to twice per 12 month cycle</td>
<td>L</td>
<td>Toronto Hydro is offside from the original intent of the OEB requirement for estimated billing. Internal Audit noted 857 instances of non-compliance within a 3 month period, which represents 0.1% of the population tested.</td>
</tr>
<tr>
<td>Inconsistent practice for authorization over bill cancellations</td>
<td>M</td>
<td>Currently there is no system approval process for bill cancels (akin to a &quot;workflow&quot; for manual adjustments within CC&amp;B). Nor are there monitoring activities implemented to detect frequently cancelled accounts or high dollar cancel bills for reasonability.</td>
</tr>
</tbody>
</table>
## Summary of Observations (Collections):

<table>
<thead>
<tr>
<th>Observation</th>
<th>Risk Level</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calculation of equal payment withdrawal amounts needs improvement</td>
<td>M</td>
<td>For equal payment plans, Toronto Hydro applies a 3% upward adjustment which is contrary to OEB the rules. While guidance exists regarding recalculation of new equal payments, the guidance was not consistently applied.</td>
</tr>
<tr>
<td>Autopay and retention of customer information requires improvement</td>
<td>M</td>
<td>Inconsistencies exist between the online and mail-in autopay application forms which detail the terms and condition for the program, potentially leading to inconsistent treatment of customers as it relates to NSF payments and time frame to revoke payment authorization. In addition, timing of withdrawals from customer accounts conflicts with dates as stipulated on the application for weekends and statutory holidays.</td>
</tr>
<tr>
<td>Reconciliation between CC&amp;B and bank is not performed</td>
<td>M</td>
<td>Although daily tender balances are reconciled to bank statements, a complete reconciliation between CC&amp;B and bank is not performed, thereby creating a risk for inaccurate customer records.</td>
</tr>
<tr>
<td>Toronto Hydro is not PCI compliant</td>
<td>H</td>
<td>Credit card information exists unencrypted in CC&amp;B. Internal Audit noted 6 instances for which credit card data was available to CC&amp;B users.</td>
</tr>
<tr>
<td>Transfer of funds and pay plan cancellations not appropriately documented</td>
<td>M</td>
<td>Internal Audit noted instances for which documentation of funds transferred among accounts in amounts of $2,000 or less was non-existent, creating opportunities for fraudulent activities.</td>
</tr>
<tr>
<td>CC&amp;B authorization matrix is not formally documented in a policy</td>
<td>M</td>
<td>Formalization of authorization matrix is required to ensure review and approval of levels granted. In addition, retailer refunds are subject to manual processes which are not consistently monitored nor are approvals consistently evidenced.</td>
</tr>
<tr>
<td>Stale-dated cheque information does not flow to CC&amp;B</td>
<td>L</td>
<td>Stale-dated information is not automatically reflected in CC&amp;B thereby inhibiting transparency in customer accounts.</td>
</tr>
<tr>
<td>Security deposit amounts for commercial customers requested needs improvement</td>
<td>L</td>
<td>Although guidance exists for the determination of security deposits, the application is inconsistent and not adequately documented.</td>
</tr>
</tbody>
</table>
### Summary of Observations (Other):

<table>
<thead>
<tr>
<th>Observation</th>
<th>Risk Level</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>The process of granting access rights is not centralized</td>
<td>M</td>
<td>A lack of centralization of oversight for the process of granting access and communication with system function owners.</td>
</tr>
<tr>
<td>Exceptions Reporting (To-Do follow-up) needs improvement</td>
<td>L</td>
<td>Various exception reporting observations were noted for the period under review.</td>
</tr>
</tbody>
</table>
Management’s Remediation Plan Progress

Outstanding Open Observations: Q3 2015 - Q3 2016

Action Plans Extended in Q3:

<table>
<thead>
<tr>
<th>Process</th>
<th>Risk Level</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Change Order Management for Facilities</td>
<td>Medium</td>
<td>Extended due date from Q3 2016 to Q4 2016 due to increased scope.</td>
</tr>
</tbody>
</table>
### Management’s Remediation Plan Progress (continued)

#### Action Plans Closed in Q3:

<table>
<thead>
<tr>
<th>Process</th>
<th>Risk Level</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Management/Governance over the Facilities Maintenance Contract</td>
<td>Medium</td>
<td>Governance meetings in the form of Quarterly Business Reviews (QBRs) have been designed and implemented.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>A non-conformance reporting (NCR) process was implemented and is highlighting corrective and preventative measures in the process.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>A vendor scorecard developed and implemented.</td>
</tr>
<tr>
<td>Vendor setup and modification</td>
<td>Low</td>
<td>Vendor Setup Form updated and reviewed with staff. Revised Vendor Setup/Change form addresses need for background checks being completed prior to setup.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Supervisory signoffs implemented for all new vendor setups.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Quarterly review meeting of setups scheduled to review vendor setup exceptions, correction and removal of duplicate vendors. BI reporting structure created to extract vendor data for periodic review.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Improvements made to the process of sharing and modification of vendor information with other departments.</td>
</tr>
<tr>
<td>Process</td>
<td>Risk Level</td>
<td>Observation (O) &amp; Remediation Plan (RP)</td>
</tr>
<tr>
<td>----------------------------------------------</td>
<td>------------</td>
<td>--------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Supervision of Distribution Grid Response</td>
<td>Low</td>
<td>O: Controls to mitigate operational and financial risks were not performed. RP: On track to be completed by December 2016.</td>
</tr>
<tr>
<td>Lack of Structured Training Program</td>
<td>Low</td>
<td>O: Lack of structured training program for staff. RP: On track to be completed by December 2016.</td>
</tr>
<tr>
<td>Security Vulnerability in System</td>
<td>Low</td>
<td>O: Aging application system prevents implementation of operating system upgrade leading to potential security weaknesses. RP: On track to be completed by December 2016.</td>
</tr>
<tr>
<td>Process</td>
<td>Risk Level</td>
<td>Observation (O) &amp; Remediation Plan (RP)</td>
</tr>
<tr>
<td>----------------------------------------------</td>
<td>------------</td>
<td>-------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Distribution of Paystubs</td>
<td>Low</td>
<td><strong>O</strong>: Manual distribution of paystubs. <strong>RP</strong>: Considering implementation of ‘e-stubs’. Decisions to be made as part of the new ERP implementation will impact remediation.</td>
</tr>
<tr>
<td>Payroll Administrator Contract</td>
<td>Medium</td>
<td><strong>O</strong>: No formal contract with ADP. <strong>RP</strong>: Decisions to be made as part of the new ERP implementation will impact remediation.</td>
</tr>
<tr>
<td>Procure to Pay Control Environment</td>
<td>Medium</td>
<td><strong>O</strong>: Controls to monitor proper purchase requisitioning and goods/service receipting not proactively instituted. <strong>RP</strong>: Increase engagement and communication to heighten visibility to exceptions and to improve behaviour. Remediation is on schedule.</td>
</tr>
<tr>
<td>Disbursement Discounts</td>
<td>Low</td>
<td><strong>O</strong>: Forfeiture of some early payment discounts. <strong>RP</strong>: Collaborate with Procurement and vendors to include payment terms on invoices, to maximize early payment discounts. Remediation is on schedule.</td>
</tr>
<tr>
<td>Adherence to sole source procure to pay process</td>
<td>Low</td>
<td><strong>O</strong>: Non-conformances to TH policy were found during review of the Sole Source and Vendor Performance process. <strong>RP</strong>: E&amp;C in progress and expected to be completed by due date.</td>
</tr>
<tr>
<td>Documentation of justification on sole sources needs improvement</td>
<td>Low</td>
<td><strong>O</strong>: Sole source justification was not always completed thereby compromising decision making. <strong>RP</strong>: Checklists and roadshows in progress and expected to be completed by due date.</td>
</tr>
</tbody>
</table>
## Management’s Remediation Plan Progress (continued)

<table>
<thead>
<tr>
<th>Process</th>
<th>Risk Level</th>
<th>Observation (O) &amp; Remediation Plan (RP)</th>
<th>Due Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facilities Change Order Management</td>
<td>Medium</td>
<td>O: Change Order management needs improvement. RP: Change order management scope increased and due date extended.</td>
<td>Q4 2016</td>
</tr>
<tr>
<td>Disparate systems used for Facilities Management</td>
<td>Low</td>
<td>O: Disparate systems used for facilities management which makes reporting inefficient RP: Non-integrated systems will be reviewed for the ERP implementation to identify opportunities</td>
<td>Q4 2016</td>
</tr>
</tbody>
</table>
Management’s Remediation Plan Progress (continued)

- Total number of outstanding issues increased to 35.
- Due to recent release of Meter to Cash Phase One report, total issues increased by 20.
- Issues greater than one year relate to [redacted] and discussed on slide 14.
Internal Audit continues to be actively engaged in assurance and consulting assignments throughout Toronto Hydro in the fourth quarter of 2016. The results of our work indicate that Management’s control over business activities remains effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
</table>
|                       | Quarterly Audit Activities                | • Phase Two Meter to Cash report was issued January 2017  
• Wave Three for ICFR was issued January 2017                                                                                           |
|                       | Management’s Remediation Plan Progress    | 35 issues currently open, with an average of eight months outstanding:  
• High – one outstanding  
• Medium – 15 outstanding  
• Low – 19 outstanding  
Phase Two Meter to Cash reported three new observations captured in the above summary. |
|                       | Internal Audit Initiatives                | Collaborated in the areas of: Accountability Officer Report Review, Fraud & Theft Investigation Review, Executive Expense Review, ERP  
Engagement, and Duplicate Invoice Testing.                                                                               |
|                       | Audit Plan Progress and Changes to the Audit Plan | Planning is underway for 2017 ICFR and Audit Program. Furthermore the team is actively supporting KPMG on the year end external audit. |
|                       | Internal Audit Group Management           | Team is engaged and working collaboratively with other departments. In January 2017, two members of the Internal Audit team were seconded to other areas. Recruitment is underway to address resourcing. |
Quarterly Audit Activities

Meter to Cash Audit (Phase Two) – Needs Improvement

Assessment Period: May 1, 2015 to August 31, 2016
Key Systems: CC&B, Ellipse, Netezza
Final Management Resolution Date: June 30, 2017

Controls Tested (includes ICFR)

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>No exceptions noted</td>
<td>3</td>
</tr>
<tr>
<td>Exceptions noted (including design gaps)</td>
<td>3</td>
</tr>
<tr>
<td>Total Controls</td>
<td>6</td>
</tr>
</tbody>
</table>

Audit Focus:

The objective of the audit was to evaluate the design and operating effectiveness of financial reporting controls within the meter-to-cash cycle to ensure:

- Revenue recognized and presented accurately;
- Accounts receivable, allowance for doubtful accounts and related bad debt expenses reasonability;
- Cost of power revenues and expenses, as well as the related retail settlement variance accounts recognized and presented accurately; and
- Journal entries and account reconciliations are prepared and reviewed on a timely basis.

Internal Audit excluded the following processes from the audit: other non-distribution revenue and regulatory balances not related to electricity revenue.

Conclusion: Needs Improvement

While financial reporting controls are in place within the meter-to-cash cycle, there are weaknesses and process improvement opportunities in the areas of completeness of bank reconciliations, compliance and enhancement to a set of robust guidelines for Allowance for Doubtful Accounts, and reasonability of unbilled revenue accrual. These findings could potentially have a negative impact to Toronto Hydro.
### Summary of Observations:

<table>
<thead>
<tr>
<th>Observation</th>
<th>Risk Level</th>
<th>Management Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unexplained difference (ranging from $140K debit to $560K credit) exists between general ledger and bank related to CC&amp;B electricity customer bank account since August 2014. At the time of the audit, management was actively investigating this issue.</td>
<td>L</td>
<td>New process includes performing daily bank reconciliations of all incoming and outgoing payments and working closely with Customer Care to investigate discrepancies.</td>
</tr>
<tr>
<td>Non-compliance to internal guideline section 3.0.2 for the calculation of Allowance for Doubtful Accounts. Guideline was last revised in 2012. Guideline should be revisited annually to incorporate historical activities and changes in the environment.</td>
<td>M</td>
<td>A comprehensive review of the Allowance for Doubtful Accounts methodology is underway. During year-end, additional analysis was prepared to validate the December 31, 2016 balances.</td>
</tr>
<tr>
<td>The quarterly unbilled revenue validation report was designed to compare the unbilled revenue accrual against the actuals for the same period. This report tested the reasonableness of approximately $300M unbilled revenue per month ceased in Q1 2016. This validation report was no longer prepared, and management was actively developing mitigating controls.</td>
<td>M</td>
<td>Management is reviewing the monthly revenue accrual process including documentation of the revised formalized process. A new report that summarizes and reviews year to date and quarterly revenue values and variance analysis is being finalized.</td>
</tr>
</tbody>
</table>
Summary of Q4 2016:

- Total number of observations remains unchanged from Q3 to Q4 2016.
- With the issuance of the Meter to Cash phase two audit, three additional observations were noted.
- During Q4, three observations were closed including an early resolution of a high risk item from the Meter to Cash phase one audit.
Management’s Remediation Plan Progress (continued)

**High Risk Outstanding Observations as at Q4:**

<table>
<thead>
<tr>
<th>Observation</th>
<th>Risk Level</th>
<th>Observation (O) &amp; Remediation Plan (RP)</th>
<th>Due Date</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Action Plans Closed in Q4:**

<table>
<thead>
<tr>
<th>Observation</th>
<th>Risk Level</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stale-dated Cheques Information Flow</td>
<td>Low</td>
<td>A pending IT service request has been raised as a requirement for the next CC&amp;B upgrade. An existing manual workaround is in place currently.</td>
</tr>
<tr>
<td>(16-05-MTC-17)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facilities Change Order Management</td>
<td>Medium</td>
<td>Change order requisition form and subcontractor Conflict of Interest disclosure forms have been implemented.</td>
</tr>
<tr>
<td>(16-04-FMO-01)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PCI Compliance</td>
<td>High</td>
<td>The business process has been revised to ensure that credit card payments are processed the same day and credit card data will not be copied and stored in TH's backup systems. The option to outsource credit card payments will be reviewed by management.</td>
</tr>
<tr>
<td>(16-05-MTC-14)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Management’s Remediation Plan Progress (continued)

- Total number of outstanding observations is 35.

- Observations greater than one year relate to [redacted] and Payroll & Disbursements.

- [redacted] and [redacted] observation are outstanding due to pending third party contract negotiations.

- Payroll & Disbursements observations are deferred to the solutions as part of the ERP implementation.

Aging of Observations as at March 1, 2017

- Q1 ’16
- Q2 ’16
- Q3 ’16
- Q4 ’16

- Less Than 6 months
- 6 Months to 1 Year
- More Than 1 Year
2017 First Quarter
Internal Audit Report

Q1, 2017, Internal Audit Report Summary
**Executive Summary**

Internal Audit continues to be engaged in assurance and consulting assignments throughout Toronto Hydro in the first quarter of 2017. The results of our work indicate that Management’s control over business activities remains *effective*.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Quarterly Audit Activities</td>
<td>Planning of the Enterprise Program Management Office Audit is underway, as is the consultation of the transformation of Project Development.</td>
</tr>
</tbody>
</table>
|        | Management’s Remediation Plan Progress | 31 issues currently open, with an average age of ten months:  
- High – one outstanding  
- Medium – 14 outstanding  
- Low – 16 outstanding |
|        | Audit Plan Progress and Changes to the Audit Plan | The audit plan will be revisited once the common objectives of Internal Audit and Enterprise Risk Management have been aligned under the leadership of VP, Audit & Corporate Compliance. |
|        | Internal Audit Group Management | Internal Audit Manager position is posted and decisions will be made on all other open positions pending the new division structure. |

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![Toronto Hydro logo](image-url)
Management’s Remediation Plan Progress

Summary of Q1 2017:

- Total number of open observations were reduced from 35 to 31 during Q1.
- Management is actively addressing the outstanding observations and has good traction to ensure full mitigation as per agreed upon timelines.

Q1 2017 - Open Observation by Risk Level

- High: 1
- Med: 16
- Low: 14
Management’s Remediation Plan Progress (continued)

High Risk Outstanding Observations as at Q1:

<table>
<thead>
<tr>
<th>Observation</th>
<th>Risk Level</th>
<th>Observation (O) &amp; Remediation Plan (RP)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Action Plans Closed in Q1:

<table>
<thead>
<tr>
<th>Observation</th>
<th>Risk Level</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disparate systems used for Facilities Management (16-04-FMO-03)</td>
<td>Low</td>
<td>Facilities staff involved in ERP Data Migration team established requirements for the ERP implementation to address required system interfaces.</td>
</tr>
<tr>
<td>CC&amp;B and bank reconciliation (16-05-MTC-13)</td>
<td>Medium</td>
<td>A formal reconciliation process that includes both debit and credit transactions has been developed and implemented.</td>
</tr>
<tr>
<td>GL and bank account (16-06-MTC-01)</td>
<td>Low</td>
<td>New process includes performing daily bank reconciliations of all incoming and outgoing payments and working closely with Customer Care to investigate discrepancies has been implemented.</td>
</tr>
<tr>
<td>Supervision of Distribution Grid Response (16-02-DGR-01)</td>
<td>Low</td>
<td>Controls established to mitigate operational and financial risks have been prioritized and are now appropriately performed.</td>
</tr>
</tbody>
</table>
Management’s Remediation Plan Progress (continued)

- Observations greater than one year relate to [redacted], Payroll & Disbursements (4), and Dispatch & Grid Response (2).

- [redacted] and [redacted] observation are outstanding due to pending third party contract negotiations.

- Payroll & Disbursements observations are deferred to the solutions as part of the ERP implementation.

Aging of Observations as at May 10, 2017

Legend:
- Less Than 6 months
- 6 Months to 1 Year
- More Than 1 Year
2017 Second Quarter
Internal Audit Report

Q2, 2017, Internal Audit Report Summary
Executive Summary

Internal Audit continues to be engaged in assurance and consulting assignments throughout Toronto Hydro in the second quarter of 2017. The results of our work indicate that Management’s control over business activities remains effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Quarterly Audit Activities</td>
<td>Reporting of the Enterprise Program Management Office Audit is underway, as is the fieldwork of Phase 1 Internal Controls over Financial Reporting testing.</td>
</tr>
</tbody>
</table>
|        | Management’s Remediation Plan Progress | 25 issues currently open, with an average age of 14 months:  
  - High – one outstanding  
  - Medium – 10 outstanding  
  - Low – 14 outstanding |
|        | Audit Plan Progress and Changes to the Audit Plan | The audit plan will be revisited once the common objectives of Internal Audit and Enterprise Risk Management have been aligned under the leadership of VP, Audit & Corporate Compliance. |
|        | Internal Audit Group Management | Interviews are underway for the Internal Audit Manager position and decisions will be made on all other open positions pending the new division structure. |

---

= Critical items requiring Audit Committee attention  
= Important issues that warrant discussion  
= Operating as expected
Management’s Remediation Plan Progress

HIGHLIGHTS
Total number of open observations were reduced from 31 to 25 during Q2. Internal Audit continues to be pleased with the depth of Management’s analysis and monitoring of their remediation projects.

Of the six observations closed this quarter:

- Five stemmed from the 2016 Meter to Cash audit. Four medium risk and one low risk. As follows:
  - ✓ The allowance for doubtful account guideline has been reviewed and updated.
  - ✓ The unbilled revenue validation process has strengthened its internal controls via a validation checklist.
  - ✓ Standardized equal payment plan calculations and quality monitoring have implemented.
  - ✓ User access controls to CC&B have been improved through new review and attestation processes.
  - ✓ The refund authorization matrix was updated and reconciliation process was implemented.

The other low risk observation closed was raised in the 2016 Payroll & Disbursements Audit which dealt with the missed opportunity of early payment discounts. New monitoring processes have been implemented and >99% of all early payment discounts were optimized in the last two months.

Outstanding Open Observations: Q3 2016 – Q2 2017*

*Cut off for remediation evaluation for Q2, 2017 was July 31, 2017
HIGHLIGHTS

The average aging of outstanding management action plans is 14 months which exceeds our target Key Performance Indicator (KPI).

This deterioration in aging is caused in part by the absence of new audit reports being issued in the last quarter as well as three very old audit issues that remain unresolved due to ongoing negotiations with related parties.

* Aging as at July 31, 2017
Executive Summary

Internal Audit continues to be engaged in assurance and consulting assignments throughout Toronto Hydro in the third quarter of 2017. The results of our work indicate that Management’s control over business activities remains effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quarterly Audit Activities</td>
<td>Phase 1 of the Internal Controls over Financial Reporting was completed this quarter. Fieldwork for Phase 2 is well underway and planning for Phase 3 work is completed. The Enterprise Program Management Office audit report is currently in draft and will be finalized before year end.</td>
<td></td>
</tr>
<tr>
<td>Management’s Remediation Plan Progress</td>
<td>Management successfully closed 10 issues this quarter five of which were older than one year. Only 15 management action plans remain open but the average age is 16 months which is older than our target KPI for this measure.</td>
<td></td>
</tr>
<tr>
<td>Internal Audit Initiatives</td>
<td>Internal Audit remains engaged in collaborative cross-departmental initiatives with stakeholders including the SAP project team, Human Resources and Regulatory.</td>
<td></td>
</tr>
<tr>
<td>Audit Plan Progress and Changes to the Audit Plan</td>
<td>A formal internal audit planning cycle is currently underway with the Executives to select additional audit projects for the next 4 - 6 quarters. This plan incorporates ERM and Corporate Compliance analysis and work effort for the upcoming year. The results will be shared in March.</td>
<td></td>
</tr>
<tr>
<td>Internal Audit Group Management</td>
<td>Nischal Siwakoti, Internal Audit Manager, joined us in September and we continue to actively recruit for open positions in the new department structure.</td>
<td></td>
</tr>
</tbody>
</table>

= Critical items requiring Audit Committee attention
= Important issues that warrant discussion
= Operating as expected
SUMMARY OF AUDIT ACTIVITIES

The first of three Internal Controls over Financial Reporting (ICFR) Review Consultation Memos were issued this quarter, thus beginning the testing and reporting cycle of the entire ICFR inventory for 2017.

As in prior years, Internal Controls are grouped by like Division or Processes and our work is coordinated with KPMG, to optimize synergies and minimize disruption to the business units. Throughout the test cycle, our inventory of ICFR controls is validated for completeness and relevance. In Phase 1, two additional controls were identified for inclusion.

**Internal Controls over Financial Reporting – Phase I**
Controls in Phase I covered a wide range of disparate control across many departments including Accounts Receivable, Accounts Payable, Inventory, Human Resources and Billing. Of the 40 controls tested, two areas for improvement were identified and both were addressed with management during the review and were appropriately remediated. With the exception of these two minor process improvement opportunities, all ICFRs were operating as designed.

**Internal Controls over Financial Reporting – Q4 Planned Work**

**Phase II – Finance Division based controls**
Controls in Phase II are focused primarily on accounting and reporting. Testing is in progress and no errors or opportunities for improvement have been identified in the work done to date.

**Phase III – Information Technology General Controls (ITGCs)**
Planning has been completed.
Management’s Remediation Plan Progress

HIGHLIGHTS
Management had an extremely successful quarter completing ten outstanding action plans. Audit continues to be pleased with the depth of Management’s analysis and monitoring of their remaining remediation projects.

Of the ten observations closed this quarter:

Five stemmed from the 2016 Meter to Cash audit (two medium risk and three low risk issues), as follows:

✓ Reconciliation of discrepancies between meter test groups and meter seal updates.
✓ Updated process and training for the timeliness and accuracy of paperwork for new meter installations and service upgrades.
✓ Implemented monitoring controls to address seal expiry.
✓ Implementation of IEE (MVSTAR Replacement Project) to address required reporting enhancements.
✓ Development of preventative script to capture inactive accounts with credit balances on security deposits.

All three remaining 2016 Payroll and Disbursements audit observations are closed (two medium risk and one low risk issue), as follows:

✓ Long term ADP contract resolution.
✓ Monitoring control implemented to track completeness of outstanding invoices for processing.
✓ Improvement opportunity to explore automated paystub distribution.

Outstanding Open Observations:
Q4 2016 – Q3 2017*

*Cut off for remediation evaluation for Q3, 2017 was October 31, 2017
Management’s Remediation Plan Progress (continued)

HIGHLIGHTS

One low risk issue from the 2016 Dispatch and Grid Response Audit

✓ A structured training program has been formalized and rolled out through the Learning Management System.

Outstanding Open Observations:
Q4 2016 – Q3 2017*

*Cut off for remediation evaluation for Q3, 2017 was October 31, 2017
HIGHLIGHTS

The average aging of outstanding management action plans is 16 months which exceeds our target Key Performance Indicator (KPI) of 12 months.

This deterioration in aging is caused due to two very old audit issues that remain unresolved due to ongoing negotiations with related parties:

1. 
2. 

Both these issues are being closely monitored at an Executive level.

Aging of Issues*

* Aging as at October 31, 2017
2017 Fourth Quarter Internal Audit Report

Q4, 2017, Internal Audit Report Summary
Executive Summary

Internal Audit continues to be engaged in assurance and consulting assignments throughout Toronto Hydro in the fourth quarter of 2017. The results of our work indicate that Management’s control over business activities remains **effective**.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image" alt="Green" /></td>
<td>Quarterly Audit Activities</td>
<td>One operational audit report, Enterprise Program Management Office, was presented to management and one Internal Controls over Financial Reporting (ICFR) Memo was issued.</td>
</tr>
<tr>
<td><img src="image" alt="Green" /></td>
<td>Management’s Remediation Plan Progress</td>
<td>Management successfully closed two issues during this quarter that were outstanding for over a year. Four new observations were added during this quarter. A total of 17 management action plans remain open with an average age of 15 months (Target KPI is 12 Months).</td>
</tr>
<tr>
<td><img src="image" alt="Green" /></td>
<td>Internal Audit Initiatives</td>
<td>Internal Audit remains engaged in collaborative cross-departmental initiatives with stakeholders including the SAP Project Aurora team and other business unit clients.</td>
</tr>
<tr>
<td><img src="image" alt="Yellow" /></td>
<td>Audit Plan Progress and Changes to the Audit Plan</td>
<td>A formal risk assessment was conducted with the Executive Team to develop the internal audit plan for the next six quarters. The risk based annual audit plan for 2018 has been included and should be approved by the Audit Committee for execution.</td>
</tr>
<tr>
<td><img src="image" alt="Red" /></td>
<td>Internal Audit Group Management</td>
<td>Githu Mundenchira and Tahir Khwaja joined the team in early 2018. Githu is an internal transfer and Tahir is a seasoned internal auditor. We continue to actively recruit for two open contract positions in the new department structure.</td>
</tr>
</tbody>
</table>
Quarterly Audit Activities

SUMMARY OF AUDIT ACTIVITIES

Internal Audit (IA) presented one audit report and issued one ICFR memo since our last report to the Audit Committee.

Enterprise Project Management Office Audit (EPMO)

EPMO is responsible for managing Toronto Hydro’s Execution Work Program (EWP) consisting of both capital and maintenance projects. Program Delivery Improvement & Governance (PDIG) is a governance function within EPMO which provides monitoring and oversight of EWP. The scope of the audit was focused on assessing the design and operating effectiveness of PDIG’s controls supporting monitoring of EWP creation via consolidation of forecasting activities; compliance and adherence to the EWP change requests; accuracy, completeness and timeliness of individual project scope in-take process; and completion of projects to ensure these are within the approved budget and timelines.

The two medium risk observations pertain to controls in the change request process over aggregate program and specific project changes. Management is actively working on a remediation strategy to close the gaps. Part of the solution will be the consolidation of information in a single ERP system as, currently, PDIG relies on two bespoke applications and Excel spreadsheets for control purposes that rely on manual inputs which are inherently prone to error.

The two low risk observations involve improvements to PDIG’s variance analysis and quality control reviews. These control functions are still developing and are approaching maturity.

EPMO Overall Rating – Needs Improvement

<table>
<thead>
<tr>
<th>Impact/Severity</th>
<th># Audit Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>0</td>
</tr>
<tr>
<td>Medium</td>
<td>2</td>
</tr>
<tr>
<td>Low</td>
<td>2</td>
</tr>
<tr>
<td>Total Issues</td>
<td>4</td>
</tr>
</tbody>
</table>

The PDIG department is fulfilling its mandate to provide governance and control in the EWP process. There are, however, opportunities to improve processes supporting their key controls to improve their EWP monitoring, variance analysis and quality assurance program. None of the observations pose a significant negative impact for Toronto Hydro nor do they impact internal controls over financial reporting.
Internal Controls over Financial Reporting

All 2017 ICFR testing has now been completed.

Throughout the test cycle, our inventory of ICFR controls was validated for completeness and relevance. In 2017, 15 additional controls were identified for inclusion. ICFR Phase 1 was completed during Q3 2017.

ICFR Phase 2
Phase II testing was primarily focused on Financial Reporting, Asset Capitalization, Treasury, Taxation and Conservation Demand Management. 51 controls were tested with two minor improvements noted and communicated to management. All ICFRs were operating as designed.

ICFR Phase 3
Phase 3, focused on Information Technology General Controls (ITGCs), has been substantively completed. Pending final review, two exceptions were raised in the 42 controls tested. Both exceptions are within the security domain area and compensating controls are in place to address the potential risk exposure. The first dealt with security log maintenance, whereby not all IT applications have been configured to fully utilize the control functions within the Security Information and Event Management (SIEM) software. Management is actively addressing configuration requirements to ensure all applications, where possible, have security logs in the SIEM.

The second exception is related to quarterly review of data center user access list/log. This has already been closed with management in Q4.

None of these weaknesses were considered material or systemic across the various platforms. These isolated weaknesses would not increase significant risk exposure in the various IT areas due to compensating controls and the overall organizational structure and control environments. With the exceptions noted and subject to final review, ITGCs were operating as designed.
Management’s Remediation Plan Progress

HIGHLIGHTS
Management successfully closed two outstanding observations. Internal Audit continues to be pleased with the depth of Management’s analysis and monitoring of their remaining remediation projects.

Both observations closed this quarter stemmed from the 2016 Sole Source and Vendor Performance audit (two low risk issues), as follows:

- Re-enforced the “No Purchase Order = No Pay” policy with vendors and implemented new Sole Source checklist for Supply Chain staff.
- Completed road shows across the organization to refresh knowledge on Procure to Pay and Sole Source processes.

The number of outstanding observations has increased by two due to four new observations reported in the EPMO audit:

- No change in total number of high risk observations.
- No change in low risk observations with two added and two closed.
- Increase of two medium risk observations from the EMPO audit.

*Cut off for remediation evaluation was February 7, 2018*
HIGHLIGHTS

The average age of outstanding management action plans is 15 months which exceeds our target Key Performance Indicator (KPI) of 12 months. However, the average aging of observations has reduced from 16 months to 15 months. Management has closed two observations that were outstanding for over one year and added four new observations during Q4 2017.

As previously communicated, the sub-optimal aging is primarily driven by two very old audit issues that remain unresolved due to ongoing negotiations with related parties:

1. [Blank]
2. [Blank]

Both these issues are being closely monitored at the Executive level.

Aging of Issues

*Aging as at February 7, 2018
2018 First Quarter
Internal Audit Report

Q1, 2018, Internal Audit Report Summary
Executive Summary

Internal Audit continues to be engaged in assurance and consulting assignments throughout Toronto Hydro in the first quarter of 2018. The results of our work indicate that Management’s control over business activities remains effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Quarterly Audit Activities</td>
<td>Audit Planning memos of Project Aurora (System Pre-Implementation) Audit and Stations and Maintenance Audit were issued. Field work is underway.</td>
</tr>
<tr>
<td>Management’s Remediation</td>
<td>Management successfully closed five outstanding</td>
<td>Management successfully closed five outstanding observations during this quarter that were outstanding for over a year. A total of 12 management action plans remain open with an average age of 17 months. Target Key Performance Indicator is 12 Months.</td>
</tr>
<tr>
<td>Plan Progress</td>
<td>observations during this quarter that were</td>
<td></td>
</tr>
<tr>
<td></td>
<td>outstanding for over a year. A total of 12</td>
<td></td>
</tr>
<tr>
<td></td>
<td>management action plans remain open with an</td>
<td></td>
</tr>
<tr>
<td></td>
<td>average age of 17 months. Target Key Performance</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Indicator is 12 Months.</td>
<td></td>
</tr>
<tr>
<td>Internal Audit</td>
<td>Internal Audit remains engaged in collaborative</td>
<td>Internal Audit remains engaged in collaborative cross-departmental initiatives with stakeholders including the SAP Project Aurora team and other business unit clients.</td>
</tr>
<tr>
<td>Initiatives</td>
<td>cross-departmental initiatives with stakeholders</td>
<td></td>
</tr>
<tr>
<td></td>
<td>including the SAP Project Aurora team and other</td>
<td></td>
</tr>
<tr>
<td></td>
<td>business unit clients.</td>
<td></td>
</tr>
<tr>
<td>Audit Plan Progress</td>
<td>The audit work is progressing in line with the</td>
<td>The audit work is progressing in line with the audit plan. No revisions or additions this quarter.</td>
</tr>
<tr>
<td>and Changes to the Audit</td>
<td>audit plan. No revisions or additions this quarter.</td>
<td></td>
</tr>
<tr>
<td>Plan</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Internal Audit Group</td>
<td>Catherine Magdaleno will join the team in May 2018.</td>
<td>Catherine Magdaleno will join the team in May 2018. Catherine is a seasoned internal auditor. We continue to actively recruit for one more open contract position in the new department structure.</td>
</tr>
<tr>
<td>Management</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
SUMMARY OF AUDIT ACTIVITIES

No audit reports or consultation memos have been issued since the last Audit Committee meeting. Two audit planning memos were issued:

Stations and Maintenance Audit
The Stations and Maintenance processes are critical to the overall health of the grid. In 2017, Toronto Hydro spent $219 M (59%) of total planned capital expenditure on infrastructure upgrades and stations life cycle management programs and $47 M (18%) of total operating expenses on maintenance activities. Additionally, the Auditor General has expressed interest in the Stations and Maintenance processes of Toronto Hydro as a result of the May 2017 vault fire and plans to audit this area later in 2018 or early 2019, depending on resources.

The objectives of this review are to evaluate the design and operating effectiveness of key controls in the Stations and Maintenance processes to ensure key operational and compliance objectives of the processes are met. This is an integrated audit which includes review of end to end processes including information technology general and application controls.

Project Aurora: SAP Implementation Audit
Project Aurora is a strategic initiative to implement a SAP ERP that will replace Ellipse and 30 other legacy systems. The project is bringing changes in terms of process standardization and automation across the organization. The project scope includes implementation of SAP ECC, SAP SuccessFactors, and SAP Ariba.

The audit includes review and evaluation of key controls around the project implementation methodology, readiness of Project Aurora Go-Live, organizational change management, and information/system security to ensure that project is implemented as per the plan and system is available and running in a sustainable manner post Go-Live.

### Stations and Maintenance Audit

<table>
<thead>
<tr>
<th>Activities/Month</th>
<th>April</th>
<th>May</th>
<th>June</th>
<th>July</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planning</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fieldwork</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Reporting</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
</tbody>
</table>

### Project Aurora: SAP Implementation Audit

<table>
<thead>
<tr>
<th>Activities/Month</th>
<th>April</th>
<th>May</th>
<th>June</th>
<th>July</th>
<th>Aug</th>
<th>Sept</th>
<th>Oct</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planning</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fieldwork</td>
<td></td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Reporting*</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
</tbody>
</table>

*Note: Reporting will include ongoing communication of observations to the project management issue log as well as capstone reporting.
Management’s Remediation Plan Progress

HIGHLIGHTS

Management successfully closed five outstanding observations bringing down the total outstanding observations to 12. Internal Audit continues to be pleased with the depth of Management’s analysis and monitoring of their remaining remediation projects.

All observations closed this quarter stemmed from the 2016 Meter to Cash audit (three medium risk and two low risk issues), as follows:

- Manual exception reporting and remediation process implemented for meter time synch (Toronto Hydro system time vs meter time) issue. PrimeRead v10 go-live will further automate this process (16-05-MTC-01);

- Two contractors assigned to complete M-ANALYS fieldwork. Established a monitoring process to ensure field work is regularly performed (16-05-MTC-05);

- Most of the Utilismart meters were replaced with 4G meters to address lenient energy tolerance validation rules. A manual validation process implemented for the few remaining meters (16-05-MTC-06);

- Monitoring process in place to timely detect and remediate multi-bill cancellations without approval (16-05-MTC-09);

- ODS System Improvement made to avoid false exception reporting. Monitoring controls implemented to manage significant debits to a customer account (16-05-MTC-20);

Outstanding Open Observations:
Q2 2017 – Q1 2018

* Cut off for remediation evaluation was April 16, 2018
HIGHLIGHTS

The average age of outstanding management action plans is 17 months which exceeds our target KPI of 12 months. Management closed five observations that were outstanding for over one year in Q1 2018.

As previously communicated, the sub-optimal aging is primarily driven by two very old audit issues that remain unresolved due to ongoing negotiations with related parties:

1. [Content not visible]
2. [Content not visible]

*Both of these issues are being closely monitored at the Executive level.*
2018 Second Quarter Internal Audit Report

Q2, 2018, Internal Audit Report Summary
Executive Summary

Internal Audit continues to be engaged in assurance and consulting assignments throughout Toronto Hydro in the second quarter of 2018. The results of our work indicate that Management’s control over business activities remains effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image" alt="Status" /></td>
<td>Quarterly Audit Activities</td>
<td>The Entity Level Controls Audit report and two control memos were issued in the quarter. Field work for Project Aurora (System Pre-Implementation) Audit and Stations and Maintenance Audit is ongoing and the planning memo for Internal Controls over Financial Reporting (ICFR) was issued as well.</td>
</tr>
<tr>
<td><img src="image" alt="Status" /></td>
<td>Management’s Remediation Plan Progress</td>
<td>Management successfully closed three outstanding observations during this quarter that were outstanding for over a year. A total of 10 management action plans remain open with an average age of 18 months. Target Key Performance Indicator is 12 Months.</td>
</tr>
<tr>
<td><img src="image" alt="Status" /></td>
<td>Internal Audit Initiatives</td>
<td>Internal Audit remains engaged in collaborative cross-departmental initiatives and has held several meetings with KPMG to align planning with work required on the SAP Project and ITGC work on legacy systems.</td>
</tr>
<tr>
<td><img src="image" alt="Status" /></td>
<td>Audit Plan Progress and Changes to the Audit Plan</td>
<td>The audit work is progressing in line with the audit plan however the Stations &amp; Maintenance audit is slightly behind schedule due to business delays due to other operational priorities which has delayed the start of other planned audits.</td>
</tr>
<tr>
<td><img src="image" alt="Status" /></td>
<td>Internal Audit Group Management</td>
<td>All staff positions have been filled with Deepak Batra joining the team in May. Effective July 24, the Audit Manager is no longer with Toronto Hydro and the VP, Audit &amp; Corporate Compliance will be managing the group while recruiting is on-going.</td>
</tr>
</tbody>
</table>
SUMMARY OF AUDIT ACTIVITIES

Internal Audit (IA) issued one Audit report, two Control memoranda and one Planning memorandum for Internal Controls over Financial Reporting (ICFR) testing.

Entity Level Control Audit

Entity Level Controls (ELCs) are often referred to as the “Tone at the Top” and involve the corporation’s values, systems, policies and processes that define an organization’s corporate culture. They establish guidelines for an organization’s governance, financial analysis and integrity, and adherence to applicable laws and professional standards.

As part of our Entity Level Control audit, Internal Audit focused on the following:

- Identifying and assessing the library of Entity Level Controls resident with the Executive and the Board of Directors to ensure appropriate delegation of authority and responsibility.

- Confirming the design of the internal control framework is comprehensive and integrated and all risks normally associated with entity control are addressed.

- Ensuring Entity Level Controls are operating with effective monitoring and communication procedures in place to escalate and resolve issues when they occur.

Entity Level Control Audit – Satisfactory

Toronto Hydro’s Entity Level Controls are well designed and working effectively. One low risk observation was identified which stems from the implementation of the new Corporate Compliance framework. The framework has been developed but is not yet fully operational and reporting is not yet robust. While this framework and supporting monitoring processes mature, there is a greater risk that compliance issues may not be properly escalated and managed consistently across the organization.

<table>
<thead>
<tr>
<th>Issues</th>
<th>Impact/Severity</th>
<th># Audit Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>High</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Medium</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Low</td>
<td>1</td>
</tr>
<tr>
<td>Total Issues</td>
<td></td>
<td>1</td>
</tr>
</tbody>
</table>

ICFR Controls Tested

<table>
<thead>
<tr>
<th>Controls Tested (includes ICFR)</th>
<th>No exceptions noted</th>
<th>Exceptions noted</th>
<th>Total ICFR Controls</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>3</td>
<td>0</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Controls Tested (includes ICFR)</th>
<th>No exceptions noted</th>
<th>Exceptions noted</th>
<th>Total Controls</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>37</td>
<td>1</td>
<td>38</td>
</tr>
</tbody>
</table>
SUMMARY OF AUDIT ACTIVITIES
Two control memoranda were issued during the quarter. Field work on the other two audits was ongoing through this quarter.

Control Memoranda – Miscellaneous Accounts Receivable
Internal Audit was requested to perform a review of Miscellaneous Accounts Receivable billing processes (Non-Electricity Billing), and a memorandum was issued with a brief summary of each stream. Additionally, a separate memorandum was issued to the Supply Chain department on the sale of inventory to Crosslinx which included recommendations to minimize risk exposure.

Stations and Maintenance Audit
The objectives of this review are to evaluate the design and operating effectiveness of key controls in the Stations and Maintenance processes to ensure key operational and compliance objectives of the processes are met. This is an integrated audit which includes review of end to end processes including information technology general and application controls.

Internal Audit has discussed the current Maintenance and Capital processes with all relevant DRPs. A Risks and Controls Matrix has been developed and confirmed with the DRPs highlighting the overall risks within these processes. Detailed testing is underway.

Project Aurora: SAP Implementation Audit
Project Aurora is a strategic initiative to implement a SAP ERP that will replace Ellipse and 30 other legacy systems. Internal Audit’s Phase 1 work which covered project management and governance has been completed, with no exceptions noted. Phase 2, Project Realization is expected to close early in Q3. Phase 3 (Data Migration) and Phase 4 (Training & Communication) will occur in Q3/4.

*Note: Reporting will include ongoing communication of observations to the project management issue log as well as capstone reporting.
Management’s Remediation Plan Progress

HIGHLIGHTS
Management successfully closed three outstanding observations bringing down the total outstanding observations to 10. Internal Audit continues to be pleased with the depth of Management’s analysis and monitoring of their remaining remediation projects.

Two of the observations closed this quarter stemmed from the 2016 Meter to Cash audit (medium risk) and one from the Dispatch and Grid Response Audit (low risk), as follows:

✓ OMS/DMS application upgrade recommendation has been addressed with the NMS 2.3 GoLive in July, 2018, greatly improving the capabilities of the control and dispatch groups (16-02-DGR-03);

✓ Tracking and monitoring process has been establish to identify and rectify any instances where transfer of funds between accounts was done without appropriate steps (16-05-MTC-15);

*Cut off for remediation evaluation was July 13, 2018
HIGHLIGHTS

The average age of outstanding management action plans is 18 months which exceeds our target KPI of 12 months. Management closed three observations that were outstanding for over one year in Q2 2018.

As previously communicated, the sub-optimal aging is primarily driven by two very old audit issues that remain unresolved due to ongoing negotiations with related parties:

1. 

2. 

Excluding these two issues, aging would be 11 months.

Aging of Issues

* Aging as at June 30, 2018
2018 Third Quarter Internal Audit Report

Q3, 2018, Internal Audit Report Summary
Executive Summary

Internal Audit continues to be engaged in assurance and consulting assignments throughout Toronto Hydro in the third quarter of 2018. The results of our work indicate that Management’s control over business activities remains effective.

<table>
<thead>
<tr>
<th>Status</th>
<th>Audit Operations</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Quarterly Audit Activities</td>
<td>Report for Maintenance and Stations Capital audit was issued. Field work on Internal Controls over Financial Reporting (ICFR) is on-going. Additional controls have been identified during the cut-over period from legacy systems to new ERP. These controls will be tested in Q4 2018.</td>
</tr>
<tr>
<td></td>
<td>Management’s Remediation Plan Progress</td>
<td>Management successfully closed five outstanding observations during this quarter. A total of 11 management action plans remain open with an average age of 14 months. Target Key Performance Indicator is 12 Months.</td>
</tr>
<tr>
<td></td>
<td>Internal Audit Initiatives</td>
<td>Internal Audit remains engaged in collaborative cross-departmental initiatives and has held several meeting with KPMG to align planning with work required on the SAP Project and ITGC work on legacy systems.</td>
</tr>
<tr>
<td></td>
<td>Audit Plan Progress and Changes to the Audit Plan</td>
<td>Maintenance and Stations Capital Audit and Project Aurora were behind schedule due to business delays and other operational priorities which has delayed the start of other planned audits. Additional controls in ICFR to cover cut-over activities are planned to be performed in Q4 along with any new controls from new ERP solution. Four (4) engagements that were planned to be completed during 2018 have not begun. Given the time elapsed since these areas were identified as audit priorities, IA suggests that they be put on hold until a risk-based audit planning exercise is completed to ensure their continued relevance within the current organizational risk profile.</td>
</tr>
<tr>
<td></td>
<td>Internal Audit Group Management</td>
<td>During the quarter, one Consultant was promoted to Finance Division. Effective September 27, the VP, Audit &amp; Corporate Compliance is no longer with Toronto Hydro. Scott Kiser from EY has been contracted until December 31, 2018 to act as interim Director for Internal Audit. Monica Martine has joined the team as a consultant on contract. Recruiting is on-going for a full time Consultant role and the Director Internal Audit &amp; Compliance role.</td>
</tr>
</tbody>
</table>

- Critical items requiring Audit Committee attention
- Important issues that warrant discussion
- Operating as expected
Quarterly Audit Activities

SUMMARY OF AUDIT ACTIVITIES

Internal Audit (IA) issued one Audit report, and one Planning memorandum for Internal Controls over Financial Reporting (ICFR) testing.

Maintenance and Stations Capital Audit

Maintenance processes are critical components to fulfill the vision of Toronto Hydro to continuously maximize customer and stakeholder satisfaction by being safe, reliable and environmentally responsible at optimal costs. Capital projects at stations enable Toronto Hydro to optimize the useful life of the assets in operations.

As part of our Maintenance and Stations Capital audit, Internal Audit focused on the following:

- All distribution assets are adequately maintained to sustain reliability of the system and optimize asset life.
- Compliance and adherence to the relevant provisions of Ontario Energy Board’s (OEB) Distribution System Code and formally documented process maps and policies of Toronto Hydro applicable to Maintenance and Stations Capital processes.
- Compliance and adherence to the metrics set by Toronto Hydro management to measure against the targets set within Custom Incentive Rate-setting (CIR) related to Maintenance and Stations Capital expenditures.
- Appropriate oversight of maintenance and stations capital projects processes to ensure that the projects are completed on time, on budget, in compliance with quality standards and are accounted for appropriately.

Maintenance and Stations Capital – Needs Improvement

The teams involved in planning, execution and monitoring of maintenance activities and stations capital work are fulfilling their mandate to achieve the overall vision of Toronto Hydro regarding customer and stakeholders’ satisfaction. There are, however, opportunities to improve processes around overall governance structure, monitoring and quality assurance of the documentation. Management has agreed with the observations and has committed to a management response and timeline for implementation for each observation.

<table>
<thead>
<tr>
<th>Issues</th>
<th># Audit Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>0</td>
</tr>
<tr>
<td>Medium</td>
<td>3</td>
</tr>
<tr>
<td>Low</td>
<td>3</td>
</tr>
<tr>
<td>Total Issues</td>
<td>6</td>
</tr>
</tbody>
</table>

TORONTO HYDRO
SUMMARY OF AUDIT ACTIVITIES
Field work on Project Aurora and Internal Controls over Financial Reporting (ICFR) was ongoing through this quarter.

Project Aurora: SAP Implementation Audit
Project Aurora is a strategic initiative to implement SAP ERP that will replace Ellipse and 30 other legacy systems. Internal Audit’s Phase 1 field work which covered project management and governance was completed, with no exceptions noted. Phase 2 field work has been completed with a few exceptions and improvement areas in Realization phase, none with a high level risk. Management addressed most of the observations with additional measures during the phase. Data Migration review has also been completed with no exceptions and Phase 3 (Data Migration and Cut-over) is near closure. Phase 4 (Security) field work is underway and is expected to get closed by Q4.

Internal Controls over Financial Reporting (ICFR)
The purpose of the Internal Controls over Financial Reporting (ICFR) review is to ensure that ICFR controls are tested on a regular basis and that the results of the testing are documented to support any attestation requirements (specifically those stemming from Bill-198) for the Certifying Officers.

Internal Audit has started reviewing ICFRs applicable over the first nine months (Jan-Sep 2018) period. Additional controls have been identified that were introduced during the cut-over period (when input to Ellipse ERP was restricted before going live with new Enterprise Connect ERP). These controls will also be tested and reported during Q4. New controls or any changes to controls due to the implementation of the new ERP solution will be performed in late Q4 2018 or early Q1 2019 depending on the resource availability.

<table>
<thead>
<tr>
<th>Project Aurora: SAP Implementation Audit</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Activities / Month</strong></td>
</tr>
<tr>
<td><strong>Planning</strong></td>
</tr>
<tr>
<td><strong>Fieldwork</strong></td>
</tr>
<tr>
<td><strong>Reporting</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Internal Controls over Financial Reporting</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Activities / Month</strong></td>
</tr>
<tr>
<td><strong>Planning</strong></td>
</tr>
<tr>
<td><strong>Fieldwork</strong></td>
</tr>
<tr>
<td><strong>Reporting</strong></td>
</tr>
</tbody>
</table>

*Note: Reporting will include ongoing communication of observations to the project management issue log as well as capstone reporting.*
Management’s Remediation Plan Progress

HIGHLIGHTS

Management successfully closed five outstanding observations bringing down the total outstanding observations from previous quarter to 5. Internal Audit continues to be pleased with the depth of Management’s analysis and monitoring of their remaining remediation projects.

One of the observations closed this quarter stemmed from the 2016 Meter to Cash audit (medium risk) and four from the EPMO Audit (two medium risk and two low risk), as follows:

- Communication requirements for Pre-authorized Debits (PAD) recommendation has been addressed with introduction of emails sent to customers with all regulatory requirements (16-05-MTC-12);
- Improvements to the Change Request (CR) Process were introduced along with the implementation of new ERP solution (17-01-EPMO-01);
- New BRP metrics on creating CRs on time for planned work was introduced (17-01-EPMO-02);
- Monthly scorecards have been updated with the new BRP metrics that reflect the updated calculation methodology that accounts for overdue PVA submissions (17-01-EPMO-03); and
- OpEx QAQC findings are now in the QAQC log as of 2018v3 completed in September 2018 (17-01-EPMO-04);

*Cut off for remediation evaluation was October 12, 2018
HIGHLIGHTS

The average age of outstanding management action plans is 14 months which exceeds our target KPI of 12 months. Management closed one observation that was outstanding for over one year in Q3 2018.

As previously communicated, the sub-optimal aging is primarily driven by two very old audit issues that remain unresolved due to ongoing negotiations with related parties:

1. Excluding these two issues, aging would be 6 months.

Ageing of Issues

- Green: Less Than 6 months
- Yellow: 6 Months to 1 Year
- Red: More Than 1 Year

* Aging as at September 30, 2018
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 10:

Reference(s):

- Exhibit 1B
- Exhibit 2B
- Exhibit 4A

Please provide details of all material productivity initiatives (capital and/or OM&A) that were undertaken or planned to be undertaken between 2015 and 2019. Please provide the estimated cost savings achieved and how those savings were calculated.

RESPONSE:

Please see Toronto Hydro’s response to 1B-CCC-14.
INTERROGATORY 11:

Reference(s): Exhibit 1B
Exhibit 2B
Exhibit 4A

Please provide details of all material productivity initiatives (capital and/or OM&A) that are planned to be undertaken during the test period. Please provide the estimated cost savings achieved and how those savings were calculated.

RESPONSE:

Please see Toronto Hydro’s response to interrogatory 1B-CCC-14.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 12:

What is the basis for the specific 3.5% upper limit on annual increases to base distribution rates? Please define what Toronto Hydro defines as base distribution rates.

RESPONSE:

This was the lowest annual average increase to base distribution rates that Toronto Hydro determined would be sufficient to fund the investments and expenses necessary to be responsive to: (1) the utility’s legal requirements including safety; (2) customer feedback; and (3) business input through expert analysis and professional judgment to develop programs that address technical and operational requirements. Please also see Exhibit 2B, Section E2, E.2.1.1 and E.2.1.2, and Exhibit 1B, Tab 1, Schedule 1.

Toronto Hydro understands base distribution rates to be the fixed and variable components of rates that recover Base Revenue Requirement, excluding rate riders.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 13:
Reference(s): Exhibit 1B, Tab 1, Schedule 1, Appendix A

Please revise the table to include show base distribution bill impacts only, and expand to include years 2015 to 2019.

RESPONSE:
Table 1 below provides summary for 2015-2024 base distribution bill changes for all rate classes.
### Table 1: 2015-2024 Base Distribution Bill Changes

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>$/30 days</td>
<td>0.00</td>
<td>6.72</td>
<td>2.15</td>
<td>1.57</td>
<td>1.00</td>
<td>0.54</td>
<td>1.37</td>
<td>1.07</td>
<td>1.89</td>
<td>1.83</td>
</tr>
<tr>
<td></td>
<td>%</td>
<td>0.0</td>
<td>22.3</td>
<td>5.8</td>
<td>4.0</td>
<td>2.5</td>
<td>1.3</td>
<td>3.3</td>
<td>2.5</td>
<td>4.2</td>
<td>3.9</td>
</tr>
<tr>
<td>Competitive Sector Multi-Unit Residential</td>
<td>$/30 days</td>
<td>0.00</td>
<td>2.50</td>
<td>2.18</td>
<td>1.80</td>
<td>1.41</td>
<td>0.31</td>
<td>1.09</td>
<td>0.85</td>
<td>1.50</td>
<td>1.45</td>
</tr>
<tr>
<td></td>
<td>%</td>
<td>0.0</td>
<td>9.9</td>
<td>7.9</td>
<td>6.0</td>
<td>4.5</td>
<td>0.9</td>
<td>3.3</td>
<td>2.5</td>
<td>4.2</td>
<td>3.9</td>
</tr>
<tr>
<td>General Service &lt;50 kW</td>
<td>$/30 days</td>
<td>0.00</td>
<td>16.17</td>
<td>6.31</td>
<td>5.05</td>
<td>3.79</td>
<td>3.67</td>
<td>3.45</td>
<td>2.68</td>
<td>4.74</td>
<td>4.59</td>
</tr>
<tr>
<td></td>
<td>%</td>
<td>0.0</td>
<td>22.9</td>
<td>7.3</td>
<td>5.4</td>
<td>3.9</td>
<td>3.6</td>
<td>3.3</td>
<td>2.5</td>
<td>4.2</td>
<td>3.9</td>
</tr>
<tr>
<td>General Service 50-999 kW</td>
<td>$/30 days</td>
<td>0.00</td>
<td>244.61</td>
<td>103.32</td>
<td>82.75</td>
<td>61.95</td>
<td>54.49</td>
<td>56.26</td>
<td>43.85</td>
<td>77.42</td>
<td>74.80</td>
</tr>
<tr>
<td></td>
<td>%</td>
<td>0.0</td>
<td>20.8</td>
<td>7.3</td>
<td>5.4</td>
<td>3.8</td>
<td>3.3</td>
<td>3.3</td>
<td>2.5</td>
<td>4.2</td>
<td>3.9</td>
</tr>
<tr>
<td>General Service 1,000-4,999 kW</td>
<td>$/30 days</td>
<td>0.00</td>
<td>1,905.01</td>
<td>848.57</td>
<td>679.46</td>
<td>508.84</td>
<td>436.73</td>
<td>461.65</td>
<td>359.69</td>
<td>635.38</td>
<td>613.95</td>
</tr>
<tr>
<td></td>
<td>%</td>
<td>0.0</td>
<td>19.5</td>
<td>7.3</td>
<td>5.4</td>
<td>3.8</td>
<td>3.2</td>
<td>3.3</td>
<td>2.5</td>
<td>4.2</td>
<td>3.9</td>
</tr>
<tr>
<td>Large Use</td>
<td>$/30 days</td>
<td>0.00</td>
<td>10,150.84</td>
<td>4,367.47</td>
<td>3,497.29</td>
<td>2,618.83</td>
<td>2,445.01</td>
<td>2,383.03</td>
<td>1,856.68</td>
<td>3,278.51</td>
<td>3,167.49</td>
</tr>
<tr>
<td></td>
<td>%</td>
<td>0.0</td>
<td>20.3</td>
<td>7.3</td>
<td>5.4</td>
<td>3.8</td>
<td>3.5</td>
<td>3.3</td>
<td>2.5</td>
<td>4.2</td>
<td>3.9</td>
</tr>
<tr>
<td>Street Lighting</td>
<td>$/30 days</td>
<td>0.00</td>
<td>0.24</td>
<td>0.46</td>
<td>0.37</td>
<td>0.28</td>
<td>0.25</td>
<td>0.25</td>
<td>0.19</td>
<td>0.34</td>
<td>0.33</td>
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<tr>
<td></td>
<td>%</td>
<td>0.0</td>
<td>3.8</td>
<td>7.3</td>
<td>5.4</td>
<td>3.9</td>
<td>3.3</td>
<td>3.2</td>
<td>2.4</td>
<td>4.2</td>
<td>3.9</td>
</tr>
<tr>
<td>Unmetered Scattered Load</td>
<td>$/30 days</td>
<td>0.00</td>
<td>5.36</td>
<td>2.07</td>
<td>1.66</td>
<td>1.24</td>
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<td>1.55</td>
<td>1.50</td>
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<tr>
<td></td>
<td>%</td>
<td>0.0</td>
<td>23.2</td>
<td>7.3</td>
<td>5.4</td>
<td>3.8</td>
<td>3.5</td>
<td>3.3</td>
<td>2.5</td>
<td>4.2</td>
<td>3.9</td>
</tr>
</tbody>
</table>

Note 1: excludes ICM rate riders.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 14:
Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 8-20

Please update all charts to show the latest available information.

RESPONSE:
Please see the updated charts below.

Table 2: Average WSIB Accident Costs (at page 8)

<table>
<thead>
<tr>
<th></th>
<th>Toronto Hydro</th>
<th>Hydro One Networks</th>
<th>Alectra Utilities</th>
<th>Hydro Ottawa</th>
<th>London Hydro</th>
<th>Enwin Utilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average WSIB Accident Costs</td>
<td>$37,825</td>
<td>$1,697,939</td>
<td>$73,901</td>
<td>$203,276</td>
<td>$78,526</td>
<td>$22,279</td>
</tr>
<tr>
<td>2014-2017</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average WSIB Accident Costs per Employee 2014-2017</td>
<td>$22.98</td>
<td>$229.45¹</td>
<td>$49.27</td>
<td>$290.39</td>
<td>$241.61</td>
<td>$70.05</td>
</tr>
</tbody>
</table>

¹ Represents the cost for all full and part-time employees. The breakdown for full time employees, as provided in the pre-filed evidence, is not available to Toronto Hydro.
Figure 2: Total Recordable Injury Frequency (TRIF) (at page 9)

Toronto Hydro notes that the TRIF chart included in the pre-filed evidence was incorrect. The correct information has been reflected in the chart above.

Figure 3: Restricted Work Days (at page 10)
Toronto Hydro experienced a significant lost time incident in 2017 which contributed to the 2017 results, i.e. greater WSIB NEER costs (above) and Performance Index results (below).
Note: 2015 OTOs written one day ahead of execution and 2016/2017 OTOs written and checked one day ahead of execution for North and written only for South.

Figure 6: Percentage of Orders to Operate Completed Ahead of Work Execution

(at page 14)

Figure 7: Average Crew Wait Times for Hold Offs (at page 15)
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 15:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B

With respect to the UMS Unit Cost Benchmarking Study:

a) Please provide a copy of the retainer and any other instructions provided to UMS.

b) Please provide a copy of the material listed in Appendix A. [Note: If the material is on the record in a previous OEB proceeding, it is acceptable to simply provide the evidentiary reference and agree to deem the material on the record in this proceeding].

c) [p.12] With respect to the peer group:
   i) Please explain in greater detail the basis for the peer group selected.
   ii) Please explain why no other Ontario utility was selected.
   iii) Which were the three utilities that declined to participate?

d) [p.17] UMS states the results are based on a 3 year average (2014-2016):
   i) Please explain precisely what is meant by this. For example, is the data for a utility simply averaged over the three years or is it weighted to account for different amount of work undertaken in each year?
   ii) Please provide separate results, for each year.

e) [p.29] Please provide the source of the data in Table C-1.
f) [p.32-33] Please provide the underlying excel spreadsheets C-8 to C-10, with all formulas intact.

g) [p.37, Table D1] please provide a copy of all similar unit cost studies undertaken previously that have been filed in regulatory proceedings or otherwise are or can be made publically available.

h) [p.55] Please provide Toronto Hydro’s response to Appendix F.

RESPONSE:

a) Please refer to Toronto Hydro’s response to interrogatory 1B-CCC-8.

b) Please refer to Toronto Hydro’s response to interrogatory 1B-Staff-9.

c) With respect to the specific inquiries regarding the peer group, the following information is provided:

i. Peer Group Selection Process: The bases for selecting the peer group used for this study included a myriad of factors, including the following but limited to:¹

   a. Significant amount of electric distribution with underground city networks, a blend of OH and UG construction, and challenges with aging infrastructure,

   b. Sizeable customer base with increasing expectations regarding safe and reliable service,

¹ Please note that the order of presentation does not infer relative importance

Panel: General Plant, Operations, and Administration
Panel: General Plant, Operations, and Administration

c. Organizational commitment to improving the efficiency and effectiveness of its workforce (i.e. higher likelihood of tracking unit costs),
d. Existence of external factors (e.g. weather / climate, traffic congestion, city ordinances, vegetation, environmental mandates, etc.) that can impact productivity, and
e. Significant contributor to city / provincial / state economies and municipal or investor finances.

i. Explanation regarding Ontario Utilities: Please refer to Toronto Hydro’s response to interrogatory 1B-Staff-6.

iii. Utilities that Declined to Participate are Consolidated Edison (New York City), Commonwealth Edison (Chicago, IL), and Public Service Electric and Gas (Newark, NJ).

d) UMS Group applied a three-year average to account for the “peaks and valleys” of specific projects and programs, in order to present a leveled view of unit costs over an extended period of time:

I. UMS Group weighted the three-year averages that formed the bases for its comparisons, thus accounting for the different amount of work undertaken in each year.

II. Toronto Hydro’s response to this request (included as part of Appendix A - (h) Unit Cost Survey - THESL September 05, 2017.xlsx) illustrates this process (please refer to column K for all asset classes and column L, line 9 where UMS Group combined the vault inspections). The peer group provided a three-year average (in lieu of providing annual costs and quantities), as a concession to ease their data collection and reporting process.
e) The sources for data in Table C-1 included (i) the Board of US Labor Statistics for the US utilities and (ii) various municipalities and provincial government websites in Canada.

f) Please refer to the attached Appendix B, titled *Unit Cost Survey (f) Plots and Graphs Working Copy.*

g) The following are the most recent examples of the UMS Group comparative analyses/benchmarking studies that are publicly available:

I. ATCO Electric PBR Rate Filing Support (please refer to the attached Appendix C, titled *(g) ATCO Electric System Maintenance Capital*)

II. FirstEnergy (JCP&L) Investment, O&M Spending and Performance Comparison Study (please refer to the attached Appendix D, titled *(g) FE-JCPL Testimony*)

III. Dayton Power and Light (AES) T&D System Refurbishment and Replacement Risk Assessment (please refer to the attached Appendix E, *(g) DPL TD Risk Analysis*)

h) Please refer to the attached Appendix A, titled *(h) Unit Cost Survey - THESL September 05, 2017.*
Focused Assessment of ATCO Electric’s System Maintenance Capital Investment Levels (2013 through 2016)

Conducted by

UMS Group Inc.
Morris Corporate Center 1
300 Interpace Parkway, Suite C380
Parsippany, NJ 07054

February 2012
ANALYSIS OF ATCO ELECTRIC 2013-2016 SYSTEM MAINTENANCE CAPITAL FORECAST

Introduction

In response to interveners’ concerns that ATCO Electric’s (hereinafter referred to as “ATCO Electric” or “the Company”) distribution System Maintenance Capital Additions forecast for the period 2013 through 2016 was not fully substantiated, the Company engaged UMS Group to conduct an independent, focused assessment of ATCO Electric’s Performance Based Regulation Application (hereafter PBR) in Proceeding ID 566 under the Alberta Utilities Commission (AUC), including its related subsequent information responses.

The overarching objective of this independent assessment was to thoroughly assess the adequacy, appropriateness, and prudence of its planned System Maintenance Capital Additions over the PBR term. In so doing, UMS Group has presented specific assessments and conclusions about the proposed level of investment and the focus of its investment programs, all within the appropriate context of other, similar electric utilities while incorporating the ATCO-specific historical investment patterns and performance, and the relevant local characteristics such as the high projected customer growth within Alberta and low system density.

Our approach is illustrated in Figure 1.1 below and consisted of the following four steps:

Figure 1.1 – UMS Group Analytic Approach

In adopting this approach, UMS Group has independently and objectively assessed the Company’s 2013 through 2016 System Maintenance Capital Additions plan. We had complete access to the Company’s technical and management team, and relied extensively on Company data and information already in the public domain under the AUC PBR proceeding; or that which was provided by the Company in response to a specific request to complete the analysis. Our approach applied a “range of reasonableness” criteria in total and at the major category levels (i.e. Growth Related Capital Additions – I-X Factor and...
Reliability, Replacement, and Safety Additions – K Factor), further comparing K Factor proposed investment levels to industry norms (again in total and within its 3 major categories), and determining the effectiveness and efficiency of the plan in managing, and where appropriate, mitigating system performance risk.

Figure 1.2, summarizing the overall Schedule of Distribution Capital Additions for the 2013 through 2016 PBR Application, was the primary source for our financial analyses.

**General Overview**

As a result of this assessment, UMS Group has concluded that the magnitude and scope of ATCO Electric’s overall capital additions planned for the PBR filing period of 2013 through 2016 fall well within the range of reasonableness based on our experience at developing, assessing, and monitoring multi-year distribution capital plans at over 25 global electric utilities over the past decade. More specifically, the Company’s system maintenance and capital additions are both appropriate and well-directed. The evidence outlined in this report supports our position that the growth and new capacity-related additions will be a large and increasing portion of the total capital additions and that the Company’s reliability and replacement related additions are relatively stable and appropriate in the face of the growing challenge of providing safe and reliable service to its customers. Specifically, this report notes that:

![Figure 1.2 – Schedule 5-2-6 from ATCO Electric’s PBR Filing](image)
• ATCO Electric’s relative investment levels are projected to decrease from 2.27 times depreciation in 2013 to 1.97 in 2016 (Figure 1.3), where other studies have shown that a “steady state” average industry-wide ratio in the range of 2.06 appropriately accounts for inflation, historical rate of replacement, reliability, and risk tolerance of all stakeholders. The fact that the Company’s projected level of investment ultimately places it in the 3rd quartile of relative spending is indicative of the system’s unique design (low customer density and many lightly-served, long distribution lines, and a large number of remote areas in comparison to other electric utilities) and the fact that the industry as a whole has tended to underinvest in its distribution assets.

Figure 1.3 – ATCO Electric’s Overall Level of Capital Additions

• The Growth Related Capital Additions average approximately 45% of the System Maintenance Capital Additions during the 2013 through 2016 PBR filing period, yet are subject to very little direct control by the utility. The comparatively high projected customer growth rates of approximately 2% per year correlate with the documented GDP growth rates for Alberta (Figure 1.4), and growth-related per new customer connection additions (less CIAC) are projected to increase at a compound average growth rate (CAGR) of 2.6%, lower than the inflation estimate of 3.2% noted in the PBR filing. Taken in its totality (i.e. increase of total growth-related costs vs. projected customer growth and inflation), the Company’s growth related capital additions projection is conservatively estimated and consistent with other elements of the PBR plan.
Figure 1.4 – Customer Growth Rates and GDP Growth Projections

Figure 1.5 – “No Growth” Capital Additions Relative to Depreciation

- Figure 1.5 provides an illustrative view of the “No Growth” Distribution Capital Additions (i.e. total capital additions less additions for customer connections, net of any CIAC) relative to Depreciation over this time frame, confirming that these additions, largely impacted by Reliability, Replacement and Safety additions (i.e. the K-Factor portion of System Maintenance Capital Additions), are well within, if not trending below, industry norms that range between 1.4 and 1.55 times depreciation. This represents a prudent and reasonable level of overall reinvestment, a view that is substantiated by further review of the three primary areas that comprise the K Factor 2013 through 2016 forecast portion of System Maintenance Capital Additions.

- In assessing the latent system performance risks related to maintaining historic levels of reliability within the context of the proposed PBR filing, the Company has, on both a macro and project basis, allocated its “No Growth” capital additions proportionate to that risk and at levels consistent with our independent analysis of the Company’s existing asset based and related asset mortality patterns.
The conclusions stated above are further explained in the following “Summary of Results” portions of this analysis summary.

Summary of Results – Reliability, Replacement and Safety Additions (K Factor)

This portion of the analysis focused on three primary categories of investments that comprise the K Factor for the 2013 through 2016 time period:

1. Asset Replacement / End of Life investments, representing over 60% of the K Factor additions, compares favorably (lower quartile) to an established peer group within the UK electric system (Figure 1.6) during the 2005-2010 (actual expenditures) and 2010-2015 (projected expenditures) cycles; a group selected as they offer a close, though not perfect comparison to ATCO Electric, and with a breakout of asset replacement cost data considerably better than that which exists for North American utilities.

Figure 1.6 – ATCO Electric vs. UK Asset Replacement Relative to Depreciation

Note that Figure 1.6 highlights two general areas of comparison for ATCO Electric: The left portion of the chart highlights the UK results during DPCR4 (2005-2010) and right portion highlights UK results during DPCR5 (2010-2015), illustrating the following points:

- ATCO Electric’s past and projected asset replacement capital additions relative to depreciation are below average (generally lowest quartile) in comparison to this UK peer group.

- ATCO Electric’s asset replacement capital additions, although nominally rising, are approximately 38% of depreciation (slightly lower than the previous period) during the PBR period of 2013-2016.
From an overall perspective, ATCO Electric's asset replacement capital additions appear to be well within the range of reasonableness when compared to other, similar electric systems. Indeed, based on this high level comparative analysis, ATCO Electric's overall asset replacement spending levels could indeed be expanded and yet still remain within a comparatively “normal” level should such increases be necessary.

2. Clearance and Safety investments, representing just over 22% of K Factor additions, includes programs that are either mandatory (e.g. Wild Fire Right of Way, which is almost half of the Clearance and Safety forecast), prudent / appropriately proactive initiatives from the viewpoint of maintaining safety (e.g. Agricultural Clearance and Double Circuit Removal Programs), or at levels typical of the industry (i.e. Vegetation Management).

Figure 1.7 – Clearance and Safety Additions by Function

In summary, in reviewing Section 5 of ATCO Electric’s PBR Application as well as the business cases provided in the company’s responses to Information Request AUC-AE-4, the Clearance and Safety additions in total, our view is that they are both reasonable and prudent:

- Wild Fire Right of Way, comprising approximately 45 to 50% of the forecasted costs from 2013 through 2016, reflects a mandatory requirement (Wildfire Prevention Agreement).

- Agricultural Clearance Program, comprising 15 to 20% of the forecasted costs from 2013 through 2016, reflect a sufficient proactive investment to transition to current requirements and thus minimize the risks related to the increased height of modern agricultural equipment.

- The Double Circuit Removal Program, comprising approximately 20% of the forecasted costs from 2013 through 2016, reflects a well-planned and prioritized scheme to address highest risk lines in terms of potential operational and safety impacts.
• Capital Vegetation Management, comprising less than 15% of the forecasted costs from 2013 through 2016, falls well within the range of reasonableness relative to OMA-related vegetation management.

3. Reliability, representing approximately 15% of the K Factor additions, includes provision for automation (reflecting a prudent, well-targeted and incremental approach at comparatively small levels of investment) and small reliability projects appropriately targeted for interruption event mitigation. The comparatively low investment level for these projects is indicative of ATCO Electric’s system reaching the point of diminishing return with respect to the simpler, more cost-effective investments (e.g. fuses and sectionalizing) and the need to address the emerging “bow wave” of equipment failure caused interruptions addressed as part of the Asset Replacement / End of Life category (addressed above).

Summary of Results – Attendant System Performance Risks Related to Reliability, Replacement and Safety Additions (K Factor)

In assessing system performance risk, our analysis addressed the most likely causes of future degradation of electric system reliability; and given a stepped increase in reported interruption events in 2010 (coinciding precisely with and typical of the implementation of a new Outage Management System), focused on system and asset reliability performance through 2009.

Given the emphasis on capital additions (i.e. investment), we viewed the variables around SAIFI (i.e. customer interruptions and number of customers) as key to initially understanding the patterns and trends that play a role in assessing the appropriateness of ATCO Electric’s past and future Reliability, Replacement and Safety investment levels. Acknowledging that the Company’s reliability performance (SAIFI) is overall better than average in comparison to its Canadian Electricity Association (CEA) peers, UMS Group sought to analyze and identify any potential lingering or emerging challenges being masked, which once unleashed could have severe consequences to all stakeholders. This required further decomposition of overall system performance, yielding the following observations and insights:

• Though there have been an increasing number of interruption events, there has yet to be an apparent degradation in overall system reliability.

• The number of customer interruptions has remained essentially unchanged, yet the average service interruption size has decreased from as many as 35 customer interruptions per event to consistently fewer than 25 customers over the past 10 years (Figure 1.8). This is generally reflective of well-targeted past investments in system protection, sectionalizing, and other interruption event-mitigation strategies.

Given the absence of any noted continued improvement (decrease) in number of customer interruptions, this likely points to ATCO Electric reaching the point of diminishing returns in deploying these cost effective approaches to maintain reliability.
ATCO Electric’s past and projected investment levels are both prudent and consistent with industry “best practices,” and to date, have contributed to maintaining overall system reliability. However, given the leveling out of the incremental effectiveness of investments aimed at service interruption mitigation, our experience in addressing aging and deteriorating electric system infrastructures and their long term impact on future reliability led us to conduct a further decomposition of the reliability performance to (1) uncover any latent system performance risks, and (2) if present, define how best to focus investments to counter these risks; and, in so doing, assess the current PBR filing for 2013 through 2016 for effectiveness in addressing these risks.

In order to further focus the analysis, past interruption events were analyzed by reviewing the source of interruption (i.e. cause). The mix of causes has not appreciably changed since 2000, but the average size of an interruption event (customer interruptions per event) and scope (customer hours per event) points heavily to equipment failure (and attendant adverse weather) causes as the point of the Company’s greatest leverage in forestalling potential degradation in reliability (Figure 1.9):

- Equipment failure related interruption events average over 41 customer outages per event and 127 customer hours per event.
• Adverse weather, oftentimes viewed as a form of equipment failure caused by excessive wind speed, ice loading, etc., leads to the need to replace / repair “brittle” equipment in the course of service restoration.

While these two sources of interruption events established a highly leveraged focus for maintaining, if not improving reliability, the next step was to determine trends in event frequency, particularly given that to date there has been no noted deterioration in reliability. Figure 1.10 illustrates an overall rising trend in customer interruptions:

![Figure 1.10 – Equipment Failure and Adverse Weather Trends](image)

A review of the following distribution assets aging profile (Figure 1.11) lends credence to the notion that the proverbial “bow wave” of challenges around aging infrastructure is approaching.

![Figure 1.11 – Distribution Assets Aging Profile](image)
The overall trend illustrated in Figure 1.11 above suggests a continually aging (and potentially deteriorating) population of distribution assets at either the 2009 to 2010 or proposed PBR filing investment levels, and supports our view that the level of investment proposed by the PBR filing will reduce system performance risk related to aging infrastructure, but does not reflect an “over reaction” or tendency to “gold plate” the solution.

The implications of this assessment of system performance risk include:

- Equipment Failure (including Adverse Weather) caused interruption events will eventually counter and ultimately dwarf the impact of the most cost-effective interruption event mitigation investments, funded under the Reliability portion of the K Factor plan.

- The sheer size (number of customer interruptions) and scope (number of customer hours per interruption event) of equipment failure caused interruption events points towards a significant degradation of reliability if not addressed prior to realization of the pending “bow wave” equipment failures.

- Given the time lag between identifying and implementing investments relating to equipment failure, the projected impact on reliability on a system-wide level, and the aging profile of distribution assets, any delay in implementing a stepped increase in Asset Replacement / End of Life Additions could significantly increase the exposure of customers to an extended period of poor reliability.

Therefore, from a programmatic perspective, the notion of a K Factor plan, with increases heavily weighted towards Asset Replacement / End of Life Additions (as is the case with this PBR filing) aligns with this assessment of system performance risk; coupled with our view that the level for this category of investment compares favorably to our established peer group of utilities (lower quartile) further supports the prudence and reasonableness of the 2013 through 2016 PBR filing.

Summary of Results – Validate Investment Levels within the Asset Replacement / End of Life Category of K Factor Additions

The Asset Replacement / End of Life plan represents the majority of Company’s “discretionary” investment capital in the K Factor portion of System Maintenance Capital Additions; and overall, from an industry comparative view, has been deemed reasonable and appropriate. The final step in our assessment involved analyzing the plan’s effectiveness (i.e. validate the allocation of proposed investment levels across specific asset classes based on insights gleaned from the previous assessment of system performance risk).

In narrowing in on the classes of equipment on which to focus investments, UMS Group looked first at the equipment failure events by cause or class of equipment, and then the distribution of K Factor forecasted additions. Our analysis, summarized in Figure 1.12, confirmed a strong relationship between the percent of forecasted K-Factor additions assigned to categories of equipment and the relative contribution of these categories to customer hours of interruption (e.g. 77% of the customer hours of interruption were attributed to line-related equipment failures and Clearance and Line related additions range between 79 and 80% of the forecasted K-Factor Additions).
Therefore, from a category of asset basis, the 2013 through 2016 PBR Filing not only reflects appropriate priority on equipment failure as a means of managing and / or mitigating system performance risk, it is also properly apportioned to address the relative contribution of each category to customer hours of interruption.

Lastly, our analysis focused on whether the Company’s investment plans for major individual asset categories are prudent and consistent with their relative contribution to system performance risk. Our approach involved estimating the Company’s experienced asset mortality trends from plant asset records (by category) and integrating these estimates with ATCO Electric’s asset population in that category (by vintage). In so doing, we estimated or forecasted, on an asset category specific basis, the expected additions, incorporating the natural aging that occurs through this time period. Acknowledging that the proposed investment levels for the Company’s Poles and Fixtures, Overhead Conductor, and Line Transformers account for 72% of the Company’s total Asset Replacement / End of Life Additions (and almost 50% of the K-Factor portion of the System Maintenance Capital PBR filing from 2013 through 2016), we selected these three categories of assets as a valid proxy for our analysis, the results of which are summarized in Figure 1.13.

NOTE: “The actuarial cost estimate in Figure 1.13 for pole replacement (2013-2016) includes an adjustment factor of 2.4 to address the higher per unit pole replacement cost vs. the lower original (green field) construction cost; these higher costs are predominantly due to additional..."
expenses from pole removal, site access, and the ancillary costs of targeted replacement vs. mass new construction."

The annual variances between the UMS Group derived replacement costs (Actuarial Estimate) and the PBR estimates, range between 4 and 14% over the filing period (2013 through 2016) and are generally higher than the Company’s planned capital additions. This supports our view that the Company’s investment levels are conservatively and properly sized, allocated, and appropriately focused on mitigating any latent system performance risk. Further, as illustrated in Figure 1.14, in extending our analyses to outlying years, it is apparent that the cost pressures related to the Asset Replacement / End of Life Category of K Factor Additions is likely to continue beyond this PBR filing.

Figure 1.14 – PBR and Projected Investment Plan of Major Categories of Assets
Therefore, our overarching conclusions are that the Company’s asset replacement investment plans are well within the range of reasonableness and are aligned to proactively address the system performance risks related to aging and/or deteriorating electric infrastructure. The table below (Figure 1.15) summarizes our conclusions by expenditure category:

**Figure 1.15 – Summary of Conclusions**

<table>
<thead>
<tr>
<th>Category</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line Moves / Encroachment</td>
<td>Part of I-X Capital Additions</td>
</tr>
<tr>
<td></td>
<td>Consistent with projected activity, historic costs and inflation estimates</td>
</tr>
<tr>
<td>Clearance and Safety</td>
<td>Part of K Factor</td>
</tr>
<tr>
<td></td>
<td>Idiosyncratic to unique jurisdictional requirements</td>
</tr>
<tr>
<td></td>
<td>Largely mandatory (Wild Fire) or appropriately conservative in proposed investment levels (Double Circuit and Agricultural Clearance Programs)</td>
</tr>
<tr>
<td></td>
<td>Capital Vegetation Management consistent with industry norms as a percent of overall Vegetation Management</td>
</tr>
<tr>
<td>Alternate Feeds</td>
<td>Part of I-X Capital Additions</td>
</tr>
<tr>
<td></td>
<td>Consistent with projected activity, historic costs and inflation estimates</td>
</tr>
<tr>
<td>Capacity Additions</td>
<td>Part of I-X Capital Additions</td>
</tr>
<tr>
<td></td>
<td>Consistent with projected activity, historic costs and inflation estimates</td>
</tr>
<tr>
<td>Reliability</td>
<td>Part of K Factor</td>
</tr>
<tr>
<td></td>
<td>Low in comparison to industry norms (likely in response to emerging issues around equipment failure / adverse weather caused outages)</td>
</tr>
<tr>
<td></td>
<td>Levels of Distribution Automation appear reasonable, but relatively low provision for small Reliability Projects potential cause for concern (emergent work could partially “crowd out” Asset Replacement / End of Life investments)</td>
</tr>
<tr>
<td>Asset Replacement / End of Life</td>
<td>Part of K Factor</td>
</tr>
<tr>
<td></td>
<td>Compares favorably (lower) with the established peer group yet reflects an appropriate shift in focus (step increase) towards addressing aging infrastructure</td>
</tr>
<tr>
<td>New Technology</td>
<td>Part of I-X Capital Additions</td>
</tr>
<tr>
<td></td>
<td>Level of proposed additions indicative of minor system improvements related to electric distribution system growth (higher than historic average which is significantly lower than industry norms)</td>
</tr>
</tbody>
</table>
Our review and analysis of ATCO Electric’s system maintenance capital additions for the period 2013-2016 has been conducted from two perspectives:

- We have conducted a top-down assessment of the Company’s overall capital investment levels, providing stakeholders with an independent assessment of the reasonableness, prudency, and appropriateness of the overall capital investment plan and thereby establishing a context for the focus of this review, the Company’s System Maintenance Capital Additions. This “in total” view of capital additions and its major components will identify whether or not the Company has developed an extraordinary investment program (i.e. either extremely low or high levels of investment) that may potentially jeopardize future performance (through unmitigated risks from lack of reinvestment) or create unreasonable rate pressure (through excessive or unnecessary spending). It will provide a comparative and informed view of potential similarities and differences between ATCO Electric and the industry. Informed stakeholders are aware that perfect cross-company comparisons are not possible given the infinite variation in utility operations, accounting principles and practices, service territories, etc., particularly given the uniqueness of ATCO Electric’s geography and system demographics. However, in our view, these comparisons do provide directional insight into the appropriateness of total capital investment levels, and by inference system maintenance capital additions.

- We have also conducted a bottom-up assessment focused on ATCO Electric’s system maintenance capital additions by major program or category of spending. While it is essential that the overall level of capital additions is prudent (noted above), it is equally important that the specific expenditures that comprise the Company’s system maintenance investment plans are appropriate to address known and prioritized needs. Simply put, these specific expenditure levels by program or class need to be appropriately balanced to address the Company’s relative risks / requirements related to the electric system, not ignore material or latent risks, and yet be focused on proper or necessary investments.

Such a bottom-up approach is inherently analytic in nature. It relies on an analysis of past electric system and asset performance, reasonable projections or estimates of future performance and risks, and judgments regarding the proper level of risks to incur in optimizing the mix of capital investment priorities, defining the levels of investment within the specific programs, all within the context of total expenditures.

The totality of these two perspectives will allow us to make specific conclusions about the Company’s system maintenance capital additions program for 2013-2016 within the context of the total capital additions program, with a proper view relative to attendant system risks (outlined in Section 3), historical investment patterns, and projected growth within Alberta.

**DISTRIBUTION CAPITAL ADDITIONS – TOP DOWN ASSESSMENT**

ATCO Electric’s planned distribution capital additions were presented in Schedule 5-2-6 of its PBR filing and are presented below in Figure 2.1. Under this plan, the total net system capital additions rises to $274.5M in 2016 (see line 30 in the diagram), almost double the
Company’s 2009 net additions of $137.5M in 2009 yet within the range of the approved GTA levels of $260.5M and $321.2M for 2011 and 2012, respectively.

Figure 2.1 also introduces several administrative topics. First, all capital-related values presented in the balance of this report will use a “capital additions” focus, except where expressly noted. This capital additions approach (as opposed to capital expenditures) is consistent the Company’s PBR filing. Naturally, actual expenditures will vary slightly from capital additions in any given period. However, presuming little or no material net change in construction work in progress (CWIP), capital additions and capital expenditures will be nearly identical and consistent within any period as well as over the long run.

Further, total capital additions will be shown net of customer contributions consistent with their treatment in rate base. All capital additions, except where expressly noted, will be presented in nominal or current year expected expenditures; thus, underlying cost estimates will embody the Company’s anticipated inflation throughout the planning horizon.

Lastly, data presented through 2010 are actual results (e.g. denoted 2010-A), data presented in 2011-2012 are approved spending levels (denoted 2012-Ap), and data presented in 2013-2016 are based on the PBR forecasts (denoted 2013-F).

Figure 2.1 – Schedule 5-2-6 from ATCO Electric’s PBR Filing

A graphical summary of the Net System Capital Additions from Figure 2.1 is presented in Figure 2.2 below.
There are a number of logical questions that follow from Figure 2.2 including:

1. How does ATCO Electric’s overall distribution capital additions compare to other systems?
2. What is the cause of the general, long run upward trend in ATCO Electric’s capital additions?
3. What is the source of the extraordinary, temporary increase in capital during the 2011-2012 time frames?
4. What is a “right” or reasonable level of net system capital additions?
5. How can stakeholders be sure that this overall level of additions is prudent?

To compare ATCO Electrics overall capital additions to other systems, Figure 2.3 presents the Company’s total distribution capital additions as a ratio to depreciation across a sample of approximately 40 U.S. based investor-owned electric utilities. In opting for this comparison (in lieu of capital additions per line km / per customer), we in essence normalize for overall investment levels relative to system demographics (e.g. customer density and system size) and highlight ATCO Electric’s reinvestment levels relative to existing rate base.
Figure 2.3 – ATCO Electric’s Overall Level of Capital Additions

Figure 2.3 above highlights the following points:

- Overall capital additions for the median U.S. electric distribution system in the peer group were typically 1.8-1.9 times depreciation during the 2005-2008 era. This was an era of moderate growth; industry growth has recently fallen slightly with diminished economic activity and correspondingly investment levels in the 2009-2010 time periods have also declined slightly. These general levels are consistent over the very long term (20-30 years) for mature electric distribution systems in North America.

- ATCO Electric’s relative investment levels in the 2013-2016 era are projected to decrease from 2.27 times depreciation in 2013 to 1.97 in 2016. This long-run level of investment will generally place ATCO Electric in the 3rd quartile of relative spending levels. It is also consistent with our general expectations, given the uniqueness of the general ATCO Electric system design and characteristics (e.g. extremely low customer density and many lightly-served, long distribution lines, and remote areas as illustrated in Figure 2.4) and the Company’s growth projections presented later in this section. Appendix A of this report further explores this measure of the appropriateness of capital additions (i.e. capital additions relative to depreciation) from an overall industry perspective, factoring in the rate of construction cost inflation, the historical rate of replacement patterns, the impact of investment level on reliability, changes in risk profile and tolerance, and the introduction of new technology. The result is a targeted capital additions level (less new service connections) of 2.06 times depreciation, certainly supporting the notion that ATCO Electric’s Capital Additions Plan is set overall at a reasonable and appropriate level.
While the Company’s overall spending levels fall within the range of reasonableness relative to industry patterns, a more thorough assessment of capital additions requires a systematic decomposition of the Company’s capital additions plan as presented in the following sub-sections.

DECOMPOSING ATCO’S ELECTRIC’S SYSTEM MAINTENANCE CAPITAL ADDITIONS

Efforts to understand, analyze, and make assessments about the overall level of capital additions of any electric system begins with some form of classification of these expenditures. There is no universal or industry-wide capital expenditure classification structure, though there are general similarities across most electric utilities. This variation in classification has been the natural result of a number of factors, including the various types of regulation (e.g. cost of service, performance based, etc.), changing technical and regulatory requirements, system ownership (public vs. investor owned) demands, and experience.

Typically, electric distribution system investments are segregated into several broad categories. These include:

- **Growth and Capacity Expansion Investments** - The electric system must continuously accommodate growth in the number and usage of its customers. Consequently, there are numerous investments of varying sizes that are broadly related to system growth. These include individual customer additions, generalized capacity expansion of the network, and major system relocations that are often related to community growth (e.g. highway expansion, encroachment on an existing utility right of ways, etc.). These costs are typically reported net of customer contributions-in-aid of-construction (CIAC). Under the Company’s PBR plan for system maintenance capital additions these investments generally fall under the I-X Factor.

- **Reliability / Replacement Investments** – These investments typically ensure the continuing safe and reliable operation of the electric system. They are expressly related to serving existing customers as opposed to adding new customers or capacity (as highlighted above). They include wide ranging investments to replace obsolete or failed equipment, mitigate or control the frequency, scope, or duration of electric system interruptions, and ensure that the electric system is safe for the
general public, customers, and company staff. Under the Company’s PBR plan for system maintenance capital additions these investments generally fall under the K-Factor classification.

- **General/Support Investments** – There are a number of general or support investments necessary to continuously enhance utility operations, including such investments as new or replacement computer hardware and software, telecommunications equipment, fleet and facilities assets, and tools and equipment. Under the Company’s PBR plan for system maintenance capital additions, these investments fall under the I-X factor or, on occasion receive special treatment under the Y- or Z-Factor.

It is also important to note that although individual investments can be so categorized, many investments, though primarily initiated for one category, also contribute indirectly to others. For example, capacity-related distribution investments will often also help to improve overall system reliability; similarly, a reliability-focused investment may also indirectly add to the level of general automation, flexibility, and capacity expansion. Thus, the point of any initial classification of investments as presented here is to aid in stakeholder understanding of the overall and focused trends in capital investment portfolios.

Figure 2.5 below summarizes ATCO Electric’s net distribution capital additions introduced in Figure 2.1 for the period 2009-2016 in the broad categories noted above.

**Figure 2.5 – Net System Capital Additions by Classification**

Figure 2.5 illustrates several important overall points related to ATCO Electric’s capital additions:

- The company’s overall capital additions trend is rising continuously throughout the planning horizon.
- There is, obviously, an especially unusual increase in 2012. Overall spending later reverts to the longer term trend level from 2013 through 2016. This 2012 increase is largely related to increased investment in new office buildings, recognized need to
more aggressively address the “bow wave” of aging infrastructure (end of life), and anticipation of significant load growth in specific areas within the province.

- Growth and new capacity-related additions (a significant portion of the I-X factor in the Company’s 2013-2016 PBR filing) will be a large and growing portion of total capital additions.

- The company’s reliability and replacement related additions (referred to as the K-factor in the Company’s 2013-2016 PBR filing) are relatively stable in the future years, but they are at elevated levels relative to recent historical levels (2008-2011).

- In the Company’s 2013-2016 PBR filing the primary drivers appear to be the growth related (I-X factor) and reliability and replacement related capital additions (K-factor). Therefore, in further decomposing this analysis, our approach will focus in these two areas: 1. Growth-related and 2. Reliability and Replacement-related additions.

**Growth Related Capital Additions (I-X Factor)**

The composition of the Company’s growth-related additions is typical of those of all regulated electric utilities. They are, generally speaking, subject to very little direct control by the utility:

- Electric utilities typically have a universal obligation to serve new customers in a non-discriminatory way, consistent with standardized extension and connection policies.

- Customer and demand growth forecasts and, ultimately, actual customer growth are typically only weakly and indirectly influenced by direct utility actions and certainly not in the short run. The wider macroeconomic growth patterns in a utility’s service territory will be the dominate force behind these investments.

- System planning criteria and standards dictate the timing of appropriate capacity expansion investments. Such standards may be briefly and temporarily relaxed to provide minor planning flexibility and balance capital priorities. However, they cannot be ignored or violated indefinitely. These standards have often been developed in conjunction with numerous regulatory and market participants to ensure overall energy system security.

Therefore, assessing the appropriateness of any growth-related distribution additions requires a multi-faceted view of the macro-economic and electric system drivers of growth, particularly given the lack of a universal standard or benchmark for appropriate growth-related additions. Figure 2.6 below presents ATCO Electric’s past and projected customer growth rates relative to a peer group of U.S. investor owned electric utilities with between 100,000 and 500,000 customers.
Figure 2.6 above illustrates several points:

- The Company’s growth rates are projected to be approximately 2% per year between 2013 and 2016. The basis of this forecast is explained in significant detail in the Company’s PBR filing, and further substantiated below.

- This level of anticipated growth places ATCO Electric in the top quartile of similar electric utilities even in the context of the “normal’ growth patterns experienced during the mid-2000s.

It is beyond the scope of this study to assess the overall accuracy of the Company’s forecast, other than to take a macro-economic view in understanding the correlation between need for electricity and GDP growth, and thereby inferring concurrence with the load growth projections supporting the 2013-2016 PBR filing.

Figure 2.7, extracted from AESO’s Future Demand and Energy Outlook (2009 -2029), projects annual growth in GDP in excess of 2% per year during the 2013 to 2016 time frame.
As Figure 2.8 below illustrates, total energy usage (broadly defined) and GDP growth have always been and always will be highly correlated (>0.9 in a multitude of energy industry research studies over an extended time period). Simply stated, economic growth in every developed economy translates to increased energy usage. Although the incremental energy requirements necessary to support incremental GDP growth may vary with time and the nature of the economy (i.e. the so-called Energy Intensity), GDP growth definitively adds to energy use.

Further, electricity’s role in the energy mix of any modern economy like that of Alberta is even more critical and growing. As an illustration, Figure 2.9 below notes that electricity use has grown from less than 5 percent to greater than 40 percent of the U.S. energy mix over
the last 60 years (1949-2010). Moreover, it is also important to highlight that this increasing role of electricity in this mix shows absolutely no sign of diminishing or abating.

**Figure 2.9 – Electricity’s Role in the Energy Mix**

![Figure 2.9](image)

Therefore, to the extent that the GDP growth projections in Figure 2.7 are accurate, the Company’s assumed growth rates of approximately 2% per year between 2013 and 2016 in Figure 3.6 appear reasonable. Presuming GDP growth and corresponding customer growth materializes as anticipated, the appropriateness and reasonableness of the Company’s capital additions plans can be further assessed by analyzing the projected investments related to incremental customers and capacity. Figure 2.10 below presents the Company’s growth-related capital additions trends on a per new customer basis.

**Figure 2.10 – Average Customer Connect and Growth Costs**

![Figure 2.10](image)
Figure 2.10 above highlights several points:

- The average cost of new customer connections (net of CIAC) ranges between $10,061 and $12,775 per customer in the 2013-2016 era. These average costs are, in fact, lower on a per new customer basis than in recent years (2009-2012). Our interpretation is that ATCO Electric’s estimated connection costs are conservatively established throughout the planning horizon. The compound average growth rate (CAGR) forecasted for these costs on a per connection basis during 2013-2016 is 2.6%, consistent with and slightly less than the 2013 inflation estimate of 3.2% as noted in the PBR filing. Therefore, presuming accuracy in the customer growth forecast, customer-related additions (net of CIAC) are conservatively forecasted.

- The total growth-related costs (net of CIAC) range between $20,422 and $25,927 per new customer from 2013 through 2016.

- Thus, the totality of this evidence suggests that the Company’s growth-related capital additions (which compose a portion of the system maintenance capital) are conservatively estimated and consistent with other related elements of the PBR plan.

Reliability, Replacement and Safety-Related Additions (K-Factor)

The challenges of addressing aging assets in all categories of public infrastructure (electric and gas transmission and distribution systems; bridges, roads and highways; water and wastewater systems; rail systems; etc.) is widely acknowledged throughout the developed world and particularly in Canada. Regardless of the nature of the system, aging assets potentially threaten public and worker safety, system performance, and reliability on critical infrastructure.

ATCO Electric’s reliability, replacement and end of life, and safety/clearance related capital additions are presented in Figure 2.11 below.

Figure 2.11 – K-Factor Capital Additions
Figure 2.11 illustrates the following overall patterns and trends:

- Total K-factor spending is planned to grow from $70.5M to 79.7M in the 2013-2016 era. The 2013-2016 average K-factor forecast reflects a 23% increase over the 2011-12 average capital additions.

- The Asset Replacement and End of Life additions are the largest portion of the K-factor capital additions in all years, averaging 63% or approximately 2/3 of all of these additions in 2009-2016 and also 63% of total additions in the PBR years of 2013-2016.

Although these increases in overall K-factor additions since 2010 are significant, calling for further analyses to ensure that they are reasonable and prudent, in applying our approach of capital additions to depreciation at the macro level, these increases are within the range of reasonableness. Figure 2.12 provides an illustrative view of the estimated “No Growth” Distribution Capital Additions (i.e. total capital addition less customer connections net of any CIAC) relative to Depreciation in comparison to the industry range for this portion of capital additions of 1.4 to 1.55 times depreciation.

**Figure 2.12 – “No Growth” Distribution Capital Additions Relative to Depreciation**

Figure 2.12 provides the following perspectives:

- After excluding customer connections additions (net of any CIAC), ATCO Electric’s PBR filing for “No Growth” additions as a ratio to depreciation is within industry norms (i.e. ranging between 1.4 and 1.55 times depreciation). Figure 2.12 also presents this measure with the Company’s Wild Fire Program excluded (which we view as an anomaly relative to the industry for comparative purposes) for additional clarity.

- In fact, the Company is trending towards the middle of the “typical” range suggesting that there could potentially be some slight (but not exceptional or problematic) “crowding out” of “No Growth” capital additions due to overall system growth (i.e. the human and equipment resources necessary to sustain the Company’s capacity.
additions potentially prohibits some replacement work that might otherwise be completed if the Company faced much lower or more typical growth rates).

Notwithstanding our view that the “No Growth” capital additions (excluding net customer connections additions and Wild Fire Program) appear to be trending towards industry norms, a review of the three primary areas that comprise the K-Factor portion of the PBR filing for System Maintenance Capital is appropriate.

Asset Replacement / End of Life Investments

Asset replacement and end-of-life investments (hereafter referred to as “asset replacement” investments) are the largest overall category of investments in the ATCO Electric’s K-Factor. The first test of the overall reasonableness of these replacement investments is the Company’s spending level relative to other, similar electric utility systems, recognizing that any such comparison needs to be:

- Based on a reasonably large sample size, ensuring the results are not based on unusual or idiosyncratic anomalies.
- Based on a common definition or classification of costs.
- Independent of potentially distorting parameters, such as currency conversions or unique regulatory treatments.

We believe that the United Kingdom (UK) electric system and regulatory reporting framework provides ATCO Electric stakeholders with one such potential basis for comparison. The UK Office of Gas and Electric Markets (OFGEM) is the regulatory authority of electricity distributors in England, Scotland, and Wales. OFGEM operates a Distribution Price Control Review (PRCR) system similar in many respects to the PBR model Alberta intends to implement in the 2013-2016 era. OFGEM is currently in the fifth (5th) cycle of price controls and the notation DPCR5 represents the 5-year period of 2010-2015. The UK first began price control in the early 1990’s with the privatization of the predecessor Regional Electric Companies (REC’s).

To use a relative measure that is also independent of potentially distorting currency conversions and proves a reasonable comparison, we compare asset replacement capital spending relative to depreciation.

For its price control process, OFGEM’s capital expenditure classification approach expressly identifies asset replacement investment levels distinct from capacity/reinforcement expenditures, other unique or “non-core” expenditures akin to the PBR’s Y- and Z Factors. This offers a close, but naturally not perfect, comparison for ATCO Electric; and with a breakout of asset replacement cost data considerably better than that which exists for North American utilities. Figure 2.13 below summaries this data from OFGEM’s most recent and publicly available industry reports.
The key observations from Figure 2.13 include:

- In the UK, overall average asset replacement expenditures were approximately 48% of system depreciation during DPCR4 (2005-2010) and are planned to be approximately 50% of system depreciation in DPCR4 (2010-2015).

- During this period, total asset replacement expenditures for the industry increased by 33%. Individual companies changed asset replacement spending levels from -4% to +80%.

- Four of 14 UK utilities increased their overall replacement expenditures by 50% or more across the 5-year price control periods.

- The Company’s significant increase in replacement expenditures in the PBR period, although nominally large, is by no means unusual or unique in comparison to other electric systems.

ATCO Electric’s asset replacement capital additions during the PBR period are presented in Figure 2.14 below.
The information presented in Figure 2.14 highlights several points:

- ATCO Electric’s asset replacement additions are approximately 38% of depreciation during the PBR period of 2013-2016 as compared to approximately 39% during the period 2009 through 2012.

- ATCO Electric’s asset replacement additions are at levels generally in the lower range of comparison relative to UK electric systems as summarized in Figure 2.15 below. Note that Figure 2.15 highlights two general eras of comparison for ATCO Electric: 1. the left portion of the chart highlights the UK results during DPCR4 (2005-2010), and 2. the right portion highlights the UK results during DPCR5 (2010-2015).

**Figure 2.15 – ATCO Electric vs. UK Asset Replacement Levels**

![Figure 2.15 – ATCO Electric vs. UK Asset Replacement Levels](image)

Figure 2.15 integrates the data from Figures 2.13 and Figure 2.14, further illustrating several points:

- ATCO Electric’s asset replacement capital additions relative to depreciation are below average (generally lowest quartile) in comparison to this UK peer group.

- ATCO Electric’s asset replacement capital additions, although nominally rising during the PBR plan years (2013-2016) are approximately 38% of depreciation during the PBR period of 2013-2016.

- At an overall level, ATCO Electric’s asset replacement expenditures appear to be well within the range of reasonableness when compared to other, similar electric systems. Indeed, based on this high level comparative analysis, ATCO Electric’s overall asset replacement spending levels could indeed be expanded and yet still remain within a comparatively “normal” level should such increases be necessary.
Clearance and Safety Investments

Line clearance and safety-related capital investments tend to be highly idiosyncratic across electric utilities and thus it is difficult to make universal cross-company comparisons. Generally speaking, line clearance and safety-related additions are part of an electric utility’s operating costs; these costs are less frequently capitalized and when they are capitalized (as is the case with some significant additions at ATCO Electric) they are usually associated with a significant new or modified safety or clearance need or standard, or the establishment of a new right-of-way (new line construction or relocation). Moreover, these capitalized additions are almost universally “mandatory,” in that the electric utility must perform the work (i.e. make the capital addition) typically at the direction of some specific legislation, municipal authority, or regulation or because it incurs a significant latent risk.

Figure 2.16 below summarizes ATCO Electric’s line clearance and safety capital additions. The upper portion presents these additions classified in the original ATCO Electric project code, and the lower portion consolidates these same additions into 4 categories by the function or purpose of the investment.

**Figure 2.16 – Clearance and Safety Additions**

The reclassification of line clearance and safety additions from Figure 2.16 above are presented in graphical form in Figure 2.17 below to identify and highlight their scope and major trends.
Figure 2.17 – Clearance and Safety Additions by Function

Figure 2.17 introduces the following key findings and contextual comments related to the Company’s clearance and safety investments:

**Wild Fire Right of Way**

- ATCO Electric’s Wild Fire Right of Way program comprises near half of the company’s line clearance and safety capital additions during the 2013-2016 era. As noted in the Company’s project summary, “the scope of work related to this program is based on obligations outlined in the Wildfire Prevention Agreement signed with the Minister of Alberta Sustainable Resource Development. Government policy requires the implementation of forest management practices to mitigate the wildfire risk potential associated with ATCO Electric facilities located within the Forest Protection Areas of the Province. The risk of wildfires originating from power line/tree contacts are increasing due to forest conditions in general and the increased exposure associated with the ongoing expansion of the electric distribution system within the Forest Protection area. These programs comply with government policy for the high-risk timber areas identified by Alberta Sustainable Resource Development – Forest Protection. Implementing the programs reduces ATCO Electric’s liability and risk to the public from a major wild fire event originating from the distribution system and also improves distribution system reliability.”

**Agricultural Clearance Program**

- The Agricultural Clearance program addresses a moderate but growing risk that results from the increasing height of modern agricultural equipment. The Company’s inquiries to farm equipment suppliers reveal that farm equipment heights currently reach as high as 4.88 m and that approximately perhaps 5-10% of farmers own equipment in that range of height. Moreover, in Alberta various regulations permit loaded commercial and farm vehicles under some conditions to reach a height of 5.3 m. Similarly, the Alberta Electrical Utility Code, Third Edition (2007) (the AEUC)

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1 AUC-AE.pdf, pg. 29
2 See Commercial Vehicle Dimensions and Weights Regulation AR315/2002
currently requires 6.0 m clearance over or alongside land likely to be traveled by road vehicles and 5.5 m line to ground clearance over or alongside land likely to be traveled by farm vehicles.

- In November of 2000, before the 2007 change in the AEUC requirement, ATCO Electric proactively changed its internal standard for new construction for ground clearance at mid-span from 4.9 m to 5.5 m for lines over agricultural land. However, a large amount of line over agricultural areas remains as it was originally constructed to the lesser codes that were in effect at the time of construction.

- The AEUC does not require upgrading of old lines to meet Code requirements, unless an unsafe condition exists. Although not a mandatory program, ATCO Electric reasonably believes that the growing number of farm vehicle contacts warrant a more proactive long term program to upgrade crossings that may conflict with the new ground clearance standard.

- The Company’s Agricultural Clearance program is not mandatory, but represents a typical safety-related addition decision facing the company or any other electric utility. Though both the AEUC and the Company have identified the latent and growing risks, this is one area where stakeholders may voice objection.

*Double Circuit Removal Program*

- The Double Circuit Removal program is designed to eliminate safety and reliability risks related to 25 kV distribution lines that share structures with 144 kV transmission lines. Prior to 1999, the vertical clearance between the top and bottom circuit of a double circuit line was based on the Electrical and Communication Utility Systems Regulation (ECUSR) design rule. In 1999, the ECUSR was superseded by the Alberta Electrical and Communication Utility Code (AECUC) and the design standards changed for new construction.

- ATCO Electric continues to have pre-1999 circuits (many 30 years or older) which should eventually be reconfigured to mitigate the safety and reliability risks (mostly related to line sag and the related damage and injury risks that could occur in an incident). ATCO Electric has a prudent approach to apply mitigation to only those lines that are at risk of a double circuit contact, beginning with the highest risk lines. ATCO Electric proposes to determine on a line by line basis whether remedial action is required based on safety and operational concerns.

*Capital Vegetation Management Program*

- ATCO Electric’s general capitalized vegetation management additions are fairly uniform from 2008 through 2016, ranging from about $2.5 to $4.0M per year. As noted in Figure 2.18 below, the Company’s capitalized portion of total vegetation management costs range between 12.5% and 20% of total vegetation management costs. In our experience, this level of capitalization of vegetation costs is typical of most major electric utilities (typical 10-20%), particularly given the uniqueness of the Company’s service territory and system growth plans (extremely rural and significant growth requires a larger amount of new line construction).
In summary, in reviewing the Clearance and Safety additions in total, our view is that they are both reasonable and prudent:

- Wild Fire Right of Way, comprising approximately 45 to 50% of the forecasted costs from 2013 through 2016, reflects a mandatory requirement (Wildfire Prevention Agreement).

- Agricultural Clearance Program, comprising 15 to 20% of the forecasted costs from 2013 through 2016, reflect a sufficient proactive investment to transition to current requirements and thus minimize the risks related to the increased height of modern agricultural equipment.

- The Double Circuit Removal Program, comprising approximately 20% of the forecasted costs from 2013 through 2016, reflects a well-planned and prioritized scheme to address highest risk lines in terms of potential operational and safety impacts.

- Capital Vegetation Management, comprising less than 15% of the forecasted costs from 2013 through 2016, falls well within the range of reasonableness relative to OMA-related vegetation management.

**Reliability Investments**

Adjudging the appropriateness of the level of ATCO Electric’s reliability investments presents a complex challenge in terms of making definitive assessments, primarily because of the recent change to a new outage management system (OMS) in 2010 and the attendant disruption to system performance trends and any linkage to capital investment levels. Therefore, acknowledging that the data post-2009 is certainly more comprehensive (e.g. shows an increase in average number of system interruptions of 73%) yet insufficient for trend analysis purposes, our analysis below is based on the continuous pre-2010 data series. Although the magnitude of system interruptions will be less, our experience with other, similar situations suggests that the trends themselves will be consistent with a focus on SAIFI (i.e. avoiding or eliminating system interruptions).

Figure 2.19 below presents the Company’s SAIFI performance from 2000 through 2009.
Figure 2.19 illustrates:

- The Company’s overall SAIFI has been generally stable over the past decade, albeit slightly higher (worse) than in the early 2000’s.

- ATCO Electric’s overall SAIFI performance compares favorably with other Canadian (CEA) electric systems.

- Consistent with the experience of other electric utilities that have transitioned to modern OMS technology, ATCO Electric should expect reported system reliability to degrade with improved data and reporting processes. By removing post-2009 system reliability performance from the analysis, we remove this anomaly in the data. We believe that, on a relative basis, any insights gleaned from looking at trends between 2000 and 2009 will not differ materially if we could normalize for this anomaly and extend the analysis to years 2010 and 2011.

In reviewing the overall reliability trends (described extensively in Section 3 of this report) we note the following general observations:

- Many cause categories showed little overall change suggesting current investment levels are at least adequate to forestall any further degradation in overall reliability performance.

- Equipment failure, weather-related, and scheduled interruptions have markedly increased over this same time frame. Based on our interviews of ATCO Electric management, the increase in scheduled interruptions is more indicative of system growth than of capital investment and prioritization. But, equipment failures and adverse weather (an indication of a “brittle” and aging system and a consequence of a largely rural system with extraordinarily high percentage of “weather exposed” overhead lines - refer to Figure 2.20 for industry comparisons) can most certainly be

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related to the allocation of capital to reliability programs (and also the previously addressed Asset Replacement / End of Life investments).

**Figure 2.20 – Percent OH Distribution Lines**

Therefore, Figure 2.21 focuses specifically on equipment failure and weather caused interruptions in the context of the Company’s overall customer interruptions patterns:

**Figure 2.21 – ATCO Customer Interruption History**

The important observations to note in reviewing the trends illustrated in Figure 2.21 include:

- Overall customer interruptions due to equipment failures and adverse weather have increased throughout the past decade.

- Equipment failure and weather related interruptions generally comprised between 30 and 40% of the total customer interruptions.

The fact that SAIFI has remained fairly constant during this same time period is likely indicative of the effectiveness of the Company’s low-cost mitigation strategies (fusing taps, sectionalizing, etc.) and vegetation management. In Section 3 of this report we address the concerns regarding maintaining this level of performance in the midst of an increased
number of these types of interruptions and the reality of maxing out on the effectiveness of programs that have kept SAIFI at acceptable levels. And, as the number of interruptions due to equipment failure takes on greater significance to total interruptions, this category of interruption will increase the average size of an interruption event (Figure 2.22).

Figure 2.22 – Average Size of Interruption Events

![Figure 2.22 – Average Size of Interruption Events](image)

The salient conclusions from Figure 2.22 include:

- Equipment failure-related interruption events are typically twice as large as the average ATCO Electric interruption (adverse weather caused system interruptions are approaching that range as well).

- Investments targeted at major equipment failures and those resulting from adverse weather can significantly improve overall reliability. As a corollary to this notion, a noted decrease in capital investment has the potential of negatively impacting reliability to the point where past focus on least-cost approaches will be overtaken by the impact of these larger outage events.

Taken together, the logical overall conclusion is that equipment failures and related adverse weather caused outages are a major cause of the Company’s growing interruption events and customer interruptions. The scope of its impact has likely been masked by other least-cost mitigation strategies / programs that will likely be overtaken by these larger scope system interruptions. This suggests an opportunity to leverage targeted investments that will measurably improve customer reliability. It would further suggest that reliability related additions should, at a minimum, be sufficient to correct these problems.

Figure 2.23 below summarizes ATCO Electric’s reliability capital additions. The upper portion presents these additions as classified in the original ATCO Electric PBR filing. The lower portion consolidates these same additions into 4 categories by the function or purpose of the investment.
Several patterns are apparent from Figure 2.23:

- ATCO Electric’s distribution automation investment levels are relatively small and uniform throughout the PBR filing period with no apparent plan to embark on a major automation / smart grid program; rather they are targeted at areas where incremental costs for automation can be effectively leveraged to significantly improve reliability. Given the industry’s propensity for avoiding “bleeding edge” technologies and the unintended consequences of hastily deployed newer technologies, we typically recommend an incremental approach to distribution automation predicated on well-established need, seemingly consistent with the approach adopted by ATCO Electric.

- The level of spending proposed for Small Reliability Projects is significantly smaller than that of comparable utilities with similar challenges in maintaining reliable service.

Taken in total, our presumption is that ATCO Electric understands the significance of an impending “bow wave” of infrastructure renewal required to safely maintain and operate the system (represented by the amount of Reliability, Replacement and Safety Additions allocated to Asset Replacement / End of Life Investments), and its potential impact on overall system reliability. Further, these spending levels reflect acceptance of the notion that the Company is nearing a point where incremental low-cost investments have run their course in terms of maintaining, let alone improving reliability.
**Summary of Conclusions**

Figure 2.24 summarizes our findings with respect to the seven categories of System Maintenance Capital contained within the PBR filing for 2013 through 2016.

**Figure 2.24 – Summary of Conclusions**

<table>
<thead>
<tr>
<th>Category</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line Moves / Encroachment</td>
<td>Part of I-X Capital Additions</td>
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<tr>
<td></td>
<td>Consistent with projected activity, historic costs and inflation estimates</td>
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<tr>
<td>Clearance and Safety</td>
<td>Part of K Factor</td>
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<tr>
<td></td>
<td>Idiosyncratic to unique jurisdictional requirements</td>
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<tr>
<td></td>
<td>Largely mandatory (Wild Fire) or appropriately conservative in proposed investment levels (Double Circuit and Agricultural Clearance Programs)</td>
</tr>
<tr>
<td></td>
<td>Capital Vegetation Management consistent with industry norms as a percent of overall Vegetation Management</td>
</tr>
<tr>
<td>Alternate Feeds</td>
<td>Part of I-X Capital Additions</td>
</tr>
<tr>
<td></td>
<td>Consistent with projected activity, historic costs and inflation estimates</td>
</tr>
<tr>
<td>Capacity Additions</td>
<td>Part of I-X Capital Additions</td>
</tr>
<tr>
<td></td>
<td>Consistent with projected activity, historic costs and inflation estimates</td>
</tr>
<tr>
<td>Reliability</td>
<td>Part of K Factor</td>
</tr>
<tr>
<td></td>
<td>Low in comparison to industry norms (likely in response to emerging issues around equipment failure / adverse weather caused outages)</td>
</tr>
<tr>
<td></td>
<td>Levels of Distribution Automation appear reasonable, but relatively low provision for small Reliability Projects potential cause for concern (emergent work could partially “crowd out” Asset Replacement / End of Life investments)</td>
</tr>
<tr>
<td>Asset Replacement / End of Life</td>
<td>Part of K Factor</td>
</tr>
<tr>
<td></td>
<td>Compares favorably (lower) with the established peer group yet reflects an appropriate shift in focus (step increase) towards addressing aging infrastructure</td>
</tr>
<tr>
<td>New Technology</td>
<td>Part of I-X Capital Additions</td>
</tr>
<tr>
<td></td>
<td>Level of proposed additions indicative of minor system improvements related to electric distribution system growth (higher than historic average which is significantly lower than industry norms)</td>
</tr>
</tbody>
</table>
ANALYSIS OF ATCO ELECTRIC’S RISK PROFILE AND SPECIFIC INVESTMENT PLANS

Like all electric distribution utilities, ATCO Electric’s capital addition plans can be broadly characterized to address the following three generalized system needs:

- System growth, which falls naturally from the Company’s obligation to serve new customers;

- Risk reduction and reliability, to ensure continued safe and reliable electric service and is predominately focused on replacing obsolete or failed equipment; and

- General support investments predominantly focused on the tools, vehicles, equipment, facilities, and various information and telecommunication technologies necessary to support widespread utility operating activities.

The primary focus of this section of the report is to summarize our analysis of the Company’s risk reduction and reliability-related investments, which are generally referred to as the K-Factor investments in the Company’s PBR application and plan for system maintenance capital.

This section of the report begins with an analysis the Company’s historic reliability performance to identify the largest apparent and emergent needs in the electric system. Many needs are obvious by actual performance (predominantly failures); others represent emerging needs related to small but growing risks in the system. Building off a this foundational understanding of the ATCO Electric primary system performance risks, our analysis will assess whether the planned mix of investments is properly aligned and balanced to address these predominant risks. The analysis then concludes with a summarized view of of the Company’s asset base, identifying aging asset trends that portend future risks (asset age is a secondary risk that rises with time as assets reach and exceed their engineering life and a primary indicator of this risk), and assessing whether the Company’s specific replacement spending in major categories is set at reasonable and appropriate levels.

OVERALL ELECTRIC SYSTEM RELIABILITY – PERFORMANCE AND TRENDS

The Company’s historic reliability performance as measured by SAIFI is presented in Figure 3.1.
Figure 3.1 – ATCO Electric Distribution SAIFI Performance

Figure 3.1 highlights that the Company’s reliability performance as measured by SAIFI is better than the average of its Canadian Electricity Association (CEA) peers and certainly could be characterized as strong and stable. However, given the long-lived nature of ATCO Electric’s electric system assets, prudent distribution system management demands a further decomposition of this performance to identify any latent or emergent risks that could affect future system operation. It is important, however, to reinforce the notion that although the following analyses may have a fault-seeking/fault-finding tone (out of necessity/design) the Company’s overall performance has been and continues to be sound.

Figure 3.2 below presents the Company’s long-run interrupt event history.

Figure 3.2 – ATCO Electric Interruption Event History
With respect to Figure 3.2, the following comments / observations apply:

- First, electric distribution reliability assessment and analysis will be properly conducted by focusing exclusively on distribution caused interruption events:
  - Loss of Supply (LoS) causes, which are attributed to failures in the generation or transmission systems, will be segregated from the distribution results.
  - Major event days (MEDs) will also be excluded from analysis because they represent an unusual or extraordinary system condition and often present conditions beyond the original system design standard. It is important to note that these events aren’t ignored; rather, they are analyzed using other methods (storm response, etc.). Further, ATCO Electric has far fewer MED events (exclusions) than other electric systems, undoubtedly related to its exceptionally low customer density. Industry exclusion methods vary, but they are generally identified by the scope of the event (e.g. number or percentage of the customers affected).

- The Company’s planned / scheduled interruption events are significant in relation to other electric systems, most likely tied to new construction or the result of overall system design / layout.

- Overall, during the 1993-2009 era, the frequency of distribution interruption events (also informally referred to as “outages”) steadily rose by about one-third (1/3), from approximately 6000 distribution interruption events per year to over 8000 interruptions per year, a significant increase, the impact of which (SAIFI) has largely been offset by a decrease in the average number of customers affected by an outage event (refer to Figures 3.3 and 3.4).

- Lastly, the Company measured a significant increase in reported interruption events in 2010, the same time that it implemented a new Outage Management System (OMS). Consistent with our experience with other electric utilities, this implementation of a new OMS introduced a significant discontinuity in the Company’s performance data and reporting practices, rendering any trending of post-2009 performance data challenging, at best. Consequently, the following analysis will focus on system and asset reliability performance through 2009.

It is first important to understand this paradox (noted above) of an increasing number of interruption events (Figure 3.2), yet no apparent degradation in overall system reliability (SAIFI) (Figure 3.1). The following Figure 3.3 illustrates the customer interruption (CI) history:
Figure 3.3 – ATCO Electric Customer Interruption (CI) History

Figure 3.3 baselines the Company’s annual number of customer interruptions (CIs), illustrating that they are essentially unchanged over an extended period of time (1993-2009) at approximately 200,000 CIs per year. Yet, as previously noted in Figure 3.2, the number of interruption events (outages) has steadily increased over this same time period. The following Figure 3.4 sheds light on this seeming disparity in logic by noting the average size of an interruption event.

Figure 3.4 – ATCO Electric Average Interruption Size

Figure 3.4 illustrates that the Company’s average interruption size (i.e. the average number of customers affected by any interruption) declined over the long run period 1993-2009 from typically 30-35 customers per event, to more recently affecting consistently under 25 customers (and some years approaching 20 customers per interruption).

There are several important findings and implications related to Figure 3.4:
• The Company apparently made investments in the 1990’s and early-2000’s time frames in electric system protection, sectionalizing, and other interruption event mitigation strategies. Adopting this approach / focus to initially address the challenge of maintaining reliability within a constrained system maintenance capital budget is consistent with strategies / tactics employed by other utilities, typically resulting in improved (decreased) service interruption event size and lower SAIFI. The fact that ATCO Electric has clearly achieved the first objective (smaller event size) but not realized a proportionate improvement in SAIFI suggests that other factors are emerging as dominant variables in determining overall system performance. Again, this is a very typical situation for most utilities.

• Our experience in analyzing reliability performance across the industry suggests that ATCO Electric is reaching a point of diminishing return with respect to maintaining or improving reliability through these traditional, yet typically cost-effective, mitigation strategies and tactics (i.e. the Company has already experienced an overall reduction in event size in the range of 40 to 50%). Therefore, just to maintain its reliability performance levels (e.g. SAIFI), the Company will need to broaden its focus to include longer term, and typically higher cost, initiatives in its overall reliability program. Consistent with the experience of other utilities, these initiatives will be focused on equipment replacement to avoid equipment failure itself rather than merely to mitigate the scope of the events.

• Overall electric system reliability statistics such as SAIFI, as illustrated in Figure 3.1, are useful in evaluating and comparing aggregated system performance, but they are trailing indicators and therefore, at times can mask emerging trends that will portend future system reliability performance.

A brief recap the findings of Figures 3.1 through 3.4 are:

• ATCO Electric’s overall reported reliability has been stable and generally compares favorably with other Canadian electricity distributors, and the Company should be commended for this performance.

• ATCO Electric’s past investments have been both prudent and consistent with industry “best practices,” thereby sustaining overall system reliability. However, from the perspective of less knowledgeable stakeholders, this positive overall performance may tend to obscure potential risks that can lead to future degradation of reliability performance.

• An analysis of ATCO Electric’s PBR Filing for System Maintenance Capital 2013 through 2016 reflects an understanding of this risk on the part of the Company, the extent of which will be explored in the following discussion.

DECOMPOSING RELIABILITY TO DETERMINE OPTIMAL FOCUS OF RISK MITIGATION

In accepting the premise that ATCO Electric is approaching or at the point of diminishing return with respect to the traditional and most cost-effective service interruption mitigation initiatives and that there are other factors which, if left unaddressed, will over time have negative consequences on reliability, the next theme of this analysis is to ascertain the extent to which the Company’s PBR filing for system maintenance capital addresses these risk.
Acknowledging that the number of interruption events are increasing (refer to Figure 3.2), the first step involves determining the source of this increase. Figure 3.5 below highlights the relative contribution of each cause to the Company’s interruption events over the past decade.

**Figure 3.5 – Mix of Interruption Causes (2000-2009)**

Excluding the “unknown/other” category, Figure 3.5 reveals that the general mix of the causes of interruption events did not materially change over the 2000 to 2009 time period. Thus, all categories of events generally increased consistently with overall increase in the total number of interruption events. Therefore, in order to determine the source of greatest risk to system performance degradation, we must compare, across these causes, event size and scope (Figures 3.6 and 3.7, respectively).

**Figure 3.6 - Average Size of Interruption Event (CI’s per Event)**
In reviewing Figures 3.6 and 3.7 in conjunction with the number of interruption events, a number of observations and implications are germane:

- Equipment failure related interruption events are the largest sized interruption events on the ATCO Electric system, averaging over 41 customers per interruption (Figure 3.6), and they further represent the category of interruption events with the greatest scope, averaging 127 customer-hours per interruption (Figure 3.7). Additionally, equipment failure events, typically a sign of aging or deteriorating infrastructure, are among the largest categories of interruption events (approximately 20% of the total). This highlights the importance of assigning priority of the non-growth system maintenance capital to equipment failure risks, whereby the Company will simultaneously address the greatest opportunity for improvement and the greatest risk of performance degradation.

- Adverse weather, when viewed across all three perspectives (Figures 3.5, 3.6 and 3.7) represents a similar impact to reliability as does equipment failure (i.e. well above average size, scope, and percentage of total events). Adverse weather is oftentimes a form of equipment failure (e.g. wind speed, ice loading, etc. leading to need to replace / repair “brittle” equipment in the course of service restoration). Therefore, in prioritizing investment towards equipment failure prevention (i.e. infrastructure renewal and replacement), the Company is in fact addressing a large portion of these events as well.

Having established that the Equipment Failure and Adverse Weather events have the greatest overall impact or leverage on improving reliability (or, alternatively, in eliminating risk), Figure 3.8 below isolates these two categories of interruption events (singularly and in total) to establish the Company’s trends in customer interruption frequency.
Figure 3.8 – Equipment Failure and Adverse Weather Trends

Figure 3.8 illustrates the following points:

- Both Equipment Failure and somewhat related Adverse Weather caused events have an overall rising trend in increased customer interruptions (a driver for SAIFI), noting that in each category, the rolling 2-year average has been above the long run average in recent years (indicative of the probable start of accelerated performance degradation due to these factors).

- Equipment failure represents approximately 75% of the total customer interruptions attributed to these two sources. It is clearly the most important category of the two, with the largest rate of increase, and given the symbiotic relationship between the two, warrants the greatest attention.

- Adding further to the rationale of prioritizing a strategy around equipment failure (and as a result significantly reduce outage events attributed to adverse weather), almost 30% of the customer interruptions (nearly 50% when unknowns are removed from the analysis) portrayed in Figure 3.4 are attributed to these two causes.

Therefore, based on a review of historic reliability performance data and consideration of the overall aging trends of the Company’s distribution assets, ATCO Electric’s strategies and tactics to reduce the number of equipment failure-related interruption events will, over the long run, result in progress at maintaining (if not improving) reliability. It is important to recognize that the past trends of an increased number of interruption events yet fairly stable SAIFI is unlikely to continue without this equipment replacement focus. That said, there are two additional points to highlight to bring context to the magnitude of this risk.

- The aforementioned recent increase in customer interruptions in the rolling 2-year average over earlier years suggests that equipment failure (and attendant adverse weather) caused interruptions will likely play a more dominant role in outlying years. Figure 3.9 supports this view, as existing distribution assets have clearly aged and,
even at proposed investment levels, are projected to age at rates commensurate to past experience.

**Figure 3.9 – Distribution Assets Aging Profile**

- The overall trend illustrated in Figure 3.9 suggests a continually aging (and potentially deteriorating) population of distribution assets at either the 2009 to 2010 or proposed PBR filing investment levels. Recognizing a range of possibilities with respect to actual condition and criticality of these assets, the specific number is not necessarily alarming, particularly given a focus on sound asset management principles. This trend does however support the view that the level of investment proposed by the PBR filing will reduce risk related to aging infrastructure, yet it does not reflect an “over reaction” or tendency to “gold plate” the solution. Note that the decrease in 2011 reflects an apparent absence of significant infrastructure replacement in 1971.

- Though well-targeted investments can result in an immediate improvement (reduction of) in customer interruptions, at the macro-level, even the most aggressive no-growth system maintenance capital plan (K-factor) will result in a time lag before a change in investment levels will result in noted overall system performance improvement. The following Figure 3.10 illustrates that there is no correlation between a change in capital investment level and change in equipment failure caused interruptions after one year (left plot). But, using ATCO Electric’s data (change in capital investment levels and change in equipment failure caused interruptions between 1996 and 2009), there is the first indication of strong correlation after four years (right plot). The implication is that that in accepting our view that the past strategies will not suffice in offsetting the future impact of continued asset aging and deterioration, there is urgency in the Company increasing its focus on replacement and end-of-life capital additions, an urgency that the current PBR filing appropriately acknowledges.
Summarizing this portion of the analysis, our view is that the Company’s proposed increases in system maintenance capital (and specifically K-Factor) is warranted not only from an industry comparative view (refer to Section 2), but also from the perspective of mitigating the risk of customers experiencing an increased number of service interruptions of longer duration. Further, acknowledging the inherent efficiency of the more proactive equipment replacement strategy represented by the PBR filing for 2013 through 2016, the extent to which ATCO Electric can get “ahead of the curve” and anticipate imminent failures (i.e. preclude service interruption events), the overall cost impact to the customer will be less (i.e. the incremental increase in rates due to a well-planned Asset Replacement / End of Life Additions program will, over the long haul, be preferred to the impact of a reactive posture in addressing anticipated increases in service restoration activities).

The remaining portions of this section further decompose the analysis to identify the major categories of equipment that have contributed most to equipment failure-related interruption events, to:

- Establish the focus of the Asset Replacement / End of Life Additions Program (i.e. proposed additions appropriately reflect and address the risks regarding equipment failure caused reliability performance degradation); and

- Validate the proposed levels of investment on key asset classes, factoring in mortality rates, anticipated replacement profiles, and empirically derived unit replacement costs.

**ESTABLISH / VALIDATE CURRENT FOCUS OF ASSET REPLACEMENT / END OF LIFE ADDITIONS**

The next step in confirming or recommending changes to the current focus of the Asset Replacement / End of Life Plan as represented in the 2013 through 2016 PBR filing is to decompose the Company’s past equipment failure caused interruption events by general class of equipment. Figure 3.11 portrays this breakout by specifying the percent of customer hours of interruptions from 2004 through 2008. We have elected to use customer hours of interruption as the broadest measure of interruption scope in this portion of the analysis.
The Company's line-related equipment failures comprise over 77% of the customer hours of interruption during this time frame, with system protection equipment (e.g. fuses, reclosers, and circuit breakers) a distant second at 17%. It is important to note that this is a generally more favorable (but atypical) mix of equipment failure related impacts, as substation equipment is often a large source of customer hours of interruption because interruptions related to this class of asset are typically linked to complete feeders / circuits. The next step in our analysis is to further decompose the line-related equipment failures by their sources (Figure 3.12).

Figure 3.12 illustrates that an overwhelming majority of line-related equipment failure sources are related to basic overhead line elements (e.g. poles, conductor, insulators and cross-arms), suggesting that lines-related equipment replacement efforts should be focused on these categories of distribution assets. And though underground cable represents a relatively low source of customer interruption hours, (4% of total line related equipment failure sources), it is slightly disproportionate to the total percentage of underground line kilometers.
(3.2%) and should also be addressed as part of the asset replacement / end of life capital maintenance program.

Given the insights and perspective gained from Figures 3.11 and 3.12 and acceptance of the view that in addressing this area, the Company would be effectively managing its risk profile while assuring maximum impact in maintaining (if not improving) reliability, our focus must necessarily shift to the actual stream of additions contained within the Company’s K-Factor capital additions during the 2013 through 2016 PBR period. In so doing we can assess the alignment of major streams of capital additions against known risks.

Figure 3.13 lists the specific projects that comprise the total K-Factor capital additions during this time period.

**Figure 3.13 – ATCO Electric’s Classified K-Factor Capital Additions**

<table>
<thead>
<tr>
<th>ID</th>
<th>Project</th>
<th>Category</th>
<th>Focus</th>
<th>2013-F</th>
<th>2014-F</th>
<th>2015-F</th>
<th>2016-F</th>
</tr>
</thead>
<tbody>
<tr>
<td>70161</td>
<td>Small Projects / Reliability Improvement</td>
<td>Reliability</td>
<td>Lines</td>
<td>$3.8</td>
<td>$5.1</td>
<td>$6.5</td>
<td>$8.7</td>
</tr>
<tr>
<td>70240</td>
<td>Swan Hills Rebuild</td>
<td>Reliability</td>
<td>Lines</td>
<td>$3.2</td>
<td>$2.3</td>
<td>$0.6</td>
<td>$0.0</td>
</tr>
<tr>
<td>70247</td>
<td>Distribution Automation</td>
<td>Reliability</td>
<td>Protect/Safety</td>
<td>$3.2</td>
<td>$1.7</td>
<td>$2.9</td>
<td>$3.1</td>
</tr>
<tr>
<td>70266</td>
<td>6L 210 Reliability Improvements</td>
<td>Reliability</td>
<td>Lines</td>
<td>$1.1</td>
<td>$0.7</td>
<td>$0.0</td>
<td>$0.0</td>
</tr>
<tr>
<td>70287</td>
<td>6L322 Resolve Voltage Imbalance</td>
<td>Reliability</td>
<td>Lines</td>
<td>$0.4</td>
<td>$1.1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>78403</td>
<td>6L348 Rebuild</td>
<td>Reliability</td>
<td>Lines</td>
<td>$2.3</td>
<td>$0.0</td>
<td>$2.1</td>
<td>$0.0</td>
</tr>
<tr>
<td>70004</td>
<td>Streetlights</td>
<td>EOL</td>
<td>Other</td>
<td>$1.6</td>
<td>$2.0</td>
<td>$2.0</td>
<td>$2.1</td>
</tr>
<tr>
<td>70004</td>
<td>Ground and Anchor Rods</td>
<td>EOL</td>
<td>Lines</td>
<td>$2.2</td>
<td>$2.4</td>
<td>$2.5</td>
<td>$2.7</td>
</tr>
<tr>
<td>7004</td>
<td>Substation &amp; Line Equipment</td>
<td>EOL</td>
<td>Substation</td>
<td>$3.2</td>
<td>$3.5</td>
<td>$3.9</td>
<td>$4.6</td>
</tr>
<tr>
<td>70004</td>
<td>Transformers</td>
<td>EOL</td>
<td>Lines</td>
<td>$2.6</td>
<td>$3.1</td>
<td>$3.4</td>
<td>$3.9</td>
</tr>
<tr>
<td>7004</td>
<td>Small Voltage Conversion</td>
<td>EOL</td>
<td>Lines</td>
<td>$2.6</td>
<td>$2.9</td>
<td>$3.3</td>
<td>$3.8</td>
</tr>
<tr>
<td>7004</td>
<td>Insulators</td>
<td>EOL</td>
<td>Lines</td>
<td>$0.9</td>
<td>$1.0</td>
<td>$1.2</td>
<td>$1.3</td>
</tr>
<tr>
<td>7004</td>
<td>Distribution Pole Replacements</td>
<td>EOL</td>
<td>Lines</td>
<td>$15.6</td>
<td>$16.9</td>
<td>$19.9</td>
<td>$22.0</td>
</tr>
<tr>
<td>7004</td>
<td>Pole Treatment</td>
<td>EOL</td>
<td>Lines</td>
<td>$2.1</td>
<td>$2.3</td>
<td>$2.5</td>
<td>$2.8</td>
</tr>
<tr>
<td>70160</td>
<td>Cable Replacement</td>
<td>EOL</td>
<td>Lines</td>
<td>$1.3</td>
<td>$1.4</td>
<td>$1.5</td>
<td>$1.5</td>
</tr>
<tr>
<td>70160</td>
<td>Cable Line Extension</td>
<td>EOL</td>
<td>Lines</td>
<td>$0.9</td>
<td>$1.0</td>
<td>$1.0</td>
<td>$1.1</td>
</tr>
<tr>
<td>70160</td>
<td>Conductor Replacement</td>
<td>EOL</td>
<td>Lines</td>
<td>$3.2</td>
<td>$3.5</td>
<td>$3.9</td>
<td>$4.6</td>
</tr>
<tr>
<td>71114</td>
<td>Replace Undg Cable in Grande Cache</td>
<td>EOL</td>
<td>Lines</td>
<td>$0.0</td>
<td>$1.3</td>
<td>$2.6</td>
<td>$1.9</td>
</tr>
<tr>
<td>70272</td>
<td>Porcelain Switch Replacements</td>
<td>EOL</td>
<td>Lines</td>
<td>$3.1</td>
<td>$3.3</td>
<td>$0.9</td>
<td>$0.0</td>
</tr>
<tr>
<td>70306</td>
<td>Drumheller Town Conversion</td>
<td>EOL</td>
<td>Lines</td>
<td>$2.2</td>
<td>$0.9</td>
<td>$0.0</td>
<td>$0.0</td>
</tr>
<tr>
<td>70008</td>
<td>Capital Forest Management</td>
<td>Ctrl/Safety</td>
<td>Clearance</td>
<td>$1.8</td>
<td>$1.8</td>
<td>$1.9</td>
<td>$1.9</td>
</tr>
<tr>
<td>70012</td>
<td>Small Projects Clearance and Safety</td>
<td>Ctrl/Safety</td>
<td>Protect/Safety</td>
<td>$1.0</td>
<td>$2.3</td>
<td>$0.6</td>
<td>$0.6</td>
</tr>
<tr>
<td>70003</td>
<td>Wild Fire Right-of-Way Program</td>
<td>Ctrl/Safety</td>
<td>Clearance</td>
<td>$6.6</td>
<td>$6.0</td>
<td>$7.0</td>
<td>$8.3</td>
</tr>
<tr>
<td>70274</td>
<td>Agricultural Area Ground Clearance</td>
<td>Ctrl/Safety</td>
<td>Protect/Safety</td>
<td>$2.1</td>
<td>$2.3</td>
<td>$2.9</td>
<td>$3.1</td>
</tr>
<tr>
<td>70360</td>
<td>Double Circuit Removal</td>
<td>Ctrl/Safety</td>
<td>Protect/Safety</td>
<td>$3.4</td>
<td>$3.5</td>
<td>$3.7</td>
<td>$3.7</td>
</tr>
<tr>
<td></td>
<td>Total (M$)</td>
<td></td>
<td></td>
<td>$70.4</td>
<td>$73.1</td>
<td>$77.5</td>
<td>$70.7</td>
</tr>
</tbody>
</table>

Figure 3.14 consolidates and sorts this list of projects by focus (e.g. clearance, lines, substation, protection/safety and other) and compares the percentage of K-Factor spending to the categories “contribution” to equipment failure caused customer hours of interruptions.

**Figure 3.14 – Classification of ATCO Electric Investment**

<table>
<thead>
<tr>
<th>Category</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>% of K-Factor Spending</th>
<th>Mix of Cust Hrs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clearance</td>
<td>8.4</td>
<td>8.7</td>
<td>9.8</td>
<td>10.2</td>
<td>12%</td>
<td>12%</td>
</tr>
<tr>
<td>Lines</td>
<td>47.7</td>
<td>49.2</td>
<td>51.9</td>
<td>52.3</td>
<td>68%</td>
<td>67%</td>
</tr>
<tr>
<td>Other</td>
<td>1.6</td>
<td>2.2</td>
<td>2.1</td>
<td>2.1</td>
<td>2%</td>
<td>3%</td>
</tr>
<tr>
<td>Substation</td>
<td>3.2</td>
<td>3.5</td>
<td>3.9</td>
<td>4.6</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>Protect/Safety</td>
<td>9.5</td>
<td>9.7</td>
<td>9.9</td>
<td>10.5</td>
<td>13%</td>
<td>13%</td>
</tr>
<tr>
<td>Grand Total</td>
<td>70.4</td>
<td>73.1</td>
<td>77.5</td>
<td>79.7</td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>

In reviewing Figures 3.13 and 3.14, our analysis would suggest that the Company’s proposed K-Factor Capital Additions Plan is appropriately comprised of investments at approximately the same proportion as the reliability risks represented as customer hours of interruptions during the 2004 through 2008 time frame (e.g. Line related equipment failures represented 77% of the Company’s total customer hours of interruptions and the lines and
clearance-related capital additions range between 79 and 80% over the 2013 through 2016 PBR period).

VALIDATE PROPOSED LEVELS OF INVESTMENT ON KEY ASSET CLASSES

Given that the overall level of the Company’s reliability and risk related additions are reasonable and in line with industry patterns (as illustrated in Section 2 of this report) and that these additions are generally focused in reasonable proportions on the Company’s major areas of system performance risk (as noted in the previous subsection), the next level of analysis appropriately focuses on whether the Company’s investment plans for individual asset categories are prudent and consistent with their relative contribution to risk.

Although the Company’s asset replacement policies are properly performance-dependant (i.e. assets that fail to meet predetermined standards are prioritized for replacement, or assets are replaced when they fail while in service) and not age-determined (i.e. assets aren’t retired simply due to age alone), asset age and useful life spans do have an important and useful role in estimating the potential future capital additions related to asset replacement. It is important to note that no electric utility can perfectly forecast asset failures and thus replacement costs. However, they can use asset mortality trends and local system historic additions patterns (i.e. prior periods of high or low growth) to estimate future end-of-life expenditures.

Our approach involves independently assessing the appropriateness of the Company’s asset replacement / EOL investments at the individual asset category level and estimating the Company’s future asset replacement additions for three of the larger addition categories (1. pole replacement, 2. line transformer replacement, and 3. overhead conductor replacement). We accomplished this by estimating the Company’s experienced asset mortality patterns from plant asset records (by category) and integrating these estimates with the ATCO Electric’s asset population in that category (by vintage). In so doing, we estimated or forecasted, on an asset category specific basis, the expected replacement additions, incorporating the natural aging that occurs through this time period.

*Line Transformers*

Beginning with Line Transformers (Account No. 47910), Figure 3.15 below presents a UMS Group estimation of the Company’s transformer mortality trends (i.e. percentage of assets removed from service as a function of transformer age).
Figure 3.15 – Estimated Transformer Mortality

The data as presented in Figure 3.15 supports the following observations:

- Line Transformers generally have very low failure rates in the first 20 or so years of life. Early transformer mortality, while rare, is more commonly due to manufacturing flaws than service use.

- Line Transformers failure rates begin to slightly increase at 20 years. For example, it requires approximately 20 years for the mortality rate to reach 5% of the original asset cohort, but only an additional 5 to 6 years for the mortality rate of the same cohort to double and reach 10%.

- Line Transformer failure rates steadily increase in years 20 through 50, with no extreme inflection points in asset mortality.

- Line Transformer mortality rises rapidly once they reach 50 years old; it is very unlikely for these assets to remain in service beyond 60-65 years.

- From our experience, these mortality patterns are similar to other electric systems in North America.

In assessing the reasonableness of the Company’s line transformer replacement plans in its PBR application, we considered these plans in the context of the expected (or predicted) replacement of the continuously aging transformer fleet as depicted in Figure 3.15 above, and combined it with the Company’s asset database (additions by vintage, adjusted for inflation in Account 47910) to estimate replacement requirements in years 2012-2020. Figure 3.16 below presents the Company’s estimated transformer replacement based on these estimated historic mortality patterns.
Figure 3.16 supports the following observations and insights:

- The Company’s expected transformer replacement costs (estimated from historic replacement trends) will range between $7.9M and $10.7M during the 2013 – 2016 time frame.
- The Company’s PBR plan forecasts $5.4M to $7.7M annually during this same time frame, clearly less than the estimated future replacement additions for transformers established or estimated via transformer mortality analysis process.

**Overhead Conductor Assets**

Applying the same analytical process to the Overhead Conductor Assets (Account No. 47400), Figures 3.17 and 3.18 below present profiles similar to those for line transformers, but with asset category-specific observations and insights.

**Figure 3.17 – Estimated Overhead Conductor Mortality**
The data as presented in Figure 3.17 supports the following observations:

- As with line transformers, overhead conductors have very low failure rates in the first 20 or so years of life. Early mortality, while rare, is more commonly due to a manufacturing flaw than service use.

- Overhead conductor failure rates begin to slightly increase after 20 years in service at a fairly constant rate over a very long period of time (to the end of the available data).

**Figure 3.18 – Estimated Overhead Conductor Replacement Needs**

Figure 3.18 supports the following observations and insights:

- The Company’s expected overhead conductor replacement costs (estimated from historic replacement trends) will range between $4.7M and $6.1M from 2013 through 2016.

- The Company’s PBR plan forecasts $5.4M to $7.2M annually during this same time frame, slightly more than the estimated future replacement additions for overhead conductors established via overhead conductor mortality analysis process.

*Poles and Fixtures*

We applied the same analytical process to the Poles and Fixtures Assets (Account No. 47300) as that used for line transformers and overhead conductor assets (graphically portrayed in Figures 3.19 and 3.20 along with asset category-specific observations and insights).
The data as presented in Figure 3.19 supports the following observations:

- Distribution poles and fixtures (Account No. 47300) have experienced very low failure rates in the first 20 or so years of life. Early mortality, while rare, is more commonly due to extraordinary, non-performance events (e.g. extreme storms, relocations, or car/pole accidents).

- Distribution poles and fixtures mortality rates begin to slightly increase after 20 years. For example, it requires approximately 20 years for the mortality rate to reach 5% of the original asset cohort, but only an additional 5-6 years for the mortality rate of the same cohort to double and reach 10%.

- Distribution poles and fixture mortality rates appear to steadily increase between years 20 and 45, with no extreme inflection points in asset mortality.

- After age 45-50, poles and fixtures are clearly nearing the end of their useful life.
Figure 3.20 highlights the following points:

- Our independent forecast of pole replacement additions (estimated from the Company's historic replacement trends and asset populations) range between approximately $20.3M and $24.5M during the 2013-2016 time frame. The per pole replacement cost estimate used to compute this range accounts for cost vs. initial construction variances attributed to greenfield vs. targeted replacement costs, additional activities related to pole removal, added peripherals when installing replacement poles, and significantly higher contractor costs due to relative scarcity of resources. That said, the unit cost used by ATCO Electric is at the industry median of range used by other North American utilities.

- The Company’s PBR plan forecasts $17.7M to $24.8M annually during this same time frame, less than the estimated future and fixture replacement additions of our independent forecast or estimate.

Summary of Analysis of Key Asset Classes Investment Levels

Figure 3.21 below summarizes our independent investment forecasts (from Company asset mortality trends and asset population profiles) presented in parallel to the Company’s PBR plans for Poles & Fixtures, Overhead Conductor, and Transformers.

![Figure 3.21 – Summary of Major Categories](image)

With respect to Figure 3.21, we offer the following observations and implications:

- Taken together, these three asset categories comprise approximately 72% of the Company’s total Asset Replacement / End of Life investments (and almost 50% of the K-Factor portion of the ATCO Electric’s System Maintenance Capital PBR filing from 2013 through 2016). So, any implications resulting from the trends represented in these tabulated summaries can be viewed as representative of the Asset Replacement / End of Life additions portion (and to a lesser degree the entire K-Factor portion) of this plan.
• Given the level of precision inherent in any assessment of this nature, the variance ranging between 4 and 14% between the forecast developed by this analysis and that submitted as the PBR filing for 2013 through 2016 is viewed as well within acceptable limits in ascertaining that these investment levels are properly allocated and appropriately focused on mitigating performance risk.

Therefore, our overarching conclusion is that the Company's asset replacement investment plans are well within the range of reasonableness given its asset base and historic asset mortality patterns.
UMS Group undertook a study to assist electric utilities in ascertaining, from an industry perspective, the annual refurbishment and replacement capital investment level necessary to offset the effect of normal T&D system deterioration. The objectives of this study were to:

- Assess the current state of the industry with respect to investment patterns.
- Substantiate the level of investment necessary to counter T&D system deterioration.
- Summarize the major considerations that affect the level at which T&D refurbishment and replacement should be made.

**Current Industry Patterns**

Our first step was to determine the current industry patterns regarding transmission and distribution investment levels as a ratio to depreciation; particularly given a view that depreciation nominally reflects the rate at which the value of an asset decreases, and it would appear logical to assume that in a steady state environment, an electric utility wishing to maintain a consistent level of performance would set annual capital additions equal to the level of depreciation.

We evaluated CAPEX-to-annual depreciation for the industry and found that the five year median ratio was 2.54 for Transmission and 1.90 for Distribution. However, this is total CAPEX which includes new construction, so we analyzed historic rates of investment and determined that on average, 20% of Transmission CAPEX is new construction and 6.7% of Distribution CAPEX involves new service connections. Adjusting for these factors, results in five year median ratios of 2.09 for Transmission and 1.78 for Distribution.

This demonstrates that as a whole, the industry recognizes that a higher level of capital expenditures than a 1:1 ratio is necessary to maintain the grid. Further, our view is that given the fact that the industry as a whole has lagged behind in making electric T&D infrastructure investments over the last 10-15 years, it’s not clear that even these ratios are high enough.
Impact of Inflation

There are a number of factors that impact the relationship between the level of capital additions incurred to build the original assets and that necessary to replace them today. These factors include the rate of construction cost inflation, the historical rate of replacement, the impact of investment level on reliability, changes in the risk profile and tolerance of both the company and its stakeholders, and the introduction of new technology.

Starting with a 1:1 ratio of CAPEX to depreciation, the first driver we analyzed for exceeding this ratio is inflation. Since the cost of replacing assets appears higher than the original construction costs, our hypothesis is that inflation plays a major role. The Handy-Whitman Index of Public Utility Construction Costs, a commonly used metric, validates this view.

As demonstrated in the chart above, over the past 30 years, the cost of constructing new Transmission and Distribution has increased significantly. Choosing the right base year for calculating the inflation factor required determining the average age of the asset base. We did so by looking at FERC Depreciation Factors as filed by utilities as part of their annual Form 1 reports. We found that the average dollar-weighted age of Transmission Assets is 13.38 years and that of Distribution Assets is 10.81 years.

These average dollar-weighted asset ages seemed lower than one would expect for an industry challenged with aging assets, so we analyzed the average age by asset classes and found that younger assets generally had a higher total dollar value than older assets. For example, even though the average dollar-weighted age of transmission towers is 21 years and the average dollar-weighted age of station equipment is 11 years, the dollar value of station equipment is approximately 2.5 times that of towers, providing a dollar-weighted average age of 13 years.
This dollar-weighted average asset age was used to identify the base years for our inflation calculation as it takes into account the higher cost of recent vs. older investments and prevents the possible double-counting of inflation inherent in using absolute asset ages. Applying this index for the aforementioned time frames, inflation factors of 0.73 and 0.85 can be established for Distribution and Transmission, respectively. Thus, capital additions would need to be 1.73:1 (Distribution) and 1.85:1 (Transmission) just to account for inflation.

Capital Investment Levels and Reliability

Next, we considered the historical rate of replacement by analyzing changes in the accumulated depreciation-to-total plant ratio over time. Utilities for which the rate of change was positive (i.e. the ratio was getting bigger) would be those for whom depreciation was growing faster than plant additions, indicating that current investment was not keeping up with the depreciation of past investment. Based on this analysis one can consider there to be two groups of utilities – those who appear to have been replacing their assets steadily and
those who appear to have under invested.

We then calculated the CAPEX-to-depreciation ratio for each group of utilities and determined that those who had been replacing their assets steadily over the last 15 years had a median 5-year average capex-to-depreciation ratio of 1.99 for Distribution and 3.65 for Transmission and those that had underinvested had a median 5-year average capex-to-depreciation ratio of 1.90 for Distribution and 2.16 for Transmission. The chart below shows the average capex-to-depreciation expense ratios for both groups over 5, 10, and 15 years.

![Capex-to-Depreciation Expense Chart]

We do not accept these numbers as absolute in defining appropriate levels of investment. However, by grouping a subset of the utilities in our sample based on this categorization (i.e. those for which we had recent reliability performance data), we can begin to demonstrate linkage between investment levels and reliability, specifically SAIFI; as the data also validates our intuition that under-investment over extended periods of time will manifest itself in poorer reliability performance (SAIFI). So, we used the split above to evaluate SAIFI for utilities who have been aggressively replacing assets against those who haven’t. Not surprisingly, we found that those with more aggressive replacement programs have experienced an average SAIFI of 1.00, better than the average SAIFI of 1.20 experienced by
utilities with lower investment levels.

While this and past analyses do not establish a direct correlation between CAPEX-to-depreciation ratios and reliability on a utility-by-utility basis, they do reveal that those utilities with more aggressive replacement programs have achieved, on average, greater reliability. None of the companies which were in the “replacing assets” group had a SAIFI worse than 1.34, while approximately 20% in the second group did have worse reliability. And, on average, the CAPEX-to-depreciation ratio for the former group was 1.69, while that for the latter was 1.46. So, one can surmise that in applying an additional 0.23 to the capex-to-depreciation ratio, utilities can anticipate significantly improved (lower) SAIFI.

Risk Tolerance

This discussion of reliability leads right into addressing the impact of risk and varying tolerance levels of electric utility internal and external stakeholders. Besides the obvious impacts of changing laws / regulations, increased regulatory scrutiny, and increased customer expectations, the most tangible risk confronting utilities revolves around its ability to maintain acceptable reliability; and given the focus on capital investment, specifically SAIFI, no one questions the notion that capital investment and reliability (as measured by SAIFI) are inexorably linked. In fact, past analyses have shown a strong correlation, but with a 4-year lag - in that a change in today’s investment level will likely manifest itself in terms of SAIFI 4 years later. That said, there are a number of short-term measures that utilities are implementing (e.g. enhanced tree trimming-O&M expense, increased fusing and reclosers on main feeders, and adaptive relaying) that mask the impact of short-term underinvestment. But, the reality of increases in equipment failure outages is starting to offset (and will soon overtake the impact of) these measures. The risk is that once this becomes a reality, the fix will take longer and, depending on the specific regulator, may require reactive / higher levels of investment without provisions for cost recovery; and possible fines. These dynamics do not factor into determining the ratio of CAPEX to depreciation, but do provide a rationale for adopting ratios consistent with the utilities with more aggressive asset replacement strategies.

Impact of Newer Technologies

Last, we have looked at the impact of the newer technologies over time. In particular, the widespread implementation of grid modernization using digital technology will likely increase the cost of replacement, as well as reduce average asset life. For example, smart grid technology will likely have a service life half that of conventional T&D equipment which will drive a higher rate of depreciation. As our analysis is based on the ratio of capex-to-depreciation, the higher rate of depreciation should drive higher capital additions, somewhat offsetting the impact of the shorter service life. For the purposes of this analysis, we would suggest an additional factor of 0.1 to account for this impact of emerging and newer technologies (a more precise calculation would require a detailed asset-by-asset assessment and assume that the constantly changing smart grid market has achieved a level of stability that does not yet exist).

Summary of Results

The following table summarizes the impact of each of these factors on the ratio of CAPEX to depreciation, recognizing that the basis is a high level view of the industry, rather than one directly reflective of any specific electric utility. The analysis shows that from an industry wide
perspective these ratios should be in the range of 2.06 for Distribution (as compared to current industry average of 1.78) and 2.18 for Transmission (as compared to current industry average of 2.09).

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<td>1.0</td>
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<td>Inflation</td>
<td>0.73</td>
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<td>Introduction of New Technologies</td>
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<tr>
<td>Current Industry Average CAPEX to Depreciation Ratio</td>
<td>1.78</td>
<td>2.09</td>
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BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

JERSEY CENTRAL POWER & LIGHT COMPANY

DIRECT TESTIMONY
Of
UMS GROUP, INC.

By
JEFFREY W. CUMMINGS, VICE PRESIDENT

Re:  JCP&L Reliability and Investment/Spending Levels
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DIRECT TESTIMONY OF JEFFREY W. CUMMINGS

INTRODUCTION

Q. Please state your name and business address.
A. My name is Jeffrey W. Cummings. My business address is 1543 Abbotsford Drive, Naperville, IL 60563.

Q. By whom are you employed and in what capacity?
A. I am employed by UMS Group Inc. (“UMS”) of Morris Corporate Center, 300 Interpace Parkway, Suite C380, Parsippany, New Jersey, 07054. I am a Vice President of UMS, a consultancy that specializes in performance management and business transformation for electric, gas and water utilities.

Q. Please generally describe the qualifications of UMS.
A. UMS has been in the business of conducting comparative performance assessments to the global utilities industry since its inception in 1989 (refer to Schedule UMS – 2 for a summarized listing of more recent and relevant projects). We have supported multiple assessments and global benchmarking programs on six continents working with state public utility commissions as well as more than 300 electric, gas and water utilities. We have augmented our analytical capabilities with a team of management consultants who are knowledgeable in best productivity and service-level performance practices to ascertain an electric utility’s efficiency and effectiveness in comparison to a “qualified” peer group, and to collaboratively develop aggressive, yet achievable performance improvement plans. Among other qualifications, UMS leads a number of Global Learning and Benchmarking consortia, which together with our portfolio of ongoing client engagements facilitates our ability to maintain “real-time” proprietary cost and
operational performance data, correlated to industry “best practices,” which is supported by an analytical framework built on the premise that industry “best performers” can be both efficient and effective.

Q. What is your professional and educational background?
A. A summary of my professional and educational background is attached to my testimony as Appendix A.

Q. What is the professional and educational background of the UMS project team?
A. The professional and educational background of the UMS project team that worked with me on this assignment is attached to my testimony as Schedule UMS – 1. Totaling over 85 years of electric utility consulting experience, with a primary focus on grid modernization and reliability, this team has distinguished itself as professional, competent and objective in similar efforts, such as we have undertaken in this engagement for Jersey Central Power & Light Company (“JCP&L” or the “Company”), for other FirstEnergy electric utility companies. In fact, the Staffs for both the Pennsylvania and Ohio utility regulatory Commissions actively participated in the selection of this team to assess the electric reliability programs and investment/spending levels for three of the other FirstEnergy electric utility companies, and accepted the team’s final findings and recommendations as submitted.

Q. Have you previously testified in proceedings before the Board of Public Utilities (“Board” OR “BPU”)?
A. No, I have never previously testified in Board proceedings. However, the UMS team and I have testified before other regulatory commissions, as outlined in Appendix A and
Schedule UMS – 1; and, as indicated above, we have performed audits and assessments on behalf of the Staffs of other utility regulatory Commissions.

Q. Please describe the purpose of your direct testimony.

A. UMS was engaged to provide third-party comparative analyses of JCP&L’s investment and spending levels and reliability performance as compared against the other FirstEnergy electric utilities, other New Jersey electric utilities, and other peer group utilities in support of the Company’s filing of a base rate petition in this proceeding.

Q. How is your testimony structured?

A. My testimony is comprised of 5 parts. Part I provides a summary of our conclusions. Part II reviews the methodology used in conducting the analyses. Parts III through V provide substantive findings and support for our conclusions in the areas of reliability, capital expenditures and operations and maintenance (“O&M”) spending.
Part I – SUMMARY OF CONCLUSIONS

Q. What were your overarching conclusions regarding JCP&L’s level of service (i.e., reliability)?

A. The Company’s reported reliability has shown consistent improvement since 2004 and JCP&L’s performance ranges between top quartile and median relative to two comparable peer groups. This attests to the Company’s effectiveness in implementing asset management-related initiatives, and industry-leading service restoration processes. As evidence of a stated commitment to continued improvement, JCP&L is planning to apply even more capital investment towards circuit protection and sectionalizing and is investigating the possibilities of creating additional circuit ties (particularly in the Northern Region).

It appears, though, that the perception of the JCP&L customer base has been notably different from the Company’s reported results. The Company is keenly aware of this situation, which is the result of a significant increase in major and, therefore, excludable, events over the past four years, culminating with the two extraordinary storms in 2011 (Hurricane Irene and the October 31 snow storm). Notwithstanding the need to continue to improve upon the enhanced communication protocols established between the two major extraordinary events in 2011 and the challenges with the timely request for, and receipt of, mutual assistance during Hurricane Irene, JCP&L’s restoration processes are adjudged commensurate to those of other industry leaders. This conclusion is based on its relatively strong standing among a peer group of EDCs experiencing the same storms and considering the number of mitigating factors the Company had to overcome during these extraordinary events (outlined in Figures III.25 and III.30).
Q. What were your overarching conclusions regarding the level and focus of JCP&L’s capital investments?

A. JCP&L’s capital investment levels have been appropriate and have not declined. Instead, the investment levels have been strong and above that of the industry median; comparing favorably with other FirstEnergy electric utilities and other electric utilities within the state of New Jersey.

JCP&L’s “core” capital investments (reliability, condition and preventive/corrective maintenance, and forced replacement-related capital) have not been “crowded out” by other priorities and are correctly focused on the highest reliability risks.

JCP&L’s capital investment portfolio optimization process has achieved the proper balance between supporting short-term system performance mandates and longer-term investments geared toward ensuring the sustainability of said performance.

Q. What were your overarching conclusions regarding the level of JCP&L’s O&M spending?

A. JCP&L’s O&M spending levels have been stable or rising since FirstEnergy’s merger with JCP&L’s predecessor parent, GPU, Inc. In fact, I observed that the JCP&L portion of O&M spending within the FirstEnergy system has been notably larger than would be expected, relative to the number of customers served.

Trends within the O&M spending categories demonstrate that JCP&L has benefited from its “affiliation” with FirstEnergy. Like all FirstEnergy electric utilities, JCP&L has been successful at managing operations expenses (economies of scale, introduction of automation, and streamlined management structures), yet JCP&L has
increased maintenance expenses to more directly address and improve system performance.

With respect to staffing levels, the current staffing of bargaining unit line and substation crews is consistent with the operational requirements to operate, maintain and provide safe and reliable service to JCP&L’s customers for normal operations.

Q. Do you see opportunities for improvement?

A. JCP&L can still realize progress in mitigating the impact of service interruptions, particularly during major storms, by installing more in-line reclosers (sectionalizing) and increasing the circuit tie schemes (i.e., improve system flexibility by expanding the current ability to back-feed from an adjacent distribution circuit in the event of an outage); but with due regard to practicality and prudence in increasing the cost of electricity to JCP&L’s customers.
Q. Please describe the key features of the methodology applied by UMS in this engagement.

A. UMS performed an initial diagnostic benchmark comparing JCP&L’s cost and service level performance data against a properly selected peer group, supported by a review of internal documentation and interviews with a representative cross-section of JCP&L’s staff, to bring perspective to, and establish context around, the initial results. This high level view has been proven to be effective in establishing overall trends and targeting areas for more in-depth analyses. With the proper selection of industry peer groups (taking into account similar geographies, climates, system configurations) and with adjustments for regional cost differences (in this case, for example, using the U.S. Bureau of Labor Statistics for regional CPI indexes), we are able to provide reliable industry comparisons. Further, this high-level view is largely supported by publicly available data (i.e., FERC Form 1, SEC 10K, Annual Reports and State Regulatory Websites), offering a high level of transparency with results that are entirely reproducible by independent parties; thus providing increased confidence in the more detailed analyses (where the identities of the entities from which the source data is derived are necessarily treated as proprietary and confidential).

The high level view was augmented with a more targeted, “bottom-up” assessment, designed to link comparisons of cost and service level data with those practices that drive an electric utility’s comparative position relative to its peer group. The sources of data were an accumulation of cost and service level data from the 40+ electric utilities that participate in the aforementioned Global Learning Consortia. The source for “best practices” comparisons are from a regular flow of benchmarking and
comparative analyses performed from over 20 electric utilities (outside of those participating in the various industry forums). In these portions of the analyses, the source data is necessarily masked (in particular, oftentimes the identity of industry participants must remain confidential), but consistency in the overall trends and profiles represented from the high-level (non-proprietary) and masked (proprietary) approaches (i.e., the totally transparent high level view and the more detailed, less transparent bottom up perspective) lends additional credence to our findings.

The specific metrics and analytical approaches used to compare JCP&L’s investment and spending levels and reliability will be described in more detail in the appropriate sections of this testimony.

Q. Please describe the composition of the peer groups of utilities selected for this analysis.

A. Given the complexity, breadth and depth of issues to be addressed in this assessment, UMS selected the following peer groups:

- National Panel for Capital Investment and O&M Spending comparisons (Source: FERC Form 1 report from over 140 electric utilities ranging between 200,000 and 3,000,000 customers).
- Regional Panel consisting of 32 electric utilities within New Jersey and the 7 states in close proximity to JCP&L (Figure II.1).
Figure II.1 – Regional Panel

<table>
<thead>
<tr>
<th>Consolidated Edison</th>
<th>Jersey Central Power &amp; Light Company</th>
</tr>
</thead>
<tbody>
<tr>
<td>Citizens Electric</td>
<td>Rockland Electric</td>
</tr>
<tr>
<td>Nantucket Electric</td>
<td>Orange and Rockland Utilities</td>
</tr>
<tr>
<td>United Illuminating</td>
<td>West Penn Power Company</td>
</tr>
<tr>
<td>Pike County Light and Power Company</td>
<td>New York State Electric and Gas Corp</td>
</tr>
<tr>
<td>Public Service Electric and Gas</td>
<td>PECO Energy Company</td>
</tr>
<tr>
<td>Rochester Gas and Electric</td>
<td>Wellsboro Electric Company</td>
</tr>
<tr>
<td>UGI Utilities</td>
<td>Central Hudson Gas and Electric Corp</td>
</tr>
<tr>
<td>NSTAR Electric and Gas</td>
<td>Metropolitan Edison Company</td>
</tr>
<tr>
<td>National Grid (NY)</td>
<td>Pennsylvania Electric Company</td>
</tr>
<tr>
<td>Connecticut Light and Power</td>
<td>Baltimore Gas and Electric</td>
</tr>
<tr>
<td>Pennsylvania Power Company</td>
<td>Delmarva Power</td>
</tr>
<tr>
<td>Massachusetts Electric Company</td>
<td>Fitchburg Gas and Electric Company</td>
</tr>
<tr>
<td>Duquesne Light Company</td>
<td>Atlantic City Electric</td>
</tr>
<tr>
<td>Western Massachusetts Electric</td>
<td>Delmarva Power Maryland</td>
</tr>
<tr>
<td>PPL Electric Utilities Corp</td>
<td>Potomac Electric Power Company (MD)</td>
</tr>
</tbody>
</table>

- Peer Group Panel of 15 electric utilities selected based on similarities in vegetation patterns, customer density, and suburban/rural characteristics (Figure II.2 illustrates the 5 step process to identify and validate the comparability of electric utilities included in this Peer Group Panel).

- Major Storm Comparison Peer Group Panel

- “Masked” Panel comprising the UMS confidential and proprietary database of “best practices.”
Figure II.2 – Peer Group Panel

1. IEEE Classification

Classification of Respondents
- Urban, Suburban, Rural
  - Rural <= 50 cust/mi (31 cust/km)
  - Suburban > 50 cust/mi <150 cust/mi
  - Urban >= 150 cust/mi (93 cust/km)

2. Vegetation Density

3. Service Territories

4. Selected Peer Panel

<table>
<thead>
<tr>
<th>Utility</th>
<th>Customers/Cust/mile</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appalachian Power Co</td>
<td>981,159</td>
</tr>
<tr>
<td>Duke Energy Carolina</td>
<td>2,396,555</td>
</tr>
<tr>
<td>West Penn Power Co</td>
<td>717,269</td>
</tr>
<tr>
<td>Central Hudson Gas &amp; Electric Corp</td>
<td>274,152</td>
</tr>
<tr>
<td>Metropolitan Edison Co</td>
<td>552,631</td>
</tr>
<tr>
<td>PSNH</td>
<td>498,175</td>
</tr>
<tr>
<td>Niagara Mohawk</td>
<td>1,297,616</td>
</tr>
<tr>
<td>Unit Energy Systems</td>
<td>78,212</td>
</tr>
<tr>
<td>PPL Electric Utilities Corp</td>
<td>1,403,899</td>
</tr>
<tr>
<td>Fitchburg Gas &amp; Electric Light Co</td>
<td>28,851</td>
</tr>
<tr>
<td>Orange &amp; Rockland Utilities Inc</td>
<td>334,608</td>
</tr>
<tr>
<td>Jersey Central Power &amp; Light Co</td>
<td>1,099,194</td>
</tr>
<tr>
<td>WMEDCO</td>
<td>206,279</td>
</tr>
<tr>
<td>Connecticut Light &amp; Power</td>
<td>1,212,276</td>
</tr>
<tr>
<td>Massachusetts Electric (Hignd)</td>
<td>1,167,000</td>
</tr>
</tbody>
</table>
In establishing these peer group panels, we were able to cross-check the comparative positions of JCP&L and proactively rationalize the impact (if any) of any uniqueness, be it attributed to regional/geographical, and/or system design considerations.

To provide a more robust measure of JCP&L’s relative performance during the two major extraordinary storm events of 2011 (Hurricane Irene and the October 31 snow storm), we expanded the comparative analyses to include electric utilities outside of New Jersey (subject to availability of information in the public domain), to be included in the Major Storm Comparison Peer Group. In so doing, we were able to establish a more substantive comparison of storm mobilization and service restoration, taking into account external factors (e.g., customer density, number of trouble locations, percent of customers affected, tree density, number of poles replaced and amount of primary conductor replaced) and their impact on service restoration. Figure II.3 summarizes the electric utilities for which information existed in the public domain to make these comparisons:

**Figure II.3 – Major Storm Comparison Peer Group**

<table>
<thead>
<tr>
<th>Electric Utility</th>
<th>Hurricane Irene</th>
<th>October 31 Snow Storm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jersey Central Power &amp; Light Company</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Connecticut Light and Power</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Rockland Electric</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Long Island Power Authority</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>NSTAR Electric and Gas (MA)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>National Grid (Massachusetts)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Public Service Electric and Gas</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Baltimore Gas and Electric</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Atlantic City Electric</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Potomac Electric Power Company (MD/DC)</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Consolidated Edison</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>New York State Electric and Gas</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Western Massachusetts Electric</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Central Hudson Gas and Electric</td>
<td></td>
<td>X</td>
</tr>
</tbody>
</table>
Finally, to make more targeted comparisons of specific programs and practices around mitigating or reducing the number of customer interruptions, service restoration, and addressing the adequacy of current staffing levels, we drew on the UMS confidential proprietary database of recent performance diagnostic/benchmarking efforts and Global Learning Consortia data (linking metrics to practices); as this level of comparative information is not readily available in the public domain. Specific comparisons included:

- General mix of causes of customer interruptions;
- Effectiveness of practices and programs to mitigate the impact of customer interruptions (e.g., sectionalizing and circuit protection);
- Effectiveness of overall vegetation management program to reduce customer interruptions;
- Effectiveness in restoring customers during non-working hours (evening, overnight and weekends);
- Capacity to respond to multiple outage events within a day;
- Industry averages pertaining to preventive and corrective maintenance completion rates; and
- Industry averages pertaining to overtime for line and substation crews.

In our effort to maximize the transparency of our analyses to all interested stakeholders, only this last category of peers and related data from the UMS confidential database and Global Learning Consortia required confidentiality.

Q. **How did UMS proceed with this third party comparative analysis?**

A. UMS partitioned the overall project into three major groupings and three supporting areas, namely:
Major Groupings (corresponding to Parts III, IV and V of this testimony):

- Comparative and trending analyses of JCP&L reliability performance and related practices under normal operations (i.e., exclusive of the two major extraordinary storms in 2011);
- Comparative and trending analyses of JCP&L capital expenditures; and
- Comparative and trending analyses of JCP&L O&M spending levels.

Supporting Areas:

- JCP&L comparative/“normalized” performance during the two major storms in 2011 (performed as an adjunct to the core reliability performance assessment);
- Comparative view of electric distribution infrastructure from an asset age/vintage perspective (performed as an adjunct to the analyses of the JCP&L capital investment process); and
- Review of staffing levels of JCP&L line and substation crews (performed as an adjunct to the analyses of the JCP&L O&M spending levels)

To perform these analyses, UMS initially requested reliability performance data (from the JCP&L outage management system (“OMS”)) and capital investment/O&M spending plans and actuals since 2004, with supplemental requests based on preliminary analyses of data and/or issues raised during on-site interviews. Suffice it to say that we were provided a plethora of data and information, which included responses to all of our requests for data and information.

Our initial efforts consisted of performing initial diagnostic benchmarks and conducting interviews. In so doing, we were able to establish context around the data and assess JCP&L’s execution of FirstEnergy’s established practices and approaches to
address customer needs with respect to reliability. To accomplish this, UMS met with 30 individuals, ranging from mid-level management to Senior Executives within JCP&L and the FirstEnergy corporate offices.

Figure II.4 illustrates in a summary manner the major activities that led to our reported outcomes, which formed the basis for this testimony.

### Figure II.4 – Summary of Major Work Activities

<table>
<thead>
<tr>
<th>Purpose</th>
<th>Conducted Reliability Performance Analyses (including Hurricane Irene and October 31 Snow Storm)</th>
<th>Assessed Capital Investment Levels (including a Comparative View of Asset age)</th>
<th>Assessed O&amp;M Spending Levels (including a Review of Lines and Substation Crews Staffing Levels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Determine relative position with respect to system performance to a comparable group of utilities</td>
<td></td>
<td>Determine relative position with respect to capital investment levels (verify the extent to which JCP&amp;L receives its “fair share” in comparison to other FE electric utilities)</td>
<td>Determine relative position with respect to O&amp;M spending levels (verify the extent to which JCP&amp;L receives its “fair share” in comparison to other FE electric utilities)</td>
</tr>
<tr>
<td>Ascertain effectiveness of current programs and practices to eliminate or mitigate the impact of service interruptions</td>
<td></td>
<td>Examine the distribution of capital investments in addressing reliability and renewal of electric distribution infrastructure amidst other competing priorities</td>
<td>Examine trends re: operations and maintenance spending separately; verifying capture of efficiencies and proper attention to aging infrastructure</td>
</tr>
<tr>
<td>Normalize JCP&amp;L’s performance in the timely restoration of electricity resulting from the 2 major storm events in 2011</td>
<td></td>
<td></td>
<td>Assess adequacy of staffing levels</td>
</tr>
</tbody>
</table>

**Inputs**
- Publicly available system performance data from annual reports and company / regulator websites
- Publicly available data regarding 2011 Major Storms
- Proprietary and confidential data from UMS Group database relating practices and processes to function-level data
- FERC Form 1 data on electric utilities serving between 200,000 and 3,000,000 customers; and for each of the previously defined peer group panels
- Budgeted and actual capital expenditures (by category and 105,989 individual capital projects during the 2004-2011 time frame)
- Age profile for 4 JCP&L electric distribution asset classes used as representative of overall asset age
- Publicly available data on the average service lives of Substations, Transformers, Circuit Breakers, Wood Poles and Distribution Transformers
- PM/CM completion rates, backlog and workload
- Overtime profile for lines and substations work crews
- Actual vs. Planned capital expenditures (2004-2011)

**Outputs**
- Comparative position and trends related to frequency and duration of service interruptions
- Impact of weather in addressing difference between reported reliability and that experienced by the customer
- Effectiveness of storm hardening and circuit protection programs
- Primary causes of interruptions (input to capital investment analysis)
- Effectiveness in restoring service as a function of time-of-day and day-of-week and volume of outage events (input to staffing analysis in support of O&M spending analysis)
- “Normalized” comparative analysis re: restoration of electricity during the 2 major storm events of 2011
- Comparative positions and trends regarding overall investment levels relative to the industry
- Comparison of capital expenditure trends to annual customer growth rates
- Comparison of investment patterns to other FE electric utilities, other NJ electric utilities, and the aforementioned peer group panels
- Evaluation of “No Growth” (CAPEX less new connections) and “Core” (reliability, condition/CM/PM, and forced replacements only) capital expenditures
- Degree of alignment between distribution of “Core” capital expenditures and source of reliability risk
- Comparative age of JCP&L electric distribution assets
- Comparative positions and trends regarding overall O&M spending levels relative to the industry
- Comparison of O&M spending patterns to other FE electric utilities, other NJ electric utilities, and the aforementioned peer group panels
- Analyses of Capital Program Execution, Lines and Substations Inspection and Maintenance, Outage Restoration Performance, and Lines / Substation Crews overtime

**Q.** To what extent did JCP&L direct and/or impact the findings and conclusions?

**A.** As previously discussed, the stated purpose of this engagement was to obtain a third-party comparative analysis of JCP&L’s investment and spending levels and reliability
performance. As such, JCP&L did not play any role in directing the composition of the industry peer groups (a key element to any comparative assessment), shaping the analytical approach, reviewing the details (as opposed to the results) of the analysis, or developing any findings and conclusions. That said, recognizing that any assessment is only as accurate and comprehensive as the data/information provided and questions asked, we followed our standard protocols of testing and developing insights with appropriate JCP&L and FirstEnergy corporate personnel to ensure an accurate and fair representation. There were no instances when our views were rebutted; rather, there were only questions or further analysis seeking or providing additional clarity and understanding of our stated positions.
Part III – RELIABILITY PERFORMANCE ANALYSIS

Q. What is the purpose of your reliability performance testimony?

A. Electric reliability performance analysis has an important role in any general rate case because maintaining or improving electric system reliability is a primary motive behind a substantial portion of any electric utility’s O&M and capital expenditures. JCP&L’s reported reliability has steadily improved since 2002 and, since 2007, has reached a point where all of the Company’s reported reliability metrics are now better than the benchmark targets established by the BPU under N.J.A.C. 14:5-8.9 - Electric Distribution Service Reliability and Quality Standards (hereinafter referred to as the “Board’s Standards” or the “BPU Standards”) (refer to Figure III.1). Nevertheless, customer and other stakeholder feedback regarding the Company’s recent performance, particularly during the 2010 through 2011 time frame when major storms caused widespread and long-duration service interruptions, makes this an important topic for analysis in JCP&L’s rate case.

The purpose of this part of the testimony is to explain JCP&L’s reliability performance and the key factors that influence it. As an introduction to this discussion, Figure III.1 presents JCP&L’s electric system reliability performance measures.
Q. Can you explain the rationale for presenting JCP&L’s reliability performance for two distinct regions, rather than the company as a whole entity?

A. JCP&L’s operations are organized as two regions, which are referred to as the Northern and Central Regions. Each Region (or operating area) is comprised of one contiguous geographic region but it is separated from the other area by a portion of another utility’s service territory. In addition to being separate electric distribution systems, the geography, customer density, and climate is also notably different between the two operating areas, driving different system designs and area-unique challenges with respect
to causes and response to service interruptions. Therefore, the Board’s Standards for reliability performance, reported as SAIFI and CAIDI, are different.

**Figure III.2 – JCP&L Reported Reliability**

<table>
<thead>
<tr>
<th>Area</th>
<th>CAIDI Benchmark</th>
<th>CAIDI Minimum</th>
<th>SAIFI Benchmark</th>
<th>SAIFI Minimum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northern</td>
<td>158</td>
<td>199</td>
<td>1.44</td>
<td>1.63</td>
</tr>
<tr>
<td>Central</td>
<td>110</td>
<td>132</td>
<td>1.26</td>
<td>1.50</td>
</tr>
</tbody>
</table>

**NOTES**

1. The benchmark levels were established as the calculated 2002-2006 average for each index.
2. The minimum reliability level is the benchmark level plus one and a half standard deviation.

Q. What are SAIFI and CAIDI?

A. As stated in JCP&L’s 2011 Annual System Performance Report, service reliability is measured by the System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI), defined as follows:

- **SAIFI** (frequency of interruptions) represents the average frequency of sustained (greater than 5 minutes in duration) interruptions per customer during a reporting period. It is calculated as the ratio of number of sustained customer interruptions per reporting period to the total number of customers served per reporting period.

- **CAIDI** (interruption duration in minutes) represents the average time in minutes required to restore service to those customers that experience sustained (greater than 5 minutes in duration) interruptions during a reporting period. It is calculated as the ratio of the sum of the sustained customer interruption durations per reporting period to the total number of sustained customer interruptions per reporting period.

Taken together, these are industry standard measures that provide a system-level
indication of the “stability” of any electric distribution system to consistently provide service to its customers (SAIFI) and, in the event of a service interruption, the “responsiveness” of an EDC in restoring service (CAIDI).

These metrics are most assuredly impacted by the level and focus of capital investment and O&M spending (our analyses of these areas is described in Parts IV and V of this testimony), as well as the implementation of programs and practices aimed at either reducing the number or mitigating the impact of service interruptions.

This part of my testimony is focused on: (1) describing JCP&L’s reliability performance relative to the Regional and Peer Group Panels of EDCs, (2) assessing JCP&L’s effectiveness in implementing commonly deployed reliability programs and practices, and (3) reconciling the apparent disparity between reported reliability and customer perceptions.

Q. **What are Major Events (“MEs”)?**

A. Briefly, MEs refer to “Major Events”.

The electricity industry has always been concerned about system reliability, but the past two decades have seen consistent industry-wide efforts to improve the related topics of both reliability measurement and electric system performance. A major focus of improved measurement is to both standardize reliability measures and make them more useful in system planning and operation. One key insight is that large but extremely infrequent events (*e.g.*, extraordinary natural or man-caused events) can distort reliability measurements (including cross-company comparisons) and, as a consequence, unnecessarily influence a company’s planning processes (*e.g.*, distorting capital allocation to address rare or extraordinary events).
Efforts to improve reliability measurement led to the recognition that some events that cause a sustained service interruption are either beyond the design criteria of the system (e.g., sustained winds much greater than design standard for extended periods) or beyond the control of the EDCs (e.g., a flood, or major external accident or event, widespread storm event). Including these unusual or extraordinary events in reliability performance measures has the effect of distorting the measurement of “normal” performance, reducing comparability, and ultimately distorting capital and O&M decision-making within utilities. Consequently, state regulators and their utilities have developed standardized criteria, which allow for excluding the impact of these unusual events from the utilities’ reported performance. Virtually every state with a reliability reporting standard has an event or ME exclusion provision.

It is also critical to note that these events aren’t “ignored” by utilities. Rather, they are addressed in the utilities’ planning processes through other means, such as mutual aid programs, storm-hardening initiatives, and revised design standards.

Q. **Is there a New Jersey-specific definition of a ME?**

A. Yes. In New Jersey, MEs are defined in N.J.A.C. 14:5-1.2 as:

“A sustained interruption of electric service beyond the control of the electric distribution company, which may include, but is not limited to, thunderstorms, tornadoes, hurricanes, heat waves or snow or ice storms, which affect at least ten percent (10%) of the customers in an operating area.”

In addition, the regulation provides that:

“When one operating area experiences a major event, the major event shall be deemed to extend to those other operating areas which are providing assistance to the affected area.”
Q. What is the significance of understanding and discussing MEs in the context of reliability?

A. This discussion is relevant as it gets to the crux of the noted disparity between reported reliability and the reliability perceived by customers, and more particularly in this case, JCP&L’s customers. In defining ME exclusions, the industry, in effect, “normalizes” for the differing climates and weather patterns as well as other events that are outside the control of an EDC. This clarifies issues of accountability for providing safe and reliable electric service to customers (*i.e.*, EDCs are held accountable for that over which they have control) and facilitates a valid comparison to other similarly configured (and situated) EDCs for possible electric system performance improvement.

Given that an important variable to excluding an event is that it must affect “at least ten percent (10%) of the customers in an operating area” (by the BPU Standards, which is typical in many other jurisdictions), these exclusions presume a certain level of understanding and acceptance on the part of customers that extended electric service interruptions will occur when an event is large enough to affect a large number of customers.

Figure III.3 presents the profile of JCP&L’s ME exclusions since 2004 with one notable factor added, that being the total duration (in terms of days) of the sum total of the MEs within a calendar year (referred to as a “Major Event Day”/“MED” or “Major Event Days”/“MEDs”).
Given the dramatic increase in number of MEDs, our view is, even without the two major storms of 2011 (Hurricane Irene and the October 31 snow storm), the significant number of MEDs in 2010 and 2011 and their impact on service, exceeded this threshold for customer acceptance.

Q. **How would you explain the trend of increased MEDs since 2008, which are well above the number experienced between 2004 and 2007?**

A. The short answer is that weather events significantly increased the number of MEDs since 2008. Although we do not profess meteorological expertise, we note an increase in storm activity in some of the major meteorological data used by the industry over the past few years. For example,

**Snowfall:** The Northeast Snowfall Impact Scale (NESIS) characterizes and ranks high impact Northeast snowstorms, which are storms with large areas of 10 inch snowfall accumulations and greater, scored as a function of the area affected by a snowstorm, the
amount of snow, and the number of people living in the path of a storm. Figure III.4, summarizes these storms since 1986 and shows a noted increase in the frequency of these high impact snow storms (*i.e.*, eight during the 2010/2011 time frame as compared to nine between 2000 and 2009 and five during the 1990s).

**Figure III.4 – High Impact Snow Storms in NE Corridor (NESIS Value)**

Rain: The Northeast Regional Climate Center (NRCC) serves a 12-state region that includes New Jersey and works cooperatively with the National Climatic Data Center, the National Weather Service, and state climate offices to acquire and disseminate accurate, current climate data and information. Drawing from this source, Figure III.5 shows a noted increase in annual precipitation in the Northeast, and an even greater increase in New Jersey (increasing to over 63 inches in 2011, a 40 percent
These independent meteorological indices suggest that the severity of the regional weather in JCP&L’s service territory has worsened over the past few years, correspondingly causing an increase in MEs, which may explain a worsening of customers’ perceptions regarding the Company’s performance, notwithstanding the improvement in its reportable reliability metrics.

Q. How does JCP&L’s reliability compare to other electric utilities across the industry?

A. As previously discussed, JCP&L has clearly demonstrated improvement in reported reliability (which takes into account the application of the exclusion criteria described above) since 2002. To compare JCP&L’s results to electric utilities across the industry, we first combined (thus, removing the distinctions between) the two operating areas that
comprise JCP&L. The source data used to develop this measure was JCP&L’s OMS. The first item of note is that our numbers are consistent with those reported by JCP&L, thus validating the accuracy of the reporting currently provided by JCP&L.

We developed two comparisons to conduct our analysis:

- JCP&L’s SAIFI and CAIDI were compared to the 32-member Regional Panel with service territories located in the seven states in close proximity to JCP&L. These systems share similar geography but are not necessarily comparable on the basis of system characteristics.

- JCP&L’s SAIFI and CAIDI were compared to the 15-member Peer Group Panel with system configurations and characteristics that are most comparable to JCP&L.

Figures III.6a, III.6b, III.7a and III.7b show that JCP&L is positioned between the industry median and top quartile in both comparisons (slightly better when compared to the Peer Group Panel).
Figure III.6a – SAIFI (Excluding MEs) vs. Regional Panel

![Image of SAIFI graph]

Source: Analysis of Regional Reports Data JCP&L

Figure III.6b – CAIDI (Excluding MEs) vs. Regional Panel

![Image of CAIDI graph]

Source: Analysis of IEEE Data JCP&L Data
Figure III.7a – SAIFI (Excluding MEs) vs. Peer Group Panel

Figure III.7b – CAIDI (Excluding MEs) vs. Peer Group Panel
Q. How do JCP&L’s practices in the areas of reliability-related planning, operations, and maintenance compare to other electric utilities?

A. UMS assessed operating practices in eight different areas and compared JCP&L’s performance in these areas to the leading practices in the industry. Specifically, we reviewed:

- Vegetation Management;
- Capacity Planning and Utilization;
- Circuit Protection/Sectionalizing;
- Relaying and Over-Current Protection;
- Emergency Preparation and Mobilization;
- Outage Restoration;
- Asset Management; and
- Storm Hardening

Overall, JCP&L has advanced to a high level of performance across these operating practices under normal operating conditions (i.e., excluding extraordinary major storms of the intensity represented by 2011’s Hurricane Irene and the October 31 snow storm). In addition, FirstEnergy continues to cross-pollinate best practices across its utility subsidiaries in New Jersey, Ohio, Pennsylvania, West Virginia, and Maryland.

Nevertheless, the Company acknowledged opportunities, and has taken steps, to improve its effectiveness in emergency preparedness and mobilization, and community and customer communications during these extraordinary events, an area we did not assess other than to confirm that the improvement actions coming out of these events have been implemented.
Furthermore, the Company has been the subject of multiple external audits/assessments since the merger of GPU with FirstEnergy in November 2001, including: (i) the Booth audit in 2003-2004, (ii) the PJ Downes reliability-related investigations of 2003 to 2004, (iii) the BPU Management Audit of JCP&L by Schumaker and Associates, completed in June 2011; and (iv) the recent Emergency Preparedness Partnerships (EPP) Report on Hurricane Irene and the October 31 snow storm and the emergency response preparedness of the New Jersey EDCs. In the case of (i) and (ii), these have led to agreed-upon requirements and, subsequently, initiatives by JCP&L to enhance its investment in electric infrastructure and improve certain business processes. With respect to (iii) and (iv), the Company awaits the Board’s disposition of these matters. However, I note that the Company fully cooperated in both of these latter proceedings and its comments on both reports reflect a cooperative attitude and approach.

Q. **How does JCP&L compare to other utilities in the area of vegetation management?**

A. FirstEnergy has long advocated cycle-based tree trimming. JCP&L, in the stipulation regarding the 2001 GPU/FirstEnergy merger, agreed to adopt the more aggressive FirstEnergy vegetation management trimming specifications and has complied with the BPU mandate that all trees be inspected and trimmed as necessary, on a 4-year cycle. The current tree trimming costs are in the range of $6,000 per mile. That, combined with a minimum amount of hot spotting (*i.e.*, non-cycle or off-cycle trimming to address a specific vegetation management issue impacting reliability in a particular location) is a sign of a mature program that has been on cycle for over a decade.

By way of cycle optimization (an industry “best practice”), JCP&L has properly trimmed more heavily on the feeder backbones (*i.e.*, the main part of a circuit from the
substation to the circuit’s key branches) and three-phase parts of its circuits. Beginning in 2009, JCP&L also went beyond what would normally be expected by instituting a one-time, predominantly capitalized, trimming program to be implemented during the 2009-2012 period, designed to remove additional overhang and hazard trees, and expand the trimming corridors of the Company’s rights-of-way (“ROW”) as discussed in Mr. Hillmer’s testimony in Exhibit JC-16.

It should be noted, however, that the Company’s Northern Region is among the most densely treed areas in the region (refer to Figure III.8). Regardless of the effort to optimize the cycle and expand the ROW, major storms (particularly of the nature of the two extraordinary major events in 2011) undoubtedly will cause heavy damage and subsequent large and extended outages.

**Figure III.8 – Regional Tree Density**
Therefore, the fact that tree-caused outages represent the second largest cause of customer interruptions (as shown later in this testimony) comes as no surprise. Because JCP&L has maintained a vegetation management program comparable to that of industry “best performers,” the number of preventable tree-caused customer interruptions is minimal (Figure III.9). Refer to Mr. Hillmer’s testimony in Exhibit JC-16 defining preventable and non-preventable.

**Figure III.9 – Tree-Caused Customer Interruptions (Excluding MEs)**

When we compared JCP&L’s percentage of preventable tree-caused customer interruptions to total tree-caused customer interruptions against a comparable peer group in the UMS confidential practices database, JCP&L was identified as a top-quartile performer in this area. Figure III.10 illustrates that JCP&L’s percentages for such preventable tree-caused customer interruptions range between one and five percent, whether “blue sky” or facing inclement weather.
Q. How does JCP&L compare in the area of capacity planning and utilization?

A. JCP&L adheres to good utility practices in capacity planning and utilization, with any projected overloads being addressed through load transfers or capacity-related projects, including the use of FirstEnergy’s 14MVA modular substation approach as a potential solution to a number of capacity issues identified during the summer of 2003. JCP&L’s territory, particularly in its Northern Region, has certain characteristic challenges as presented in the table below:

<table>
<thead>
<tr>
<th>Measure</th>
<th>Central Region</th>
<th>Northern Region</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customers per Mile</td>
<td>86</td>
<td>60</td>
</tr>
<tr>
<td>Percent Underground</td>
<td>42%</td>
<td>29%</td>
</tr>
<tr>
<td>Percent Circuits with Auto Ties</td>
<td>6%</td>
<td>0%</td>
</tr>
<tr>
<td>Substations Fed by Radial Sub Transmission</td>
<td>3</td>
<td>10</td>
</tr>
</tbody>
</table>
With its lower customer density, limited underground construction, fewer automated feeder tie schemes, and more radially-supplied substations, JCP&L’s Northern Region is more susceptible to outages and potentially longer outage durations than the Central Region. The difficulty of addressing this potential vulnerability to outages is underscored in this Region by the use of FirstEnergy’s 14MVA modular substation approach as a potential solution to a number of capacity issues. Though effective for low-load density applications, the modular substation design (\textit{i.e.}, a single transformer, with a two feeder lay-out) in the context of these system limitations may leave those areas, potentially susceptible to extended outages, should the sub-transmission lines or substation transformers experience failures. However, our view is that JCP&L has adopted a very sensible and prudent approach in addressing an industry-wide challenge to any electric utility that services a comparatively large and rural area with long, radial overhead lines, and must continually balance the inherent trade-offs between solutions that are highly costly to its customers and the need to manage and mitigate outage risk.

**Q. How does JCP&L compare to other electric utilities in the area of circuit protection and sectionalizing?**

**A.** JCP&L adheres to FirstEnergy’s guidelines in fusing all taps and in the deployment of reclosers to minimize the impact of customer interruptions on distribution feeder backbone outages. Consequently, JCP&L has invested heavily in this area as part of the Accelerated Reliability Improvement Program (“ARIP”) initially undertaken in 2003. Due to noted geographic and system differences between the two regional areas, the Central Region is more protected than the Northern Region in terms of the use of
reclosers and the existence of non-radial substations; and there remain opportunities to
further sectionalize circuits in both regions (more so in the Northern Region).

In evaluating the effectiveness of past efforts, Figure III.11 shows an overall
improvement in the form of a 30% reduction in the size of a typical JCP&L outage since
2004 (median level performance when compared against comparable EDCs in the UMS
confidential practices database).

Referring back to the discussion on Major Events (MEs), one would normally
expect a reduction of MEs to coincide with an effective circuit protection and
sectionalizing initiative. Given our conclusion that JCP&L’s circuit protection and
sectionalizing initiative has been effective, the fact that MEs have increased in spite of
such a program is further evidence of the role weather has played in the differing
perspectives as between reported reliability and the customer experience.

Figure III.11 – Average Outage Size (Excluding MEs)
Q. How does JCP&L compare in the area of relaying and over-current protection?

A. It is our view that FirstEnergy has established itself as an industry leader in deploying adaptive relaying, a practice that has been extended to JCP&L where 70% of the substations have been so configured (compares favorably to other EDCs). This allows for a selection between normal operating mode (“fuse sacrifice”) and storm event mode (“fuse-save”).

- The normal operating mode reduces the impact of outage events by limiting the number of customers that experience an interruption to those downstream from the fuse (typically customers on a tap). This assumes that all faults are permanent, erring on the side of preventing a substation breaker from locking open and sparing customers the inconvenience of a momentary interruption.

- During storm events, where wind or lightning make temporary faults more likely, saving the fuse prevents larger numbers of sustained outages in favor of more frequent but momentary outages. In so doing, customers may be spared a longer duration outage caused by a fuse operation.

Q. How does JCP&L compare in the area of emergency preparation and mobilization?

A. JCP&L’s use of FirstEnergy’s E-Plan and the ability to receive mutual assistance from affiliated companies within the FirstEnergy system provides for an effective and fully integrated major event response. Further, as all personnel are working under a common Manual of Operations, with the same construction standards and using the same terminology and equipment, the work force is rapidly scalable and immediately effective. The scalability extends beyond the use of additional crews to include hazard responders, damage assessors and regional dispatch office (“RDO”) dispatchers. While the practices
embedded in the FirstEnergy E-Plan can be characterized as “best in class,” and JCP&L’s service restoration performance during normal operations (i.e., blue sky and normal inclement weather) bears that out, the effective implementation of the E-Plan was challenged during the two major extraordinary events in 2011. During Hurricane Irene, over-reliance on one of JCP&L’s greatest strengths, the anticipated availability of other FirstEnergy resources (initially deployed elsewhere based on initial forecasts of the storm track), delayed the request for outside mutual assistance. Moreover, the sheer magnitude of damage experienced in both storms severely tested the operation of the FirstEnergy E-Plan. A more detailed comparative assessment of these events follows, illustrating that mitigating factors placed JCP&L at a most disadvantageous position when compared to other electric utilities in the Major Storms Comparison Peer Group; while at the same time demonstrating that JCP&L’s performance (adjusting for these factors) is indicative of effective emergency preparation and mobilization practices.

Q. **How does JCP&L compare in the area of outage restoration?**

A. Besides achieving overall favorable trends with respect to CAIDI (Figure III.1), JCP&L’s evening and overnight CAIDI as a percent of change from daylight hours CAIDI compares favorably to a comparable peer group within the UMS confidential practices database. Similar comparative statements can be made between weekday and weekend CAIDI.

- Figures III.12a and III.12b shows that evening CAIDI (variance to daytime) has been in the top quartile (although 2007 is an outlier due to extremely strong daytime performance), and since 2007, overnight performance has been at median or better.
Figure III.12a - CAIDI Variance – Evening vs. Normal Working Hours (Excluding MEs)

Source: Analysis of JCP&L vs. 45 Utility Years

Figure III.12b – CAIDI Variance – Overnight vs. Normal Working Hours (Excluding MEs)

Source: Analysis of JCP&L vs. sample of 45 Utility Years
Figure III.13 compares JCP&L’s weekday vs. weekend CAIDI to EDCs within the UMS confidential practices data base, illustrating that the Company’s 6% variation is well within the norms of the peer group (identified as “A” through “G”).

**Figure III.13 – Weekday vs. Weekend CAIDI Comparisons (Excluding MEs)**

The results presented in Figures III.1, III.12a, III.12b, and III.13 substantiate JCP&L’s effectiveness in the use of its first responder program, deployment of alternate shifts, and callout process; as well as its overall commitment to service restoration. The following Figures III.14a and III.14b attests to the efficiency of JCP&L’s service restoration practices.
Service restoration (as measured by CAIDI) is predictable and relatively stable in both the Northern and Central Regions, with JCP&L being able to effectively handle up
to 45 outage events per day with little or no variability in results (comparing favorably to
the UMS confidential practices database); and the variability in performance matches
average levels of up to 70 outage events per day, which is extraordinary and indicative of
scalable and well-conceived practices.

Q. How does JCP&L compare to other electric utilities in the area of Asset
Management?

A. Asset Management, as it pertains to electric distribution reliability, addresses those
practices that direct the planning of capacity, inspection, maintenance, replacement and
risk management related to electric distribution system assets. Portions of these topics
have already been discussed in this testimony (i.e., vegetation management, capacity
planning, circuit protection, and sectionalizing). Other areas explored during our
assessment included:

- JCP&L’s Inspection and Maintenance Programs. JCP&L reports 100 percent
  compliance with respect to periodic inspections (Figure III.15):
Figure III.15 – Summary of Reliability and Maintenance Programs

<table>
<thead>
<tr>
<th>Program</th>
<th>Equipment</th>
<th>Frequency</th>
<th>Total Number of Units</th>
<th>2011 Target (No. of Inspections)</th>
<th>No. of Inspections Completed</th>
<th>Percent of Target Completed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution</td>
<td>Capacitor Banks</td>
<td>Annually</td>
<td>4,744</td>
<td>4,744</td>
<td>4,744</td>
<td>100%</td>
</tr>
<tr>
<td></td>
<td>Reclosers</td>
<td>Annually</td>
<td>1,074</td>
<td>1,074</td>
<td>1,074</td>
<td>100%</td>
</tr>
<tr>
<td>Transmission</td>
<td>Aerial</td>
<td>Twice per Year</td>
<td>NA</td>
<td>2</td>
<td>2</td>
<td>100%</td>
</tr>
<tr>
<td>Sub-Transmission</td>
<td>Ground Line Poles</td>
<td>10-Year Cycle</td>
<td>39,000</td>
<td>3,431</td>
<td>3,431</td>
<td>100%</td>
</tr>
<tr>
<td>Substation</td>
<td>General</td>
<td>Monthly</td>
<td>326</td>
<td>3,914</td>
<td>3,914</td>
<td>100%</td>
</tr>
<tr>
<td></td>
<td>Critical Relay Schemes</td>
<td>4-Year Cycle</td>
<td>801</td>
<td>177</td>
<td>177</td>
<td>100%</td>
</tr>
<tr>
<td></td>
<td>Infrared Inspections</td>
<td>Annually</td>
<td>327</td>
<td>327</td>
<td>327</td>
<td>100%</td>
</tr>
<tr>
<td></td>
<td>Battery</td>
<td>Annually</td>
<td>322</td>
<td>322</td>
<td>322</td>
<td>100%</td>
</tr>
</tbody>
</table>

NOTE: The information contained in III.15 was extracted from JCP&L’s 2011 Annual Performance Report.

Consistent with industry standard, the Company also conducts visual inspections of distribution circuits and equipment (which assures compliance with the National Electric Safety Code (NESC) and identifies any discrepancies that might impact service reliability, equipment operation, or safety), including transmission and distribution pole inspection and maintenance programs to ensure the integrity of in-service poles in maintaining safe and reliable service (both on a 10-year cycle).

Our assessment did not audit these programs; but did review them to ascertain their existence and content relative to industry practice. Further, JCP&L aligns to the industry in terms of scope and frequency of various inspection programs.

We did review completed maintenance records to ascertain closure rates on generated work orders (a majority of which originate from these programs). Figure
III.16 shows that corrective maintenance work orders for distribution lines have increased significantly between 2009 and the end of 2011, an expected trend (particularly in light of the two major extraordinary storms in 2011), further substantiated by the fact that over 66% of those work orders opened in 2011 were originated between September 1st and December 31st. Even with the “burst” of remedial activity reflected by the work orders, JCP&L maintained percent completion rates within the averages represented by the UMS confidential practices database (70 to 75 percent).

**Figure III.16 – Lines Maintenance Performance**

With respect to substation maintenance performance, Figure III.17 shows that the numbers of work orders for corrective maintenance and preventive maintenance inspections have remained fairly constant and the completion rates for corrective maintenance work orders have been higher than the industry average range of 75% to 80% (compared to comparable EDCs within the UMS’s confidential practices database). JCP&L also reports that 100% of all substation preventive maintenance requirements were completed over this 3-year period.
• **JCP&L’s Highest Priority Circuit Program.** Consistent with many EDCs, JCP&L uses another index, SAIDI (System Average Interruption Duration Index), which is the product of CAIDI multiplied by SAIFI (or the sum of customer interruptions divided by total number of customers served) to track circuit performance and determine which circuits, with some remedial action, present the best opportunities for reliability improvement. The remedial action to be taken is determined during regularly scheduled regional reliability team meetings based on a review of circuit CAIDI and SAIFI and subsequent cause analyses. The average improvement in SAIDI for these circuits is 45%, indicative of an effective program.

• **Sustainability** of the electric distribution assets forms the crux of an asset management program. For typical EDCs with predominantly overhead lines serving suburban and ex-urban communities, equipment failure outages represent the largest source of customer interruptions (Figure III.18).
Figure III.18 – Causes of Customer Interruptions (Excluding MEs)

A more in-depth look reveals that since 2005, equipment (including line) failures are the largest cause of JCP&L outages (Figure III.19). Within that category, conductor related failures (including those related to the use of tree cable) are a predominant contributor (Figure III.20).
Figure III.19 – Customer Interruptions from Lines/Equipment Failure (Excluding MEs)
Figure III.20 – Breakout of Conductor Customer Interruptions (Excluding MEs)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Conductor</td>
<td>74055</td>
<td>91356</td>
<td>172243</td>
<td>197264</td>
<td>187483</td>
<td>158517</td>
<td>189275</td>
<td>174075</td>
</tr>
<tr>
<td>Crossarm</td>
<td>25945</td>
<td>7136</td>
<td>4013</td>
<td>7181</td>
<td>9201</td>
<td>9290</td>
<td>21570</td>
<td>14792</td>
</tr>
<tr>
<td>Cutout</td>
<td>36106</td>
<td>35586</td>
<td>33431</td>
<td>33836</td>
<td>39592</td>
<td>41167</td>
<td>68012</td>
<td>69632</td>
</tr>
<tr>
<td>Fuse</td>
<td>4896</td>
<td>17048</td>
<td>3893</td>
<td>14823</td>
<td>18888</td>
<td>18852</td>
<td>8542</td>
<td>13887</td>
</tr>
<tr>
<td>Pole</td>
<td>2753</td>
<td>162</td>
<td>4888</td>
<td>6138</td>
<td>5794</td>
<td>7941</td>
<td>16103</td>
<td>9246</td>
</tr>
<tr>
<td>Recloser/Breaker</td>
<td>42343</td>
<td>34005</td>
<td>52752</td>
<td>35588</td>
<td>60085</td>
<td>39313</td>
<td>70204</td>
<td>40407</td>
</tr>
<tr>
<td>Sub Equip</td>
<td>17077</td>
<td>22237</td>
<td>9200</td>
<td>38334</td>
<td>46478</td>
<td>66173</td>
<td>51235</td>
<td>32244</td>
</tr>
<tr>
<td>Transformer</td>
<td>55605</td>
<td>24060</td>
<td>34043</td>
<td>41795</td>
<td>36437</td>
<td>39948</td>
<td>49286</td>
<td>44427</td>
</tr>
<tr>
<td>Grand Total</td>
<td>459741</td>
<td>403844</td>
<td>543667</td>
<td>468431</td>
<td>410152</td>
<td>402341</td>
<td>520122</td>
<td>469752</td>
</tr>
</tbody>
</table>

Our assessment of the effectiveness of JCP&L’s asset management program with respect to prioritizing reliability-focused investments will be addressed in more detail in the following section of my testimony, Capital Expenditure Assessment (Part...
IV). However, suffice it to say that the distribution of capital expenditures is consistent with the underlying causes of customer interruptions.

Q. How has JCP&L progressed with storm hardening the distribution system?

A. Many of the initiatives related to storm hardening have already been addressed:

- The Company has an effective vegetation management program which extends beyond what would normally be expected, applying the industry “best practices” of enhanced tree trimming where appropriate, and it has embarked on an aggressive capital program to remove additional overhang and danger trees from off the ROW.

- The Company has made substantial progress in circuit protection and sectionalizing, with additional improvement to be realized over the next couple of years. Further protection of the feeder backbones will serve to mitigate the impact of storms by reducing the number of customers impacted by an event. As previously stated, to the extent that JCP&L can prudently address the need for additional circuit tie schemes, the scope and subsequent effectiveness of sectionalizing can be expanded.

- The initial deployment of the adaptive relaying strategy, an acknowledged industry “best practice,” began in 2007 and was fully deployed during the first half of 2008. As previously stated, this technology allows JCP&L to adapt the protective relaying schemes to storms by preventing larger numbers of sustained outages in favor of more frequent but momentary ones.

- Various inspection and maintenance programs were previously summarized, with the Distribution and Transmission Pole Inspection and Maintenance Programs comprising the portion of these programs linked to storm hardening. The Company
reports compliance with the 10-year inspection cycles for both programs and compares favorably to comparable EDCs tracked in the UMS confidential practices database in closing corrective maintenance work orders.

One area of storm hardening not yet addressed is the effectiveness of lightning protection. The Company has a historically small proportion of lightning-caused interruptions, which has continued to decrease as a primary cause over the past 4 years (Figure III.21).

Figure III.21 – Lightning Caused Customer Interruptions (Excluding MEs)
Q. Although you have made reference to the two major extraordinary storms in 2011 for the most part you have focused on JCP&L’s reliability exclusive of these events. Why have you taken this approach?

A. As stated at the outset of this testimony, one element of this engagement was to provide a third-party comparative analysis of the Company’s reliability performance in the context of its capital investment and O&M spending levels against other FirstEnergy electric utilities, other New Jersey electric utilities, and other peer group utilities. This required a fundamental approach that looked at baseline reliability performance under normal operating conditions, the basis for all capital investment and O&M spending plans and traditional industry comparisons.

Q. Is it important, however, to also consider JCP&L’s performance with respect to these two storms?

A. Yes. These two extraordinary major events have had a significant impact on external perceptions regarding JCP&L’s performance to the point that the positive trend in system reliability over the past four years has been effectively erased in the eyes of many external stakeholders. Therefore, it was appropriate to perform a comparative review of JCP&L’s performance, targeted towards these events, and relative to a group of EDCs that is broader than just those serving New Jersey customers (referred to in Part II as the Major Storm Comparison Peer Group).

Of course, we also acknowledge the EPP report (Performance Review of EDCs in 2011 Major Storms) dated August 9, 2012, the findings, conclusions and recommendations of which we do not intend to address or challenge. Our intent is only to shed more light on the apparent disparity between JCP&L’s reliability performance,
which adheres to industry “best practices,” on the one hand, and the customer perception of service quality, on the other. Previous discussion herein has noted the increase in storms (snowfall and precipitation) over the past few years leading to a significant increase in MEs. However, it appears that a major concern has arisen regarding the Company’s performance during these two extraordinary events in 2011, and a lingering perception that JCP&L’s response was somehow insufficient.

**Q. What companies comprise the major storm peer group of EDCs used for your assessment of JCP&L’s performance during the 2011 events?**

**A.** As stated in Part II of this testimony addressing the two major extraordinary storms in 2011, we selected a Major Storm Comparison Peer Group Panel for the comparative analyses, to include EDCs outside of New Jersey (subject to the availability of information in the public domain), summarized below (Figure III.22).

**Figure III.22 – Major Storm Comparison Peer Group**

<table>
<thead>
<tr>
<th>Electric Utility</th>
<th>Hurricane Irene</th>
<th>October 31 Snow Storm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jersey Central Power &amp; Light Company</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Connecticut Light and Power</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Rockland Electric</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Long Island Power Authority</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>NSTAR Electric and Gas (MA)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>National Grid (Massachusetts)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Public Service Electric and Gas</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Baltimore Gas and Electric</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Atlantic City Electric</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Potomac Electric Power Company (MD/DC)</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Consolidated Edison</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>New York State Electric and Gas</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Western Massachusetts Electric</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Central Hudson Gas and Electric</td>
<td></td>
<td>X</td>
</tr>
</tbody>
</table>
Q. **What metrics did you use to compare performance?**

A. UMS compared the Company to this peer group relative to mobilization (expressed as time to reach peak staffing) and customers restored (expressed as 95% of customers restored). In selecting 95% customer restoration (as opposed to 100% customer restoration), we strove to isolate the impact of more rural and less dense circuits in order to form a more reasonable basis for comparison of performance.

Q. **Are the utilities in the Major Storm peer group comparable to JCP&L?**

A. The common attribute of the Major Storm Comparison Peer Group Panel is that they all experienced the same storm events and there exists a variety of analyses of their individual or collective service restoration performance in the public domain. Naturally, the EDCs vary widely with respect to the amount of damage they sustained, the percent/number of customers affected, and the basic geographic and system characteristics (e.g., customer density, tree density, degree of automation, and rural/urban service territory). Nevertheless, despite these differences, cross-company comparisons can be valuable.

   Our analysis attempts to report the comparative performance of JCP&L against the Major Storm Comparison Peer Group Panel in a way that highlights these different factors with complete transparency (i.e., no attempt was made to make adjustments for these factors).

Q. **What major factors affected the performance of the Major Storm Comparison Peer Group Panel and why are they so significant?**

A. No two electric systems, nor the scope or extent of a storm’s damages to these systems, are, of course, the same. To bring perspective to these comparisons we focused on the
following differentiating factors as items to consider when comparing or evaluating EDC performance in the wake of these two storms:

- Amount of Vegetation (only 4 of the 14 EDCs listed in Figure III.22, including JCP&L, have a significant amount of territory in the region’s most heavily treed areas)
- Percent of Customers Affected (EDCs are staffed with reasonable assumptions regarding outage size)
- Number of Customers per Trouble Location (speaks to the rate at which service can be restored as circuits are returned to service)
- Number of poles replaced (offers context to the amount of damage sustained during the storm)
- Amount of Primary Conductor Replaced (offers context to the amount of damage sustained during the storm)
- Amount of Snow during the October 31 snow storm (the combined effect of heavily-foliated areas and heavy snow fall was a primary driver of the amount of damage sustained among the nine utilities for which we have information for this specific storm).

Notwithstanding the previously discussed challenges to the implementation of JCP&L’s E-Plan during Hurricane Irene and the October 31 snow storm, and the need to continue to improve the effectiveness of communication protocols with communities and customers during major extraordinary storms, these factors should be considered in comparing EDC performance.
Hurricane Irene

Q. How did JCP&L compare to the other EDCs with respect to the scope of the damage or breadth of impact it sustained during Hurricane Irene?

A. Figure III.23 provides a relative comparison of JCP&L to the other EDCs during Hurricane Irene (where public information is available). The most severe scope or breadth of impact would be the highest or first relative position.

Figure III.23 – JCP&L Relative Comparison of Scope during Hurricane Irene

<table>
<thead>
<tr>
<th>Measure</th>
<th>Relative Position</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percent of Customers Affected</td>
<td>No.1</td>
<td>71 percent. Only 4 of the EDCs exceeded 50 percent of customers</td>
</tr>
<tr>
<td>Number of Customers per Trouble Location</td>
<td>No.2</td>
<td>24.9. Lowest was 14.3. 2 of the other 3 NJ EDCs exceeded 100</td>
</tr>
<tr>
<td>Number of Trouble Locations</td>
<td>No. 2</td>
<td>31,900 (3 times the peer group median)</td>
</tr>
<tr>
<td>Number of Poles Replaced</td>
<td>No. 5</td>
<td>466 (slightly higher than the peer group median)</td>
</tr>
<tr>
<td>Amount of Primary Conductor Replaced</td>
<td>No. 1</td>
<td>248,160 FT. Only CL&amp;P was close at 234,603. The next closest was 136,652 FT</td>
</tr>
</tbody>
</table>

Figure III.23 strongly suggests that context is important in assessing JCP&L’s restoration performance, including factoring in the impact of being the first or second most disadvantaged utility in 4 of the 5 measures (i.e., the shaded areas).

Q. Using 95% customer restoration as the performance metric how did JCP&L’s restoration performance in Hurricane Irene compare to other utilities?

A. JCP&L achieved 95% restoration on September 2\textsuperscript{nd}, which was comparable to, or better than, the performance of CL&P, NYSEG, BG&E and LIPA. Figure III.24 provides comparison profiles of the restoration performance of the 12 EDCs listed in Figure III.22
for which we had data regarding Hurricane Irene, followed by Figure III.25 that shows JCP&L’s relative position in light of the major factors presented in Figure III.23.

**Figure III.24 – Percent of Customers Restored by Evening (Hurricane Irene)**
Figure III.25 – Tabulation of Mitigating Factors (95% Restoration)

<table>
<thead>
<tr>
<th>EDC</th>
<th>Hours to Restore</th>
<th>Number of Customers</th>
<th>Percent of Customers</th>
<th>Number of Orders</th>
<th>Customers per Order</th>
<th>Poles Replaced</th>
<th>Conductor Replaced</th>
<th>Vegetation</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACE</td>
<td>80</td>
<td>273,898</td>
<td>52%</td>
<td>2,588</td>
<td>105.8</td>
<td>59</td>
<td>136,661 ft</td>
<td>Low</td>
</tr>
<tr>
<td>PEPCO</td>
<td>86</td>
<td>227,000</td>
<td>29%</td>
<td>NA</td>
<td>NA</td>
<td>36</td>
<td>50,000 ft</td>
<td>Low</td>
</tr>
<tr>
<td>NSTAR</td>
<td>114</td>
<td>506,000</td>
<td>43%</td>
<td>10,130</td>
<td>50.0</td>
<td>93</td>
<td>NA</td>
<td>Medium</td>
</tr>
<tr>
<td>Rockland</td>
<td>115</td>
<td>27,220</td>
<td>38%</td>
<td>974</td>
<td>31.1</td>
<td>27</td>
<td>5,714 ft</td>
<td>Low</td>
</tr>
<tr>
<td>PSE&amp;G</td>
<td>123</td>
<td>872,492</td>
<td>40%</td>
<td>7,500</td>
<td>116.3</td>
<td>599</td>
<td>NA</td>
<td>Low</td>
</tr>
<tr>
<td>ConEd</td>
<td>123</td>
<td>143,000</td>
<td>4%</td>
<td>2,851</td>
<td>50.2</td>
<td>91</td>
<td>NA</td>
<td>Low</td>
</tr>
<tr>
<td>NGRID</td>
<td>130</td>
<td>484,000</td>
<td>42%</td>
<td>33,900</td>
<td>14.3</td>
<td>238</td>
<td>27,245 ft</td>
<td>High</td>
</tr>
<tr>
<td>JCP&amp;L</td>
<td>148</td>
<td>780,000</td>
<td>71%</td>
<td>31,900</td>
<td>24.9</td>
<td>466</td>
<td>248,160 ft</td>
<td>High</td>
</tr>
<tr>
<td>BG&amp;E</td>
<td>150</td>
<td>756,395</td>
<td>61%</td>
<td>17,349</td>
<td>43.6</td>
<td>348</td>
<td>17,238 ft</td>
<td>Low</td>
</tr>
<tr>
<td>NYSEG</td>
<td>163</td>
<td>145,778</td>
<td>34%</td>
<td>NA</td>
<td>NA</td>
<td>438</td>
<td>NA</td>
<td>Medium</td>
</tr>
<tr>
<td>CL&amp;P</td>
<td>183</td>
<td>671,000</td>
<td>56%</td>
<td>16,101</td>
<td>41.7</td>
<td>1,292</td>
<td>234,603 ft</td>
<td>High</td>
</tr>
<tr>
<td>LIPA</td>
<td>196</td>
<td>523,000</td>
<td>48%</td>
<td>18,926</td>
<td>27.6</td>
<td>900</td>
<td>NA</td>
<td>Medium</td>
</tr>
</tbody>
</table>

NOTES:

1. “NA” denotes that UMS was not able to find data from public sources
2. Shaded area denotes that this factor places the EDC in a more disadvantaged position than the vast majority of the other EDCs that form this particular peer group panel.

In reviewing the data and information contained within Figure III.25, although JCP&L was just below the median for the group of utilities in terms of time to restore service to 95% of its customers, the fact that the Company was among the two most disadvantaged relative to other electric systems in all but one category suggests (i) a commendable level of diligence applied to overcoming these obstacles and (ii) the effectiveness of practices used to restore service.

Q. How did JCP&L compare with respect to mobilization?

A. In analyzing the Company’s mobilization of tree and line/service crews (as distinguished from service restoration), we do note opportunity for improvement (Figures III.26a and III.26b).
JCP&L mobilized significantly more crews than all but one utility in response to Hurricane Irene. However, the changing forecast regarding the path of the hurricane as previously discussed herein created delays in FirstEnergy requesting mutual assistance for line and service crews outside FirstEnergy. However, JCP&L did expedite the
mobilization of tree crews to achieve peak staffing by August 31st (in line with PSE&G), a necessary precursor to the full-scale mobilization of line and service crews (Figures III.27a and III.27b).
Q. How does JCP&L’s restoration performance compare to the other EDCs with respect to the factors outlined above during the October 31 Snow Storm?

A. Figure III.28 provides JCP&L’s relative position to the EDCs affected by the October 31 snow storm (where detailed information was publicly available on service restoration).

**Figure III.28 – JCP&L Relative Position during the October 31 Snow Storm**

<table>
<thead>
<tr>
<th>Measure</th>
<th>Relative Position</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percent of Customers Affected</td>
<td>No.6</td>
<td>40 percent. Primarily impacted the North Region (more localized than Hurricane Irene)</td>
</tr>
<tr>
<td>Number of Customers per Trouble Location</td>
<td>No.1</td>
<td>17.7 (even less leverage than during Hurricane Irene)</td>
</tr>
<tr>
<td>Number of Trouble Locations</td>
<td>No. 2</td>
<td>25,000 (over twice that of PSE&amp;G and more than 15 times that of Rockland)</td>
</tr>
<tr>
<td>Number of Poles Replaced</td>
<td>No. 2</td>
<td>612 (3 times the group median) attributed to non-preventable tree caused damage to conductor and poles</td>
</tr>
<tr>
<td>Amount of Primary Conductor Replaced</td>
<td>No. 1</td>
<td>720,000 feet (almost 10 times the amount replaced by PSE&amp;G)</td>
</tr>
</tbody>
</table>

As with Hurricane Irene, Figure III.28 strongly suggests that the context is important for assessing JCP&L’s restoration performance including factoring in the impact of being the first or second most disadvantaged utility in 4 of the 5 measures (*i.e.*, the shaded areas).

Q. Using 95% customer restoration as the performance metric, how did JCP&L’s performance in the October 31 Snow Storm compare?

A. JCP&L achieved 95% restoration on November 4th, which was comparable or better than the performance of CL&P, NGRID (MA), WMECO and O&R. Figures III.29 provides the comparison profiles of the 9 EDCs listed in Figure III.22 for which we had storm
performance data, followed by Figure III.30 that shows JCP&L’s relative position in light of the key factors presented in Figure III.28.

**Figure III.29 – Percent of Customers Restored by Evening (October 31 Snow Storm)**

<table>
<thead>
<tr>
<th></th>
<th>31-Oct</th>
<th>1-Nov</th>
<th>2-Nov</th>
<th>3-Nov</th>
<th>4-Nov</th>
<th>5-Nov</th>
<th>6-Nov</th>
<th>7-Nov</th>
<th>8-Nov</th>
<th>9-Nov</th>
</tr>
</thead>
<tbody>
<tr>
<td>JCP&amp;L</td>
<td>53%</td>
<td>57%</td>
<td>77%</td>
<td>89%</td>
<td>97%</td>
<td>98%</td>
<td>98%</td>
<td>98%</td>
<td>99%</td>
<td>100%</td>
</tr>
<tr>
<td>CL&amp;P</td>
<td>11%</td>
<td>27%</td>
<td>37%</td>
<td>54%</td>
<td>70%</td>
<td>78%</td>
<td>90%</td>
<td>96%</td>
<td>99%</td>
<td>100%</td>
</tr>
<tr>
<td>Rockland**</td>
<td>31%</td>
<td>60%</td>
<td>68%</td>
<td>79%</td>
<td>93%</td>
<td>99%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td></td>
</tr>
<tr>
<td>NSTAR (MA)</td>
<td>81%</td>
<td>93%</td>
<td>97%</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nat Grid (MA)</td>
<td>32%</td>
<td>54%</td>
<td>71%</td>
<td>80%</td>
<td>90%</td>
<td>94%</td>
<td>98%</td>
<td>100%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PSE&amp;G</td>
<td>71%</td>
<td>82%</td>
<td>89%</td>
<td>93%</td>
<td>97%</td>
<td>99%</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>WMIECO*</td>
<td>23%</td>
<td>34%</td>
<td>46%</td>
<td>55%</td>
<td>73%</td>
<td>87%</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ConEd</td>
<td>57%</td>
<td>68%</td>
<td>88%</td>
<td>95%</td>
<td>97%</td>
<td>99%</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CHG&amp;E</td>
<td>53%</td>
<td>83%</td>
<td>95%</td>
<td>99%</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Figure III.30 – Tabulation of Mitigating Factors (95% Restoration)

<table>
<thead>
<tr>
<th>EDC</th>
<th>Hours to Restore</th>
<th>Number of Customers</th>
<th>Percent of Customers</th>
<th>Number of Orders</th>
<th>Customers per Order</th>
<th>Poles Replaced</th>
<th>Conductor Replaced</th>
<th>Vegetation</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSTAR</td>
<td>85</td>
<td>227,000</td>
<td>19%</td>
<td>9,800</td>
<td>23.2</td>
<td>58</td>
<td>NA</td>
<td>Medium</td>
</tr>
<tr>
<td>CHG&amp;E</td>
<td>108</td>
<td>147,958</td>
<td>54%</td>
<td>2,027</td>
<td>67.1</td>
<td>89</td>
<td>220,000 ft</td>
<td>High</td>
</tr>
<tr>
<td>ConEd</td>
<td>111</td>
<td>135,913</td>
<td>4%</td>
<td>4,098</td>
<td>33.2</td>
<td>46</td>
<td>172,271 ft</td>
<td>Low</td>
</tr>
<tr>
<td>JCP&amp;L</td>
<td>153</td>
<td>443,000</td>
<td>40%</td>
<td>25,000</td>
<td>17.7</td>
<td>612</td>
<td>720,000 ft</td>
<td>High</td>
</tr>
<tr>
<td>PSE&amp;G</td>
<td>153</td>
<td>636,898</td>
<td>29%</td>
<td>11,000</td>
<td>57.9</td>
<td>298</td>
<td>75,708 ft</td>
<td>Low</td>
</tr>
<tr>
<td>Rockland</td>
<td>176</td>
<td>35,000</td>
<td>49%</td>
<td>1,500</td>
<td>23.3</td>
<td>34</td>
<td>5,014 ft</td>
<td>Low</td>
</tr>
<tr>
<td>NGRID</td>
<td>183</td>
<td>535,935</td>
<td>46%</td>
<td>7,740</td>
<td>69.2</td>
<td>200</td>
<td>76,511 ft</td>
<td>High</td>
</tr>
<tr>
<td>WMECO</td>
<td>192</td>
<td>140,000</td>
<td>65%</td>
<td>3,342</td>
<td>41.9</td>
<td>236</td>
<td>638,692 ft</td>
<td>High</td>
</tr>
<tr>
<td>CL&amp;P</td>
<td>206</td>
<td>807,000</td>
<td>67%</td>
<td>25,475</td>
<td>31.7</td>
<td>1,655</td>
<td>NA</td>
<td>High</td>
</tr>
</tbody>
</table>

**NOTES:**

1. “NA” denotes that UMS was not able to find data from public sources
2. Shaded area denotes that this factor places the EDC in a more disadvantaged position than the vast majority of the other EDCs that form this particular peer group panel.

In reviewing the data and information contained within Figure III.30, JCP&L represented the median among the nine EDCs in terms of restoring service to 95% of its customers. The fact that the Company was among the two most disadvantaged in all but two of the categories, again speaks to the diligence the Company applied to overcoming these obstacles and the practices used to restore service, including implementing lessons learned from the previous hurricane event.

**Q. How did JCP&L compare with respect to mobilization?**

**A.** JCP&L’s challenges during the October 31 snow storm were more related to the amount of damage caused by falling trees than to issues around crew mobilization. Though the overall mobilization curve (Figures III.31a and III.31b) may suggest otherwise, the fact that JCP&L was ahead of all the utilities in reaching maximum staffing in tree crews.
(Figures III.32a and III.32b), and mobilized the line crews at a slightly slower pace, was both prudent and effective.

**Figure III.31a – Peak Number of Crews (October 31 Snow Storm)**

**Figure III.31b – Time to Reach Peak Line Crew Staffing (October 31 Snow Storm)**
Figure III.32a – Time to Reach Peak Tree Crew Staffing (October 31 Snow Storm)

![Time to Reach Peak Tree Crew Staffing graph](image)

Figure III.32b – Peak Number of Crews on Shift (October 31 Snow Storm)

![Peak Number of Crews on Shift graph](image)
Q. What is the nature of JCP&L’s capital expenditures and how should the Company’s customers and other stakeholders evaluate its level of capital spending?

A. JCP&L’s capital expenditures, typical of any electric utility, are largely the result of system growth (i.e., both adding new customers and reinforcing or expanding the general distribution system in anticipation of future load growth), asset replacement or refurbishment requirements (e.g., addressing aging, obsolete, or failed assets and related equipment reliability needs), asset relocation demands (e.g., addressing occasional municipal road expansions that required utility assets to be moved to support public needs) and various relatively smaller, but nevertheless noteworthy, general investments in system support assets, new safety features, tools and equipment, and other general business needs.

There is no definitive or formulaic approach to precisely define the “right” level of capital expenditures for JCP&L, or any electric utility. All utilities face continuing investment needs and also discretionary investment decisions where management must balance the benefits of an investment (e.g., reduction of risk of future service interruptions) with the corresponding increase in customer rates and the practical limitations on available capital. In our experience, the most informative approach to assessing capital expenditures is to ensure that, first, the Company’s overall spending levels are reasonable and consistent with industry patterns and practices, and second, that the Company’s specific investments are properly allocated to, and targeted toward, its unique system requirements, needs, and risks.

Q. How do you assess the Company’s overall spending levels?

A. An assessment of JCP&L’s overall capital spending levels is the natural starting point
and it is inherently a “top-down” and comparative analysis. The objective is to define a reasonable range or estimate for the Company’s overall investment levels considered in the context of the utility’s idiosyncratic factors such as system design (e.g., overhead vs. more costly underground systems), growth rates, and regional cost differences. A comparative, or benchmarking, approach is the most effective way to make such an assessment.

**Q. How do you assess the Company’s specific investments?**

**A.** An assessment of the level, priorities, and effectiveness of any utility’s specific capital expenditure programs also requires a detailed review of investment programs in the context of the Company’s historic and anticipated system needs (e.g., forecasted load growth, and/or failure patterns of various types of equipment). Simply put, while each electric system has unique needs, there are common patterns and practices that apply to all systems. Consequently, a strictly comparative approach would potentially miss these unique needs or risks. This second type of analysis is therefore necessarily “bottom-up” and seeks to assess management’s alignment of its investment programs with the electric system’s known needs, risks, and requirements.

The balance of this portion of our testimony explains the results of our “top down” and “bottom up” analysis of JCP&L’s capital expenditures.

**Q. How have you assessed the Company’s overall capital expenditure patterns in a “top-down” manner?**

**A.** Our primary data source for the “top-down” analysis of JCP&L’s capital expenditures was the FERC Form 1 accounting records of the investor-owned electric utilities identified in the benchmarking peer groups introduced previously in this testimony.
These data sets are used because they are publicly available to all stakeholders for all U.S. investor owned utilities and they are available in a convenient, electronic format. Moreover, they embody standardized industry accounting practices that have been universally promulgated for decades by FERC, state commissions, and predecessor regulatory agencies. These reports are also periodically audited by FERC, utilities’ independent auditors, and other regulatory agencies. Lastly, they have been used for decades in innumerable regulatory proceedings as the “best available” data when conducting summary level analyses and comparisons.

Such analyses occasionally draw criticism for lack of perfect standardization and self-reporting. As with all accounting records, there are no universal interpretations or perfect implementations of accounting procedures or practices. However, in our experience, the standardization, accessibility, independent auditing, and widespread acceptance of these FERC records to conduct high-level analysis and draw summary level conclusions far outweighs any shortcomings that may exist in their lack of perfect comparability. The comparisons resulting from these analyses are said to be “directionally accurate.”

Q. **What background information is necessary to understand your “top down” assessment of the Company’s overall capital expenditures?**

A. Electric transmission and distribution systems are composed of long-lived assets whose engineering and accounting lives are commonly 20, 30, or more years. Consequently, investment in any given year represents only a tiny fraction of the total cumulative system investment. Moreover, the Company’s total historic investment levels will typically illuminate unique characteristics of system design, past investment rates, and
Consequently, an appropriate starting point is to understand JCP&L’s system investment history as defined by the net distribution plant in service, which is the cumulative past investment (gross additions) less the accumulated depreciation of these same assets. Figure IV.1 presents JCP&L’s net distribution plant in service per customer relative to the U.S. Electric Utilities Industry peer group described as the National Panel in Part II.

Figure IV.1 – Net Distribution Plant per Customer

NOTE: 3rd quartile equates to higher investment levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are investing at levels below the industry median.

Figure IV.1 illustrates that JCP&L’s current Net Distribution Plant per Customer is approximately $1,978 per customer (2011), almost identical to the median industry level of $1,959 per customer for the U.S. utilities industry. This level of past investment
should not be interpreted as either “good” or “bad,” but offers initial insights into the nature of JCP&L’s electric system. Specifically, JCP&L is predominantly a suburban and ex-urban electric system that is also predominantly an overhead system with a radial (as opposed to “networked”) system design. This is the same configuration as the majority of U.S. electric systems, and thus JCP&L’s median level is consistent with it being a ‘typical’ U.S. electric system. Generally speaking, utilities with extensive urban, underground, and highly-networked electric systems have relatively high Net Distribution Plant per Customer and, correspondingly, they also have much higher distribution rates consistent with higher net plant in service.

JCP&L’s Net Distribution Plant per Customer has remained stable relative to the overall industry trends since 2002 (i.e., when FirstEnergy completed its merger with JCP&L’s predecessor holding company parent, GPU, Inc.), during an era of generally rising investment levels. This suggests that JCP&L has been generally reinvesting, overall, at a rate consistent with the industry. Moreover, because distribution systems are composed of long-lived assets and system designs are stable, any material variance from this wider industry trend would (if it existed) be evidence of JCP&L’s Net Distribution Plant per Customer position changing relative to the industry. To the contrary, JCP&L’s relative position since the 2002 timeframe has been quite stable.

It is also noteworthy to underscore the trend in JCP&L’s Net Distribution Plant per Customer from a previously steady, “mid-third quartile” level in the 1988-1998 era to a near-median level by 2002. While not an extraordinary change by industry standards, it does warrant further analysis to consider whether the shift resulted from a material change in investment patterns; a topic for further discussion later in this testimony.
Q. How should the Company’s recent capital expenditure levels be evaluated and what are your conclusions related to them?

A. The best high-level relative or comparative assessment of any electric system’s investment rate is to consider its capital expenditures relative to its annual depreciation. The rationale for this approach is straightforward. First, larger electric systems with more assets have correspondingly larger depreciation expenses that are well correlated to net plant values. Consequently, considering investment levels relative to depreciation offers a way to adjust or “normalize” for differences in utility size. Second, there are obvious and natural patterns in investment levels relative to depreciation that are closely tied to utility rates and rate-making.

As an illustration; consider a simplified, hypothetical utility with zero customer or demand growth and investment levels equal to depreciation (i.e., the ratio of capital expenditures to depreciation equals 1.0). Such a utility, with all other attributes being constant, would have universally stable rates. Conversely, a utility with re-investment levels that are multiples of depreciation without extraordinary growth will have significantly rising net plant values and, therefore, likely rising customer rates.

Although a utility’s distribution capital expenditures are not clearly delineated in FERC Form 1 records, a utility’s distribution gross plant additions have proven to be an exceptionally strong proxy for distribution capital expenditures\(^1\). Consequently, Figure IV.2 presents JCP&L’s Distribution Plant Additions relative to Depreciation in the context of the U.S. Electric Industry.

\(^1\) The primary differences between plant additions and budgeted capital expenditures are predominantly timing differences across accounting periods (e.g., unclassified assets) and customer contributions that may be included in budgeted capital expenditures but are presented on a net basis in distribution plant accounts. The cumulative variance between JCP&L’s capital expenditures and plant additions during 2004-2011 is approximately 1% of capital expenditures. This minor variance is typical of most utilities.
Figure IV.2 – Distribution Plant Additions/Depreciation

NOTE: 3rd quartile equates to higher investment levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are investing at levels below the industry median.

Figure IV.2 illustrates that JCP&L’s overall relative investment levels have increased significantly in the past decade. Such investment levels were previously in the median to 1st (i.e., lowest) quartile levels but have recently increased to the 3rd or 4th quartile levels. Completely and accurately interpreting Figure IV.2 also requires the context of industry and JCP&L growth patterns (a major driver of capital expenditures), which is presented in Figure IV.3 below.
NOTE: 3rd quartile equates to higher investment levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are investing at levels below the industry median.

The combination of Figures IV.2 and IV.3 highlights numerous relevant industry and JCP&L-specific patterns.

- First, industry customer growth rates were quite stable for a very long period at a median level of about 1.2% per year during 1990-2006. Thereafter, growth rates fell significantly with the declining national economic conditions beginning in 2007.

- Second, the industry experienced declining investment levels in the 1990’s despite relatively constant growth patterns during that same era. These patterns have been explained by significant regulatory uncertainty in numerous jurisdictions during that era following the Energy Policy Act of 1992 and various state-level “transition
to competition” initiatives. These patterns are apparent in JCP&L’s investment levels in this same (pre-FirstEnergy) period. As noted in Figures IV.2 and IV.3, JCP&L’s growth rates were above the industry median level and generally rising, but its relative investment levels (the ratio of plant additions to depreciation) were declining and below median. Taken together, it more fully explains the relative declining net plant per customer in the pre-2002 era illustrated in Figure IV.1.

- More recently, the industry’s reinvestment level stabilized during the 1999-2005 time period, rose in the middle of the decade, and then declined with the 2008-2011 economic malaise. In the post-2003 era, JCP&L (then under FirstEnergy’s ownership) significantly increased its relative reinvestment levels, especially when compared to the 1990’s (when JCP&L was under GPU ownership). Further, from 2004 through 2006, JCP&L’s investment levels were by any standard extraordinary.

- Despite its customer growth rates at, or below, industry median levels, the Company’s strong investment trend has continued through 2011. This suggests that, at an overall level, the Company has sustained a strong overall investment commitment and, more significantly, that this investment has focused predominately on the existing JCP&L electric system rather than on adding new customers.

JCP&L’s 2011 estimated capital additions were undoubtedly affected by that year’s major storm events and therefore warrant some special analysis. A review of the Company’s storm-related distribution capital expenditures in 2011 reveals that they were approximately $98 million. Figure IV.4 restates Figure IV.3 to show a normalized level
of expenditures.

Figure IV.4 – Distribution Plant Additions/Depreciation, 2011 Normalized

NOTE: 3rd quartile equates to higher investment levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are investing at levels below the industry median.

Figure IV.4 eliminates the estimated effect of JCP&L’s 2011 extraordinary storm-related capital. In our opinion, this is an extremely conservative interpretation of JCP&L’s capital expenditures because the major storms of 2011 undoubtedly prevented significant capital activities that would have otherwise occurred but for the redirection of construction crews to address storm-related reconstruction. Nevertheless, JCP&L’s relative investment levels in 2011 as measured by additions/depreciation were still at a median level when compared to industry patterns.

Overall, the Company’s investment rates have been strong and much higher than the industry median level.
Q. Have JCP&L’s overall investment patterns been adversely affected by investment patterns in FirstEnergy’s other distribution utilities?

A. No. JCP&L’s investment patterns have been demonstrated to be strong and generally above industry median in the previous analysis. Given that JCP&L is a subsidiary of a multi-state holding company based in Ohio, we understand that some have expressed a concern regarding how these patterns for JCP&L compare to other FirstEnergy utility companies. Figure IV.5 illustrates a similar analysis for FirstEnergy’s distribution utilities in its other jurisdictions.

Figure IV.5 – Distribution Additions/Depreciation for FirstEnergy Utilities

![Graph showing distribution gross additions/depreciation for FirstEnergy utilities](image)

NOTE: 3rd quartile equates to higher investment levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are investing at levels below the industry median.

Figure IV.5 illustrates that JCP&L’s investment patterns have been very similar to that of other FirstEnergy electric distribution companies. FirstEnergy’s Ohio companies
experienced their lowest level of reinvestment concurrent with the formation of FirstEnergy in 1998 after a long period of declining relative investment. Since the 1998 merger that created FirstEnergy, the levels of investment in the Ohio companies has steadily increased, but not to the level experienced by JCP&L.

A similar pattern of increased investment occurred in FirstEnergy’s Pennsylvania companies immediately following FirstEnergy’s 2001 merger with GPU. There was a sharp and sustained increase in the relative investment levels. Any trends related to the 2011 Allegheny Energy acquisition are obviously not yet apparent in the data regarding Maryland and West Virginia operations.

Consequently, there is no evidence whatsoever of investment “portfolio balancing” across the FirstEnergy system that would suggest reduced or disproportionate capital expenditures for JCP&L. Moreover, there certainly is no evidence that FirstEnergy’s Ohio operating companies are receiving “preferential” treatment related to their proximity to its corporate headquarters in Akron, Ohio.

On the contrary, we believe there is also increasing evidence (in conjunction with separate O&M findings included in Part V of this testimony) that there is a clear impact from operationalizing FirstEnergy practices and processes, which can only be characterized as having a strong, positive influence on overall capital investment patterns.

These FirstEnergy investment levels are especially noteworthy in the context of generally weaker–than–industry growth rates presented in Figure IV.6. Taken together, Figures IV.5 and IV.6 provide evidence that FirstEnergy’s investments in all its operating companies (including JCP&L) have been focused on maintaining and improving existing systems, not new customer additions.
NOTE: 3rd quartile equates to higher investment levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are investing at levels below the industry median.

Q. Using a similar approach, how has JCP&L’s overall distribution investment patterns compared to those of New Jersey’s other distribution utilities?

A. Figure IV.7 presents this same Distribution Additions/Depreciation profile on a consistent basis for the four New Jersey investor-owned electric utilities.
Figure IV.7 illustrates that the New Jersey investor-owned-utilities have had investment patterns similar to the industry as a whole. Specifically, investment levels fell in the pre-2000 era and have increased since. Moreover, JCP&L’s investment patterns have been strong when compared with other New Jersey electric utilities.

The year-to-year investment patterns display some volatility that may make conclusions less certain or less apparent from a simple visual inspection. Consequently, Figure IV.8 summarizes the cumulative 5-year investment rates for JCP&L as compared to the other three New Jersey investor-owned utilities for periods ending in 2011 and 2010 (to ensure that extensive 2011 storm investments do not distort, on an overall basis, any JCP&L or statewide conclusions).
Figure IV.8 – 5-Year Summary of New Jersey Investment Rates

<table>
<thead>
<tr>
<th>Company</th>
<th>2006-2010</th>
<th>2007-2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Atlantic City Electric Company</td>
<td>3.00</td>
<td>3.34</td>
</tr>
<tr>
<td>Jersey Central Power &amp; Light Company</td>
<td>2.20</td>
<td>2.25</td>
</tr>
<tr>
<td>Rockland Electric Company</td>
<td>1.83</td>
<td>1.89</td>
</tr>
<tr>
<td>Public Service Electric and Gas Company</td>
<td>2.20</td>
<td>2.27</td>
</tr>
<tr>
<td>Total NJ</td>
<td>2.28</td>
<td>2.37</td>
</tr>
</tbody>
</table>

Figure IV.8 demonstrates that JCP&L’s investment rates have been absolutely typical of the investment rates of the other New Jersey utilities, and, indeed, almost identical to that of Public Service Electric and Gas Company (PSE&G) its nearest and larger neighboring system.

Q. You note that JCP&L’s distribution capital expenditures have been strong in comparison to other systems; what have been the trends in JCP&L’s absolute levels of capital expenditures?

A. Figure IV.9 presents the Company’s distribution plant additions during the 2004-2011 time periods.
NOTE: During 2006 JCP&L closed a large backlog from Account 106 - "completed not yet classified" to account 101 - "completed and classified." This resulted in credits to the poles and structures accounts and increases to conductor and transformer accounts. When the capital projects were initially set-up, only one account could be selected in the accounting system, and typically the poles or structures account was selected, even though transformers and conductors were also installed. At the time of close-out to account 101, the proper asset account split was determined and refined to the proper account.

Figure IV.9 illustrates that JCP&L’s capital expenditures have been stable over a long period of time. Capital additions at an account/asset category level have also been relatively stable in key asset accounts (e.g., overhead conductor, and/or line transformers). Importantly, the major underground initiatives in Morristown do not appear to have “crowded out” normal system investment. The abnormally large 2011 capital expenditures, even after adjusting for the effect of the one-time major events, were well above that of prior years.

The FERC reported numbers in 2006 include corrections to prior years (negative
numbers) that, when included, confirm that overall levels of investment have consistently risen throughout the 2004-2011 time period despite decreasing new customer growth rates.

It is also noteworthy to add that JCP&L’s investment levels have not been impacted by any major, one-time investments. Consequently, there is no evidence that extraordinary events or other, atypical investments have “crowded out” conventional system investment levels.

Q. Given that you have determined that JCP&L’s overall investment levels have been appropriate, have the actual investments been properly focused on the needs of the system?

A. The FERC Form 1 public records of JCP&L, and all electric utilities, summarize the financial impact of the Company’s total system investments but they do not provide or record the rationale for individual investment decisions. Consequently, any assessment of the effectiveness of JCP&L’s investments must necessarily rely on detailed analysis of the Company’s historic investment records and ultimately link these investments to its known system needs, risks, and commitments.

To accomplish this, we analyzed the Company’s specific investment records throughout the 2004-2011 periods. At the outset of summarizing our findings it is important to highlight certain key points:

- Given the scope of the analysis (105,989 records), we necessarily relied on the Company’s existing classification methods.

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2 Our analysis reviewed the Company’s 105,989 capital investments spanning over the 2004-2011 period. These investments were classified in a variety of ways, including the line of business (e.g., transmission vs. distribution), the investment reason (e.g., mandatory vs. discretionary investments), and the rationale or motive (e.g., to enhance capacity, to improve reliability, to replace failed assets).
Like all utilities, JCP&L’s investment classification definitions changed from time to time. We made every effort to integrate the Company’s records into a consistent view of overall investment spending. For example, the Company maintained a “fix-it-now” budget for several years that was organized to address failed, failing, or obsolete assets in the field. Although this budgeting method has changed over time, its overall effect (e.g., asset replacement) naturally continues.

Investment classification isn’t a “pure” process. For example, some of the Company’s reliability investments were considered “mandatory”, but were obviously intended to improve system performance (especially in the 2004-2006 timeframe). Nor should investment categories be considered as mutually exclusive; for example, replacing obsolete or deteriorated equipment improves system reliability.

Our overall approach was to isolate the effects of changing business conditions (such as changing customer growth rates) that potentially obscure the Company’s investments that are focused on its existing electric distribution system. Similarly, infrequent events, such as major storms or one-time investments in facilities or information systems, also potentially obscure the patterns of the Company’s investment focused on the existing electric system.

Consequently, our approach was to estimate JCP&L’s “no growth” distribution capital expenditures to enable industry comparisons that eliminate the effects of varying growth rates on investment, both at JCP&L and in our Peer Group Panel of comparable utilities. Further, our approach was to then further decompose these “no growth” capital

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3 Overall, we note that the Company’s investment records and planning methods are both strong and characterized by continuous improvement. In our experience, the historic analysis conducted as part of our testimony would not have been possible with many utilities having weaker investment records and methods.
expenditures to isolate the “core” expenditures on the system infrastructure focused on, for example, system reliability or refurbishment (as opposed to other uses like information technology, facilities, or relocations).

Q. What is the relevance of “No Growth” capital expenditures?

A. One of the primary challenges in comparing the capital expenditures of utility systems is that the level of anticipated and actual customer growth is a major factor in determining any utility’s total capital expenditure needs. Customer and load growth not only varies among utilities (some communities are growing rapidly; others are not, or some are even contracting) but it can also vary significantly from year to year at the same utility as noted in Figure IV.3.

Consequently, an ideal comparative analysis would eliminate the variation in capital expenditures due to the changing growth patterns and exclusively highlight those investments focused on the existing electric system. To conduct this analysis within the constraints of the industry’s FERC-defined accounting methods, the best reasonable first estimate of a utility’s “no growth” capital expenditure is to consider its total capital expenditures excluding expenditures related to meters, services, and customer installations (which latter investments provide a reasonable estimate of “growth-related” investments).

Figure IV.10 presents JCP&L’s estimated “no growth” capital expenditures in the context of the U.S. electric utilities industry.
Figure IV.10 illustrates that the industry median for estimated “No-Growth” Capital Expenditures/Depreciation ranges between 1.4 and 1.55. JCP&L’s 2004-2011 average “No Growth” Capital/Depreciation was 1.55, at the high end of this industry median range. Our interpretation is that JCP&L’s overall “no growth” capital expenditures between 2004 and 2011 are, in total, well within the range of what we would expect. Naturally, year-to-year variations do occur. For example, 2008 was lower than normal, but with mitigating circumstances: 2004-2005 were years of high investment levels, and the 2008 reinvestment levels reflect a year of widespread financial uncertainty. Since 2008, JCP&L’s reinvestment rates, as defined by this “no growth” definition of capital expenditures, have steadily increased.

Broader evidence to support the reasonableness of the industry’s “no growth” level of capital expenditures is also available in the wider industry patterns since 2008.
By examining the growth rates of the entire industry in Figure IV.3, it is clear that across the entire industry growth slowed to the point where the entire industry experienced near zero growth, with the lowest quartile experiencing zero or even negative growth. In this same period, the total capital expenditures/depreciation as shown in Figure IV.2 also declined sharply, with the lowest quartile levels dipping slightly below the 1.5 level (and consistent with the 1.4-1.55 industry median estimate noted above).

**Q. Presuming that the Company’s “No Growth” capital expenditures have been adequate in total, how does one determine that JCP&L’s investments are focused properly and effectively on the Company’s needs?**

**A.** Evaluating the effectiveness of Company’s capital expenditures focused on its existing electric system requires further decomposition of its capital expenditures to identify and evaluate those specific expenditures that are focused on sustaining or improving the performance of the electric system as distinguished from the Company’s other, non-system performance-related, but nonetheless necessary, investments. The Company’s other non-system performance-related capital expenditures are diverse and typical of all electric utilities. They include such items as investments to relocate system assets (for example, as mandated by a major municipal road expansion) or expenditures for new information technology, tools, or equipment. These other investments, many of which are mandatory and not discretionary, while appropriate, may have little or no direct impact on the actual or measurable reliability of the Company’s electric system.

Consequently, to conduct this assessment to determine whether the Company’s investments have been adequate and properly focused on its electric system needs and risks, we have evaluated the Company’s “core” capital expenditures focused on electric
system performance. However, it is important to note that the industry’s regulated accounting practices do not expressly define such core, system-related expenditures. Therefore, we must formulate our own definition to identify, highlight and assess the level of these investments.

Our definition of core capital expenditure begins with total capital expenditures and removes the one-time effects of capitalized storm expenditures that obviously vary from year to year. It further removes the Company’s capacity and growth-related capital expenditures, including new business and capacity/new load related investments, and removes any expenditure for system relocations, all which are conducted for reasons other than to improve performance.

Figure IV.11 presents JCP&L’s estimated core capital expenditures for 2004-2011 as defined above.

**Figure IV.11 – Classifying Core Capital Expenditures**

<table>
<thead>
<tr>
<th>Item</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total CAPEX</td>
<td>123,872,219</td>
<td>150,975,571</td>
<td>114,083,260</td>
<td>129,559,391</td>
<td>106,206,954</td>
<td>133,606,141</td>
<td>132,398,350</td>
<td>234,552,325</td>
</tr>
<tr>
<td>Less Storms</td>
<td>-970,102</td>
<td>-6,413,922</td>
<td>-5,176,012</td>
<td>-2,514,013</td>
<td>-11,436,779</td>
<td>-8,954,241</td>
<td>-11,205,267</td>
<td>-116,347,813</td>
</tr>
<tr>
<td>Non-Storm CAPEX</td>
<td>122,902,116</td>
<td>146,361,639</td>
<td>108,906,748</td>
<td>127,044,777</td>
<td>94,770,175</td>
<td>124,651,830</td>
<td>121,193,083</td>
<td>138,204,512</td>
</tr>
<tr>
<td>Less Reinforcement</td>
<td>-6,158,237</td>
<td>-19,210,335</td>
<td>-11,102,814</td>
<td>-14,799,270</td>
<td>-7,903,512</td>
<td>-5,664,736</td>
<td>-3,224,174</td>
<td>-4,205,257</td>
</tr>
<tr>
<td>Less Capacity/New Load</td>
<td>-10,613,718</td>
<td>-9,055,544</td>
<td>-12,082,059</td>
<td>-17,135,031</td>
<td>-11,217,346</td>
<td>-8,699,341</td>
<td>-3,809,218</td>
<td>-6,019,483</td>
</tr>
<tr>
<td>Existing System CAPEX</td>
<td>68,172,875</td>
<td>73,942,781</td>
<td>53,042,259</td>
<td>65,233,153</td>
<td>44,813,598</td>
<td>72,523,873</td>
<td>85,455,927</td>
<td>100,155,729</td>
</tr>
<tr>
<td>Less Relocations/Reg</td>
<td>-7,570,257</td>
<td>-10,204,621</td>
<td>-3,944,347</td>
<td>-8,928,393</td>
<td>-4,617,499</td>
<td>-4,915,440</td>
<td>-6,277,202</td>
<td>-5,005,866</td>
</tr>
<tr>
<td>Core System CAPEX</td>
<td>60,602,619</td>
<td>63,308,340</td>
<td>49,097,912</td>
<td>54,331,760</td>
<td>39,218,999</td>
<td>67,608,342</td>
<td>79,178,721</td>
<td>95,149,863</td>
</tr>
<tr>
<td>Less Vegetation</td>
<td>-4,105,326</td>
<td>-1,170,179</td>
<td>-766,384</td>
<td>-560,562</td>
<td>-2,551,024</td>
<td>-16,329,344</td>
<td>-12,780,845</td>
<td>-20,809,358</td>
</tr>
<tr>
<td>Core System CAPEX (x/veg)</td>
<td>56,497,292</td>
<td>61,438,181</td>
<td>48,331,528</td>
<td>53,764,198</td>
<td>37,067,075</td>
<td>51,279,048</td>
<td>66,397,879</td>
<td>74,340,005</td>
</tr>
</tbody>
</table>

Figure IV.12 summarizes these same core capital expenditures in graphical form.
Figure IV.12 – Core Capital Expenditures (2004-2011)

Figure IV.12 illustrates that JCP&L’s 2004-2011 average core distribution capital expenditures were approximate $55 million per year. It is noteworthy that 2009-2011 levels have ranged between 10% and 70% above this average level; 2006 and 2008 were years of relative lesser investment, as previously noted. Overall, there is no evidence that the Company has reduced these core distribution capital expenditures.

Further review and analysis of the Company’s core distribution capital expenditures (Figure IV.11) highlights the implementation of a new, significant, and non-recurring vegetation management initiative since 2009. This initiative is designed to reduce vegetation-caused customer interruptions caused by line contacts from trees that are outside (i.e., beyond the scope of) the system’s normal right-of-way (ROW) clearance program. Although this ROW clearance expansion initiative is certainly designed to
improve system performance and is focused on the existing electric system (i.e., it is a “core” investment), it may appropriately be asked whether this significant expenditure potentially distorts any overall conclusions or potentially “crowds out” other investments. Figure IV-13 presents JCP&L’s core distribution capital investment patterns, excluding its vegetation–related capital investments.

**Figure IV.13 – Core Capital Expenditures (Excluding Vegetation)**

Figure IV.13 highlights that, even after excluding the Company’s recent capitalized vegetation initiative, JCP&L’s core capital expenditures have been stable overall and rising significantly in recent years. In summary, it would be difficult to reach any conclusion other than that the Company has been strongly and consistently committed to its core capital investment needs and opportunities.
Q. Given that the Company’s core distribution capital expenditures have been stable and rising recently, how does one determine that these investments are focused properly and effectively on the Company’s needs?

A. Evaluating the effectiveness of the Company’s core investment programs requires ascertaining the purpose or objectives of these expenditures in the context of the Company’s past and anticipated reliability performance.

Figure IV.14 presents the Company’s core capital expenditures for 2004-2011 classified by the major investment categories used by the Company throughout this same period.

Figure IV.14 – Core Distribution Capital Expenditures (2004-2011)

<table>
<thead>
<tr>
<th>Capital Category</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>REL-Reliability</td>
<td>4,781,183</td>
<td>7,885,050</td>
<td>5,411,826</td>
<td>10,486,821</td>
<td>3,068,561</td>
<td>4,824,508</td>
<td>5,1</td>
</tr>
<tr>
<td>REL-Reliability-Mandated</td>
<td>24,135,110</td>
<td>13,941,591</td>
<td>5,128,579</td>
<td>3,537,820</td>
<td>174,420</td>
<td>-40,895</td>
<td></td>
</tr>
<tr>
<td>Total Reliability</td>
<td>28,916,293</td>
<td>21,826,641</td>
<td>10,540,405</td>
<td>14,024,641</td>
<td>3,242,982</td>
<td>4,783,613</td>
<td>5,1</td>
</tr>
<tr>
<td>Fix It Now</td>
<td>4,984,696</td>
<td>9,743,701</td>
<td>8,836,787</td>
<td>10,797,098</td>
<td>15,581,079</td>
<td>924,381</td>
<td></td>
</tr>
<tr>
<td>O&amp;M-Corrective Maint</td>
<td>7,002,739</td>
<td>7,484,644</td>
<td>5,986,240</td>
<td>5,333,083</td>
<td>37,627</td>
<td>4,344,674</td>
<td>2,3</td>
</tr>
<tr>
<td>O&amp;M-Operations</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>O&amp;M-Preventive Maint</td>
<td>0</td>
<td>537,809</td>
<td>148,638</td>
<td>531,544</td>
<td>15,673</td>
<td>590,820</td>
<td>1,3</td>
</tr>
<tr>
<td>CND-Obsolete/Det Equip</td>
<td>1,407,355</td>
<td>2,965,575</td>
<td>1,432,608</td>
<td>519,585</td>
<td>13,420</td>
<td>-14,849</td>
<td></td>
</tr>
<tr>
<td>Total Condition/CM/PM/etc.</td>
<td>16,958,079</td>
<td>24,388,883</td>
<td>20,468,921</td>
<td>23,042,526</td>
<td>16,649,856</td>
<td>19,284,305</td>
<td>18,2</td>
</tr>
<tr>
<td>Line Forced Replacements</td>
<td>9,537,814</td>
<td>14,353,814</td>
<td>14,784,710</td>
<td>12,633,857</td>
<td>16,622,138</td>
<td>24,664,576</td>
<td>37,4</td>
</tr>
<tr>
<td>Substation Forced Replacements</td>
<td>0</td>
<td>0</td>
<td>2,971</td>
<td>33,035</td>
<td>1,049,102</td>
<td>292,531</td>
<td>2,7</td>
</tr>
<tr>
<td>Total Forced Replacements</td>
<td>9,537,814</td>
<td>14,353,814</td>
<td>14,790,685</td>
<td>12,666,892</td>
<td>17,671,240</td>
<td>24,957,007</td>
<td>40,2</td>
</tr>
<tr>
<td>OTH-Other</td>
<td>-2,130,665</td>
<td>-464,081</td>
<td>380,724</td>
<td>885,748</td>
<td>60,833</td>
<td>6,589</td>
<td>2</td>
</tr>
<tr>
<td>FAC-Facilities-Region</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>89,861</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>FAC-Real Estate</td>
<td>-5,006</td>
<td>434,710</td>
<td>891,610</td>
<td>451,304</td>
<td>-18,822</td>
<td>6,322</td>
<td></td>
</tr>
<tr>
<td>MTR-Meter Related</td>
<td>49,394</td>
<td>1,150</td>
<td>22</td>
<td>0</td>
<td>0</td>
<td>586</td>
<td></td>
</tr>
<tr>
<td>Not assigned</td>
<td>4,028</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OTH-Damage Claims</td>
<td>2,728,428</td>
<td>-499,323</td>
<td>954,027</td>
<td>329,066</td>
<td>1,580,909</td>
<td>1,328,042</td>
<td>1,9</td>
</tr>
<tr>
<td>OTH-Joint Use</td>
<td>315,918</td>
<td>290,699</td>
<td>281,048</td>
<td>2,218,836</td>
<td>-1,558,530</td>
<td>596,862</td>
<td></td>
</tr>
<tr>
<td>OTH-Other</td>
<td>0</td>
<td>2,974</td>
<td>73</td>
<td>14</td>
<td>0</td>
<td>-3,061</td>
<td></td>
</tr>
<tr>
<td>STR-Lighting</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>282,525</td>
<td></td>
</tr>
<tr>
<td>FAC-Facilities-Region</td>
<td>123,008</td>
<td>1,102,425</td>
<td>14,160</td>
<td>-9,501</td>
<td>38,608</td>
<td>2,454</td>
<td></td>
</tr>
<tr>
<td>Tool-Tools &amp; Equip</td>
<td>0</td>
<td>0</td>
<td>9,853</td>
<td>64,811</td>
<td>0</td>
<td>33,804</td>
<td></td>
</tr>
<tr>
<td>Total Other</td>
<td>1,085,106</td>
<td>868,843</td>
<td>2,531,518</td>
<td>4,030,139</td>
<td>102,997</td>
<td>2,254,123</td>
<td>2,6</td>
</tr>
</tbody>
</table>
Figure IV.14 illustrates a normal and typical challenge related to retrospective analysis of any electric utility’s capital expenditures. Specifically, budget categories and procedures change and improve over time making year-to-year comparisons of any individual category potentially confusing or misleading. For example, the Company had a “fix-it-now” budget category to account for, and address, failed, failing, or high-risk assets as they were discovered in the field by the Company’s personnel in the pre-2009 era. A cursory review of budget categories might suggest that this “fix-it-now” effort has been curtailed. However, this would be an incorrect interpretation because these same investment activities continue, but they have merely been reclassified (for budget purposes) under the “forced replacement” categories. As Figure IV.14 indicates, the “forced replacement” categories are now being addressed at much higher levels than in previous years.

Despite these year-to-year budgeting changes and improvements, solid insights can nevertheless be gained by reviewing these investment categories individually and collectively. Figure IV-15 below illustrates the Company’s Distribution Reliability (narrowly defined) expenditure categories.
Figure IV.15 shows that the Company’s discretionary reliability investments have been rising since 2008. This has occurred in an era when the Company’s reported “capital-related” reliability (SAIFI) has been improving to much better than its benchmark performance as noted in Part III of my testimony.

Figure IV.16 presents the Company’s total Condition, Preventive Maintenance (PM), and Corrective Maintenance (CM) related distribution capital expenditures.
Figure IV.16 illustrates that JCP&L’s Condition-Based Maintenance ("CBM"), Corrective Maintenance ("CM") and Preventive Maintenance ("PM") related expenditures have been relatively stable at $16-19 million annually throughout the 2004-2011 period. The slightly higher levels earlier in the period were related to the “fix-it-now” budget (previously noted), that has more recently been addressed (i.e., budgeted) separately in the “forced replacement” budget category (and it was typically in the $10-15 million range through 2007). Indeed, absent the effects of this reclassification, CBM/CM/PM related investments have been rising throughout this era.

Moreover, capital expenditures related to failed or potentially failing (i.e., forced replacement) equipment has risen significantly in the 2004-2011 period as presented in Figure IV.17.
Figure IV.17 illustrates that JCP&L’s forced replacement equipment-related capital expenditures for substation and distribution lines assets have risen consistently and significantly over the past 8 years (from ~ $9 million in 2004 to over $45 million in 2011). Taken together, the forced replacement equipment-related expenditure increases more than compensate for any minor decreases in (strictly defined) “reliability” expenditures and the reclassification of “condition” expenditures in Figures IV-15 and IV.16.

Figure IV.17 illustrates the composition of the Company’s Forced Replacement Equipment-Related Capital Expenditures.
Figure IV.18 illustrates that these expenditures split out approximately 80/10/10 between overhead, underground, and substation areas. Predominantly, this category of capital expenditures includes numerous small capital projects focused on “follow-up” items identified in CBM reports and system operations assessments (Power On) related to reliability performance. The details of these expenditures are presented in Figure IV.19 below.
Q. What evidence is there that the Company properly allocates its capital expenditures to its most important needs?

A. As noted in the Introduction section of our testimony, we are intimately familiar with the JCP&L capital planning and budgeting processes that are used across the FirstEnergy electric utilities. Based on our view of the industry, the Company’s risk-based capital investment classification, analysis, and allocation processes are consistent with industry-leading practices; and JCP&L’s investments undergo rigorous technical analysis and multiple levels of peer-, management- and executive-review. One measure of its overall effectiveness is to review the results of the capital allocation, comparing the ultimate rationale or focus of the approved investments as compared to the sources or causes of customer interruptions. It is important to note that the Company’s capital expenditure allocation procedures are not expressly “designed” to allocate capital expenditures in this way; rather, this analysis is designed as an “ex-post” assessment of whether or not the investment capital expenditures properly flowed to initiatives that address the major causes of customer interruptions.

Figure IV.20 illustrates a reclassification of the Company’s core capital expenditures originally presented in Figure IV.14, classifying them based on the focus of the investments (e.g., underground, overhead, substation, other) in the Forced
Replacement ("FRC"), Reliability, and CM/PM classifications.

Figure IV.20 – Classification of Core Capital Expenditures

<table>
<thead>
<tr>
<th></th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>FRC Subtotal</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Underground</td>
<td>101,166</td>
<td>197,423</td>
<td>347,217</td>
<td>327,872</td>
<td>471,742</td>
<td>388,670</td>
<td>1,047,847</td>
<td>1,492,056</td>
</tr>
<tr>
<td>Substation</td>
<td>1,884,481</td>
<td>2,097,157</td>
<td>2,247,522</td>
<td>1,443,865</td>
<td>2,753,081</td>
<td>4,907,500</td>
<td>7,565,400</td>
<td>5,505,539</td>
</tr>
<tr>
<td>Overhead</td>
<td>2,552,167</td>
<td>12,059,234</td>
<td>12,195,946</td>
<td>10,895,155</td>
<td>14,446,418</td>
<td>19,660,836</td>
<td>21,677,367</td>
<td>38,820,206</td>
</tr>
<tr>
<td>Total</td>
<td>9,537,814</td>
<td>14,353,814</td>
<td>14,790,685</td>
<td>12,666,892</td>
<td>17,671,240</td>
<td>24,957,007</td>
<td>40,290,614</td>
<td>45,817,801</td>
</tr>
<tr>
<td><strong>Reliability</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Land/TT/Other</td>
<td>447,770</td>
<td>33,420</td>
<td>288,135</td>
<td>471,778</td>
<td>1,601,257</td>
<td>333,870</td>
<td>129,406</td>
<td>38,040</td>
</tr>
<tr>
<td>Underground</td>
<td>962,996</td>
<td>2,008,361</td>
<td>1,852,867</td>
<td>1,094,657</td>
<td>612,792</td>
<td>1,169,862</td>
<td>180,941</td>
<td>668,747</td>
</tr>
<tr>
<td>Substation</td>
<td>872,106</td>
<td>495,549</td>
<td>440,482</td>
<td>1,323,983</td>
<td>403,565</td>
<td>35,653</td>
<td>-4,253</td>
<td>432</td>
</tr>
<tr>
<td>Overhead</td>
<td>26,633,451</td>
<td>19,285,111</td>
<td>7,858,921</td>
<td>11,134,223</td>
<td>625,367</td>
<td>3,244,228</td>
<td>4,877,641</td>
<td>8,485,312</td>
</tr>
<tr>
<td>Total</td>
<td>28,910,295</td>
<td>21,826,641</td>
<td>10,540,405</td>
<td>14,024,641</td>
<td>3,242,982</td>
<td>4,783,013</td>
<td>5,183,735</td>
<td>9,192,531</td>
</tr>
<tr>
<td><strong>CM/PM</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Land/TT/Other</td>
<td>0</td>
<td>59,216</td>
<td>1,956</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>47,239</td>
<td>354,037</td>
</tr>
<tr>
<td>Underground</td>
<td>5,468,313</td>
<td>8,227,695</td>
<td>6,338,543</td>
<td>6,482,537</td>
<td>2,770,154</td>
<td>4,515,758</td>
<td>4,252,261</td>
<td>5,371,571</td>
</tr>
<tr>
<td>Substation</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>664,852</td>
<td>641,319</td>
<td>522,863</td>
<td>311,847</td>
</tr>
<tr>
<td>Overhead</td>
<td>11,489,766</td>
<td>16,101,971</td>
<td>14,128,421</td>
<td>16,552,988</td>
<td>13,214,850</td>
<td>14,127,228</td>
<td>13,454,051</td>
<td>10,204,740</td>
</tr>
<tr>
<td>Total</td>
<td>16,958,079</td>
<td>24,388,883</td>
<td>20,468,921</td>
<td>23,042,526</td>
<td>16,648,856</td>
<td>19,284,305</td>
<td>18,206,884</td>
<td>16,342,195</td>
</tr>
<tr>
<td><strong>Category Totals</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Land/TT/Other</td>
<td>447,770</td>
<td>92,636</td>
<td>290,091</td>
<td>471,778</td>
<td>1,601,257</td>
<td>333,870</td>
<td>176,645</td>
<td>392,078</td>
</tr>
<tr>
<td>Underground</td>
<td>6,532,446</td>
<td>10,433,480</td>
<td>8,538,627</td>
<td>7,912,066</td>
<td>3,854,688</td>
<td>6,074,291</td>
<td>5,481,048</td>
<td>7,532,373</td>
</tr>
<tr>
<td>Substation</td>
<td>2,756,886</td>
<td>2,592,707</td>
<td>2,688,004</td>
<td>2,767,848</td>
<td>3,823,498</td>
<td>5,584,472</td>
<td>8,084,011</td>
<td>5,817,818</td>
</tr>
<tr>
<td>Overhead</td>
<td>45,675,384</td>
<td>47,450,516</td>
<td>34,283,288</td>
<td>38,582,366</td>
<td>28,286,635</td>
<td>37,032,292</td>
<td>50,099,060</td>
<td>57,510,259</td>
</tr>
<tr>
<td>Grand Total</td>
<td>55,412,186</td>
<td>60,569,338</td>
<td>45,800,010</td>
<td>49,734,058</td>
<td>37,564,078</td>
<td>49,024,925</td>
<td>63,750,763</td>
<td>71,252,528</td>
</tr>
<tr>
<td><strong>Misc/Other</strong></td>
<td>1,085,106</td>
<td>868,843</td>
<td>2,531,518</td>
<td>4,030,139</td>
<td>102,997</td>
<td>2,254,123</td>
<td>2,647,116</td>
<td>3,087,477</td>
</tr>
<tr>
<td><strong>Total &quot;Core&quot; Capital</strong></td>
<td>56,497,292</td>
<td>61,438,181</td>
<td>48,331,528</td>
<td>53,764,198</td>
<td>37,667,075</td>
<td>51,279,048</td>
<td>66,397,879</td>
<td>74,430,005</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Share of &quot;Core&quot; Capital</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land/TT/Other</td>
<td>1%</td>
<td>0%</td>
<td>1%</td>
<td>1%</td>
<td>1%</td>
<td>4%</td>
<td>1%</td>
<td>0%</td>
</tr>
<tr>
<td>Underground</td>
<td>12%</td>
<td>17%</td>
<td>19%</td>
<td>16%</td>
<td>10%</td>
<td>12%</td>
<td>9%</td>
<td>11%</td>
</tr>
<tr>
<td>Substation</td>
<td>5%</td>
<td>4%</td>
<td>6%</td>
<td>6%</td>
<td>10%</td>
<td>11%</td>
<td>13%</td>
<td>8%</td>
</tr>
<tr>
<td>Overhead</td>
<td>82%</td>
<td>78%</td>
<td>75%</td>
<td>78%</td>
<td>75%</td>
<td>78%</td>
<td>78%</td>
<td>81%</td>
</tr>
<tr>
<td>Grand Total</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Source of Equipment Failure CTs</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ovh &amp; Undg</td>
<td>96%</td>
<td>94%</td>
<td>98%</td>
<td>92%</td>
<td>89%</td>
<td>84%</td>
<td>90%</td>
<td>93%</td>
</tr>
<tr>
<td>Substation</td>
<td>4%</td>
<td>6%</td>
<td>2%</td>
<td>8%</td>
<td>11%</td>
<td>16%</td>
<td>10%</td>
<td>7%</td>
</tr>
</tbody>
</table>

Figure IV.20 demonstrates that JCP&L’s risk/reliability core capital expenditures...
are aligned to the Company’s historic and changing sources of forced replacements. For example, substation expenditures as a percent of total expenditures are closely aligned with sources of forced replacement equipment–related customer interruptions (previously defined as “CIs”).

Moreover, (i) capital expenditure levels within categories, and (ii) adjustments to investment levels, are dynamic, displaying both increases and decreases between 2004 and 2011. The Company’s spending will rise in areas of increasing sources of forced replacements within the respective categories (e.g., substations vs. lines). The results of these investments are clearly apparent in JCP&L’s reliability performance presented in Part III of this testimony.

Taken together, we believe this data offers strong evidence that the Company’s core capital expenditures are reflective of sound practices around asset management and, more specifically, capital investment portfolio optimization.

Q. Is the Company’s recent unusually large scope of, and focus on, capitalized vegetation management investments appropriate?

A. In addition to its recent increases in core capital expenditures, JCP&L has also made significant investments in vegetation management as part of a ROW clearing/clearance expansion program. This is a one-time initiative that will encompass the Company’s current four-year trimming cycle during 2009-2012.

The Company’s performance of its normal vegetation management practices is strong. Its four-year tree trimming cycle, consistent with the Board’s Standards, is among the industry’s most aggressive, going above and beyond the industry, where many U.S. electric utilities have five or more year trimming cycles. For companies like JCP&L who
are already “on cycle”, traditional trimming will typically lead to little or no measurable improvement (i.e. reduction) in vegetation-caused interruptions, because the causes of these remaining interruptions are trees that are not (and cannot be) trimmed under the Company’s normal cycle. At best, “on-cycle” ROW trimming only sustains current performance once performance has reached the levels attained by JCP&L. This is best illustrated in Figure IV.21, which clearly demonstrates that the Company has substantially mitigated the “preventable” tree-caused customer interruptions (i.e., those caused by trees that fall within the Company’s existing cleared ROW).

**Figure IV.21 – Sources of Vegetation Caused Interruptions**

Figure IV.21 demonstrates that the vast majority of JCP&L’s vegetation outages are now “non-preventable,” meaning they result from trees not susceptible to trimming through its normal trimming cycle. Despite substantially mitigating preventable
vegetation-caused customer interruptions (about which more details are presented in Part III of this testimony), the Company nevertheless continues to see vegetation as a significant source of customer interruptions as shown in Figure IV-22. This is typical for predominantly overhead, suburban and ex-urban systems, with higher than average tree density, such as JCP&L.

Figure IV.22 – Causes of Customer Interruptions

![Figure IV.22](image)

Figure IV-22 illustrates that like most northern utilities, vegetation remains the second largest cause of interruptions after equipment/line failure (which are also being aggressively addressed by “core” capital increases, particularly since 2009). Consequently, JCP&L’s only approach to reducing these remaining vegetation-related interruptions – and one we endorse - is to pursue its ROW expansion and removal of “danger trees” off the ROW as illustrated in Figure III.23; but not at the expense of other capital investment programs, which is not an issue for JCP&L (as previously dispelled).
Q. In its appropriate focus on reliability, has the Company been able to keep pace with the age and condition of its electric delivery infrastructure?

A. This is an appropriate question because the issues around revitalizing the electric distribution infrastructures are relevant amidst the predominance of equipment failure-related outages and the emerging priorities related to smart grid. The question also speaks to the risk management tradeoffs between funding investments and programs that meet short-term reliability performance objectives and those that address longer-term sustainability challenges. In answering the question, UMS selected four critical asset classes to use as a proxy:

- Substation Transformers
- Distribution Wood Poles
• Distribution Line Transformers

• Substation Breakers

Though age is not the sole or even primary determinant of asset failure (other factors such as operating and maintenance history, condition and even criticality play a significant role in repair vs. replacement strategies and decision-making around end-of-life projections), it does provide a comparative indicator of an electric utility’s commitment to replacing infrastructure. Therefore, UMS focused on the average age of these four asset classes and their age profile, and compared them with their expected service lives (gleaned from a number of studies in the public domain ranging from industry journals to renowned research groups and established consultancies; and a deductive analysis of information available in the FERC Form 1 reports).

Applying this approach, Figures IV.24 through IV.27 provide age profiles for these four asset classes within the JCP&L system along with their average ages:
Figure IV.24 – Substation Transformers Age Profile

The average transformer age is approximately 35 years with 80% of the substation transformers younger than 50 years of age.

Figure IV.25 – Distribution Wood Poles Age Profile

The average age for wood poles is 34.5 years with less than 2% of the circuits
with poles older than 50 years and an additional 23.9% of the circuits with poles aged between 40 and 50 years.

The average age for distribution line transformers is 19 years with approximately 85% of the distribution line transformers younger than 25 years of age.

The average age for substation breakers is 33 years with 88% younger than 50
years of age.

Figure IV.28 provides and encapsulated summary of the average ages of these asset classes with average service lives across the industry; and additional insights to aid in assessing the appropriateness of the current asset management strategy and supporting capital investment levels around electric distribution infrastructure revitalization.

**Figure IV.28 – Asset Class Age Comparisons**

<table>
<thead>
<tr>
<th>Asset Class</th>
<th>Average Age</th>
<th>Average Service Life</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation Transformers</td>
<td>35 years</td>
<td>40 to 50 years</td>
<td>JCP&amp;L’s substation transformer fleet is below the average age of transformers of a “typical” U.S. utility (35 to 40 years) and well below the estimated service life for most of its fleet; and substation transformer failures have been minimal.</td>
</tr>
<tr>
<td>Distribution Wood Poles</td>
<td>34.5 years</td>
<td>40 to 45 years</td>
<td>OSMOSE ranks JCP&amp;L’s territory in Zones 2-3 (of 5 with 5 being the worst) in terms of decay severity, meaning that JCP&amp;L should expect its pole life to extend to the higher end of the average service life. The current inspection and testing program and plans to replace up to 2 percent of the poles annually should be sufficient to keep pace with necessary wood pole replacements.</td>
</tr>
<tr>
<td>Distribution Line Transformers</td>
<td>19 years</td>
<td>35 years</td>
<td>Comparatively young fleet of distribution line transformers.</td>
</tr>
<tr>
<td>Substation Breakers</td>
<td>33 years</td>
<td>40 to 45 years</td>
<td>A significant percent of JCP&amp;L’s substation breaker fleet is within the range that coincides with their average service life. Compliance with the circuit breaker inspection and testing program should provide the means to proactively identify substation breakers in need of replacement.</td>
</tr>
</tbody>
</table>

In assessing the implications of the information provided in Figure IV.28, it would appear that JCP&L is effectively managing its capital portfolio to achieve optimum balance between supporting short-term system performance mandates and revitalizing the infrastructure for long-term sustainability, an underlying theme in FirstEnergy’s overall asset management strategy dating back to 2006.
Q. How did UMS evaluate the Company’s Distribution Operations and Maintenance (“O&M”) expenditures?

A. Our evaluation of JCP&L’s Distribution O&M expenditures followed an approach that parallels the methods introduced and outlined in Part IV of this testimony. Specifically, we performed a “top down” analysis that was comparative in nature, designed to assess the overall level and trends of the Company’s O&M expenditures in the context of the U.S. electric utility industry and in comparison with similarly configured utilities. Such an analysis does not define a precise “right” level of spending. However, it does offer evidence of whether or not JCP&L’s expenditures are within the normal range of expenditures that should be expected for the Company. It also provides a mechanism to identify and explain any material variances JCP&L may have from that of a similar utility.

We also reviewed the level and trends of expenditures of the major categories of O&M expenses, in other words a “bottom-up” assessment, to analyze whether they are sufficient and properly focused on the JCP&L system needs and whether such expenses are producing the desired results (for example, reduction in customer interruptions or timely response to service outages).

Q. Is there any background information that is necessary for an effective assessment of JCP&L’s O&M expenditures?

A. Any analysis of JCP&L’s and FirstEnergy’s overall O&M expenditure patterns requires an understanding of its business context. FirstEnergy was formed in 1997 through the merger of Ohio-based utilities Ohio Edison Company and Centerior Energy (a product of a predecessor merger of the The Toledo Edison Company and The Cleveland Electric...
Illuminating Company). FirstEnergy subsequently completed a merger with GPU, Inc. (“GPU”) in November 2001. At the time of the merger, GPU was comprised of the Pennsylvania Electric Company, Metropolitan Edison Company, and JCP&L operating companies. For analysis purposes, the first full calendar year of combined FirstEnergy/GPU operations was 2002. FirstEnergy also recently acquired Allegheny Energy, Inc. (“AYE”), a transaction which closed in February 2011. AYE was comprised of West Penn Power Company, Monongahela Power Company, and The Potomac Edison Company. For analysis purposes, 2011 was substantially a full year of combined FirstEnergy/AYE operations.

This historic business context is important because many of the more relevant trends in O&M expenditures have significant inflection points concurrent with these business milestones. Consequently, the time-series graphs that are set forth in the Figures of this Part V of our testimony highlight/annotate these business events clearly on the x-axis (date range).

Second, this analysis necessarily relies on some of the conclusions developed in other parts of this testimony, most notably, the electric system reliability performance analysis presented in Part III and the capital expenditures analysis presented in Part IV of this testimony.

Q. **What has been the general pattern of Distribution O&M expenditures at JCP&L and at FirstEnergy?**

A. Figure V.1 presents JCP&L’s and FirstEnergy’s O&M expenditures since 1988.
Total Distribution O&M expenditures have been generally rising across both the entire FirstEnergy system and within JCP&L’s own system throughout the period 1988-2008. Across the entire FirstEnergy system, including JCP&L, Distribution O&M expenditures notably declined in the period 2009-2010. This overall O&M expenditure reduction was related to a major, one-time, system-wide focus by FirstEnergy to implement an aggressive vegetation management initiative that resulted in an increase of capital expenditures to expand the tree-trimming corridors within the FirstEnergy electric utilities rights-of-way (“ROW”). The effect of this program was a temporary shift of vegetation management expenditures from O&M to capital. The details of this program at JCP&L are presented in previous parts of this testimony and a detailed analysis of these expenditure changes are presented later in this Part V of the testimony.

We understand that a concern has been raised as to whether JCP&L, which has
historically been an operating utility within a larger utility holding company structure (currently within the FirstEnergy system, and previously within the GPU system), is garnering its “fair share” of holding company system financial resources. To address this concern, Figure V.2 presents JCP&L’s share of total FirstEnergy Distribution O&M expenditures concurrent with its share of total FirstEnergy customers.

Figure V.2 – JCP&L Share of FirstEnergy O&M Expenditures

Figure V.2 illustrates that JCP&L’s proportion of the total FirstEnergy O&M expenditures within the total FirstEnergy system has always been greater than its corresponding share of customers. This is the case even during the 2009-2010 time frame when the Company made deliberate O&M reductions due to the increase in capitalized vegetation management expenditures.

Recognizing that the FirstEnergy system operates utilities in a variety of regions
of the U.S., it is logical to also consider whether regional cost difference (e.g., variation in wages, operating costs) may explain this disproportionately high share of O&M spending at JCP&L. These expenditure allocation patterns exist regardless of whether nominal (i.e., “as reported”) costs are considered (Figure V.2), or whether the Company’s costs are adjusted to reflect regional cost variations among the FirstEnergy operating companies (using U.S. Bureau of Labor Statistics regional cost deflators as noted in the Introduction section of this testimony). The results of this analysis are presented in Figure V.3.

**Figure V.3 – JCP&L Share of FirstEnergy (Regionally Adjusted O&M Expenditures)**

One can see the impact of applying these regional cost adjusters. However, with the exception of 2008, the share of O&M spending allocated and spent by JCP&L has tracked well above its proportionate share based on number of customers served.
Q. How do JCP&L’s Distribution O&M expenditures compare with other electric utilities?

A. There are numerous ways to compare or benchmark electric utility distribution O&M expenditures. We believe that the best approach to understanding a utility’s distribution O&M cost trends is to begin in a “top-down” approach with nominal, or “as reported,” values and then dissect the utility’s O&M costs to identify underlying trends. Where appropriate, steps are taken to normalize costs (i.e., adjust them to reflect measurable differences to increase the degree of comparability) or introduce narrower peer groups of utilities to refine the levels of comparability.

Figure V-4 initiates our comparative analysis by presenting JCP&L’s Distribution O&M costs on a per customer basis in comparison to the U.S. electric utilities industry.
Figure V.4 – Distribution O&M Expenses per Customer vs. National Panel

NOTE: 3rd quartile equates to higher spending levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are spending at levels below the industry median.

Figure V.4 illustrates that JCP&L’s Distribution O&M costs per customer have historically been at the 3rd quartile level (i.e., higher spent per customer than industry median) when compared to overall industry levels. It is important to highlight that this should not necessarily be considered “good” or “bad”; rather, spending levels are often driven by structural system characteristics and weather patterns that are beyond a company’s control.

For example, many electric systems with low distribution O&M cost per customer operate in desert and semi-tropical areas of the U.S. with very low vegetation levels and have correspondingly exceptionally low tree trimming expenditures (tree trimming costs are a major portion of O&M costs for a “typical” system). Consequently, the more
relevant attribute of Figure V.4 is the ability to identify material changes in relative levels. As previously noted, the decline in 2009-2011 versus the prior levels was related to temporary changes in vegetation management policies and practices. With the exception of that change, overall expenditure levels have consistently been at the 3rd quartile level.

Q. JCP&L operates in a relatively high cost environment on the East Coast of the United States. Do regional cost differences affect conclusions about JCP&L’s Distribution O&M expenditures?

A. Regional cost differences do have a minor impact on comparative analyses of electric utility costs. Cost differentials vary from year to year, and from region to region. Generally, the regional costs vary 9-12% overall, with the highest costs in the Northeast and West regions of the U.S., and the lowest costs generally in the South and Midwest. These costs are predominantly driven by differences in wages, fuel, and taxes in various regions.

Figure V.5 restates Figure V.4 by normalizing each utility’s Distribution O&M costs using the U.S. Bureau of Labor Statistics annual regional cost deflators across the 1988-2011 dataset.
Figure V.5 – Regionally Adjusted Distribution O&M Costs/Customer vs. National Panel

NOTE: 3rd quartile equates to higher spending levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are spending at levels below the industry median.

Figure V.5 illustrates that JCP&L’s general patterns and trends related to Distribution O&M costs per customer remain consistent when using regionally adjusted costs. Generally, under the regionally adjusted dataset, the summary statistic (1st quartile, median, etc.) levels rise slightly but JCP&L’s relative position is unchanged. Generally, the Company’s consistently 3rd quartile cost level (Figure V.4) is slightly refined to a median-3rd quartile level (Figure V.5).

An alternative approach to assessing the impact of regional cost differences is to narrow the comparison group of utilities to those that operate in JCP&L’s geographic region. Figure V.6 presents JCP&L’s Distribution O&M cost per customer in comparison
to the Regional Panel of utilities operating in the seven states surrounding New Jersey (details of this peer group are presented in Part II of this testimony and listed in Figure II.1).

Figure V.6 – Distribution O&M Costs/Customer vs. Regional Panel

![Distribution O&M Costs/Customer vs. Regional Panel](image)

NOTE: 3rd quartile equates to higher spending levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are spending at levels below the industry median.

The general trends of JCP&L’s costs as compared to the Regional Panel are consistent with those of the National Panel, although the comparative cost levels have changed slightly. For example, JCP&L’s Distribution O&M cost per customer is generally at a “median” level in comparison to the Regional Panel in 2006-2008 and 2011 (and much of the earlier era). Correspondingly, JCP&L’s cost levels were “3rd quartile” under a national scale as shown in Figure V-4.
Q. How do JCP&L’s Distribution O&M expenditures compare to electric utilities that are most similar to it in terms of being predominantly overhead and predominantly suburban/ex-urban systems, and operating in the Middle Atlantic region?

A. Figures V.5 and V.6 taken together suggest that JCP&L’s Distribution O&M costs per customer are most accurately characterized as slightly higher than industry median levels, whether compared with a cost-normalized approach (Figure V.5) or the Regional Panel listed in Figure II.1 (Figure V.6).

A still more narrow comparison can be made through a peer group of utilities that operate in the same mid-Atlantic area as JCP&L, that have similar high levels of tree foliage (tree trimming is a major portion of distribution O&M expenditures), and that have customer densities similar to JCP&L (i.e., less than 50 customers per line mile). The details of this peer group were presented in Part II of this testimony (Figure II.2). Figure V.7 presents JCP&L’s distribution O&M cost per customer relative to this more narrowed peer group.
Figure V.7 – Distribution O&M Costs/Customer vs. Peer Group Panel

NOTE: 3rd quartile equates to higher spending levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are spending at levels below the industry median.

Figure V.7 highlights that JCP&L’s Distribution O&M costs have generally been at median or higher levels, consistent with Figures V.5 and V.6

Taken together, the analysis of evidence presented in Figures V.4-V.7 suggests that JCP&L’s Distribution O&M expenditures are quite typical of most electric utilities, approaching median or high-median levels with the increasingly narrow or more selective National, Regional and Peer Group Panels defined in Part II. Generally, the Company’s expenditure patterns have followed industry trends (i.e., generally rising long run trends), with the only unusual deviations related to known and planned changes in vegetation management spending patterns (years 2009-2010) explained above and in further detail.
Q. What are the recent patterns of the Company’s Distribution Operations expenditures versus its Distribution Maintenance expenditures?

A. Although the overall JCP&L Distribution O&M expenditures have steadily increased throughout the period as noted in Figure V-1 (with the noted decrease in 2009-2010 related to capitalized vegetation management), the trends of JCP&L’s distribution operations versus distribution maintenance expenditures have been quite different as illustrated in Figure V.8

**Figure V.8 – Distribution Operations vs. Maintenance Expenditures**

Figure V.8 illustrates that JCP&L’s distribution maintenance expenditures have risen significantly in the post 2002 era (*i.e.*, post-FirstEnergy merger). Conversely, JCP&L operating expenditures have fallen significantly during this same period.
FirstEnergy’s overall Distribution operations versus maintenance expenditures show patterns consistent with those of JCP&L as illustrated in Figure V.9. Specifically, they show a strong increase in overall distribution maintenance expenditures and a concurrent expected reduction in system operating costs.

**Figure V.9 – FirstEnergy Operations vs. Maintenance Expenditures**

Figures V.8 and V.9 taken together clearly suggest that there is a deliberate operations and maintenance strategy within the FirstEnergy operating utilities to promote operational efficiency and allocate more funding where it brings the most benefit to its customers (i.e., maintenance).

The sources of these operating expenditure changes are presented in Figure V.10.
Figure V.10 – Operating Expenditures by Account

The major reductions have occurred in the area of miscellaneous operating expenses, which includes the costs of significant record keeping, mapping, clerical, outage/trouble recording, and administrative costs not provided in other accounts. Other significant reductions have occurred in supervision and engineering costs.

These divergent trends of distribution operations expenses vs. distribution maintenance expenses are summary-level evidence that many of the overall efficiency objectives of the FirstEnergy mergers were, in general, successful. Distribution operations expenses have been reduced through improved processes, improved systems, streamlined organizations, and the capture of economies of scale where available across the FirstEnergy system. Based on the performance trends with respect to service restoration (CAIDI), these efficiencies and economies of scale have not occurred at the
cost of decreased service levels; resulting in more funding being allocated to maintaining the assets.

Q. How do JCP&L’s Distribution Operations costs compare to other electric utilities on a per customer basis?

A. Figure V.11 presents JCP&L’s distribution operations expense on a per customer basis.

Figure V.11 – Distribution Operations Costs per Customer

NOTE: 3rd quartile equates to higher spending levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are spending at levels below the industry median.

Figure V.11 illustrates that JCP&L’s distribution operations expenses have been declining on a per customer basis for over a decade and most recently have been at top quartile levels. Moreover, this JCP&L trend is counter to a gently rising long-run industry trend illustrated in Figure V.11.
Q. Do JCP&L’s relative operating cost reduction trends also persist when compared to a regional group of utilities or a peer group of similarly configured electric utilities?

A. Yes, the general trends of declining distribution operations costs per customer persist regardless of whether comparisons are made to the Regional Panel or Peer Group Panel. Specifically, JCP&L’s declining cost per customer is counter to the pervasive trend of slightly rising distribution operations costs per customer for most utilities. The primary differences are related to the relative operating costs of JCP&L versus these peer groups. For example, considering the total Distribution O&M cost previously described in this testimony, JCP&L is close to median levels relative to the Regional Panel and Peer Group Panel and is 3rd quartile when compared to the National Panel.

Figure V.12 presents this comparison relative to the previously defined Regional Panel and Figure V.13 presents this comparison relative to the Peer Group Panel of similar utilities.
NOTE: 3rd quartile equates to higher spending levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are spending at levels below the industry median.
Q. Should JCP&L’s lower operating costs be viewed positively or negatively?

A. The Company’s overall reliability performance is the appropriate test as to whether or not these increased efficiencies and lower costs in operations are prudent and acceptable.

First, as shown in Figure V.1, JCP&L’s total Distribution O&M costs have risen over the long run (except for the noted change due to capitalized vegetation management work in the 2009 through 2011 time period) despite the reduction in operating costs. This aggregate increase suggests that the Company’s reductions in operations costs have been offset by increases in maintenance expenditure.

Second, JCP&L’s average customer restoration times have been improving throughout this same period when these operations costs have been declining. Figure V.14 and V.15 present the CAIDI for JCP&L’s Central and Northern Region, respectively.

**Figure V.14 – Central Region Reported CAIDI (Excluding MEs)**
Figures V.14 and V.15 demonstrate that the Company’s response to service interruptions has been stable or improving during the same period when operations costs have declined. There is no indication that the Company’s reduced operating costs have compromised its ability to respond to customer service interruptions. Taken together, these cost changes (i.e., reductions in operations expenses and increases in maintenance expenses) should be viewed positively by JCP&L customers and other stakeholders.

**Q.** Have other New Jersey electric utilities experienced a similar reduction in distribution operations costs?

**A.** Figure V.16 presents the annual distribution operations costs of New Jersey’s investor owned electric utilities since 1988.
Figure V.16 illustrates that no other New Jersey-based investor-owned electric utility has demonstrated a major reduction in distribution operations costs similar to JCP&L. On the contrary, the other New Jersey-based electric utilities have demonstrated slightly rising distribution operations costs consistent with the overall industry trends as noted in Figure V.11. Although it is beyond the scope of this testimony to fully analyze this topic, we believe that the corresponding reductions in distribution operations costs at other FirstEnergy utilities, consistent with JCP&L’s cost patterns and, also, counter to overall industry trends, offer tangible evidence of FirstEnergy’s positive impact on its operating companies associated with its operations cost reduction and operational efficiencies - - resulting in lower costs to JCP&L’s customers.
Q. How do JCP&L Distribution Maintenance costs per customer compare to other utilities?

A. Figures V.17, V.18, and V.19 present JCP&L’s distribution maintenance costs per customer relative to the National, Regional, and Peer Group Panels described in Part II.

Figure V.17 – Distribution Maintenance Costs/Customer vs. National Panel

NOTE: 3rd quartile equates to higher spending levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are spending at levels below the industry median.
Figure V.1 – Distribution Maintenance Costs/Customer vs. Regional Panel

Figure V.19 – Distribution Maintenance Costs/Customer vs. Peer Group Panel

NOTE: 3rd quartile equates to higher spending levels than the industry median which represents the point of intersection between 2nd and 3rd quartile. 1st quartile electric utilities are spending at levels below the industry median.

Figures V.17, V.18, and V.19 all illustrate that JCP&L’s Distribution maintenance costs
per customer have trends similar to total Distribution O&M expenditures. Specifically, JCP&L has generally remained at 3rd quartile levels compared to the National Panel, but high-median/3rd quartile in Regional and Peer Group Panel comparisons. Moreover, there are three noteworthy periods in the dataset:

- There was a significant increase after the GPU-FirstEnergy merger in the early 2000’s;
- There was a decrease related to transition of costs to capitalized vegetation management in 2009; and
- There was a significant increase in 2011 related to two major extraordinary storm events.

Q. How can JCP&L’s recent changes in Distribution Maintenance cost patterns be demonstrated not to be a negative trend or outcome?

A. A review and analysis of the Company’s Distribution maintenance expenditures highlights that, other than the previously noted changes to vegetation management related expenditures (i.e., an expanded and capitalized ROW clearance program in lieu of the more typical maintenance-oriented trimming), there has been no noted decrease in the maintenance of critical electric distribution assets.

Figure V.20 below presents Company’s Distribution maintenance expenditures from 2004-2011.
Figure V.20 illustrates several key points.

- Overhead lines maintenance is by far the largest category of Distribution maintenance expenditures. This is quite typical of electric systems like JCP&L that are primarily suburban and ex-urban systems with a significant percentage of overhead lines.

- Most of JCP&L’s general distribution maintenance expenditure categories are quite stable over long periods of time (i.e., those categories without numeric labels in Figure IV.19). The Company has notable increases in 2007 and 2008 in underground and substation assets related to past increases to address known problems.

- By far the largest and most volatile of the Company’s Distribution
maintenance expenditures are related to overhead lines maintenance expenditures.

Q. Is the Company’s 2009-2012 ROW expansion program reducing the total expenditures on overhead lines (i.e., regardless of whether it is capitalized or expensed)?

A. Figure V.21 provides a tabulation of the Company’s distribution forestry (vegetation management) costs from 2007 through 2011.

Figure V.21 – Forestry Program Costs (2004 – 2011) ($M)

<table>
<thead>
<tr>
<th>Category</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Program Capital</td>
<td>4.1</td>
<td>1.8</td>
<td>0.8</td>
<td>0.6</td>
<td>2.6</td>
<td>16.2</td>
<td>12.4</td>
<td>20.4</td>
</tr>
<tr>
<td>Program O&amp;M</td>
<td>11.8</td>
<td>20.1</td>
<td>9.7</td>
<td>12.1</td>
<td>13.8</td>
<td>3.0</td>
<td>5.3</td>
<td>9.3</td>
</tr>
<tr>
<td>Unplanned</td>
<td>1.4</td>
<td>1.6</td>
<td>2.9</td>
<td>2.4</td>
<td>0.8</td>
<td>0.7</td>
<td>0.6</td>
<td>0.5</td>
</tr>
<tr>
<td>Storm</td>
<td>0.9</td>
<td>1.6</td>
<td>3.1</td>
<td>2.8</td>
<td>5.8</td>
<td>3.2</td>
<td>7.7</td>
<td>23.9</td>
</tr>
<tr>
<td>TOTAL</td>
<td>18.2</td>
<td>25.3</td>
<td>16.5</td>
<td>17.9</td>
<td>23.0</td>
<td>23.1</td>
<td>26.0</td>
<td>54.1</td>
</tr>
<tr>
<td>TOTAL (Less Storm)</td>
<td>17.3</td>
<td>23.5</td>
<td>13.4</td>
<td>15.1</td>
<td>17.2</td>
<td>19.9</td>
<td>18.3</td>
<td>30.2</td>
</tr>
</tbody>
</table>

NOTE: Program Capital includes direct and indirect costs.

Figure V.21 reveals that the Company’s total vegetation management expenditures have not been reduced from 2004 through 2011, and, indeed, significantly increased in 2011 even when adjusting for the storms.

Q. Does the Company’s focus on this vegetation issue represent a proper priority?

A. Regarding the appropriateness of the Company’s ROW clearance expansion program (evident by the amount of program capital spent since 2009 as compared to prior years), several elements of this testimony (notably, Part III – Reliability and Part IV – Capital Expenditures) have contained extensive analysis on this topic. That testimony has
demonstrated that the Company has made significant improvement in reducing vegetation-related customer interruptions by maintaining a four-year inspection and trimming cycle, such that the number of “preventable” tree-related interruptions represents only a tiny portion (1-3%) of the total vegetation-related interruptions. Nevertheless, tree-related interruptions remain a significant and the second leading cause of interruptions after equipment failure as presented in Figure V.22. Consequently, the Company’s ROW clearance expansion initiative is an appropriate next step in its continuous improvement of its vegetation management strategy.

Figure V.22 – Causes of Customer Interruptions

Q. Accepting the premise that JCP&L’s O&M spending levels are consistent with those of similarly configured utilities, has JCP&L maintained the staffing levels necessary to support overall system requirements?

A. Yes. In answering the question, we first acknowledge that a traditional headcount
comparison may not be conclusive, given the uniqueness of the synergies associated with JCP&L’s “affiliation” with FirstEnergy:

- Internal resources, fully conversant with FirstEnergy system-wide practices and procedures, can be pooled to respond to unplanned outages;
- Subject Matter Experts can be leveraged across the FirstEnergy system, eliminating the need for duplicate centers of operational or asset-related expertise; and
- Some administrative functions lend themselves to consolidation.

Therefore, our analysis focused on the outcome-based performance metrics most often impacted by staffing levels. Focusing specifically on the bargaining unit line and substation personnel, we reviewed JCP&L’s execution in outage restoration, capital projects, and preventive and corrective maintenance; comparing the amount of overtime hours (as a percent of total hours) with those among other electric utilities in the UMS confidential practices database. We found as follows:

- With respect to outage restoration, earlier in this testimony we have addressed the positive trends in CAIDI (Figures V.14 and V.15) as well as JCP&L’s ability to restore service within acceptable limits during traditional non-business hours (refer to Figures III.12 and III.13), and handle significantly more outage events in a day than the UMS confidential practices database norm of 35 to 40 (refer to Figure III.14).
- JCP&L executes its capital plan as illustrated in Figures V.23a and V.23b where JCP&L has consistently invested at levels above its plan.
Figure V.23a – Actual vs. Planned Capital Expenditures (Total Dollars)

Figure V.23b – Actual vs. Planned Capital Expenditures (Percent of Planned)
• PM and CM completion rates for lines and substation hover at or above the performance levels of other similarly configured utilities in the UMS confidential practices database (refer to Figures III.16 and III.17 and accompanying discussion).

• JCP&L has experienced only slightly higher than average overtime rates, not particularly alarming, given the weather experienced during the 2010 through 2011 time frame (Figure V.24).

**Figure V.24 – Overtime Hours (Percent of Total Hours)**

![Overtime Hours Graph](image)

In reviewing the outcomes represented by these analyses, it is our view that JCP&L staffing levels are consistent with those required to meet the day-to-day requirements and to support emergency restoration, excluding, however, storms of the magnitude experienced with Hurricane Irene and the October 31 snow storm where assistance from other resources, within or outside the FirstEnergy system, is required.
Q. Did UMS reach any conclusions as a result of its extensive review and analysis of JCP&L? 
A. Yes, we did. Given the length and detail of the testimony, it is probably worthwhile to point out that our conclusions are summarized in Part I of this testimony and not restated here.

Q. Does this conclude your testimony? 
A. Yes, it does.
SUMMARY AND BACKGROUND

Mr. Cummings has over 31 years of professional consulting experience, with an extensive background in both engineering and strategic and operational planning for the large investor-owned utilities and municipalities in North America and Australia.

As a Vice President with UMS Group, a consultancy that specializes in performance management and business transformation for electric, gas and water utilities, he supports these clients in addressing key strategic and operational challenges and has most recently focused on T&D network modernization, maintenance program optimization, electric system reliability, fleet management, and regulatory strategy. He has also provided support in the areas of capital investment planning and prioritization, asset strategy and plan development, performance optimization, and organizational transformation.

Prior to joining UMS Group, Mr. Cummings operated an independent consulting practice for nearly a decade where he supported utilities in the areas of strategic and operational planning, organizational development, technical and commercial management, and merger and acquisition assessment and implementation. Earlier in his career he held a series of engineering leadership positions at Vectra Technologies (formerly Pacific Nuclear and a publicly traded nuclear services company) and ultimately became Vice President of Nuclear Engineering. In that capacity, he served as the profit/loss manager for over 425 professional engineers across 5 regional offices in the U.S. In performing this role, he actively engaged in formulating strategies for customer development, product/service expansion, business consolidation, and oversaw the management of over 500 projects annually for approximately 75 percent of the U.S. nuclear utilities. These projects typically were linked to requirements generated by the U.S. Nuclear Regulatory Commission or the full range of U.S. nuclear forums/governing entities (e.g. INPO, IEEE, etc.); and during his tenure with Stone and Webster Engineering, he performed a number of engagements addressing the conduct of maintenance, work planning and execution, and overall system performance.

Mr. Cummings holds an M.S. degree in Operations Research from the U.S. Naval Postgraduate School and a B.S. degree from the U.S. Naval Academy at Annapolis, Maryland.

HIGHLIGHTS OF EXPERIENCE

- Assisted a Canadian electric utility in offering an independent third party assessment of a recent PBR filing performing high-level comparative analyses of proposed growth and infrastructure renewal capital investments over a 5-year period; and assessing the risk of returning to previously established lower capital investment plans. This effort included providing testimony as part of a formal hearing with the Provincial Utility Commission.
Served as Project Director for a full-scale business renewal effort, establishing a plan to improve the efficiency of capital investments, and decrease O&M spending by as much as $50 million a year without any noted decrease in system performance. Conducted across Power Production, Transmission and Distribution and Customer Service, this effort launched a series of initiatives that over 10 years will decrease spending levels by a cumulative $500 million, and set the stage for adopting the relevant aspects of PAS55. Areas of focus included comparative cost and service level analyses, work planning and execution, performance dashboards, transmission and distribution reliability, capital portfolio optimization, and business value/risk tolerance frameworks.

Served as Project Director of four comprehensive assessments for separate Transmission and Distribution operating companies of a large US-based electric holding company. Three involved a review of practices and processes related to electric system reliability as measured by SAIFI, CAIDI and SAIDI with a thorough review of historical results (as reported in their outage management systems) and supporting reliability programs. Specifically, these assessments analyzed service interruptions, service restoration, organization and staffing, and capital/operating spending patterns with the objective immediately and sustainably improving performance; and included formal presentations to Commission staff across 2 regulatory jurisdictions. The fourth assessment involved a thorough review of the electric distribution infrastructure from both an asset health and condition and energy efficiency viewpoint, resulting in a long term strategy and plan to transform the network to 21st century standard. This involved identification of key technical and financial legacy issues, incorporation of a number of constraints and factors (e.g. financial, technology and social equity), and a holistic portrayal of costs and benefits from both a portfolio and individual circuit/substations perspectives; and the articulation of the plan tailored for each external stakeholder (e.g. commission staff/regulator, legislators, environmentalists, shareholders and customers).

Assisted a large Northeastern utility in identifying over $80 million of O&M cost reduction initiatives without impacting service level (e.g. customer service, system reliability or safety). Areas of focus included electric transmission and distribution, customer operations, gas distribution and asset management. The final outcome has been incorporated into a long range plan to improve earnings despite an unfavorable outcome is a recent rate case filing.

Performed a capital and O&M spending diagnostic for a mid-level Midwest utility in support of an overall business case to infuse more capital into its transmission and distribution infrastructure. The case was compelling enough to present to the Board of Directors and the Commission State and will be a cornerstone for subsequent strategic planning and future rate filings.
• Supported a mid-level Midwest utility in its energy efficiency/demand response filing with the state regulatory and governing entities. Applied industry comparative analyses in demonstrating value capture for all stakeholders (investors, customers and utility), and validated that the proposed program met the intent and letter of the legislative mandate.

• Conducted an enterprise-wide capital efficiency assessment for a Canadian Utility spanning electric transmission and distribution and power generation. In reviewing their planned capital expenditures over a 10-year period, Mr. Cummings developed a plan to (1) reduce the current plan by 25 percent and (2) optimize the allocation of capital over the 10-year capital planning horizon.

• Strategic advisor for a major transformation effort within a U.S. Midwest municipality, that included conducting performance diagnostics of its engineering and production divisions, development of a work planning and outage management program (and support processes), and a number of initiatives focused on achieving organizational alignment.

• Assisted a large Australian electricity distribution utility in optimizing the size and mix of its fleet of vehicles and attached equipment, factoring in financial constraints, environmental requirements, and the aligning of work level, staffing and specific task descriptions. The process of arriving at a plan to reduce capital investments by as much as $20.0 million and operating expenses by $1.2 to $2.0 million involved the active participation of the company’s internal customers (i.e. users of the fleet assets), resulting in organizational acceptance of the outcome. Mr. Cummings extended this effort to a large Western U.S. electric municipality, developing a strategy and plan to achieve comparative results.

• Led the implementation of a process (and supporting software) to optimize the capital spending profile across three operating companies within a large US-based electric and gas company (electric transmission and distribution, gas transmission, distribution and storage, fleet, and electric generation); as well as one of the largest gas utilities in the US Midwest. In performing these projects, Mr. Cummings facilitated the linkage of a proposed investment’s value and its contribution to overall corporate strategy as well as the risk should a specific investment be deferred; and equally important, implemented the process in a manner that garnered organizational support for change.

• Oversaw the implementation of an industry forum to identify trends and perform causal analyses on the failure of critical transmission equipment and components. In pooling industry equipment/component performance data, the goal was to apply statistically relevant data to accurately predict failure patterns establish optimum replacement vs. refurbishment criteria. In parallel with the initial formation of this forum, Mr. Cummings also performed the following:
– Comprehensive performance diagnostic across all functions of one of the largest electric municipalities within the US Southwest. In so doing, he provided a plan of action to maintain service levels yet reduce operating costs by as much as 25 percent. The recommendations were adopted and integrated with the municipality’s five-year operating plan.

– Development of a preventive and corrective fleet (vehicle and attached equipment) maintenance program, adopting many of the best practices from the petroleum and U.S. Naval programs, and tailoring them to application in a gas municipality environment. The project team, led by Mr. Cummings, provided a detailed process manual (with supporting process maps), an implementation plan (i.e. process/procedure changes and additions, technology enhancements and organization adjustments), and a series of key measures to assist the utility in adopting the recommendations. The program was embraced by both the municipality and city government officials.

– Participated in a task force and subsequently joined the implementation team in developing and executing a five-year plan to revamp the electric transmission and distribution infrastructure for the Chicago business district. This effort involved the translation of highly technical specifications and detailed budgeting information into terms easily understood by commission staff, city government, and the utility’s customers. The resulting plan was adopted by the Board of Directors, accepted by the City of Chicago, and supported by the commission staff and state regulator.

While supporting implementation, Mr. Cummings developed the strategies and plans for initially routing, certifying, designing, and installing 135kV and 345kV transmission to meet projected load growth and system reliability requirements. He played a key role in shortening the certification period by as much as 50 percent. This required effective liaison and communication with the Illinois Commerce Commission and Army Corps of Engineers as well as coordination of Commonwealth Edison’s engineering and construction organizations and their assigned “contractors of choice.”

– Provided consulting services to a number of technology based enterprises including gas and electric utilities, engineering and architectural firms and manufacturers of electric components. The projects included:

    – Strategic and Operational Planning and Integration (Linkage of Business Vision, Core Values, Financial Goals and Core Business Processes, maintaining a balance between long-range sustainability of the business and short range stakeholder expectations).


– Technical and Commercial Management (Ensuring a proper balance between achieving profit/loss targets and meeting the quality standards as specified by the customer)

– Merger and Acquisition Assessment and Implementation

• Worked in a variety of capacities for a nuclear engineering consulting company, serving initially as a Project Manager and ultimately as the Vice President of Nuclear Engineering. Over this 11-year period he played a major role in growing annual revenues from $5.0 million to $50.0 million while increasing market penetration to approximately 75 percent of the US nuclear utilities. Many of the skills and competencies used by Mr. Cummings in his roles as management consultant (summarized above) were developed through hands-on experience in managing over 425 engineering professionals and overseeing the management of over 500 projects annually.

• Worked in a variety of capacities for Stone and Webster Corporation, primarily assigned to major nuclear power plant design and construction projects. Specific assignments included:
  
  – Assignment to the Beaver Valley Power Station project, establishing a projects control process and system within the Duquesne Light Company to manage the installation of Three Mile Island modifications in support the second refueling outage, improving actual performance in terms of work performed and schedule duration from the initial refueling outage by a factor of three. Following this effort, Mr. Cummings shifted his focus to the unit under construction (unit no. 2) where he installed a process to facilitate the final turnover of the systems (and accompanying documentation) to plant operations over an 18-months period.

  – Assignment to Clinton Power Station, where he acted as Project Controls Manager for the contractor, facilitating the lifting of 12 Nuclear Regulatory Commission (NRC) imposed stop work orders and subsequent construction and turnover of the plant to the Illinois Power Company (IPC). Key activities over a two-year period included a successful Fuel Load Caseload presentation to the NRC, support to IPC in preparing and presenting rate cases to the Illinois Commerce Commission (ICC) for cost recovery, installing an information system to track the turnover of all systems,
and instituting an integrated cost and schedule process and system to support weekly and monthly reporting to project and IPC executive management. His role in integrating the construction and system turnover schedules (and subsequent development of computerized detailed system turnover punch lists) served as a primary catalyst for successful completion of the Clinton Power Station project.

- Served in the U.S. Navy in increasingly responsible roles culminating as a Weapons Officer on a destroyer, USS Robert E. Peary (FF-1073). In this capacity, he managed and led three divisions totaling 100 sailors, responsible for the maintenance and operation of all weapon and detection systems, the major equipment necessary to support basic seamanship evolutions, and daily consumables for the entire ship’s force. He left the U.S. Navy in 1980, having earned the Navy Achievement Medal for his efforts during two extended deployments and extraordinary performance in the areas of Anti-submarine Warfare and Naval Gunfire Support.

RECENT ARTICLES AND SPEECHES


- “Grid Modernization: A Roadmap to Tomorrow’s Infrastructure...Don’t Get Lost on the Way to AMI,” a white paper written in April 2009.
## Schedule UMS – 1

### UMS Group Project Team

The following table summarizes the experience of the 4 individuals assigned to the UMS Group team. Detailed CVs are also included in this attachment for Messrs. O’Neill, Seibert and Morris.

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<tr>
<th></th>
<th>Cummings</th>
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<th>Seibert</th>
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SUMMARY AND BACKGROUND

Dan O’Neill is President and Managing Consultant of O’Neill Management Consulting, LLC, a specialty consulting firm dedicated to providing focused management consulting services to the utility industry. As such, he has worked with the key principals of Chicago Energy Associates LLC, Jim Seibert and UMS Group, Jeff Cummings, on a number of assignments; including three directly comparable to the proposed work for the New Jersey BPU. In addition, he has personally led more than seventy-five engagements with many of the largest utilities as his clients, and has played a leading role in T&D reliability and emergency management, speaking at conferences, publishing in industry journals, and serving as an expert for many in the industry.

Mr. O’Neill has over twenty-seven years of industry experience, including four years as a utility financial executive and the remainder with major consulting firms serving the industry. Besides his asset management and reliability work, he has consulted on decision analysis, activity-based budgeting, work management, and information systems planning.

In the area of assessing reliability performance and designing reliability improvement programs, Mr. O’Neill has led or played a leading role in at least a dozen such assignments, including some mandated by utility commissions and some initiated by utilities in response to recent events. Jurisdictions involved included TX, IL, IN, OH, MD, DC, NY, OH, PA, CT, NJ, and NH.

In addition to these engagements specifically focused on reliability assessments/audits, he has performed over fifty reliability-related assignments to achieve process improvement in areas such as vegetation management, lightning mitigation, animal mitigation, distribution automation, worst circuit improvement, feeder hardening, stray voltage, underground secondary network performance, underground residential distribution cable renewal, project prioritization, asset management, capacity planning, substation maintenance, transmission asset renewal, etc. In the area of emergency management, Mr. O’Neill has led a number of engagements and founded and chaired for the last five years a leading conference on Emergency Preparedness and Service Restoration for Utilities.

He holds a Ph.D. in economics from MIT, taught at Georgia Tech’s College of Industrial Management, and is past president of the Atlanta Economics Club and of The Planning Forum’s Atlanta Chapter.

HIGHLIGHTS OF EXPERIENCE:

- During 2007-9, played a leading role in three comprehensive commission-mandated electric T&D reliability assessments for separate operating companies of a large US-based utility holding company. These assessments included all T&D system planning, budgeting, operations, maintenance, and construction practices, CAPEX and OPEX spending, and performance with a special focus on electric system reliability. Each assessment resulted recommendations and action plans to significantly improve reliability that were ultimately approved by regulators.
• Led multiple engagements assisting clients in filing prepared testimony regarding electric reliability or gas system integrity. Examples include:
  – Led electric reliability assessments for twelve major utility operating companies, including coaching for three before and while they went through external audits of their reliability functions.
  – Developed a reliability improvement program using the funds obtained from the sale of generation assets to improve T&D reliability. Filed as part of testimony on disposition of proceeds of sale of assets.
  – Developed statistical analysis of increased frequency of underground equipment failures. Filed a report to ongoing special committee.
  – Estimated the marginal cost of additional capacity based on multiple regression analysis. Testimony prepared, but rate case not filed – settlement reached instead.
  – Prepared first formal reliability report to commission, including full asset management program explanations and details. Assisted in subsequent filings.
  – Assisted multiple clients in preparing programs to respond to commission inquiries after reliability crises, including two from the summer of 1999 that prompted the DOE task force, two from hurricanes, one from a series of major events in the same year, and many others from not meeting predetermined reliability goals.
  – Led two engagements involved in auditing and/or restating the reliability indices (SAIDI, SAIFI, CAIDI) of major companies. In addition, led multiple engagements to assist companies in benchmarking their reliability performance relative to other utilities. Assembled a database of publicly available (but not easily collected) reliability statistics.
  – Assisted multiple gas companies in preparing programs that were filed with their commissions regarding adequacy of system integrity funding for cast iron and bare steel main replacement programs. Assistance included filing prepared testimony for a gas commission on multiple occasions, including live testimony with cross-examination by commissioners, staff, and People’s Counsel.

• Led a review of storm restoration best practices and developed a storm mobilization model for a major utility operating in both the Mid-Atlantic and the Mid-West. The model allows the company to use weather forecasts to more accurately and quantitatively predict damage and resource requirements in order to mobilize more effectively in the early stages of a storm. Implemented a similar model at three other major companies. Assisted two other companies in quantifying the relationship of outages to weather.

• Led an outage communication survey of over a dozen companies, exploring best practices. Also helped a major utility implement improved estimated restoration time procedures through better data analysis and better use of existing systems.
• Led reliability and asset management-related decision analysis projects for twelve major utilities, allowing them to save millions of dollars and improve reliability by prioritizing capital and maintenance related to electric reliability and gas system integrity. The method focuses on the cost-effectiveness of reliability and asset management programs based on explicit activity-based models of risk, reliability and system integrity.

• Assisted two companies in establishing and developing their capabilities in failure analysis, including a detailed set of procedures, analytical and statistical tools to assist in root cause analysis, and guidance in developing effective failure analysis incident reports.

• Directed strategy studies at two major utilities including a competitive wholesale market assessment with explicit modeling of market-clearing prices for capacity and energy in the eastern U.S., and a telecom market entry strategy for an electric and gas utility.

• At a major public power generation and transmission authority, led separate efforts to optimize its coal mix, inventory and transport options and to optimize its fossil clean air programs.

• At a UK regional electricity company, directed quick-win process improvements focused on call center and back office functions.

• Conducted information system planning efforts at five utilities to determine the scope and best-in-class design of new transmission and distribution work management systems, outage management systems or geographic information systems.

• Led efforts at three utilities to re-design their financial and operational reporting to reflect the cost and impact of major work activities such as new construction, line clearing, pipe replacement, etc. Also assisted in setting up transfer prices and internal/external marketplaces for products/services.

• Analyzed the business case for over ten major mergers, acquisitions, or divestitures, and led the distribution merger integration team for the merger of an electric company and a gas company.

RECENT ARTICLES & SPEECHES

• “Twenty Things to Remember about Distribution Reliability,” Power Grid International, March, 2010,

- “Myths and Realities in Energy Delivery Asset Management Tools and Information Systems,”
- EPRI 4th Power Delivery Asset Management Conference, Chicago, October 8, 2008 (available to EPRI PD AM program sponsors).
- “AEP - Ohio's Line Inspection Programs - Moving Beyond Compliance,” EEI TD&M Conference, Seattle, October 8, 2008 (paper by R. Ivinskas, with assistance from Dan O'Neill).
• “Myths and Realities in Projecting the Trend of Future URD Cable Failures, A Comparison Study,” EEI Transmission, Distribution, and Metering (TD&M) Conference, Houston, April 6, 2006.
• “Reliability Trends,” EEI TD&M Conference, Executive Track, Tampa, April 4, 2005.
• “Project Prioritization,” EEI TD&M Conference, Spring 2003, St. Louis, April 7, 2003, with Malcolm Thaden.
• “A Road Map To The Next Level Of Reliability,” Public Power, November-December, 2000, with Howard Friedman.
• “Keeping the Lights On: A Discussion of Current Trends in Reliability Regulation,” EUCI Electric System Reliability In a Competitive Environment Conference, Denver, November 9, 1999
JAMES M. SEIBERT

SUMMARY AND BACKGROUND

Mr. Seibert is an internationally-experienced management consultant with a 22-year career as an advisor to clients in the global Energy and Utilities industries. He founded Chicago Energy Associates LLC (CEA) in 2007 to serve clients on strategic and operational issues and has most recently focused on asset management, modernization planning, electric reliability, and merger initiatives. His experience with electric, gas, steam, and water utilities on 4 continents has spanned Power Production, Transmission and Distribution (T&D), Customer Service, and Support Services business issues. His professional work combines superb strategic, financial, regulatory, and operational expertise. He is a frequent speaker and author on industry topics.

Prior to founding CEA during 2001-2007, he served as the Managing Director of UMS Group’s Europe and Middle East utility consulting practice. Based in Cleveland, Ohio, Mr. Seibert spent a substantial portion of this period living and working in the United Kingdom and the United Arab Emirates in this leadership role. During this period he led multiple asset management (AM) related assignments, with a particular focus on leading major business transformations and supporting AM services suppliers with business development initiatives in the utilities market.

From 1992-2000, Mr. Seibert rose from an Associate Consultant to become a Vice President in the Energy Delivery practice of Navigant Consulting; he was an officer in Navigant Consulting’s Chicago-based predecessor firm (Metzler & Associates) and a member of the management team that led its 1996 public offering (NYSE:NCI). During 9 years at Navigant Consulting he led process improvement, operations analysis, new venture strategy, and merger integration projects. Prior to joining Navigant Consulting and while earning his MBA and CPA credentials, Mr. Seibert spent 4 years as a systems engineer with Andersen Consulting (now Accenture).

Mr. Seibert holds an MBA from the University of Chicago and a BS in Industrial & Systems Engineering from The Ohio State University. He is also a Certified Public Accountant (CPA).

HIGHLIGHTS OF EXPERIENCE:

- In 2011 Mr. Seibert conducted a comprehensive reliability assessment of the T&D system of a large Canadian utility. This initiative included a detailed analysis of the utility’s 2004-2010 outage event history to define primary and root causes of outage events, operational performance of its four operating divisions, and the key reliability issues and patterns facing the Company. It resulted in a targeted improvement plan.

- During 2010-11 he has been engaged by several private equity (PE) firms in New York and Dubai to support their electricity sector investment initiatives. This work has included a Middle East market analyses for electricity-related construction services, due diligence for the acquisition of an energy efficiency and demand response (EE&DR) services business in the Midwest U.S., and the valuation and acquisition of a regional T&D engineering firm.
In 2011 he developed a T&D modernization plan (technical, financial, and regulatory strategy) for four operating companies of a multi-state U.S. electric utility holding company.

During 2010 Mr. Seibert led an investment group’s initiative to develop a 3200 MW combined cycle gas turbine power plant and desalinization facility in the Kingdom of Saudi Arabia (KSA). This independent power project included international investors in a public-private partnership (PPP) structure with KSA government entities. His role was to design the overall financial structure, partnership agreements, and development plan.

In early 2010 Mr. Seibert conducted an independent assessment of a Midwestern electric utility’s Smart Meter and energy efficiency and conservation (EE&C) plans as embodied in its recent regulatory filings. This analysis reviewed the reasonableness and prudency of the implementation of AMI, EE&C measure selection and program design, customer and rate impact, and demand and energy savings. This assessment supported stakeholder settlement negotiations and resulted in modified regulatory filings and recommendations.

During 2009-2010, Mr. Seibert led the development of Electric T&D long range plan (through 2030) for the electric and steam utility business units of a 3+million customer East Coast combination utility. This plan embodied the capital and O&M plans and programs, and it included a detailed rate impact analysis. It spanned all transmission, distribution, and customer service elements of the utility and addressed both internal and external strategic issues and trends. The project culminated in a stakeholder-focused plan that will ultimately be a public filing with the utility’s regulator.

During 2008-9, Mr. Seibert developed a long-range (15+year) T&D Modernization Plan for a mid-Atlantic electric utility that evaluated and sequenced the Company’s complete network reconstruction, automation, and Smart Grid investments. It included an innovative benefits analysis for measuring all customer, company, environmental, and societal benefits of the Company’s modernization investments and culminated in a stakeholder focused Modernization Plan.

During 2007-9, Mr. Seibert conducted three comprehensive electric T&D reliability assessments for separate operating companies of a large US-based utility holding company. These assessments included all T&D system planning, budgeting, operations, maintenance, and construction practices, CAPEX and OPEX spending, and performance with a special focus on electric system reliability. Each assessment resulted recommendations and action plans to significantly improve reliability that were ultimately approved by regulators.
• During 2007-9, Mr. Seibert supported merger integration efforts to combine two Midwestern electric utilities by analyzing their operating costs and performance and developing integration targets for all elements of the Company’s transmission, distribution, customer services, and support functions. This work included detailed cost and performance benchmarking and best practices of all utility business functions and a review of the Company’s planning, budgeting, forecasting, and reporting processes, organization, and systems.

• In 2010 Mr. Seibert conducted a due diligence assignment to support a private equity (PE) firm’s acquisition of an energy services business focused on providing energy efficiency and demand response (EE&DR) services in the Midwest U.S. market. This analysis included defining the market for these services in a seven state region and the buying patterns of utilities for these services. The results included market projections sufficient to support external financing requirements of the acquisition.

• During 2010 Mr. Seibert led an investment group’s initiative to develop a 3200 MW combined cycle gas turbine power plant and desalinization facility in the Kingdom of Saudi Arabia (KSA). This independent power project will include international investors in a public-private partnership (PPP) structure with KSA government entities. His role has been in designing the overall financial structure, partnership agreements, and development plan. This project is currently in the implementation stage.

• During 2006-7, Mr. Seibert led an Asset Management Transformation initiative for the Power Production business unit of U.S. utility with a 4000+MW fossil fleet. This effort included the design and development of a centralized Asset Management organization and processes for Asset Strategy, Resource Strategy, Investment Planning, and Performance Management. It also included a new centralized outage planning/management and new centralized engineering functions. He also led a team to develop a multi-year, risk-based capital planning, prioritization, and budgeting process.

• During 2005-6, Mr. Seibert led a Strategic Asset Management business transformation for a large Middle Eastern power and water transmission utility. His team of 6 professionals built a “case for change” that included a detailed operational assessment of the power and water system; a strategic assessment of the key stakeholder requirements and the utility’s current and future business strategy, structure, and processes; and a comprehensive financial and regulatory model of the enterprise to measure the economic benefits of the Company’s transformation initiative on its planned initial public offering (IPO).
  - The team’s successful business case led to a comprehensive business transformation project that included redesigned business processes to implement the Strategic Asset Management business model for the entire utility, a redefined organization
(including roles and responsibilities), a performance management framework, and an assessment of the utility’s current and planned information systems.

- During 2004-5, Mr. Seibert served as the engagement director to a UK-based investment banking firm where he led an operational evaluation of the entire National Grid/Transco (NGT) natural gas distribution network. This UK-wide system is composed of 8 “DN’s” (distribution networks) of at least 2 million customers. The team’s role was to:
  - Conduct operational assessments of all of these systems using both public and proprietary benchmarking information
  - Identify and quantify potential sources of cost savings available in the potential acquisition of each DN.
  - Develop the key operational assumptions for the investment case(s).
  - Develop the implementation plans for key improvement initiatives.
  - The client successfully acquired a 2M customer/$2.2B gas distribution network and Mr. Seibert led a team of 8 consultants and 25+ client employees responsible for the re-design of all “front-office” (utility planning, operations, construction, and customer-related) business processes, organizational design, regulatory strategy, performance management framework, and IT architecture.

- Throughout 2004, Mr. Seibert served as an engagement manager responsible for leading a team charged with improving a multi-state IOU’s corporate planning and budgeting processes and its supporting technology, with special emphasis on implementing CAPEX optimization tools and processes. This effort included:
  - Designing and developing an enterprise-wide standardized capital budgeting/financial analysis model to evaluate all generation, energy delivery, and corporate investments.
  - Developing business planning policies and procedures to support a multi-year, multi-business unit capital and O&M budgeting process.
  - Defining the integration requirements for an enhanced PeopleSoft ERP system to support a streamlined capital budgeting, capital authorization, and tracking process.

- During 2002-5, Mr. Seibert led a variety of corporate development and business divestiture engagements for several clients. These efforts were predominately in unregulated business units and in non-strategic regulated assets:
− As Engagement Director, he assisted a diversified investor-owned utility in the restructuring of a major real estate development project in Sonora, Mexico and its related utility infrastructure construction and operations plans. He led the financial restructuring of this project, including establishing the financing and loan repayment terms and schedules. He evaluated a variety of business models for utility infrastructure construction and utility operations and he negotiated operating and financing agreements between lenders, developers, and operators.

− As Engagement Director, he led 3 separate divestiture initiatives of Water production, storage & distribution systems from an investor-owned utility to municipal and private ownership. He was responsible for leading the business valuation, offer design, offering memorandum, and negotiation strategy. These successful divestitures occurred at a premium to book and rate-base value and in excess of the client’s expectations.

− As Engagement Manager, he led an effort to create an account management capability and initial key account plans for an infrastructure services company that provides engineering, procurement, construction, and operating services to the investor-owned and municipal utility markets. He assisted in the implementation efforts by supporting key account activities at several client firms.

• Mr. Seibert led an initiative of two utilities to combine their operations to form two new companies that will provide Asset Management (AM) and Utility Services (both field and back-office services) to the founders and to other utility systems in the Ontario, Canada market. He led efforts to:

  − Assess the current and potential cost and operating performance of the redesigned AM and Utility Services processes of both the founding utilities and the prospective businesses, with special emphasis of their future competitiveness in utility market.

  − Develop and implement plans to transition the AM and Utility/Network Services’ organizations, processes, and information systems of each company to support the new enterprise model.

  − Prepare business development plans to support the launch of these AM and Utility Services businesses to the commercial market.

• Mr. Seibert jointly led an engagement team responsible for developing and launching a new, unregulated venture focused on providing Asset Management services to electric and gas T&D utilities. His team designed initial service offerings, key business processes, start-up organization, sales & marketing strategy, and overall business plan to support a launch in September 2001. Mr. Seibert led a series of business development initiatives for its
initial sales campaign and in establishing key strategic relationships with financial partners.

- During his nine years at Navigant Consulting, Mr. Seibert led or participated in over 20 consulting engagements in virtually all major aspects of electric, gas, and water utility operations. Some illustrative examples of these projects include:
  - As Engagement Director, Mr. Seibert led a series of projects over a one-year period to design and reorganize a major combination gas & electric distribution business unit for the post-deregulation environment. The initiative included process, staffing, organization, and technology recommendations that were linked to shareholder expectations.
  - As Engagement Director, he led a team that created the strategy and development plan for transforming a non-profit, independent electric system operator with global aspirations into a for-profit enterprise. This initiative required CEO- & Board of Directors’-level interaction and defined the strategy that was accepted & implemented.
  - As Engagement Director, Mr. Seibert led over 10 major projects to review & improve the Transmission, Distribution and Customer Service operations of Electric and Gas systems at major IOU’s. These projects included detailed staffing analyses, best-practices & work process improvement initiatives, and business-unit consolidations for major T&D construction & operations, metering, and call center functions.
  - As Engagement Director, Mr. Seibert led a client’s efforts to develop 3000MW of simple- and combined-cycle gas-fired power plants. He led efforts to prepare commodity price forecasts, finance strategy, partnership structure, and shareholder analysis.
  - As Engagement Director, he led a one-year long industry analysis project of the pre- and post-PURPA independent U.S. electric power industry, including a project-level decomposition of the sources of profitability for over a dozen private and public IPP competitors. As part of this effort, he led a complete economic and shareholder evaluation all phases of project development and implementation.
  - As Engagement Manager, Mr. Seibert led numerous assignments during a 31-month period for a single client to develop an Energy Services business from start-up to $125M in revenue. He led development of the overall business strategy and profitability plan, technology assessment and strategy (HVAC, lighting, process, and controls technologies), and sales and marketing strategy and plan.
− As Engagement Manager, he led a profitability and market assessment of the wholesale and retail natural gas marketing business unit for a major IOU. As part of this project, he prepared an organization and technology plan to develop an energy trading operation.

• Mr. Seibert began his consulting career as a Systems Engineer at Andersen Consulting (now Accenture) in 1988. During his 4-year tenure he participated in projects that included system requirements definition, database and system design, programming/system development, testing, and implementation of large-scale transaction systems in an IBM mainframe environment. His clients were electric and gas utilities and he focused on Customer Information and Work Management systems. During this period Mr. Seibert also earned the CPA designation and an MBA degree while working full-time.

RECENT ARTICLES & SPEECHES

• “Storm Clouds Forming : The coming cash flow and dividend stress at America’s electric utilities”, Public Utilities Fortnightly, May 2012
• “Tax Burdens and Barriers to T&D Modernization”, Public Utilities Fortnightly, April 2011.
• “Shared Services for Electric, Gas and Oil Companies”, originator and Chairman of Platt’s/McGraw-Hill Shared Services conference, Chicago, IL, September 13-14, 2004.
• “Maximizing Asset Management Opportunities in an Evolving Market”, speech and workshop with Mark Crowson (Vice President, TXU Utility Solutions) at CBI Asset Management Conference, Philadelphia, PA, August 1, 2002.

SUMMARY AND BACKGROUND

Mr. Morris is a Senior Associate of UMS Group. He has 24 years of consulting and management experience with the last 17 years spent in the electric and gas utility industries. He has significant expertise in strategic planning and financial analysis and has written/edited dozens of analytical reports on utility industry topics. He has helped numerous clients in both the financial services and utility sectors perform business analysis, develop business and operating plans, and identify opportunities to increase profitability through increased revenue or reduced cost.

Prior to joining UMS, Mr. Morris worked for both Andersen Consulting and Navigant Consulting. He also founded Research Reports International a business focused on providing data and information on key issues facing electric and gas industry executives. Mr. Morris holds a B.A. in Economics and an M.B.A. both from Cornell University.

HIGHLIGHTS OF EXPERIENCE

- Performed a performance assessment of a Midwestern electric utility’s Electric Delivery organization. Benchmarked cost and service level performance against peer utilities to identify potential areas of concern. Conducted practices interviews with representatives from all major functions and across the hierarchy to identify work and management practices that were contributing to performance issues. Developed recommendations for improving business performance that included changes in culture, management philosophy, work practices, and processes. Identified and recommended key performance indicators to monitor implementation of recommendations and track actual performance improvement.

- Led industry-wide best practices and benchmarking study of Materials Handling for coal-fired power plants in North America. Analyzed design characteristics, performance results, staffing levels, costs, and practices at over 20 plants. Developed survey instrument, recruited industry participants, administered survey, performed practices interviews, and oversaw analysis and development of final report.

- Led project to assist a European state-owned Transmission System Operator in developing an innovation management process to ensure state-of-the-art technology adoption and operation in their grid. Performed benchmark of key transmission grid technologies to identify current and future market penetration. Surveyed and interviewed
top performing utilities to identify best practices in technology monitoring, assessment, and selection, R&D outsourcing, technology commercialization, and innovation management. Developed recommendations on changes to culture, processes, systems, and business orientation required to implement a more innovation business structure.

- Led a study to help a major U.S. combination utility understand industry best practices for improving its inventory control and accuracy tools and processes. Designed and implemented survey of utility industry practices regarding inventory segmentation and cycles, counting and reconciliation, training and technology, and controls and key performance indicators. Interviewed Study participants to identify common and best industry practices. Study included a dozen U.S. utilities and identified both common and best industry practices in these areas, as well as benchmarked KPIs.

- Led a benchmark of safety performance for a major U.S. combination utility to help it develop performance metrics for different functional areas of its electric delivery business. Recruited a group of 22 peer utilities to participate in the benchmark in order to share data on safety performance. Performed analysis of data and developed recommendations on modifying safety performance targets to more appropriately reflect danger inherent in different business functions.

- Led multi-utility study on Transmission New Construction Project Management for a dozen utilities experiencing significant growth in their transmission capital spending. Analyzed cost, performance, and practices in design, construction, project/program management, and vendor management. Developed survey instrument, recruited industry participants, administered survey, performed practices interviews, and oversaw analysis and development of final report.

- Provided independent assessment of a Northeastern utility’s outage restoration capabilities, staffing levels, and asset replacement in support of a rate case filing. Performed analyses to determine utility’s performance in relation to regional peers and in support of filed testimony.

- Led engagements for a number of major electric and gas utilities to analyze various financial aspects of their business and develop strategic plans to respond to changes in the regulatory structure of the market. Has also evaluated the potential for numerous competitive, non-regulated business structures and products for utility clients built on leveraging their existing competencies.

- Has significant expertise in the area of Smart Grid, Renewable Energy, Distributed Generation and other Energy 2.0 technologies, having authored a number of analytical papers on these subjects and their impact on the industry. These papers have included analyses of the business case for Wind, Solar, Biomass, and Ocean Power; gaining
customer acceptance of the Smart Grid, the impact of PHEVs on electric infrastructure, the potential of Vehicle-to-Grid (V2G) power to provide ancillary services, the impact of dynamic pricing on electricity usage, and the ability of real-time feedback to reduce electricity consumption.

- Developed a business plan for a Western electric utility to enter into a competitive metering business. Identified the value chain, competitors, core competencies, and market potential to define alternative business strategies. Performed industry analysis and developed a financial model for the recommended business strategy. Identified target markets, developed competitive positioning, and defined the organization structure for the proposed new business unit.

- Developed a business strategy for a Midwestern gas utility to expand its competitive meter services business. Evaluated the existing business to identify weaknesses and limitations; developed and evaluated alternatives for growing the business; and developed a plan to reposition the business and drive growth through acquisitions. Also evaluated acquisition and partnership candidates and recommended targets. Identified the capabilities required to succeed in implementing the new business strategy.

- Evaluated the ability of a Midwestern gas utility to successfully manage and operate a newly purchased water utility. Evaluated personnel skill sets and technology/assets available to support the water business; identified key areas of management and operational concern; and developed recommendations on improving management and operations to alleviate concerns.

- Evaluated the existing marketing programs of a large Southern electric utility to determine their effectiveness. Analyzed their strategic, operational, and financial fit with corporate objectives; developed a financial model to measure profitability of programs; and made recommendations on continuing, modifying, or discontinuing programs.

- Analyzed of the operating framework for Telecommunication Services within the service territory of a major Western electric utility to. Evaluated different business models for participating in the market and developed recommendations on entering the business based on a model that best fit the client's core competencies.

- Led the redesign of the Distribution, Marketing, and Customer Service organizations of a large Southern electric utility to meet expected changes in regulation of business. Identified options for future environments, analyzed the financial impact on business, and evaluated the likelihood of occurrence. Developed an organizational design and identified operational imperatives to provide flexibility to deal with changing environment.

- Worked directly with the chief executive officers of two Western combination utilities to define strategic direction of new entity to be formed by merger of two utilities. Identified
and evaluated potential for strategic alternatives. Defined culture change required to support new direction and developed key values. Worked with senior officers to ensure understanding of and resolve questions regarding strategy. Defined the organizational structure of a post-merger company. Developed the organization structure and defined roles and responsibilities for business units, support units, and their officers. Identified and developed the required corporate governance processes.

- Led a business process redesign for invoicing delinquent and deficient taxpayers in a Northeastern State. Performed detailed analysis of existing processes to identify opportunities for performance improvement. Developed a nine month plan to implement improvements. Managed team in design, construction, and implementation of new systems to automate formerly manual processes.

- Consolidated multiple divisional customer databases and accounting systems of a large Eastern insurance company into centralized databases and systems. This tool allowed a single view into all customers and products, as well as providing consolidated financial information to decision makers.

- Project managed multiple efforts to design, build, and implement systems and processes to support new Telecommunications products and product enhancements for a major international telecommunications company. Involved understanding business requirements, defining architectural placement of business functions, defining relationships between systems and processes, and managing implementation to schedule and budget.

- Developed and implemented systems and processes for a major international telecommunications company to re-sell another company’s Local telecommunications service in order to gain experience and a foothold in a new market area. At the same time, led effort to define and design facilities-based Local telecommunications service project.
**Schedule UMS – 2**

**Recent Relevant Experience**

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<thead>
<tr>
<th>Client/Project</th>
<th>Date</th>
<th>Relevant Analyses</th>
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<tbody>
<tr>
<td>ATCO Electric</td>
<td>2012</td>
<td>• Capital Additions</td>
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<td>PBR Rate Filing Support</td>
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<td>• Investment levels for Asset Replacement/ End of Life, Clearance and Safety, and Reliability</td>
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<td>• System Performance Risk Mitigation</td>
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<td></td>
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<td>• Focus and Timing of Investments</td>
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<td>BC Hydro</td>
<td>2009</td>
<td>• Overall Industry Comparisons (CAPEX, O&amp;M and Reliability)</td>
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<tr>
<td>Investment Effects on Dx Reliability</td>
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<td>• Costs per Avoided Interruption (by Program)</td>
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<td>• Investment/Spending and Reliability Comparisons</td>
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<td>• Aging Infrastructure Impact Analysis</td>
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<td>Dayton Power and Light</td>
<td>2010</td>
<td>• Capital Investment Levels</td>
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<tr>
<td>T&amp;D Performance Diagnostic</td>
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<td>• O&amp;M Spending Levels</td>
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<td>• Aging Infrastructure Trends and Comparisons</td>
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<tr>
<td>Dayton Power and Light</td>
<td>2011</td>
<td>• Reliability and Equipment Failure</td>
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<td>System Refurbishment and Replacement Risk Assessment</td>
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<td>• Capacity/Reinforcement</td>
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<td>• Adequacy of Capital Investment and O&amp;M Spending Levels</td>
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<td>• Capital Investment Levels and Reliability</td>
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<tr>
<td>FirstEnergy (Met-Ed, CEI and Penelec)</td>
<td>2007 to 2009</td>
<td>• System Reliability Performance</td>
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<td>Reliability Assessments</td>
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<td>• O&amp;M Spending Levels</td>
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<td>• Maintenance Performance</td>
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<td>• Storm Hardening Effectiveness</td>
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<td>FirstEnergy PA Utilities</td>
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<td>• High Level Capital Investment and O&amp;M Spending Comparisons</td>
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<td>Performance Analysis Benchmarking and Rate Strategy</td>
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<td>• System Maintenance Performance</td>
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<td>• Aging Workforce Analysis</td>
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<td>Nova Scotia Power</td>
<td>2011</td>
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<td>Enterprise-wide Performance Diagnostic</td>
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<td>• Investment Renewal Comparison</td>
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<td>• Asset Recovery Comparison</td>
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<th>Description</th>
<th>Year/Span</th>
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<td>Puget Sound Energy Distribution Planning Benchmark Project</td>
<td>2010</td>
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<td>• Overtime Analysis/Comparisons</td>
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<td>Puget Sound Energy Capital Investment Adequacy Study</td>
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<td>• Distribution Planning Criteria Comparative Analysis</td>
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<td>SaskPower Capital Efficiency and O&amp;M Spending Assessments</td>
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<td>Seattle City Light T&amp;D Performance Diagnostic</td>
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DPL Transmission and Distribution Operations

T&D System Refurbishment and Replacement Risk Assessment

Final Report

12 August 2011
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• Executive Summary
  • Overall Approach
  • Risk Framework
  • Reliability and Equipment Failure
  • Capacity / Reinforcement Challenges
  • Financial Legacy / Adequacy of Capital Investment and O&M Spending Levels
  • Capital Investment Levels and Reliability
  • Appendix A – Equipment Failure Data
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Executive Summary

• DPL’s current risk level / profile is judged to be medium (page 8). Specifically, DPL has:

  – Strong and recently improving reliability performance and a solid relationship with PUCO Staff offset by acknowledged aging / deteriorating electric T&D infrastructure (pages 11 and 33).

  – Consistently maintained low CAPEX and O&M spending levels over an extended period while successfully emphasized investments and activities aimed at maintaining short-term reliability performance (pages 18 and 19).

  – Some current “Regulatory Margin” in measured reliability performance (actual SAIFI of 0.83 vs. performance standard of 1.07), but the margin is likely to diminish due to the probable deterioration of reliability influencing equipment (cutouts, URD cable, substation equipment) over the next 3 to 5 years (equipment failure trends are increasing) (pages 13-14 and Appendix B).

  – Special capacity and system utilization challenges (page 16). Although overall system peak load and energy sales are well off prior highs (predominately from industrial decline), localized capacity challenges (e.g. ex-urban growth, large institutional needs) may strain capital budgets and compete for replacement / refurbishment reinvestment.

  – Comparatively and consistently reinvested at low levels while enjoying high regulated returns (measured by return on assets and return on net plant) that could expose it to potential stakeholder criticism and “second guessing” in the event of a downturn in reliability (page 20).

• Increased reinvestment in the T&D system will be necessary to sustain current reliability and O&M spending levels (and current medium risk level) in the 3-5 year planning horizon. Maintaining current, low reinvestment levels will likely see DPL’s risk profile degrade to a high level within 3-5 years (page 13 with bases provided in Appendix A).

  – DPL’s strong and improving reliability performance as measured by SAIFI and CAIDI with extremely low funding levels demonstrates the Company’s sound approach in optimizing available CAPEX and O&M funds. Although limited, the capital allocations invested in substations vs. lines generally matches the spread of CIs across these categories of assets (slight bias toward substation). Simply put, DPL has demonstrated much success at maximizing the value of its expenditures (page 22).

  – The focus of any incremental capital investment should be in replacement / refurbishment of critical equipment (though comparatively less than industry norms, equipment failures still represent approximately 30 percent of the customer interruptions) (pages 11 and 12, Appendix D).

  – Absent increased planned and targeted replacement spending, the likely failure rate acceleration of critical equipment will either “crowd out” CAPEX and O&M spending intended for other uses, lead to budget overruns, and result in temporary reliability degradation that may put the Company in a high risk situation (pages 14, 29-32).
Executive Summary  (Continued)

• The consequences of falling short of reliability performance standards justifies additional proactive investment (page 9 and Appendix C):
  – In all instances researched by UMS Group (6 utilities), state commissions mandated an independent assessment/audit of the utility’s performance (at a total cost to the utilities averaging $500,000). The result of these mandated audits were a performance improvement plan with specific measurable actions and required additional capital investment and O&M spending levels.
  – Though the range of financial impacts was broad, a $15.0 to $45.0M incremental increase in capital over a three-year period and $5.0M to $10.0M in O&M spending over that same time period is typical.
  – In the majority of cases (and most notably in Ohio) there has been no provision for recovery of either the assessment costs or the costs of implementing the improvement plans.

• Recommended increases in annual Capital Funding by $25.0M annually over the next 5 years. Specifically the following 3 initiatives:
  – Assuming a 10-year program to replace T&D assets well past their useful and technical life (page 33), $17.5M of additional capital is recommended for years 2012 through 2016, decreasing to $12.5M for years 2017 through 2021.
  – Increase funding to replace pre-1985 vintage URD cable by $5.0M to achieve a 50/50 split between proactive and reactive replacement activity thus precluding the “crowding out” of other capital or O&M programs, and ultimately limiting the disruptions to work planning caused by these emergent failures (pages 29 and 30); and
  – Increase the current capital investment plan by an additional $2.5M to (1) replace “problem” cutouts (pages 31 and 32); thereby providing an additional SAIFI margin of 0.06, and (2) address unbudgeted low-cost, high impact capital measures (e.g. danger trees, U-bushings and transformer monitoring).

• As the figure to the right illustrates, but for the initial year of investment, the recommended increase in capital investment, maintains DPL at its historical position, below the U.S. IOU Median.
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### Project Approach

**Activities**
- Defined Business Risk Framework
  - Established technical and performance characteristics and accompanying business / financial impacts for low, medium and high risk scenarios
  - Reviewed the experience of 6 other utilities in failing to meet system reliability performance mandates
  - Assessed DPL’s risk profile against this framework
- Performed High Level Reliability Analyses
  - Assessed SAIFI (Outages, Cis, CMIs by cause) against established reliability standard and reviewed outage history to ascertain areas on which to focus the project
  - Established a range of likely trends re: future SAIFI performance
- Analyzed Capacity, Replacement, Reinforcement Challenges
  - Analyze equipment related causes and equipment spending a performance trends
  - Determined system peak and sales trends and related capital requirements
  - Segmented MWH delivered to identify potential vulnerability to future unanticipated load growth
  - Defined DPL’s exposure as medium (refer to slide 9)
- Identified Financial Legacies / Assessed Adequacy of Funding
  - Compared DPL CAPEX, O&M Spending, replacement rate levels with other U.S. utilities
  - Estimated historic and projected failure trends
  - Confirmed future SAIFI projections and probable consequences by assessing key variables across 3 of the top categories from a CI perspective
- Assessed Capital Investment Levels and Reliability
  - Compared capital investment levels against customer interruptions (lines vs. substations)
  - Assessed level of reliability and replacement capital plans for lines and substations
  - Identified future SAIFI projections and probable consequences by assessing key variables across 3 of the top categories from a CI perspective
  - Confirmed that DPL is among the lowest in CAPEX, and O&M spending
  - Lines maintenance costs judged to be sufficient (vegetation management)
  - Identified some exposure should DPL fail to meet mandated performance targets-comparatively high regulated return on assets / return on net plant and high residential billing
  - Confirmed that capital investment allocation was consistent with spread of customer interruptions across major asset categories

**Outcomes**
- Determined that the primary focus of the project should be on equipment failure
  - Presented a range of future SAIFI projections based on modest and aggressive acceleration of current failure rates
  - Confirmed future SAIFI projections and probable consequences by assessing key variables across 3 of the top categories from a CI perspective
- Identified unanticipated load growth as a potential risk in the event of an economic turnaround and a return to previous levels of industrial and large commercial customers
- Confirmed that DPL is among the lowest in CAPEX, and O&M spending
  - Lines maintenance costs judged to be sufficient (vegetation management)
  - Identified some exposure should DPL fail to meet mandated performance targets-comparatively high regulated return on assets / return on net plant and high residential billing
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<table>
<thead>
<tr>
<th>Exposure (Risk) Level</th>
<th>Low Risk</th>
<th>Medium Risk**</th>
<th>High Risk</th>
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</thead>
</table>
| Technical / Performance Characteristics | • Stable or slightly diminishing predictability related to equipment failure and reliability  
• CAPEX and O&M spending at or above industry median  
• System is sufficiently storm hardened  
• Customer interruption mitigation / elimination under control with some focus on localized performance issues (e.g. CEMI, CELID conditions)  
• System designed to absorb any reasonable increase in load  
• Strong and consistent customer satisfaction  
• Significant “margin of error” in mandated reliability performance measures to absorb unusual events yet meet performance mandates  
• Relationship with Regulator and Staff approaches that of a “partnership” (yet maintaining appropriate protocols) | • Significant number of technical legacy issues exist but being addressed via a long term investment strategy  
• Hovering between low quartile and industry median in CAPEX and O&M spending  
• Normalized “year-over-year” decrease in number of excludable major events  
• Reliability at or near mandated performance levels (small “margin of error” to avoid regulatory scrutiny)  
• Reliability program heavily weighted towards mitigating customer interruptions with increasing emphasis on long-term sustainability  
• Some capacity to absorb unanticipated load growth  
• Mixed review regarding customer satisfaction  
• Strength of relationship with Regulator and Staff based entirely on annual performance | • Accelerating aging / deteriorating infrastructure  
• Obvious low (lowest quartile) in CAPEX and O&M spending, especially over extended periods  
• System performance strongly weather dependent  
• Consistently weak or sub-standard reliability  
• Reliability program addresses short-term measures to mitigate customer interruptions  
• Insufficient capacity to absorb unanticipated growth in load  
• Significant customer perception / satisfaction degradation  
• “Hands off” or hostile relationship with Regulator and Staff |
| Business / Financial Impact | • Moderate / manageable unplanned CAPEX and O&M expenditures | • Increased unit costs due to emergent work activities  
• O&M spending tension (unplanned outages exceed assumptions)  
• Shifting priorities in CAPEX throughout the year  
• Increased regulatory oversight | • Commission mandated assessments  
• Commission mandated CAPEX, OPEX expenditures without recovery  
• Performance-related penalties  
• Reduced Allowed Return / ROE |

NOTE: Blue font denotes DPL relative to specified technical / performance characteristic. ** Characterizes UMS Groups overall assessment.
Range of Outcomes of High Risk-Related Consequences (Business / Financial Impact)

**Basis for Projection:** Reviewed the recent experience of 6 utilities across 4 regulatory jurisdictions with DPL-comparable demographics re: urban/rural mix, regulatory style, and size and/or location of service territory:

- **Ohio:** Cleveland Electric Illuminating (CEI) and American Electric Power-Ohio (AEP)
- **Pennsylvania:** Metropolitan Edison Company (Met-Ed) and Pennsylvania Electric Company (Penelec)
- **Maryland:** Potomac Electric Power Company (PEPCO)
- **Missouri:** AmerenUE

**Universal Findings:** Independent of each specific circumstance, the following common approaches were adopted by each jurisdiction:

- An independent consultant was directed to perform a focused audit of the utility’s performance, incurring in fees and expenses averaging $500K, resulting in reliability performance improvement plans to improve system reliability performance (SAIFI, CAIDI, and SAIDI) both from short-term and long-term sustainability perspectives.
- Though most jurisdictions could have assessed penalties, the philosophy appears to have been to mandate significant spending to improve the T&D system with particular focus on storm hardening and circuit protection.

**Summary of Observations:** The following table tabulates the range of outcomes experienced by thee utilities (a detailed synopsis of these examples is provided in Appendix C):

<table>
<thead>
<tr>
<th>Utility</th>
<th>Driver</th>
<th>Outcome</th>
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</thead>
</table>
| Cleveland Electric Illuminating (CEI) | Missed mandated SAIFI and CAIDI targets | Additional capital investment of $7.8M (no provision for recovery)  
Increase annual O&M spending by $0.3M (no provision for recovery)  
Define a long-term plan to fund replacement / refurbishment of aging electric distribution infrastructure |
| American Electric Power-Ohio (AEP) | Storm-related outages | Spend an additional $10.0M on tree trimming (no provision for recovery) |
| Metropolitan Edison Company (Met-Ed) | Missed mandated SAIFI and SAIDI targets | Additional capital investment of $15.0M (no provision for recovery)  
Increase in annual O&M spending of $2.6M (no provision for recovery) |
| Pennsylvania Electric Company (Penelec) | Missed mandated SAIFI and SAIDI targets | Additional capital investment of $5.0M (no provision for recovery)  
Increase in annual O&M spending of $2.7M (no provision for recovery) |
| Potomac Electric Power Company (PEPCO) | Storm-related outage | Additional capital investment of $100.0M over 5 years  
Increase in O&M spending of $15.0M over 5 years |
| AmerenUE                       | Storm-related outages    | Additional capital investment of $300M over 3 years  
Increase in O&M spending or capital maintenance of $199M over 3 years |
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Focus of Analyses – Part 1: Reliability and Equipment Failure

- DPL’s reliability standard is 1.07 for SAIFI, 125.51 for CAIDI
- A new reliability standard application must be filed by June 30, 2012
- A two year period over standard would likely cause significant regulatory scrutiny.
- All data is shown retrospectively using the current (2010) Ohio measurement standard, excluding Major Event Days (MEDs) and Transmission outages

- Equipment failure is the largest contributor to SAIFI and most directly linked to CAPEX – typical of most electric systems
  - Represents more than 1/3 of the causes of SAIFI
  - Closely tied to capital expenditures
  - Changes in capital expenditures (e.g. unplanned growth, reductions, etc.)
- DPL has made notable improvement (reduction) in Tree and Other categories in past 3 years
  - This is closely related to O&M expenditures
**Focusing on CIs Caused by Equipment Failure**

- The largest contributors (by facility type) to CIs have been consistent over the past 3 years.
- The top 5 facility types are the source of over 50% of CIs.
- The top 8 facility types are the source of about 67.5% of the CIs.
- We have identified URD Cable, Cutouts and critical Substation Equipment (Circuit Breakers and Transformers) as proxies for identifying the range of possible impacts of equipment failure.

<table>
<thead>
<tr>
<th>Equipment Failure</th>
<th>CIs (5-YR Average)</th>
<th>PCNT of CIs</th>
<th>Trend</th>
<th>Outage Events (5-YR Average)</th>
<th>Outage Size (5-YR Average)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cutouts*</td>
<td>28,265</td>
<td>16.6%</td>
<td>Increasing</td>
<td>684</td>
<td>41</td>
</tr>
<tr>
<td>Substation Equipment*</td>
<td>18,509</td>
<td>10.8%</td>
<td>Increasing</td>
<td>15</td>
<td>1,233</td>
</tr>
<tr>
<td>Underground Primary Cable (URD)*</td>
<td>21,892</td>
<td>12.8%</td>
<td>Increasing</td>
<td>278</td>
<td>78</td>
</tr>
<tr>
<td>Overhead Primary Wire</td>
<td>20,288</td>
<td>11.8%</td>
<td>Flat</td>
<td>125</td>
<td>162</td>
</tr>
<tr>
<td>Substation Riser Cable</td>
<td>7,607</td>
<td>4.5%</td>
<td>Flat</td>
<td>7</td>
<td>1,086</td>
</tr>
<tr>
<td>Cross arm</td>
<td>7,547</td>
<td>4.4%</td>
<td>Increasing</td>
<td>29</td>
<td>260</td>
</tr>
<tr>
<td>Jumper / Streamer</td>
<td>7,490</td>
<td>4.4%</td>
<td>Increasing</td>
<td>103</td>
<td>72</td>
</tr>
<tr>
<td>Connection</td>
<td>3,722</td>
<td>2.2%</td>
<td>Flat</td>
<td>158</td>
<td>24</td>
</tr>
<tr>
<td>Other</td>
<td>55,452</td>
<td>32.5%</td>
<td>Flat</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>170,772</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Appendix A provides more detail as well as a more comprehensive listing of the facilities that contribute to equipment failure related CIs.

Appendix B illustrates the range of impacts for a representative cross-section (noted with an asterisk) of equipment failure categories (summarized on following slide).
Estimating / Projecting DPL’s Erosion of “Margin”

• Under these planning scenarios, the non-equipment related CIs are presumed to be stable during 2011-2015
  – Presumes continued strong performance from tree-related outages

• The details for developing high and low SAIFI projections are provided in Appendix A

Key Point: Assuming that the traditional measures to mitigate / eliminate CIs (e.g. sectionalizing, circuit protection, and tree trimming) to offset “natural” degradation of SAIFI have run their course (i.e. equipment failure is now the controlling variable), a moderate projection of SAIFI (i.e. mid-point in the above figure) suggests that DPL will be in non-compliance with the current PUCO reliability performance mandates by 2015
## Range of Equipment Failure Related Impacts

<table>
<thead>
<tr>
<th>Category of Impact</th>
<th>Source</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Likely failure rate acceleration will result in worsening SAIFI and either “crowd out” CAPEX or O&amp;M spending intended for other uses or lead to budget overruns</td>
<td>• URD Cable</td>
<td>Well-staged replacement program leads to lower unit rates (efficient work and resource planning) and over time, reduced O&amp;M due to fewer unplanned outages</td>
</tr>
<tr>
<td>Erosion of “safety margin” of SAIFI relative to reliability performance mandates</td>
<td>• URD Cable</td>
<td>Due to amount of URD cable to be replaced, the best remedy is to increase the capital budget to enable proactive replacement of known trouble areas (current budget will only sustain replacement of failed cable) Proactive replacement of all “problem” cutouts can be accomplished within 3 years, providing an estimated SAIFI margin of 0.06 (Estimate $3M to $5M in addition to that already budgeted between now and 2013)</td>
</tr>
<tr>
<td>Fewer yet more significant outages in terms of customer interruptions</td>
<td>• Substation Equipment is the second largest source of CI’s (individually) and multiple categories make it the largest source</td>
<td>In the absence of specific knowledge of each asset’s health and condition, criticality to the overall T&amp;D system, and detailed maintenance and operating history, asset age can serve as a proxy to estimate the amount of CAPEX necessary to align DPL with the industry – in the range of $125M to 150M beyond that budgeted in the current plan</td>
</tr>
</tbody>
</table>
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• Executive Summary
• Overall Approach
• Risk Framework
• Reliability and Equipment Failure
• **Capacity / Reinforcement Challenges**
  • Financial Legacy / Adequacy of Capital Investment and O&M Spending Levels
  • Capital Investment Levels and Reliability
  • Appendix A – Equipment Failure Data
  • Appendix B – Equipment Failure Related Impacts
  • Appendix C – Case Studies
  • Appendix D – Equipment Failure Comparisons / Trends
Focus of Analyses – Part 2: Capacity / Reinforcement Challenges

- DPL’s overall system peak is well off (-10%) the 2005-2007 high, consistent with declining industrial load in the DPL service territory (left chart).
- These changes in peak are also apparent in total energy delivered (right chart). Specifically:
  - 2010 Total MWH sales are -8% lower than the 2007 recent peak and -11% lower than the 2002 all-time peak
  - However, residential sales remain substantially at all-time highs in the mid-2000’s (i.e. no decline)
  - Commercial sales also are very close to previous all time highs

- The technical implications of this demand and sales environment include:
  - Diminished utilization in previously highly industrialized areas and in declining urban residential areas
  - Continued substantial capacity / reinforcement needs (despite negative macro trends) that are localized in:
    - Integrating ex-urban areas that become residential and small commercial areas (e.g. Austin Boulevard / I-75)
    - Growing suburban and ex-urban larger institutional demands (e.g. WPAFB, Miami Valley Hospital, and University of Dayton)
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Focus of Analyses – Part 3: Financial Legacy / Adequacy of Investment and Spending Levels

• DPL’s net Distribution plant per customer (upper left chart) is historically and currently among the lowest in the U.S.. This is the result of:
  – Overall system design characteristics (comparatively less redundancy, automation, etc.)
  – Low replacement / reliability reinvestment over an extended period (upper right chart)

• Reinvestment levels have generally been lower than industry levels
  – DPL could be exposed to criticism of its reinvestment rates (low) in the context of its relatively high levels of return on net plant or return on net assets (next slide)

• O&M (particularly maintenance) expenditures have generally been at industry average (next slide)
DPL Distribution O&M Profile

- DPL’s Distribution O&M cost per customer (left chart) is historically and currently among the lowest in the U.S.
  - Operating costs per customer are exceptionally low (upper right)
  - Maintenance costs per customer are fairly steady at industry average levels (lower right)
  - Lines maintenance costs per customer (far right) are at or above industry average levels, suggesting strong vegetation management spending (resulting in lower than normal tree-related outages)

NOTE: The Operations Costs reflect FERC accounts 580-589 and Maintenance Costs reflect FERC accounts 590-599
DPL Return Profile

- A rapid comparison of DPL’s regulated return on assets and return on net plant suggests that it may be earning at a very high level.

- This adds to the Company’s risk level if overall reliability performance degrades as a result of equipment related (i.e. reinvestment related) failures.
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Assessing the Planned Allocation of DPL’s Capital Plans

- DPL’s estimated reliability and replacement capital plans for field and substation appear relatively stable for the 2011-2015 planning horizon
  - Almost uniform at $45-46m in each of the next 5 years
  - Accounts for 35-45% of total capital spending by year

- Substation related spending averages out at 29.7% of the reliability and replacement reinvestment; the balance is in the field (lines, transformers, poles, etc.)

- The mix of replacement / reliability expenditures planned over the next 5 years is consistent with the equipment failure related customer interruption (CI) history
  - Substation related equipment failures account for ~25% of CIs; planned 5-year capital investments are approximately 29.7% of the replacement capital
  - The slight bias toward substation expenditures is appropriate due to a slight (relative) growth trend in CIs, and the larger potential impact per incident
DPL’s Historic Relationships Between Reliability and Capital Investments

- Outage events and customer interruptions (CIs) appear to be closely correlated
- Outages and CIs steadily increased from 2002 through 2008; then decreased from 2009 to 2010, yet remained above the earlier levels (left chart)
- DPL’s investment patterns (right chart) clearly had different characteristics based on level of capital investment:
  - Pre-2006, DPL Distribution investment (net of meter, services, and customer investments) were less than $40M (Direct correlation between investment levels and equipment failures – failures drove investment)
  - 2006-2010: Investment levels well above $50M per year-inverse relationship between investment levels and equipment failure related CIs / outages

- The “spike” in capital investment in 2006 (“A”) resulted in reduced CIs in 2009 (“B”), aligning with previous studies that substantiate a 2 to 3-year lag between a change in investment levels and actual performance,
- Comparing pre-2006 investment levels and CI trends with those of post-2006 and factoring in the projected risk profile yields the following insights:
  - Capital investments (net of meter and customer-related investments) in the range of $60M-70M ($20M increase over 2010 levels) are necessary to realize measurable improvement in reducing equipment-related CIs.
  - Given the time delay of 2 to 3 years described above and the projected risk by 2015 (page 13), the timing for this increase in investment is immediate.
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## Appendix A – DPL’s CIs from Equipment Failure

<table>
<thead>
<tr>
<th>CI Name</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2010 % of 2006-10</th>
<th>2010 % of 2010 Cum</th>
<th>2010 Syr Avg</th>
<th>Est Trend</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cutout</td>
<td>20,336</td>
<td>27,800</td>
<td>33,104</td>
<td>38,545</td>
<td>33,536</td>
<td>22%</td>
<td>21%</td>
<td>29,265</td>
<td>Rising</td>
</tr>
<tr>
<td>Substation Equipment</td>
<td>3,801</td>
<td>27,753</td>
<td>13,971</td>
<td>18,543</td>
<td>28,477</td>
<td>12%</td>
<td>12%</td>
<td>18,509</td>
<td>Rising</td>
</tr>
<tr>
<td>Underground Primary Cable</td>
<td>29,861</td>
<td>18,246</td>
<td>22,727</td>
<td>16,186</td>
<td>22,440</td>
<td>12%</td>
<td>14%</td>
<td>21,892</td>
<td>Rising</td>
</tr>
<tr>
<td>Overhead Primary Wire</td>
<td>17,510</td>
<td>24,396</td>
<td>23,906</td>
<td>19,244</td>
<td>16,352</td>
<td>12%</td>
<td>12%</td>
<td>20,288</td>
<td>Flat</td>
</tr>
<tr>
<td>Jumper/Streamer</td>
<td>10,069</td>
<td>6,357</td>
<td>6,912</td>
<td>3,893</td>
<td>10,216</td>
<td>4%</td>
<td>4%</td>
<td>7,490</td>
<td>Rising</td>
</tr>
<tr>
<td>Crossarm</td>
<td>8,961</td>
<td>9,478</td>
<td>9,717</td>
<td>7,882</td>
<td>7,882</td>
<td>4%</td>
<td>4%</td>
<td>7,457</td>
<td>Rising</td>
</tr>
<tr>
<td>Connection</td>
<td>5,595</td>
<td>2,602</td>
<td>3,631</td>
<td>1,838</td>
<td>4,946</td>
<td>2%</td>
<td>3%</td>
<td>3,722</td>
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</tr>
<tr>
<td>Substation Riser Cable</td>
<td>12,996</td>
<td>12,850</td>
<td>1,397</td>
<td>6,883</td>
<td>4,107</td>
<td>2%</td>
<td>3%</td>
<td>7,607</td>
<td>Flat</td>
</tr>
<tr>
<td>Substation Bushing/Insulator</td>
<td>1</td>
<td>3,803</td>
<td>1%</td>
<td>2%</td>
<td>82%</td>
<td>2%</td>
<td>2%</td>
<td>1,902</td>
<td>Falling</td>
</tr>
<tr>
<td>Overhead Transformer</td>
<td>2,011</td>
<td>2,854</td>
<td>1,581</td>
<td>2,445</td>
<td>3,133</td>
<td>1%</td>
<td>2%</td>
<td>2,406</td>
<td>Unknown</td>
</tr>
<tr>
<td>Padmount Transformer</td>
<td>2,886</td>
<td>2,630</td>
<td>2,883</td>
<td>2,262</td>
<td>2,914</td>
<td>2%</td>
<td>2%</td>
<td>2,551</td>
<td>Rising</td>
</tr>
<tr>
<td>Disconnect Switch</td>
<td>2,432</td>
<td>6,358</td>
<td>2,880</td>
<td>2%</td>
<td>88%</td>
<td>3,900</td>
<td>Rising</td>
<td>89%</td>
<td>Flat</td>
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<tr>
<td>Fuse Barrel</td>
<td>1,801</td>
<td>1,968</td>
<td>1,805</td>
<td>1,363</td>
<td>2,689</td>
<td>1%</td>
<td>1%</td>
<td>1,925</td>
<td>Rising</td>
</tr>
<tr>
<td>Pole</td>
<td>1,962</td>
<td>5,191</td>
<td>5,474</td>
<td>9,328</td>
<td>2,583</td>
<td>3%</td>
<td>3%</td>
<td>4,912</td>
<td>Flat</td>
</tr>
<tr>
<td>Capacitor Bank</td>
<td>158</td>
<td>2,338</td>
<td>2,654</td>
<td>2,857</td>
<td>2,574</td>
<td>2%</td>
<td>2%</td>
<td>2,116</td>
<td>Flat</td>
</tr>
<tr>
<td>Airbreak Switch</td>
<td>5,884</td>
<td>3,778</td>
<td>2,854</td>
<td>1,875</td>
<td>2,654</td>
<td>1%</td>
<td>1%</td>
<td>3,391</td>
<td>Flat</td>
</tr>
<tr>
<td>Arrestor</td>
<td>11,514</td>
<td>3,433</td>
<td>4,343</td>
<td>3,985</td>
<td>1,727</td>
<td>2%</td>
<td>1%</td>
<td>5,010</td>
<td>Flat</td>
</tr>
<tr>
<td>Insulator</td>
<td>802</td>
<td>9,889</td>
<td>13,129</td>
<td>3,744</td>
<td>1,445</td>
<td>4%</td>
<td>4%</td>
<td>5,802</td>
<td>Flat</td>
</tr>
<tr>
<td>Splice - Overhead</td>
<td>535</td>
<td>256</td>
<td>521</td>
<td>505</td>
<td>1,145</td>
<td>0%</td>
<td>0%</td>
<td>592</td>
<td>Flat</td>
</tr>
<tr>
<td>Recliner</td>
<td>1,545</td>
<td>932</td>
<td>934</td>
<td>1,756</td>
<td>822</td>
<td>1%</td>
<td>1%</td>
<td>1,984</td>
<td>Flat</td>
</tr>
<tr>
<td>None</td>
<td>512</td>
<td>690</td>
<td>5,458</td>
<td>73</td>
<td>759</td>
<td>0%</td>
<td>0%</td>
<td>1,498</td>
<td>Flat</td>
</tr>
<tr>
<td>Fuse Tail</td>
<td>1,122</td>
<td>1,698</td>
<td>927</td>
<td>844</td>
<td>576</td>
<td>0%</td>
<td>0%</td>
<td>1,033</td>
<td>Flat</td>
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<tr>
<td>Regulator</td>
<td>132</td>
<td>2,736</td>
<td>2,249</td>
<td>772</td>
<td>523</td>
<td>1%</td>
<td>1%</td>
<td>1,262</td>
<td>Flat</td>
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<tr>
<td>Underground Service Cable</td>
<td>223</td>
<td>566</td>
<td>289</td>
<td>93</td>
<td>445</td>
<td>0%</td>
<td>0%</td>
<td>330</td>
<td>Flat</td>
</tr>
<tr>
<td>Static Wire</td>
<td>1,208</td>
<td>1,109</td>
<td>2,923</td>
<td>4,100</td>
<td>391</td>
<td>1%</td>
<td>1%</td>
<td>1,946</td>
<td>Flat</td>
</tr>
<tr>
<td>LBC/Module</td>
<td>641</td>
<td>748</td>
<td>373</td>
<td>359</td>
<td>361</td>
<td>0%</td>
<td>0%</td>
<td>406</td>
<td>Flat</td>
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<tr>
<td>Guy Wire</td>
<td>1,915</td>
<td>4,111</td>
<td>59</td>
<td>25</td>
<td>305</td>
<td>0%</td>
<td>0%</td>
<td>1,283</td>
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</tr>
<tr>
<td>Elbow/Termination</td>
<td>730</td>
<td>396</td>
<td>923</td>
<td>399</td>
<td>248</td>
<td>0%</td>
<td>0%</td>
<td>533</td>
<td>Flat</td>
</tr>
<tr>
<td>Overhead Secondary Wire</td>
<td>880</td>
<td>293</td>
<td>359</td>
<td>201</td>
<td>220</td>
<td>0%</td>
<td>0%</td>
<td>391</td>
<td>Flat</td>
</tr>
<tr>
<td>Underground Secondary Cable</td>
<td>45</td>
<td>552</td>
<td>62</td>
<td>765</td>
<td>208</td>
<td>0%</td>
<td>0%</td>
<td>326</td>
<td>Flat</td>
</tr>
<tr>
<td>Overhead Service Wire</td>
<td>357</td>
<td>194</td>
<td>911</td>
<td>114</td>
<td>203</td>
<td>0%</td>
<td>0%</td>
<td>356</td>
<td>Flat</td>
</tr>
<tr>
<td>Pothead</td>
<td>3,329</td>
<td>7,350</td>
<td>4,897</td>
<td>1,048</td>
<td>186</td>
<td>1%</td>
<td>1%</td>
<td>3,322</td>
<td>Flat</td>
</tr>
<tr>
<td>Commercial Underground, Meter</td>
<td>90</td>
<td>1</td>
<td>18</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>0%</td>
<td>37</td>
<td>Flat</td>
</tr>
<tr>
<td>Commercial Underground, LTC</td>
<td>241</td>
<td>10</td>
<td>10</td>
<td>7</td>
<td>10</td>
<td>0%</td>
<td>0%</td>
<td>56</td>
<td>Flat</td>
</tr>
<tr>
<td>Substation Transformer</td>
<td>779</td>
<td>31,604</td>
<td>17</td>
<td>8</td>
<td>6%</td>
<td>0%</td>
<td>0%</td>
<td>8,102</td>
<td>Flat</td>
</tr>
<tr>
<td>Auto Transformer</td>
<td>3,342</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>3,342</td>
<td>Flat</td>
</tr>
<tr>
<td>Other - See Comment</td>
<td>42</td>
<td>38</td>
<td>11</td>
<td>0</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>30</td>
<td>Flat</td>
</tr>
<tr>
<td>PMH</td>
<td>3</td>
<td>655</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>329</td>
<td>Flat</td>
</tr>
<tr>
<td>Splice - Underground</td>
<td>7</td>
<td>66</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>18</td>
<td>Flat</td>
</tr>
<tr>
<td>Substation Breaker</td>
<td>67</td>
<td>9,941</td>
<td>2,086</td>
<td>0</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>4,032</td>
<td>Flat</td>
</tr>
<tr>
<td>Oil Switch</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0</td>
<td>Flat</td>
</tr>
<tr>
<td>Total</td>
<td>146,993</td>
<td>195,612</td>
<td>205,403</td>
<td>145,746</td>
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### Appendix A – Outage Events from Equipment Failure

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### Appendix A – Typical Equipment Failure Outage Size

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<td>Pothead</td>
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<td>Substation Breaker</td>
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<tr>
<td>Oil Switch</td>
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Contents

- Executive Summary
- Overall Approach
- Risk Framework
- Reliability and Equipment Failure
- Capacity / Reinforcement Challenges
- Financial Legacy / Adequacy of Capital Investment and O&M Spending Levels
- Capital Investment Levels and Reliability
- Appendix A – Equipment Failure Data
- Appendix B – Equipment Failure Related Impacts
- Appendix C – Case Studies
- Appendix D – Equipment Failure Comparisons / Trends
Appendix B – Equipment Failure – URD Cable

**URD Cable Failure History**

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<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
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<td>338</td>
<td>275</td>
<td>371</td>
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<td>3.3%</td>
<td>4.7%</td>
<td>4.9%</td>
<td>5.8%</td>
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</table>

**Projected URD Cable Failures**

- DPL experienced an increasing number and percentage of failures between 2004 and 2010
  - Trend is likely to continue (projecting between 500 and 650 failures in 2015 (Failure rates between 10 and 14 percent)
- Assuming sustaining the current budget for future URD replacement, the accelerating number and rate of failures will contribute to a worsening of SAIFI and impact either the amount of work performed within pre-established CAPEX/OPEX budgets or lead to CAPEX/OPEX budget overruns (next slide)
Appendix B – Equipment Failure – URD Cable (Continued)

- DPL invested $6.2M in URD cable replacement in 2010 and with the most recent adjustment is planning on investing $4.7M in 2011.

- No indication in current pro forma that investment level is likely to increase

- Current plans are to accommodate CAPEX overruns by reclassifying work as O&M (may be feasible up to a point)

- In addition to a worsening of SAIFI and CAIDI, projected continuation of accelerated number / rate of URD cable failures will likely lead to a combination of the following:

  - “Cannibalizing” O&M (current practice) and CAPEX (no choice but to replace cable-service restoration)

  - Highest possible unit rates (URD cable replacement currently 15 to 20 percent proactive-will likely shift to 100 percent reactive by 2012)

  - Lack of proactive replacement implies a direct correlation between URD cable failures and related contribution to SAIFI and CAIDI (proactive replacement programs will serve to dampen the acceleration of URD cable failures in outlying years)

### Table: Capital Investment Scenarios ($K)

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<th>2010</th>
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<th>2012</th>
<th>2013</th>
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### Chart: Projected CAPEX Requirements vs. Budget ($K)
# Appendix B – Equipment Failure – Cutouts

## Failure and Replacement History

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<td>663</td>
<td>730</td>
</tr>
<tr>
<td>No. of Planned Replacements</td>
<td>33</td>
<td>307</td>
<td>197</td>
<td>737</td>
<td>2670</td>
</tr>
<tr>
<td>Failure Rate</td>
<td>2.6%</td>
<td>3.0%</td>
<td>3.4%</td>
<td>3.2%</td>
<td>3.8%</td>
</tr>
</tbody>
</table>

## Key Assumptions
- 16,000 cutouts require replacement (end of 2010)
- Unit cost to replace: $375
- 47 CIs per cutout failure caused outage
- 30% of failures require significant repairs ($4,500)

## 3 Scenarios – 3 Outcomes

### Scenario No. 1: Number of Failures Steady at 3-YR Average / Remain within $1.75M Annual Budget

<table>
<thead>
<tr>
<th>Year</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of Outages/Failures</td>
<td>709</td>
<td>709</td>
<td>709</td>
<td>709</td>
<td>709</td>
<td>709</td>
<td>657</td>
<td>0</td>
</tr>
<tr>
<td>No. of Planned Replacements</td>
<td>1614</td>
<td>1614</td>
<td>1614</td>
<td>1614</td>
<td>1614</td>
<td>1614</td>
<td>1405</td>
<td>0</td>
</tr>
</tbody>
</table>

- CAPEX investment 2011 through 2017: $12.0M
- Customer Interruptions 2011 through 2018: 230,817

### Scenario No. 2: Number of Failures Increase 1% per Year / Remain within $1.75M Annual Budget

<table>
<thead>
<tr>
<th>Year</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of Outages/Failures</td>
<td>737</td>
<td>745</td>
<td>752</td>
<td>760</td>
<td>767</td>
<td>775</td>
<td>783</td>
<td>327</td>
</tr>
<tr>
<td>No. of Planned Replacements</td>
<td>1496</td>
<td>1465</td>
<td>1433</td>
<td>1400</td>
<td>1368</td>
<td>1335</td>
<td>1301</td>
<td>558</td>
</tr>
</tbody>
</table>

- CAPEX investment 2011 through 2018: $12.9M
- Customer Interruptions 2011 through 2018: 265,340

### Scenario No. 3: 3-YR Completion Plan

<table>
<thead>
<tr>
<th>Year</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of Outages/Failures</td>
<td>737</td>
<td>745</td>
<td>752</td>
</tr>
<tr>
<td>No. of Planned Replacements</td>
<td>1496</td>
<td>6138</td>
<td>6132</td>
</tr>
</tbody>
</table>

- CAPEX investment 2011 through 2018: $8.8M
- Customer Interruptions 2011 through 2018: 105,000
An additional $2.5M per year for 2 years (2012 and 2013) will result in an overall 33% savings in CAPEX over an 8 year period

- Expedited 3-Year Schedule (Scenario 3) results in total investment of $8.8M
- Operating within a self-imposed $1.75M budget results in cumulative CAPEX investment of $12M to $13M

An additional $2.5M per year for 2 years (2012 and 2013) will produce an additional margin in SAIFI of 0.06 in years 2014 and beyond
Appendix B – Equipment Failure / Aging T&D Infrastructure – High Level Summary

The following categories of T&D assets presented typically cover over half of the capital dollars required for infrastructure replacement and in the absence of specific knowledge of each asset’s health and condition, criticality to the T&D system, and maintenance and operating history, asset age serves as a proxy to estimate the required CAPEX to make these replacements.

<table>
<thead>
<tr>
<th>Structures / Units</th>
<th>21 to 40 Years</th>
<th>&gt;40 Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage</td>
<td>Number</td>
<td>Percent</td>
</tr>
<tr>
<td>345kV</td>
<td>2,313</td>
<td>62%</td>
</tr>
<tr>
<td>138kV</td>
<td>5,541</td>
<td>31%</td>
</tr>
<tr>
<td>69kV</td>
<td>17,859</td>
<td>40%</td>
</tr>
</tbody>
</table>

Dx and Tx Substation Assets

<table>
<thead>
<tr>
<th></th>
<th>Total Number</th>
<th>Number</th>
<th>Percent</th>
<th>Number</th>
<th>Percent</th>
<th>Peer Group Norm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circuit Breakers</td>
<td>1,313</td>
<td>221</td>
<td>17%</td>
<td>439</td>
<td>33%</td>
<td>15 to 25%</td>
</tr>
<tr>
<td>Power Transformers</td>
<td>351</td>
<td>123</td>
<td>35%</td>
<td>120</td>
<td>34%</td>
<td>5 to 10%</td>
</tr>
</tbody>
</table>

Based on the age profiles, the following replacement profile will bring these T&D assets within that of the peer group norm:

- 345kV Transmission Structures: 200
- Circuit Breakers: 53
- Power Transformers: 85

$125.0M (Most of which is beyond that budgeted in the 10-YR Pro Forma)
Appendix B – Equipment Failure / Aging T&D Infrastructure – Substation Equipment (Circuit Breakers)

DPL’s circuit breakers are, on average, older than industry norm, suggesting the need for a fairly aggressive replacement requiring an additional $9.4M in CAPEX over the next few years:

- 31 percent of 33kV and greater circuit breakers have been in service for over 40 years (industry norm is 15 percent).
- 35 percent of 4kV and 12kV circuit breakers have been in service for 40 years (industry norm is 25 percent).

Failure rates for 4kV and 12kV circuit breakers have been slightly more than 2 per year (1.3 percent); and slightly more than 1 per year for 33kV and 69kV circuit breakers (1.7 percent).

Though failure rates are relatively low, any failure can have significant impact on reliability (1,200 to 1,500 CIs per outage).
Appendix B – Equipment Failure / Aging T&D Infrastructure – Substation Equipment (Transformers)

Transformer Profile of Failures

<table>
<thead>
<tr>
<th>Number of Failures</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replacement Cost</td>
<td>$387.4</td>
<td>$6,682.4</td>
<td>$1,782.4</td>
<td>$5,036.7</td>
<td>$1,900.0</td>
</tr>
<tr>
<td>Cost per Replacement</td>
<td>$387.4</td>
<td>$2,227.5</td>
<td>$891.2</td>
<td>$1,259.2</td>
<td>$1,900.0</td>
</tr>
</tbody>
</table>

- Transformer failure rates range between 0.3 and 1.1 percent:
  - Average failure rate is 0.6 percent
  - Though a low failure rate, reliability impact on a per event basis is significant (1,000 to 1,500 CIs)

- Average replacement cost is $1.4M per event (equates to $122M to align with peer group in terms of percent of transformers in service more than 40 years)
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• Executive Summary
• Overall Approach
• Risk Framework
• Reliability and Equipment Failure
• Capacity / Reinforcement Challenges
• Financial Legacy / Adequacy of Capital Investment and O&M Spending Levels
• Capital Investment Levels and Reliability
• Appendix A – Equipment Failure Data
• Appendix B – Equipment Failure Related Impacts
• **Appendix C – Case Studies**
• Appendix D – Equipment Failure Comparisons / Trends
**Background:**

Rule 4901:1-10-10 of the Ohio Administrative Code requires each electric distribution utility ("EDU") to annually report its performance against a set of system reliability targets. As of 2006, the Cleveland Electric Illuminating Company (CEI) had not met its annual system, customer average interruption duration index, ("CAIDI"), target, (95 minutes), since the rule became effective in 1999. Additionally, CEI had not met its annual system, customer average interruption frequency index, ("SAIFI"), target, (1 interruption per customer served), since 2002.

During 2005, CEI management and Public Utilities Commission of Ohio, ("PUCO"), Staff discussed a set of interim targets and a commitment that if the Company missed any of the interim targets (refer to 2006 and 2007 interim targets listed below), CEI would hire an independent consultant to provide PUCO Staff with an independent assessment of CEI’s infrastructure and operational practices. The Consultant would make recommendations to improve reliability in the CEI service territory by identifying steps that would need to be taken to make meaningful improvements in CEI’s CAIDI and SAIFI performance levels. CEI missed all of its interim targets for 2006, thus triggering the hiring of a Consultant:

<table>
<thead>
<tr>
<th>Measures</th>
<th>2005 Actual</th>
<th>2006 Actual</th>
<th>2006 Target</th>
<th>2007 Target</th>
<th>2009 Target</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIFI (Customer Interrupts)</td>
<td>1.71</td>
<td>1.21</td>
<td>1.11</td>
<td>1.06</td>
<td>1.0</td>
</tr>
<tr>
<td>CAIDI (Minutes)</td>
<td>113.5</td>
<td>125.3</td>
<td>115.0</td>
<td>110.0</td>
<td>95.0</td>
</tr>
<tr>
<td>SAIDI (Minutes)</td>
<td>194.5</td>
<td>151.6</td>
<td>127.7</td>
<td>116.6</td>
<td>95.0</td>
</tr>
</tbody>
</table>

**Outcome:**

As a result of the assessment, CEI accepted recommendations to adopt a two-pronged approach to meet short-term performance targets by 2009, and address the longer term concern of sustainable reliability performance:

- Actions to mitigate and/or eliminate customer interruptions (6 specific initiatives to reduce SAIFI by 0.22 requiring incremental investments of $7.8M and 7 additional initiatives to further enhance results)
- Actions to improve service restoration (6 specific initiatives to reduce CAIDI by 25 minutes requiring incremental increase of O&M spending of $0.3M and 2 additional initiatives to further enhance results)
- Specified criteria re: capital investment levels (20 percent increase) and hiring dictates, and endorsement of an overall Asset Management strategy to replace and/or refurbish the current electric distribution infrastructure.
Cleveland Electric Illuminating (CEI) (Continued)

Implications:
Though the ESSS rules that govern these performance mandates clearly stipulates that “failure to meet a performance standard for 2 consecutive years shall constitute a violation” and that remedies in the form of fines ($10,000 per day for each such failure) and restitution for damages to the customers can be applied; the PUCO Commission Staff opted for an assessment. As a result, CEI lost a degree of autonomy with respect to hiring, was assigned extremely prescriptive short-term measures with financial mandates to invest an additional $7.8M in capital and spend an additional $0.3M in O&M per annum, and challenged to develop a comprehensive strategy to replace and / or refurbish an aging electric distribution infrastructure. The fact that the performance targets themselves are significantly lower (better) than peer group averages (and in the case of SAIFI top quartile), bears no relevance in terms of relief from Commission Staff. Electric Distribution Companies need to view these commitments as uncompromising with fairly severe consequences when found to be in non-compliance.
American Electric Power Ohio (AEP)

Background:
A report issued in April 2006 by the PUCO staff found that AEP Ohio (comprised of 2 subsidiaries: Columbus Southern Power Company and Ohio Power Company) had failed to meet obligations required under the agreement reached in the December 2003 Stipulation Agreement to improve its service. The reliability issues related to outages customers had experienced, whether the power failures could have been prevented through better maintenance efforts and the length of time it took for the company to restore service. The 2006 report showed that while performance improved in the portions of AEP’s service area that had experienced the most power outages, electric reliability declined in other service areas..

Outcome:
AEP Ohio, comprised of Columbus Southern Power Company and Ohio Power Company, filed a plan in October 2006 with the Public Utilities Commission of Ohio (PUCO) to enhance distribution system reliability and improve the overall customer experience. The plan proposed an additional annual average investment of approximately $130 million over a five year period on vegetation management, equipment replacement, infrastructure upgrades and improved use of technology, to reduce outages and improve service reliability. Presented with a modest increase in rates ($0.0016 per kWh for Columbus Southern Power customers and $0.0023 for Ohio Power customers). Specific targeted initiatives included:

• Vegetation Management  
• Overhead Line Inspection  
• Accelerated Equipment and Hardware Replacement (including cutouts and lightning arrestors)  
• Advanced Metering Infrastructure  
• Underground Cable Replacement  
• Distribution Substation Refurbishment

On the insistence of the Office of the Ohio Consumers’ Council (OCC), the above proposed rate increase was avoided, and the final agreement required AEP Ohio to spend $10 million for proactive cycle-based tree trimming efforts, an activity for which PUCO reserved the right to oversee how the money would be spent, and that the company would not be allowed to recover via rate increases.
Metropolitan Edison Company (Met-Ed)

Background:
FirstEnergy Corporation entered into a Reliability Settlement Agreement with the Pennsylvania Commission (PAPUC) for all of its Pennsylvania operating companies in November 2004 after an investigation launched by the PAPUC showed that the companies had not been meeting established standards. In that agreement, FirstEnergy committed to improving the service reliability of its three Pennsylvania companies by increasing its investment in the electric distribution infrastructure, increasing reliability-related O&M spending (particularly vegetation management), and where applicable, improving service restoration.

For Metropolitan Edison (Met-Ed), this resulted in the establishment of SAIFI, CAIDI and SAIDI benchmarks (specified below) and standards, recognizing that “benchmark” signifies the proper performance target, but “standard” provides some latitude for borderline major events (e.g. storms that do not qualify as excludable). Met-Ed failed to meet standard performance between 2004 and 2006, with SAIFI showing continued degradation from 1.55 to 1.73 (equipment failure and tree-caused outages were a primary cause of this degradation). As a result, the PAPUC Commission Staff initiated its prerogative to require an independent consultant to conduct a focused audit of the planning, design, construction, operations, and maintenance practices, polices, and procedures of Met-Ed and to recommend action plans to be implemented to improve service reliability.

<table>
<thead>
<tr>
<th>2002</th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual SAIFI</td>
<td>1.22</td>
<td>1.1</td>
<td>1.55</td>
<td>1.7</td>
</tr>
<tr>
<td>SAIFI Benchmark</td>
<td>1.15</td>
<td>1.15</td>
<td>1.15</td>
<td>1.15</td>
</tr>
<tr>
<td>SAIFI Standard</td>
<td>1.38</td>
<td>1.38</td>
<td>1.38</td>
<td>1.38</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>2002</th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual CAIDI</td>
<td>116</td>
<td>114</td>
<td>127</td>
<td>122</td>
</tr>
<tr>
<td>CAIDI Benchmark</td>
<td>117</td>
<td>117</td>
<td>117</td>
<td>117</td>
</tr>
<tr>
<td>CAIDI Standard</td>
<td>140</td>
<td>140</td>
<td>140</td>
<td>140</td>
</tr>
</tbody>
</table>

NOTE: Red font denotes where Met-Ed is not in compliance with the 2004 Settlement Agreement
**Metropolitan Edison Company (Met-Ed) (Continued)**

**Outcome:**

As a result of the independent assessment, Met-Ed accepted 18 short and long-term recommendations for incorporation into its Electric System Reliability Improvement Plan across the following dimensions:

- Strengthen the Distribution Feeder Backbone
- Minimize Multiple Customer Interruptions outside the Distribution Feeder Backbone with a particular focus on Worst Performing Devices
- Improve Restoration Times (System-wide) with expansion of the alternate shift and increased emphasis on call back response
- Reduce Corrective Maintenance particularly in addressing line inspection discrepancies

In addition to funding the third-party assessment (total cost of about $0.5M), Met-Ed committed to an increase in annual O&M spending of $2.6M, aimed at reducing improving (reducing) SAIDI by 31 minutes. Additional capital requirements of $15M to address the shortfalls identified in the assessment were already included in the Met-Ed capital spending plan.

By 2008 and 2009 the company sustained at or near benchmark SAIDI performance (139 and 134, respectively)
Pennsylvania Electric Company (Penelec)

Background:
FirstEnergy Corporation entered into a Reliability Settlement Agreement for all of its operating companies with the Pennsylvania Commission in November 2004 after an investigation launched by the PAPUC showed that the companies had not been meeting established standards. In that agreement, FirstEnergy committed to improving the service reliability of its three Pennsylvania companies by stepping up its investment in the electric distribution infrastructure, increasing reliability-related O&M spending (particularly vegetation management), and where applicable, improving service restoration.

For Penelec, this resulted in the establishment of SAIFI, CAIDI and SAIDI benchmarks (specified below) and standards, recognizing that benchmark signifies the performance target, but standard provides some latitude for borderline major events (e.g. storms that do not qualify as excludable). As illustrated below, Penelec fell short of standard in 2008 in all three measures (and fell short of a rolling 3-year average in SAIFI and SAIDI). As a result, Penelec unilaterally proposed that it implement a focused third-party audit of its planning, design, construction, operations, and maintenance practices, polices, and procedures with an expectation of receiving recommendations to action plans to improve service reliability.

### Average Electric Reliability Indices for Penelec

<table>
<thead>
<tr>
<th>Performance Index</th>
<th>Rolling 12-Month Average</th>
<th>Rolling 3-Year Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIFI</td>
<td>1.26</td>
<td>1.52</td>
</tr>
<tr>
<td>CAIDI</td>
<td>117</td>
<td>141</td>
</tr>
<tr>
<td>SAIDI</td>
<td>148</td>
<td>213</td>
</tr>
</tbody>
</table>

**NOTE:** Red font denotes where Penelec is not in compliance with the 2004 Settlement Agreement
Pennsylvania Electric Company (Penelec) (Continued)

Outcome:
As a result of the assessment, Penelec accepted 7 recommendations for incorporation into its Electric System Reliability Improvement Plan across the following dimensions to improve (reduce) SAIDI by 33 minutes:

<table>
<thead>
<tr>
<th>Recommendation</th>
<th>SAIDI Impact</th>
<th>Cost Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Implement 2nd Phase of Circuit Protection (200 Reclosers)</td>
<td>6.0 minutes</td>
<td>$2.5M</td>
</tr>
<tr>
<td>Enhanced Tree Trimming and Cycle Optimization</td>
<td>6.0 minutes</td>
<td>$1.0M</td>
</tr>
<tr>
<td>Line Inspection and Repair (Anticipating more items from thermography and CHC)</td>
<td>2.0 minutes</td>
<td>$0.5M</td>
</tr>
<tr>
<td>Lightning Protection</td>
<td>3.0 minutes</td>
<td>$2.5M</td>
</tr>
<tr>
<td>Systematize Storm Pre-Mobilization</td>
<td>10.0 minutes</td>
<td>$0.6M</td>
</tr>
<tr>
<td>Reinforce “Cut and Run”</td>
<td>5.0 minutes</td>
<td>$0.1M</td>
</tr>
<tr>
<td>Install Directional Fault Indicators</td>
<td>1.0 minutes</td>
<td>$0.5M</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>33.0 minutes</strong></td>
<td></td>
</tr>
</tbody>
</table>

In addition to funding the third-party assessment ($0.5M), Penelec committed to an increase in annual O&M spending of $2.7M and one-time CAPEX increase of $5.0M.
Potomac Electric Power Company (PEPCO)

Background:

Severe storms in July 2010 caused nearly half a million customers (approximately 60 percent of their total customers) to lose power. Many of these customers sustained service interruption for several days, prompting a hearing between PEPCO and the Maryland Public Service Commission (MD PSC). This occurred in the wake of joint PEPCO and MD PSC adoption of the new Electric Quality of Service Standards, aimed at improving PEPCO’s service reliability and increasing its accountability for performance. Besides providing for penalties in the event of performance shortfalls, these standards put PEPCO on notice that reliability could be considered during the future rate cases.

Consequently, it came as no surprise when the hearing resulted in an Order No. 83526 where the MD PSC instituted a proceeding, Case No. 9240, to investigate, among other things: (i) the number of customers affected by major power outages in the PEPCO service territory during the summer of 2010; (ii) the root causes for the scope, frequency, and duration of outages, both storm and non-storm related; (iii) the communication failures that reportedly occurred and continued to occur between PEPCO and affected customers; and (iv) PEPCO’s reported inability to communicate estimated times of restoration to affected customers in a timely manner. As part of this investigation, PEPCO, on behalf of the Commission, hired an independent consultant to conduct a thorough evaluation of its electric distribution system reliability.

The noted downturn in reliability in 2004 was the result of damage caused by Hurricane Isabel and PEPCO’s lack of proactivity in performance preventive maintenance in its aftermath. The result is 4th quartile performance in eliminating or mitigating customer interruptions (SAIFI). New rules issued by the MD PSC require gradual improvement on a yearly basis, beginning in 2013 of 9% per year. The expectation is that PEPCO will rank in the top tier of electric distribution systems by 2020.
Outcome:
As a result of the assessment, PEPCO adopted its previously developed Reliability Enhancement Program (REP) as non-discretionary (previously discretionary) along with a commitment to be more proactive in the following areas:

- Conducting Vegetation Management
- Providing accurate ETRs during service outages
- Performing Outage History and Cause Analyses
- Communicating with Customers during Major Storm Events

In addition to funding the third-party assessment ($0.25M), Penelec committed to an increase in annual O&M spending of $3.0M and CAPEX of $20.0M for 5 years:

**Reliability Enhancement Program (REP) Summary**

<table>
<thead>
<tr>
<th>Component</th>
<th>Baseline Plan (Annual)</th>
<th>Baseline Plan (5-Year)</th>
<th>REP (Annual)</th>
<th>REP (5-Year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enhanced Vegetation Management</td>
<td>$4.3M</td>
<td>$21.5M</td>
<td>$7.3M</td>
<td>$36.5M</td>
</tr>
<tr>
<td>Priority Feeders</td>
<td>$4.5M</td>
<td>$21.5M</td>
<td>$7.3M</td>
<td>$36.5M</td>
</tr>
<tr>
<td>Load Growth</td>
<td>$12.0M</td>
<td>$60.0M</td>
<td>$12.0M</td>
<td>$60.0M</td>
</tr>
<tr>
<td>Distribution Automation</td>
<td>$1.2M</td>
<td>$6.0M</td>
<td>$3.0M</td>
<td>$15.0M</td>
</tr>
<tr>
<td>URD Cable Replacement</td>
<td>$6.3M</td>
<td>$31.5M</td>
<td>$7.5M</td>
<td>$37.5M</td>
</tr>
<tr>
<td>UG/Substation Improvements</td>
<td>$0.0M</td>
<td>$0.0M</td>
<td>$15.0M</td>
<td>$75.0M</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>$28.3M</strong></td>
<td><strong>$141.5M</strong></td>
<td><strong>$51.3M</strong></td>
<td><strong>$256.5M</strong></td>
</tr>
</tbody>
</table>
AmerenUE

Background:
Severe Storms In 2006 and 2007 resulted in unprecedented service interruptions to more than 1.5 million utility customers in the AmerenUE (St. Louis, Missouri) service territory. These storms had been unmatched in severity and frequency in the utility's history and cost $223 million in 2006 alone. In July 2006, back-to-back storms with wind speeds in excess of 90 mph affected 950,000 customers in Illinois and Missouri. In November and December 2006, and in January 2007, severe weather struck again, this time in the form of ice storms. These storms were the worst to hit Ameren's Illinois and Missouri region in the last 30 years. The 2006 ice storm affected 520,000 customers and the 2007 storm affected 350,000 customers. To a large extent, these storm systems affected the same customers and a similar geographical area.
AmerenUE (Continued)

Outcome:

AmerenUE voluntarily selected a consultant, experienced in evaluation electric utilities’ storm response, to make recommendations on hardening its energy delivery system. The resulting reliability improvement plan, part of a more comprehensive $1 billion program called “Power On,” called for additional investments of hundreds of millions of dollars over a three year period to further fortify the power grid and make it less prone to widespread outages.

- $100 million a year for 3 years to bury miles of overhead power lines, particularly those susceptible to falling trees and limbs.
- $28 million a year for 3 years for more circuit and device inspections and repairs to fix problems with poles and hardware before they fail.
- $45 million a year for 3 years for tree trimming (doubling the previous budget for vegetation management)

AmerenUE anticipated any MPSD mandates by proactively committing to these levels of investment and spending.
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- Executive Summary
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- Appendix D – Equipment Failure Comparisons / Trends
Equipment Failure SAIFI

The following graphs/charts compare DPL with 5 other similarly configured utilities in terms of equipment failure-caused outages and their significance to overall SAIFI:

- DPL’s customers experience a comparatively small percentage of CIs as a result of equipment failures:
  - Equipment Failure caused SAIFI for DPL ranges around 0.30 (4 of the 5 utilities surveyed are significantly higher)
  - The fluctuation around 30 percent is somewhat reflective of varying levels of capital investment

- Though 3 of the 5 utilities surveyed are have even higher percentages, Equipment Failure caused SAIFI for DPL has represented around 35% of its SAIFI since 2007:
  - Suggests more cost-effective short-term measures (sectionalizing, circuit protection, tree trimming) have pretty much run their course, requiring a shift to addressing equipment failure (typically more capital intensive)
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 16:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, Appendix B, p. 55

On the same basis as the information required in Appendix F, ‘Unit Cost Tab’, please provide actual information for 2017 and 2018, and forecast information for each year between 2019 and 2024. Please update the table to provide 2018 actual information.

RESPONSE:

Please see Appendix A for the unit costs associated with 2017. Actuals for 2018 are not available at this time. Forecast information for 2019-2024 is not available on the same system-wide basis as the actuals provided for 2014-2017. Toronto Hydro forecasts asset volumes and total costs at a program level using various program-specific methodologies such that using those forecasts to generate system-wide values is neither practical nor reasonable.
<table>
<thead>
<tr>
<th>Category</th>
<th>(THESL Asset Name)</th>
<th>Per Unit of Measurement (i.e., each, per meter/foot, per kilometre/mile, per hectare, etc.)</th>
<th>2017 Number of Units (if known)</th>
<th>Unit Costs (2017)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1  Wooden Pole Replacement</td>
<td>Wooden Poles</td>
<td>Each</td>
<td>2759</td>
<td>$6,454</td>
<td></td>
</tr>
<tr>
<td>3  UG XLPE Replacement</td>
<td>U-G Pri Cable- XLPE(In Duct)</td>
<td>Meter</td>
<td>355284</td>
<td>$125</td>
<td>Assumed to be in duct (PVC) by Major Asset Definition for ISA purposes</td>
</tr>
<tr>
<td>4  UG PILC Replacement</td>
<td>U-G Primary Cable- PILC</td>
<td>Meter</td>
<td>0</td>
<td>$ -</td>
<td>Does not include PILC Spot Replacement (Piece-out and Leakers)</td>
</tr>
<tr>
<td>5  Vegetation Management - Tree Trimming</td>
<td></td>
<td>Km</td>
<td>1676</td>
<td>$2,147</td>
<td></td>
</tr>
<tr>
<td>6  Vegetation Management - Herbicide</td>
<td></td>
<td>Data not available</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7  Pole Test and Treat</td>
<td></td>
<td>Each</td>
<td>14671</td>
<td>$18</td>
<td></td>
</tr>
<tr>
<td>8  Overhead Line Patrol</td>
<td></td>
<td>Kilometer</td>
<td>7045</td>
<td>$44</td>
<td></td>
</tr>
<tr>
<td>9  Vault Inspection</td>
<td>Network Vault Inspection</td>
<td>Each</td>
<td>3095</td>
<td>$355</td>
<td></td>
</tr>
<tr>
<td>10 OH Manual Switches</td>
<td>O-H Switches</td>
<td>Each</td>
<td>371</td>
<td>$18,336</td>
<td>OH CKT Renewal</td>
</tr>
<tr>
<td>11 OH Remote/Motor Operated Switches</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>DVSFS-Mate R1 Switch Renewal</td>
</tr>
<tr>
<td>12 Overhead (Poletop) Transformer Replacement</td>
<td>O-H Transformers</td>
<td>Each</td>
<td>716</td>
<td>$10,969</td>
<td>OH CKT Renewal</td>
</tr>
<tr>
<td>13 Padmount Transformer Replacement</td>
<td>U-G Transformers</td>
<td>Each</td>
<td>1060</td>
<td>$20,596</td>
<td>UG CKT Renewal</td>
</tr>
<tr>
<td>14 Underground (submersible and vault) Transformer Replacement</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>15 Network Transformer Replacement</td>
<td>Network Unit (Tx &amp; Protector)</td>
<td>Each</td>
<td>62</td>
<td>$90,666</td>
<td>Network Vault Renewal and Network Unit Renewal</td>
</tr>
<tr>
<td>16 Network Protector Replacement</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Combined with Transformer</td>
</tr>
<tr>
<td>17 Oil Breaker Replacement</td>
<td>Subst Eq Indr Brk</td>
<td>Each</td>
<td>0</td>
<td>$ -</td>
<td>Circuit Breaker Renewal</td>
</tr>
<tr>
<td>18 SF6 Breaker Replacement</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>19 Vacuum Breaker Replacement</td>
<td>Subst Eq Switch Air</td>
<td>Each</td>
<td>2</td>
<td>$1,264,981</td>
<td>Station Switchgear Renewal</td>
</tr>
<tr>
<td>20 Station Switchgear (Air) Replacement</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Data not available</td>
</tr>
<tr>
<td>21 Station Switchgear (GIS) Replacement</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 17:

Reference(s): Exhibit 1B, Tab 2, Schedule 2

For each of the 12 DSP measures, please provide the 2013 to 2017 results in a tabular instead of a chart format.

RESPONSE:

Please see Table 1 below.

Table 1: 2015-2019 DSP Measures Results (2013-2017)

<table>
<thead>
<tr>
<th>Measure</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIDI (Hours)</td>
<td>1.12</td>
<td>0.89</td>
<td>0.99</td>
<td>0.91</td>
<td>0.91</td>
</tr>
<tr>
<td>SAI FI (# of times)</td>
<td>1.34</td>
<td>1.18</td>
<td>1.31</td>
<td>1.28</td>
<td>1.18</td>
</tr>
<tr>
<td>MAIFI (# of times)</td>
<td>2.37</td>
<td>2.55</td>
<td>2.72</td>
<td>2.64</td>
<td>2.52</td>
</tr>
<tr>
<td>CAIDI (Hours)</td>
<td>0.84</td>
<td>0.75</td>
<td>0.76</td>
<td>0.71</td>
<td>0.77</td>
</tr>
<tr>
<td>FESI 7 (# of feeders)</td>
<td>33</td>
<td>36</td>
<td>23</td>
<td>25</td>
<td>12</td>
</tr>
<tr>
<td>Outages Caused by Defective Equipment (# of outages)</td>
<td>636</td>
<td>711</td>
<td>572</td>
<td>519</td>
<td>484</td>
</tr>
<tr>
<td>Distribution System Plan Implementation Progress (%)</td>
<td>105%</td>
<td>147%</td>
<td>100%</td>
<td>101%</td>
<td>99%</td>
</tr>
<tr>
<td>Stations Connection Capacity Availability (# of stations)</td>
<td>5</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Planning Efficiency: Engineering and Support Costs (%)</td>
<td>7%</td>
<td>8%</td>
<td>8%</td>
<td>9%</td>
<td>9%</td>
</tr>
<tr>
<td>Supply Chain Efficiency: Materials Handling On-Cost (%)</td>
<td>11%</td>
<td>14%</td>
<td>11%</td>
<td>11%</td>
<td>10%</td>
</tr>
<tr>
<td>Construction Efficiency: Internal vs. Contractor Cost (%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Efficiency: Asset Assembly Labour Input</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>NA</td>
</tr>
</tbody>
</table>

*Note: This information is being field confidentially, in accordance with the OEB's Decision on Confidentiality in this case, (December 14, 2018) at pages 2 and 3.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 18:
Reference(s): Exhibit 1B, Tab 3, Schedule 1, Appendix 1.2, p. 2

Please provide a copy of the referenced Discussion Guide and the printed primer.

RESPONSE:

The Discussion Guides in relation to the Mid-Market and Low-Volume Customer Focus Groups are attached as Appendix A and B, respectively.

The printed primer in relation to the Mid-Market Customer Focus Groups is available on pages 19 and 20 of Appendix 1.2 of the Innovative Report (Exhibit 1B, Tab 3, Schedule 1, Appendix A). The printed primer in relation to Low-Volume Customer Focus Groups can be found at pages 18 and 19 of Appendix 1.1 of the Innovative Report.
Discussion Guide

Toronto Hydro Mid-Market Customer Focus Groups

February 28, 2017 – North Toronto
Head Research: 5075 Yonge Street, Suite 601

March 1, 2017 – North Toronto
Head Research: 5075 Yonge Street, Suite 601
Section 1: Introduction

Time: 10 minutes

Thank participants for coming tonight.


b. Independence of moderator from the client, no stake in the topics being discussed.

c. We will be discussing electricity tonight. I will be covering a lot of ground, asking for your help and asking you to think a lot!

d. No wrong answers. Looking for your opinions, and if they are different from everyone else's, that’s great, it’s exactly what I am looking for!

e. Confidentiality – recording the group, internal purposes only, just to remember what you said.

f. At some points, I will ask you work on own, and after we will discuss.

g. Sometimes I ask everyone my questions, other times I might not. If I haven't asked you, feel free to jump in or piggyback on someone else’s answers. But we have a lot of material to cover, and I want to make sure I hear from everyone, so please avoid side conversations, talking over each other and so on – I want to make sure everyone has enough airtime.

h. Cell phones – please turn off now, not just in silent mode – explain why.

i. Now that we’ve covered the ground rules, let’s go around the room and please introduce yourself, first name only is fine, and tell me a little about yourself and what you do, and what your passion in life is.

MODERATOR: With each respondent, toss out the ball of string!
Section 2: Landscape

**Time: 10 minutes**

Q1. Who is your electricity supplier?
Prompt and reinforce as Toronto Hydro.

Q.2. Can you tell me what Toronto Hydro does? Prompts: What its service is, what part of the system it manages.

**NOTES to moderator:** After short free discussion, intervene by handing out background stimuli.

Q3. Can you tell me when your business first became a customer of Toronto Hydro?
Probes:
- First point of contact
- What was the process of becoming a customer like? Describe.
- Other spontaneous probes as appropriate
Q4. **BOARD EXERCISE**: Can you tell me, since that first point of contact, what other types of contact you have had with Toronto Hydro?

**Probes:**

- Billing
- New Account
- Outage
- Service/reliability issue
- Product issue
- Informational
- Conservation
- Field Encounters (interactions with “Orange Coats”)
- Safety concern

Q5. **How did you find out where to go or what to do?**

Q6. **What was your next step?**
Section 3: Customer Experience

Time: 20 minutes

NOTE: Use ‘post & cluster’ technique.

Q7. Building on the types of experiences you have identified; can you tell me a bit about what you expected from Toronto Hydro in that interaction?

Q8. What did you come away feeling best about?

Q9. What did you come away not feeling good about?

Q10. How did you feel in this interaction?

Q11. How well did you feel your expectations were understood?

Q12. What were the disconnect points?

Q13. Overall, can you give me a word or short phrase that summarizes what you expect in service from Toronto Hydro?
Section 4: Customer Service Projective

Time: 20 minutes

Q14. In the interactions you have had with Toronto Hydro, were they prepared for the types of questions you had?

Q15. Are there concerns or issues you feel Toronto Hydro is not able to address?

Q16. What could be done to address these concerns?

BUILD OUT ON BOARD

Q17. Overall, does Toronto Hydro’s approach to customer service meet your expectations?

PROBE: needs, platforms, touchpoints, issues

PROBE: Expectations vs. aspirations

Q18. Do you feel Toronto Hydro had the same expectations of itself that you have of them?
Section 5: Building the Future

Time: 40 minutes

NOTE: Use ‘post & cluster’ technique.

Q19. I’m going to ask you to put on your ‘future viewing goggles’ for this next part! What are the issues or challenges in electricity you see emerging over the next decade?

Post on board.

PROBE if not unaided:

- Global issues (climate change, population growth, changing economies)
- Local issues (demand, capacity, reliability)
- Changes coming from technology (internet of things)
- Changes coming from lifestyles (in home storage, transportation electrification)
- Customer service needs (new services)
Q21. What do you expect from Toronto Hydro in response?

**DEEPER PROBES**: List on Board, note factors of importance:

**Safety**: External, on the streets, Internal – in the home

**Reliability**: Frequency of outages
  - Length of outages
  - Major events/disasters
  - Cybersecurity
  - Level of redundancy

**Demand/Capacity**: Investment to meet population/jobs growth
  - Investment to meet technological changes (transportation electrification)

**Quality**: Stability of voltages

**Customer Service**: Investing in communications (sensors on lines, live callers, interactive tools, etc.)
Continue on second board:

Q22. What are the tangible outcomes you expect from Toronto Hydro on these?

Topical Probes:

- price
- efficiency / productivity
- reliability
- safety
- customer service
- social commitments
- technology
- environmental

*Criteria Probes: drill down exercise*

What does a successful outcome look like?

Q23. What is the balance between costs to consumers and these outcomes?

Probe:

- Where should the next dollar you are willing to spend go to?

Q24. What are the consequences for not achieving these outcomes?

Probes:

- personal consequences
- future generation consequences
- social consequences
Section 6: Wrap-Up

Time: 15 minutes

Q25. MODERATOR: Start with a statement describing consultations generally.

- Mandated by government
- Utilities are obligated
- Public – reports are made public
- Reports can be challenged by experts and interested groups

How should Toronto Hydro consult with you in the future on the things we have discussed today? What do you need to know to be able to make a meaningful contribution? What do you need to be able to assess choices and options in a meaningful way? What is the best way to provide you that and obtain your feedback?

Probe for the optimal consultation model:

On Board: list:

- workbook style consultations
- Public forums/in person
- Surveys
- Email/online consultation

Q26. Are there any issues relating to electricity and/or Toronto Hydro coming out of this discussion we haven’t touched on?

Q27. Overall, after this discussion, has anything changed for you in how you view electricity or Toronto Hydro?
Thank and dismiss

COLLECT ALL PRINT MATERIALS

• I need everyone to hand in their documents
• Name tags
• Please don’t discuss on the way out
• Sign out

Thank respondents for their help and wish them a good night and safe journey home!
Discussion Guide

Toronto Hydro Customer Focus Groups

December 5, 2016 – Central Toronto
Consumer Vision: 2 Bloor St. West, 3rd Floor

December 6, 2016 – North York
Westin Prince Hotel: 900 York Mills Road
Section 1: Introduction

Time: 10 minutes

Thank participants for coming tonight.


b. Independence of moderator from the client, no stake in the topics being discussed.

c. We will be discussing electricity tonight. I will be covering a lot of ground, asking for your help and asking you to think a lot!

d. No wrong answers. Looking for your opinions, and if they are different from everyone else's, that’s great, it’s exactly what I am looking for!

e. Confidentiality – recording the group, internal purposes only, just to remember what you said.

f. At some points, I will ask you work on own, and after we will discuss.

g. Sometimes I ask everyone my questions, other times I might not. If I haven’t asked you, feel free to jump in or piggyback on someone else’s answers. But we have a lot of material to cover, and I want to make sure I hear from everyone, so please avoid side conversations, talking over each other and so on – I want to make sure everyone has enough airtime.

h. Cell phones – please turn off now, not just in silent mode – explain why.

i. Now that we’ve covered the ground rules, let’s go around the room and please introduce yourself, first name only is fine, and tell me a little about yourself and what you do, and what your passion in life is.

MODERATOR: With each respondent, toss out the ball of string!
Section 2: Landscape

Time: 15 minutes

Q1. Is everyone here a Toronto Hydro customer?

Q2. Can you tell me what Toronto Hydro does? Prompts: What its service is, what part of the system it manages.

NOTE to moderator: After short free discussion, intervene by handing out and reading the following statement:

Toronto Hydro is the part of the system that takes the electricity from provincial transmission towers and brings it to your home through a network of wires, poles and other equipment that is owned and operated by Toronto Hydro. It doesn’t generate that electricity, or carry it from the place it is generated. It is the local distribution company. For reference, Toronto Hydro’s services represent about 25% of the average billing.

Q3. Can you recall what your first experience with Toronto Hydro was? Secondary: What was the first point at which you became a customer?

Q4. BOARD EXERCISE: Can you tell me, since that first point of contact, what other types of contact you have had with Toronto Hydro?

Probes:

- Billing
- New Account
- Outage
- Service/reliability issue
- Product issue
- Informational
• Conservation
• Field Encounters (interactions with “Orange Coats”)
• Safety concern

Q5. Can you tell me about how that contact started? The steps along the way?
Section 3: Customer Experience

Time: 20 minutes

NOTE: Use ‘post & cluster’ technique.

Q7. Building on the types of experiences you have identified:
   Can you tell me a bit about what you expected from Toronto Hydro in that interaction? What were you expecting from Toronto Hydro?
   PROBE:
   - in the interaction
   - in the process
   - in the outcome
   - post outcome

Q8. What did you come away feeling best about?

Q9. What did you come away not feeling good about?

Q10. In these interactions you have had with Toronto Hydro, were they prepared for the types of questions you had?

Q11. How well did you feel Toronto Hydro understood your expectations?

Q12. What could have been done better or differently?

Q13. Overall, does Toronto Hydro’s approach to customer service meet your expectations?
PROBE: needs, platforms, touchpoints, issues
PROBE: Expectations vs. aspirations

Q14. Overall, can you give me a word or short phrase that summarizes what you expect in service from Toronto Hydro?
Section 4: Future Expectations

Time: 45 minutes

NOTE: Use ‘post & cluster’ technique.

Q15. I’m going to ask you to put on your ‘future viewing googles’ for this next part!
What are the issues or concerns do you see emerging over the next decade relating to Toronto Hydro’s services?

Post on board.

PROBE if not unaided:

• Global issues (climate change, population growth, changing economies)
• Local issues (demand, capacity, reliability)
• Changes coming from technology (internet of things)
• Changes coming from lifestyles (in home storage, transportation electrification)
• Customer service needs (new services)

Q16. What do you expect from Toronto Hydro in response?

DEEPER PROBES: List on Board, note factors of importance:
Safety: External, on the streets, Internal – in the home
Reliability: Frequency of outages
   Length of outages
   Major events/disasters
   Cybersecurity
   Level of redundancy
Demand/Capacity: Investment to meet population/jobs growth
Investment to meet technological changes (transportation electrification)

Quality: Stability of voltages

Customer Service: Investing in communications (sensors on lines, live callers, interactive tools, etc.

Continue on second board:

Q17. What are the tangible outcomes you expect from Toronto Hydro on these?

Topical Probes:
- price
- efficiency / productivity
- reliability
- safety
- customer service
- social commitments
- technology
- environmental

* Criteria Probes: drill down exercise

Q18. What does a successful outcome look like?

Q19. What is the balance between costs to consumers and these outcomes?

Probes:
- Which add value to you?
- What is that value?
- What can Toronto Hydro realistically achieve?
Q20. What are the consequences for not achieving these outcomes?

Probes:

- personal consequences
- future generation consequences
- social consequences
Section 6: Wrap-Up

Time: 15 minutes

Q21. MODERATOR: Start with a statement describing consultations generally.

- Mandated by government
- Utilities are obligated
- Public – reports are made public
- Reports can be challenged by experts and interested groups
- Consultations are about choices, not about rules

How should Toronto Hydro consult with you in the future on the things we have discussed today? What do you need to know to be able to make a meaningful contribution? What do you need to be able to assess choices and options in a meaningful way? What is the best way to provide you that and obtain your feedback?

Probe for the optimal consultation model:

On Board: list:

- workbook style consultations
- Public forums/in person
- Surveys
- Email/online consultation

Q22. Are there any issues relating to electricity and/or Toronto Hydro coming out of this discussion we haven’t touched on?
Q23. Overall, after this discussion, has anything changed for you in how you view electricity or Toronto Hydro?

Thank and dismiss

COLLECT ALL PRINT MATERIALS

• I need everyone to hand in their documents
• Name tags
• Please don’t discuss on the way out
• Sign out

Thank respondents for their help and wish then a good night and safe journey home!
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 19:
Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 4

Please provide a table showing capital investments of Toronto Hydro for each year from 2010 to 2017 actual, and 2018 to 2024 forecast, and demonstrate that the investments in the five year CIR period “exceed historical levels”.

RESPONSE:
Table 1 below provides the historical capital investments of Toronto Hydro from 2010 to 2017 and Table 2 provides the forecasted capital expenditures from 2018 to 2024. Renewable Generation Facility Assets and Other Non Rate-Regulated Utility assets have been excluded. The historical average from 2010 and 2017 is $458 million. The five year CIR average for the period from 2018 to 2024 is $562 million, which represents an increase in the required capital expenditures of approximately 23 percent over the historical average from 2010 to 2017.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPEX</td>
<td>401</td>
<td>446</td>
<td>288</td>
<td>446</td>
<td>586</td>
<td>491</td>
<td>508</td>
<td>497</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Bridge (in $ millions)</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPEX</td>
<td>435</td>
<td>426</td>
<td>514</td>
<td>579</td>
<td>584</td>
<td>562</td>
<td>571</td>
</tr>
</tbody>
</table>
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 20:

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

Please provide a table setting out all differences between a) the current PSE cost benchmarking methodology, b) the 2015 PSE cost benchmarking methodology, and c) the 4th Generation OEB cost benchmarking methodology, including without limitation variables used, calculation methods, data set, etc. In each case, please provide an explanation of the reason the expert thinks the current PSE benchmarking methodology is superior for Toronto Hydro, or an evidentiary reference providing that explanation. Please identify each difference that the expert believes does not have a material impact on the expert’s results.

RESPONSE (PREPARED BY PSE):

The table below provides a comparison of the 2015 PSE cost benchmarking research (2015 PSE Study) and the 4th Generation OEB cost benchmarking research (4th Generation OEB Study, or OEB Study) relative to the current PSE benchmarking research (2018 PSE Study, or “current study”). At times the 2015 PSE Study and the 4th Generation OEB are referred to collectively as “the previous studies.”

<table>
<thead>
<tr>
<th>Current PSE Study</th>
<th>2015 PSE Study</th>
<th>4th Generation OEB Study</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methodology</td>
<td>(2015 PSE Study)</td>
<td>(4th Generation OEB Study)</td>
</tr>
<tr>
<td>Variables Used</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Calculation Methods</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Data Set</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

At times the 2015 PSE Study and the 4th Generation OEB are referred to collectively as “the previous studies.”
Table 1: Comparison of Differences in Current PSE Study and Previous Studies

<table>
<thead>
<tr>
<th>Summary of Differences</th>
<th>2015 PSE Study Model (with U.S.-only dataset)</th>
<th>2015 PSE Study Model (with Ontario plus U.S. dataset)</th>
<th>4th Generation OEB Model</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>The 2018 PSE Study used additional or improved variables that were not present in the previous studies.</td>
<td>Variables in 2018 PSE study but not in 2015 PSE Study (or improved):</td>
<td>Variables in 2018 PSE study but not in 2015 PSE Study (or improved):</td>
<td>Variables in 2018 PSE study but not in 4th Generation OEB Study:</td>
<td>2018 PSE Study variables are improved compared to the previous studies. PSE made significant research efforts to upgrade the urban variable to address one of the three Board concerns with the 2015 PSE Study. Providing a continuous variable (as opposed to a binary “urban/not urban” variable) addresses Board comments, and more than 40 utilities in the 2018 sample had some areas classified as “urban”. The %AMI variable enables the cost impacts of installing smart meters to be adjusted for. Relative to the OEB Study and the 2015 PSE Study, beyond the congested urban and %AMI variables, variables such as forestation, elevation, and percent undergrounding have been important additions as well.</td>
</tr>
<tr>
<td>Improved peak demand variable</td>
<td>Improved congested urban variable</td>
<td>Improved congested urban variable</td>
<td>% Congested urban</td>
<td></td>
</tr>
<tr>
<td>Improved congested urban variable</td>
<td>Forestation variable</td>
<td>Forestation variable</td>
<td>% Forestation</td>
<td></td>
</tr>
<tr>
<td>%AMI meters</td>
<td>Elevation variable</td>
<td>Elevation variable</td>
<td>% AMI meters</td>
<td></td>
</tr>
<tr>
<td>%UG*%CU</td>
<td>% Underground variable</td>
<td>% Underground variable</td>
<td>% Underground variable</td>
<td></td>
</tr>
<tr>
<td>Ontario binary variable</td>
<td>%UG*%CU</td>
<td>Ontario binary variable</td>
<td>%UG*%CU</td>
<td></td>
</tr>
<tr>
<td>Ontario binary variable</td>
<td>Improved peak demand variable</td>
<td>Improved peak demand variable</td>
<td>% Electric customers served</td>
<td></td>
</tr>
<tr>
<td>Summary of Differences</td>
<td>2015 PSE Study Model (with U.S.-only dataset)</td>
<td>2015 PSE Study Model (with Ontario plus U.S. dataset)</td>
<td>4th Generation OEB Model</td>
<td>Explanation</td>
</tr>
<tr>
<td>---------------------------------------------------------------------</td>
<td>----------------------------------------------</td>
<td>-------------------------------------------------------</td>
<td>--------------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Variables not included in current study, but included in previous studies</td>
<td>Variables in 2015 PSE Study, but not in 2018 PSE Study:</td>
<td>Variables in 2015 PSE Study, but not in 2018 PSE Study:</td>
<td>Variables in 4th Generation OEB Study, but not in 2018 PSE Study:</td>
<td>The % residential variable is not needed in the current study, since that variable is a proxy for load factor—but there is already a direct measure of peak demand in the 2018 PSE Study model. The % distribution variable did not warrant inclusion into the 2018 model, due to the coefficient being incorrectly signed. A measure of density was considered but the coefficient sign was not statistically significant. Regarding the OEB Study, PSE does not believe there is an adequate theoretical basis for including retail deliveries. From an engineering perspective, distribution total costs are driven by the customer connections and the capacity the system needs to be built to meet. While deliveries will impact generation costs, we see no theoretical basis for volumes impacting distribution costs. The customer growth variable was considered but consistent data could not be constructed for the Ontario distributors (including Toronto Hydro) for years prior to 2002 to enable the variable to be consistently calculated.</td>
</tr>
<tr>
<td></td>
<td>% Residential Deliveries</td>
<td>% Residential</td>
<td>Retail Deliveries</td>
<td></td>
</tr>
<tr>
<td></td>
<td>% Distribution</td>
<td>Density variable</td>
<td>Average Line Length</td>
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<tr>
<td></td>
<td></td>
<td>% Distribution</td>
<td>Customer Growth</td>
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</tr>
<tr>
<td>Dataset differences relative to current study</td>
<td>Current study includes six Ontario distributors, whereas 2015 U.S. study only included U.S. utilities</td>
<td>Current study included six Ontario distributors rather than the entire Ontario industry. Please see the response to 1B-Staff-35, part c for an explanation on why PSE only included six Ontario distributors.</td>
<td>Current study includes U.S. distributors and six Ontario distributors. OEB Study includes all Ontario distributors, but no U.S. distributors.</td>
<td>PSE believes that including U.S. distributors is essential when benchmarking an outlier utility like Toronto Hydro. Toronto Hydro is an extreme outlier in an Ontario-only dataset in terms of both size and urban characteristics. We do think that combining the Ontario and U.S. datasets is appropriate as long as variables can be consistently defined and the study does not sacrifice key variables in the process. This is why we added six Ontario distributors to the U.S. dataset for the current study.</td>
</tr>
<tr>
<td>Total cost definition</td>
<td>HV expenses added to Toronto Hydro and Ontario distributors in current study to assure cost consistency with U.S. sample; CSI expenses excluded for all utilities to address a key concern noted in the 2015 Board Decision; bad debt expenses excluded to match OEB Study cost definition.</td>
<td>Same as column to the left. HV expenses added to Toronto Hydro and Ontario distributors in current study; CSI expenses excluded for all utilities; bad debt expenses excluded.</td>
<td>Contributions in aid of construction (CIAC) not included for current study to be consistent with U.S. data, but are included for OEB Study. High voltage expenses included in current study to be consistent with U.S. data, but are not included for OEB Study. CSI expenses are not included in current study to be consistent with U.S. data and address a key concern mentioned in 2015 Board Decision, but are included for OEB Study.</td>
<td>This cost definition is consistent throughout the sample. Including HV expenses was necessary to accomplish this. The exclusion of CSI expenses was to address one of the Board’s three benchmarking concerns from 2015. PSE’s approach is now the same as that of Board Staff’s consultant in this regard. Bad debts are excluded, consistent with the 4th Generation benchmarking cost definition.</td>
</tr>
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<td>-------------</td>
</tr>
<tr>
<td><strong>Model specification</strong></td>
<td>Total cost is divided by input price index before estimation, rather than having a system of equations. Quadratics included for the business conditions.</td>
<td>Same as previous column. Total cost is divided by input price index before estimation, rather than having a system of equations. Quadratics included for the business conditions.</td>
<td>Total cost is divided by input price index before estimation, rather than having a system of equations. Quadratics included for the business conditions.</td>
<td>No material impact is expected from dividing total cost by the input price index. The change was made to facilitate research efficiency, move towards simplicity, and be more transparent in the econometric equation. Quadratic interactions were included for the business conditions to include the curvature of the impacts of each variable.</td>
</tr>
<tr>
<td><strong>Asset price inflation projections and input price inflation</strong></td>
<td>PSE uses a Conference Board of Canada (CBoC) projection for asset price inflation in the current study, rather than the historical growth rate in the Handy-Whitman indexes. PSE made the change to using the CBoC projections to address a concern noted in the 2015 Board Decision. The current study matches the assumption used by Board Staff’s consultant in their research for Oshawa PUC. PSE used U.S. indexes for the input price inflation, with a Canadian PPP adjustment for Ontario distributors.</td>
<td>Same as prior column. PSE uses a Conference Board of Canada projection for asset price inflation, rather than the historical growth rate in the Handy-Whitman indexes. PSE used U.S. indexes for the input price inflation, with a Canadian PPP adjustment for Ontario distributors.</td>
<td>No asset price inflation projections were used for OEB Study, since all data is historical. The OEB Study used Canadian GDP-IPI, AWE, and EUCPI for inflation projections, whereas current study includes mostly U.S. distributors, so the Ontario distributors have a Canadian PPP adjustment to the inflation projections.</td>
<td>This change was made to address one of the three main Board concerns with the 2015 benchmarking research. Determining an accurate inflation forecast is difficult; however, it is our opinion that our current approach is at the lower bound of appropriate inflation estimates and should alleviate the Board’s concerns in this area. The choice of the input price inflation measures (using U.S. historical indexes with a PPP adjustment) will likely have a small impact on the results.</td>
</tr>
</tbody>
</table>
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 21:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 3

SEC is interested in understanding how the current PSE cost benchmarking methodology compares with the OEB’s approved cost benchmarking methodology. To assist in this, please apply the current PSE cost benchmarking methodology to each of the ten largest electricity distributors in Ontario, including Toronto Hydro, for each of the years 2014-2017, and compare the results to the results of the OEB’s approved cost benchmarking methodology for those same distributors for the same years. Please ensure that the comparison includes each of the six utilities PSE added to its dataset individually, and not aggregated as Alectra.

RESPONSE (PREPARED BY PSE):

Expansion of the sample to include the top ten Ontario distributors, and adding an additional year to the sample, would require a substantial amount of work and take a significant amount of time. PSE does not currently have all of the necessary data for these 10 distributors and does not know whether all such data would be readily available. Data on items such as wage levels would need to be gathered. This task therefore could not be completed in the time allotted, and also would have limited (if any) additional value. The requested results using the current PSE methodology can be provided for the seven Ontario distributors already included in the dataset for the years 2014-2016, and these results can be compared to the OEB cost benchmarking results for those years.

Panel: Expert Witnesses
The results and comparison below address SEC’s interest in understanding how the current PSE cost benchmarking methodology compares with the OEB’s benchmarking methodology. As can be seen by the table below, the two benchmarking methodologies produce somewhat similar results for a number of the distributors, with the exceptions being Toronto Hydro and Kitchner-Wilmont. Enersource, Horizon Utilities, London Hydro, and Hydro Ottawa would all remain in the same stretch factor cohort group with either approach. EnWin would move one group higher from 0.3% to 0.45%. Kitchner-Wilmont would move up two groups higher (from 0.15% to 0.45%), and Toronto Hydro would move down three groups (from 0.60% to 0.15%). The similarities in results for a number of the smaller Ontario distributors, and the differences in results for Toronto Hydro, are explained by a number of reasons, including the following three main ones: (i) the methodology used by the OEB has no urban congestion variable, and the smaller Ontario distributors do not have much of an urban congestion challenge (in contrast to Toronto Hydro); (ii) the sample used by the OEB methodology consists of Ontario distributors, all, except for Hydro One, are smaller than Toronto Hydro – that methodology is therefore more accurate for other Ontario distributors (i.e. not Toronto Hydro); and (iii) the methodology used by the OEB assumes that the costs of capital construction are the same across the province, when in fact, these costs are much higher in Toronto compared to other smaller places in Ontario.

Given that Toronto Hydro’s PSE-projected benchmarking scores converge to the 0.30% stretch factor group during the CIR period (assuming full funding of the spending amounts), PSE is recommending a 0.30% stretch factor.
## Table 1: Comparison of Benchmarking Scores

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Toronto Hydro</td>
<td>-22.8</td>
<td>+49.9</td>
<td>-21.4</td>
<td>+51.5</td>
<td>-18.3</td>
<td>+52.3</td>
<td>-16.0</td>
<td>+52.9</td>
</tr>
<tr>
<td>Enersource</td>
<td>+2.4</td>
<td>-13.9</td>
<td>+9.1</td>
<td>-8.2</td>
<td>+10.4</td>
<td>-6.8</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>EnWin</td>
<td>+15.7</td>
<td>+10.9</td>
<td>+16.4</td>
<td>+9.9</td>
<td>+15.4</td>
<td>+9.6</td>
<td>NA</td>
<td>+5.3</td>
</tr>
<tr>
<td>Horizon Utilities</td>
<td>-6.0</td>
<td>-5.3</td>
<td>-2.9</td>
<td>-2.1</td>
<td>-4.1</td>
<td>-3.9</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Kitchner-Wilmont</td>
<td>+14.0</td>
<td>-19.0</td>
<td>+11.5</td>
<td>-22.3</td>
<td>+12.0</td>
<td>-20.4</td>
<td>NA</td>
<td>-19.9</td>
</tr>
<tr>
<td>London Hydro</td>
<td>-6.6</td>
<td>-12.8</td>
<td>-3.8</td>
<td>-9.9</td>
<td>-2.0</td>
<td>-8.0</td>
<td>NA</td>
<td>-7.1</td>
</tr>
<tr>
<td>Hydro Ottawa</td>
<td>+10.3</td>
<td>+12.7</td>
<td>+13.3</td>
<td>+15.2</td>
<td>+12.9</td>
<td>+15.7</td>
<td>NA</td>
<td>+16.5</td>
</tr>
</tbody>
</table>
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 22:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 6

SEC is interested in understanding the impact of the %CU variable and the %UG*%CU variable on the results in Table 1. Please re-specify and rerun the PSE model without those variables, and provide the results in the same form as Table 1.

RESPONSE (PREPARED BY PSE):
This request is to create and run a different model that is not PSE’s model, and is a fundamentally different approach. Excluding these variables, and creating a model without them, is not a proper or robust approach and would produce misleading results in portraying Toronto Hydro’s cost performance. Serving a congested urban core and constructing underground power lines in congested urban areas significantly increases a distributor’s total costs. This fact has been confirmed both empirically and through engineering analysis. Excluding these variables from the model would be ignoring important and statistically significant cost drivers that are significant at a 99.9% confidence level. Excluding variables that have both strong engineering and statistical support will produce misleading results that suffer from omitted variable bias. See also the responses to 1B-SEC-28 and 1B-Staff-32 (b) in respect of the importance of these variables.
INTERROGATORY 23:

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

SEC is seeking to understand how Toronto Hydro’s cost performance compares to the benchmark over different time periods. To this end, we have prepared the following spreadsheet that expands Table 1. (A live version of the spreadsheet is included with the filing of these interrogatories)

<table>
<thead>
<tr>
<th>Year</th>
<th>Actual</th>
<th>Increase</th>
<th>Benchmark</th>
<th>Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>$436,128</td>
<td></td>
<td>$641,275</td>
<td></td>
</tr>
<tr>
<td>2006</td>
<td>$450,686</td>
<td>3.34%</td>
<td>$681,212</td>
<td>6.23%</td>
</tr>
<tr>
<td>2007</td>
<td>$502,433</td>
<td>11.48%</td>
<td>$744,486</td>
<td>9.29%</td>
</tr>
<tr>
<td>2008</td>
<td>$556,429</td>
<td>10.75%</td>
<td>$813,528</td>
<td>9.27%</td>
</tr>
<tr>
<td>2009</td>
<td>$595,932</td>
<td>7.10%</td>
<td>$852,775</td>
<td>4.82%</td>
</tr>
<tr>
<td>2010</td>
<td>$647,456</td>
<td>8.65%</td>
<td>$882,130</td>
<td>3.44%</td>
</tr>
<tr>
<td>2011</td>
<td>$710,544</td>
<td>9.74%</td>
<td>$912,729</td>
<td>3.47%</td>
</tr>
<tr>
<td>2012</td>
<td>$691,388</td>
<td>-2.70%</td>
<td>$910,814</td>
<td>-0.21%</td>
</tr>
<tr>
<td>2013</td>
<td>$727,152</td>
<td>5.17%</td>
<td>$925,488</td>
<td>1.61%</td>
</tr>
<tr>
<td>2014</td>
<td>$777,414</td>
<td>6.91%</td>
<td>$976,095</td>
<td>5.47%</td>
</tr>
<tr>
<td>2015</td>
<td>$826,886</td>
<td>6.36%</td>
<td>$1,024,030</td>
<td>4.91%</td>
</tr>
<tr>
<td>2016</td>
<td>$861,394</td>
<td>4.17%</td>
<td>$1,034,492</td>
<td>1.02%</td>
</tr>
<tr>
<td>2017</td>
<td>$904,560</td>
<td>5.01%</td>
<td>$1,061,642</td>
<td>2.62%</td>
</tr>
<tr>
<td>2018</td>
<td>$964,885</td>
<td>6.67%</td>
<td>$1,095,430</td>
<td>3.18%</td>
</tr>
<tr>
<td>2019</td>
<td>$999,492</td>
<td>3.59%</td>
<td>$1,122,407</td>
<td>2.46%</td>
</tr>
<tr>
<td>2020</td>
<td>$1,044,567</td>
<td>4.51%</td>
<td>$1,148,601</td>
<td>2.33%</td>
</tr>
<tr>
<td>2021</td>
<td>$1,085,324</td>
<td>3.90%</td>
<td>$1,174,549</td>
<td>2.26%</td>
</tr>
<tr>
<td>2022</td>
<td>$1,134,689</td>
<td>4.55%</td>
<td>$1,201,662</td>
<td>2.31%</td>
</tr>
<tr>
<td>2023</td>
<td>$1,180,820</td>
<td>4.07%</td>
<td>$1,229,463</td>
<td>2.31%</td>
</tr>
<tr>
<td>2024</td>
<td>$1,225,282</td>
<td>3.77%</td>
<td>$1,257,907</td>
<td>2.31%</td>
</tr>
</tbody>
</table>

Total 19 Year Increase: 180.95%  96.16%
CAGR - 19 years: 5.59%  3.61%
Increase from 2017: 35.46%  18.49%
CAGR - 7 years: 4.43%  2.45%
With respect to Table 1 and the above spreadsheet:

a) Please confirm that the calculations and results shown above are correct.

b) Please add a column to the above table showing the increase in outputs assumed for each year in the expected costs. Please confirm that the same increase in outputs has been assumed for each year in the forecast Toronto Hydro costs. Please provide the expected costs for the period 2020 to 2024 using the PSE model if the outputs are assumed to remain at 2019 levels.

c) Please reconcile, mathematically, the rates of increase for Toronto Hydro on the above table with the rates of increase of the CPCI proposed in Ex.1B/4/1, p. 13, Table 5.

d) Please confirm that, in seventeen of the nineteen years, Toronto Hydro’s actual cost increases were higher than the PSE benchmark.

e) Please confirm that, for each of the years in the CIR period, Toronto Hydro proposes to increase its costs at a rate in excess of the benchmark set by its own expert, and that on average it proposes to increase its costs from 2017 to 2024 by almost double the PSE benchmark increase.

f) Please explain why, in the expert’s opinion, the expected costs for a distributor like Toronto Hydro were expected to increase over the nineteen years in the model period by more than twice the rate of inflation. What underlying or systemic factors existed during this period, in the expert’s opinion, that resulted in Toronto Hydro’s costs rising at a much greater rate than the costs of other
businesses in the Canadian economy?

g) Please provide a detailed explanation of any investigations carried out by the expert to determine the reasons why Toronto Hydro’s actual costs in 2005 were only 64.4% of the expected costs for that year using the current PSE cost benchmarking methodology.

h) Please confirm that, if the Board only allowed the rates (and therefore costs) of Toronto Hydro to increase at the same rate as the PSE benchmark from 2018 to 2024, Toronto Hydro’s total costs for the five year CIR period would be $548 million less than those proposed in the current application, and costs (and therefore rates) in 2024 would be $153 million (12.53%) less than proposed by Toronto Hydro.

RESPONSE (PREPARED BY PSE):

a) We can confirm that the actual and benchmark costs in the table match those in the 2018 PSE Study and that the arithmetic percentage increases are calculated correctly. However, in displaying the percentage increases, the conventional approach is to show these logarithmically rather than arithmetically. Please see page 27 of the PSE report for an example of how to calculate a logarithmic difference. The arithmetic approach used in SEC’s expanded table requires a decision on which denominator to use in showing the change between the two numbers. In contrast, the logarithmic approach will produce the same answer regardless of that choice. In the table prepared by SEC, the arithmetic approach is used with the prior year as the chosen denominator. This will tend to exaggerate the percentage increase, due to the prior
year typically being the lower value. The table below shows the logarithmic percentage differences.

PSE Expanded Table 1 (Logarithmic)

<table>
<thead>
<tr>
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<td>$1,225,282</td>
<td>3.7%</td>
<td>$1,257,907</td>
<td>2.3%</td>
</tr>
</tbody>
</table>

Total 19 Year Increase 103.3% 67.4%
CAGR - 19 years 5.44% 3.55%
Increase from 2017 30.35% 16.96%
CAGR - 7 years 4.34% 2.42%

b) The table below provides Toronto Hydro’s outputs, which are the number of customers and maximum peak demand. The percentage increase is calculated arithmetically, to match the calculations found in the table in the question. However,
as we stated in our answer to the previous question, the logarithmic method is preferred. The increase in outputs is based on projections provided to PSE by Toronto Hydro. The forecasts in outputs are the inputs for determining the benchmark levels of Toronto Hydro’s costs. The columns added by PSE are shaded in green.

Table 1 with THESL Outputs

<table>
<thead>
<tr>
<th>Year</th>
<th>Actual</th>
<th>Increase</th>
<th>Benchmark</th>
<th>Increase</th>
<th>Number of Customers</th>
<th>Increase</th>
<th>Maximum Peak Demand</th>
<th>Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>$436,128</td>
<td>3.34%</td>
<td>$641,275</td>
<td>21.9%</td>
<td>676,678</td>
<td>5,005</td>
<td>5,018</td>
<td>0.26%</td>
</tr>
<tr>
<td>2006</td>
<td>$450,686</td>
<td>3.34%</td>
<td>$681,212</td>
<td>23.5%</td>
<td>678,106</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2007</td>
<td>$502,433</td>
<td>11.48%</td>
<td>$744,486</td>
<td>23.9%</td>
<td>679,913</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td>$556,429</td>
<td>10.75%</td>
<td>$813,528</td>
<td>23.3%</td>
<td>684,145</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>$595,932</td>
<td>7.10%</td>
<td>$852,775</td>
<td>12.0%</td>
<td>690,243</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>$647,456</td>
<td>8.65%</td>
<td>$882,130</td>
<td>4.4%</td>
<td>700,386</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td>$710,544</td>
<td>9.74%</td>
<td>$912,729</td>
<td>3.7%</td>
<td>709,323</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>$691,388</td>
<td>3.17%</td>
<td>$910,814</td>
<td>3.4%</td>
<td>718,661</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td>$727,152</td>
<td>5.17%</td>
<td>$925,488</td>
<td>3.8%</td>
<td>734,576</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>$777,414</td>
<td>5.91%</td>
<td>$976,095</td>
<td>4.8%</td>
<td>744,252</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>$826,886</td>
<td>5.36%</td>
<td>$1,024,030</td>
<td>5.1%</td>
<td>758,311</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>$861,394</td>
<td>3.47%</td>
<td>$1,034,492</td>
<td>4.4%</td>
<td>761,920</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>$904,560</td>
<td>5.01%</td>
<td>$1,061,642</td>
<td>4.5%</td>
<td>768,126</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>$964,885</td>
<td>5.47%</td>
<td>$1,095,430</td>
<td>4.1%</td>
<td>773,961</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td>$999,492</td>
<td>3.59%</td>
<td>$1,122,407</td>
<td>3.3%</td>
<td>779,962</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td>$1,044,567</td>
<td>4.51%</td>
<td>$1,148,601</td>
<td>2.3%</td>
<td>787,303</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2021</td>
<td>$1,085,324</td>
<td>3.90%</td>
<td>$1,174,549</td>
<td>2.5%</td>
<td>794,105</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2022</td>
<td>$1,134,689</td>
<td>4.55%</td>
<td>$1,201,662</td>
<td>2.3%</td>
<td>801,729</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2023</td>
<td>$1,180,820</td>
<td>4.07%</td>
<td>$1,229,463</td>
<td>2.3%</td>
<td>809,403</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
<tr>
<td>2024</td>
<td>$1,225,282</td>
<td>3.77%</td>
<td>$1,257,907</td>
<td>2.3%</td>
<td>817,078</td>
<td>5,018</td>
<td>0.26%</td>
<td></td>
</tr>
</tbody>
</table>

Total 19 Year Increase | 180.95% | 96.16% | 20.75% | 0.26%
CAGR - 19 years | 5.69% | 3.61% | 1.09% | 0.01%
Increase from 2017 | 35.46% | 18.49% | 6.37% | 0.00%
CAGR - 7 years | 4.43% | 2.45% | 0.91% | 0.00%

If the Toronto Hydro system stayed at its projected 2019 output values for both customers and maximum peak demand, the benchmark costs for the 2020 to 2024 period would be as indicated in the column shaded green in the following table. Note: the maximum peak demand is already projected to remain flat in the PSE report.
Table 1 with THESL Outputs (Outputs stay at 2019 Level)

<table>
<thead>
<tr>
<th>Year</th>
<th>Actual</th>
<th>Increase</th>
<th>Benchmark</th>
<th>Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>$436,128</td>
<td>3.34%</td>
<td>$641,275</td>
<td>6.23%</td>
</tr>
<tr>
<td>2006</td>
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<td>7.10%</td>
<td>$852,775</td>
<td>4.82%</td>
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<td>8.65%</td>
<td>$882,130</td>
<td>3.44%</td>
</tr>
<tr>
<td>2011</td>
<td>$710,544</td>
<td>9.74%</td>
<td>$912,729</td>
<td>3.47%</td>
</tr>
<tr>
<td>2012</td>
<td>$691,388</td>
<td>-2.70%</td>
<td>$910,814</td>
<td>-0.21%</td>
</tr>
<tr>
<td>2013</td>
<td>$727,152</td>
<td>5.17%</td>
<td>$925,488</td>
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<td>$1,257,907</td>
<td>2.31%</td>
</tr>
</tbody>
</table>

Total 19 Year Increase 180.95% 96.16%
CAGR - 19 years 5.59% 3.61%
Increase from 2017 35.46% 18.49%
CAGR - 7 years 4.43% 2.45%

1) c) We are unsure what the question is requesting.

2) d) Confirmed. Given Toronto Hydro’s low-cost position at the beginning of the sample, with actual costs being $200 million below benchmark costs, we would expect convergence to the benchmark value. This would make it likely there would be more years where actual cost increases exceed benchmark cost increases.
e) The PSE benchmarking study makes assumptions and normalizations in calculating the actual costs reported in the study. The cost levels reported by PSE are not equivalent to the revenue requirement and cost levels being requested by Toronto Hydro. We can confirm that the actual costs shown for Toronto Hydro in Table 1 increase at a rate in excess of the benchmark calculated by PSE. This is to be expected for a utility that is requesting a C factor to meet its capital needs. By our calculations, the increase is not double (or near double) the PSE benchmark increase. The PSE benchmark increases by $196 million from 2017 to 2024. Toronto Hydro’s actual (projected) total costs increase by $320 million during that same period.

f) The expected costs (benchmark costs) increased by about 3.5% annually during the full sample period. There are two primary reasons this is higher than the general rate of inflation.

The first is that Toronto Hydro’s system added customers during this period. Since the 3.5% is measuring costs, and customers are the primary driver of costs, we would expect the growth rate in the number of customers to increase a utility’s costs above the industry input price inflation. In Toronto Hydro’s case, customers grew by 1.1% during the sample period. The second primary reason is that the electric distribution industry has experienced industry-specific input price inflation at a level higher than the general economy. This is due to the different input components of the electric distribution industry relative to the composition of the economy at large. An example of this is that the price of copper has increased by an annual growth rate of approximately 4.4% from 2005 to the present day. Capturing these differences is why using an asset price inflation index that is specific to the electric distribution industry is important.
g) There were no investigations carried out by PSE to determine the reasons why Toronto Hydro’s actual costs in 2005 were only 64.4% of the expected costs for that year. Toronto Hydro in 2005 and onward has consistently been below its cost benchmarks with convergence towards the benchmarks.

h) The PSE benchmarking study makes assumptions and normalizations in calculating the actual costs reported in the study. The cost levels reported by PSE are not equivalent to the revenue requirement and cost levels being requested by Toronto Hydro. We can confirm that in this hypothetical scenario posed by this question, the total costs in Table 1, if summed for all five CIR years, would be $548 million lower if the benchmark increase rate was used. Such a result would ignore Toronto Hydro’s capital needs or imply that the additional capital needs identified by the company throughout its proposal are not reasonable or justified. This average is just under $110 million per year. In 2024, the difference would be $153 million.

An additional point is necessary. If the proposed capital spending plan were in fact significantly reduced by a Board decision, then the projected actual total costs of Toronto Hydro would also be significantly reduced. This would likely push Toronto Hydro to the 0.15% stretch factor cohort during the CIR period. Therefore, if the capital spending program proposed by Toronto Hydro were significantly reduced (in this hypothetical scenario), PSE’s recommended stretch factor would likely become 0.15% rather than 0.3%.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 24:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 13

Please advise what other material factors, besides “response to outages”, are captured by the CAIDI metric.

RESPONSE (PREPARED BY PSE):
Examples include types and complexity of outages, as well as traffic congestion and location of outages.

Panel: Expert Witnesses
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 25:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 15, 27

SEC is seeking to have a better understanding of the choices of business condition variables used in the PSE cost benchmarking model.

a) Please provide the full list of business condition variables considered by PSE in developing its econometric cost benchmarking model.

b) For each variable not used in the final model, please explain the reasons for that decision.

RESPONSE:

a) The business condition variables considered by PSE for inclusion, but which were not included in the model were:

- Density variable (Sqkm of service territory per customer)
- Extreme weather variable (sum of annual hourly degrees above 30 degrees Celsius or below negative 15 degrees Celsius)
- Wind variable (sum of knots above 10 knots in each hour of the year)
- System growth variable (10-year change in the number of customers)
- Pole loading variable for distribution
- Percent distribution

Panel: Expert Witnesses
b) The variables and the reasons for not including them in the model are summarized below. The selection criteria used by PSE for inclusion into the model is that the first order term of the variable must have the correct sign (i.e. be aligned with a priori theory of its cost impact), be statistically significant at a 90% confidence level, and have available data that is plausible.

- Density variable (Sqkm of service territory per customer)
  - **Reason for exclusion:** Variable was correctly signed but not statistically significant.

- Extreme weather variable
  - **Reason for exclusion:** Did not have weather data for the Ontario distributors included in the sample. This variable did come in properly for a U.S.-only dataset.

- Wind variable
  - **Reason for exclusion:** Did not have weather data for the Ontario distributors included in the sample, and incorrect sign with U.S.-only dataset.

- System growth variable (10-year change in the number of customers)
  - **Reason for exclusion:** Didn’t have full 10-year growth in customers for Ontario distributors. This variable did come in properly for a U.S.-only dataset.

- Pole loading variable for distribution
  - **Reason for exclusion:** Didn’t have this variable processed for the Ontario distributors, and incorrect sign with U.S.-only dataset.

- Percent Distribution
  - **Reason for exclusion:** Incorrect sign that did not align with theory.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 26:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 17

SEC is seeking to understand the impact of the cost adjustments made by PSE. Please provide a table showing the amounts of each of the high-voltage expenses, CIAC, bad debt expenses, and CSI expenses excluded in the last year of the historical data period from each of the seven Ontario distributors, including Toronto Hydro, included in the expert’s dataset. For Toronto Hydro, please also advise the amounts of each of those categories excluded for each of the years 2020-2024.

RESPONSE (PREPARED BY PSE):

The table below provides the breakdowns for the categories. HV capital additions are not available for the non-Toronto Hydro distributors in 2016; the plant addition data already includes HV additions, so we did not need to have the breakdown to include those expenses. Also, there are no CIAC projections for Toronto Hydro for the years 2020 to 2024. The additions provided to PSE from the company did not include CIAC. Costs are in millions of Canadian dollars. The CIAC additions for the Ontario distributors are estimated based on the ratio of gross plant in service with CIAC and without CIAC in 2011, since additions reported on the RRR include CIAC.
### Table 1: Breakdown of Categories

<table>
<thead>
<tr>
<th>Distributor</th>
<th>Year</th>
<th>HV OM&amp;A Expenses</th>
<th>HV Capital Additions</th>
<th>CIAC Additions</th>
<th>Bad Debt Expenses</th>
<th>CSI Expenses</th>
</tr>
</thead>
<tbody>
<tr>
<td>Toronto Hydro</td>
<td>2016</td>
<td>0.0</td>
<td>0.0</td>
<td>32.8</td>
<td>5.2</td>
<td>2.5</td>
</tr>
<tr>
<td>Toronto Hydro</td>
<td>2020</td>
<td>0.0</td>
<td>46.2</td>
<td>NA</td>
<td>7.1</td>
<td>2.8</td>
</tr>
<tr>
<td>Toronto Hydro</td>
<td>2021</td>
<td>0.0</td>
<td>4.0</td>
<td>NA</td>
<td>7.2</td>
<td>2.8</td>
</tr>
<tr>
<td>Toronto Hydro</td>
<td>2022</td>
<td>0.0</td>
<td>32.9</td>
<td>NA</td>
<td>7.3</td>
<td>2.9</td>
</tr>
<tr>
<td>Toronto Hydro</td>
<td>2023</td>
<td>0.0</td>
<td>73.7</td>
<td>NA</td>
<td>7.5</td>
<td>2.9</td>
</tr>
<tr>
<td>Toronto Hydro</td>
<td>2024</td>
<td>0.0</td>
<td>45.7</td>
<td>NA</td>
<td>7.6</td>
<td>3.0</td>
</tr>
<tr>
<td>Enersource</td>
<td>2016</td>
<td>0.0</td>
<td>NA</td>
<td>0.1</td>
<td>1.0</td>
<td>0.0</td>
</tr>
<tr>
<td>EnWin</td>
<td>2016</td>
<td>0.2</td>
<td>NA</td>
<td>0.8</td>
<td>0.9</td>
<td>0.1</td>
</tr>
<tr>
<td>Horizon Utilities</td>
<td>2016</td>
<td>0.0</td>
<td>NA</td>
<td>2.7</td>
<td>1.1</td>
<td>0.0</td>
</tr>
<tr>
<td>Kitchner-Wilmont</td>
<td>2016</td>
<td>1.7</td>
<td>NA</td>
<td>3.8</td>
<td>0.1</td>
<td>0.3</td>
</tr>
<tr>
<td>London Hydro</td>
<td>2016</td>
<td>0.0</td>
<td>NA</td>
<td>3.1</td>
<td>0.7</td>
<td>0.2</td>
</tr>
<tr>
<td>Hydro Ottawa</td>
<td>2016</td>
<td>1.3</td>
<td>NA</td>
<td>20.9</td>
<td>1.4</td>
<td>5.0</td>
</tr>
</tbody>
</table>
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 27:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 18, 21

With respect to input prices:

a) Please explain why the expert did not use the same measure of input prices that the OEB uses to calculate inflation.

b) Please provide tables for each of the seven Ontario distributors showing the changes in OM&A inputs assumed by PSE, and a breakdown of each such assumption.

c) Please reconcile the resulting changes in assumed input prices with the assumed 1.2% inflation factor used by Toronto Hydro in the Application (e.g. Table 5).

RESPONSE (PREPARED BY PSE):

a) Important measures of input prices for a benchmarking study are the input price levelizations used to adjust for the fact that items like wages and construction costs vary from city to city and region to region. For example, salaries and wages will tend to be significantly higher in New York City than in Madison, Wisconsin. These differences need to be properly adjusted to create a level playing field for the entire sample within the benchmarking study.

A key difference in the PSE Study versus the OEB Study is that the PSE adjusts for the construction cost differences between the utilities using RSMeans construction cost
indexes by city. A city like Toronto is likely to have higher construction costs than a
city like London, ON. The OEB Study assumes all the Ontario distributors have equal
capital prices. This will tend to unfairly harm the benchmarking scores of utilities
serving higher cost regions, such as Toronto Hydro. PSE has corrected for this
omission in our study.

PSE also updated our labour levelizations using 2010 Canadian census data and U.S.
Bureau of Labor Statistics (BLS) data. We are unsure of how the OEB Study specifically
adjusted for labour input prices but we use the updated Canadian Census on over 100
job occupations to create a composite wage level that matches the composition of an
electric utility. We used Bureau of Labor Statistic (BLS) data to match those same
occupations for the U.S. sample.

After the levelizations are set, growth rates (inflation) are applied to move the
levelized input prices from year to year. PSE used Handy-Whitman indexes for electric
distribution in constructing the capital input price. The OEB Study methodology uses
the Canadian Electric Utility Construction Price Index (EUCPI). However, the EUCPI has
been discontinued as of 2014. Further, PSE is of the opinion that it is more
appropriate to use a construction cost inflation index that is specific to the electric
distribution industry, rather than other possibilities that are generalized to either the
electric utility industry or just the utility industry at large. For the Ontario distributors,
we did translate the Handy-Whitman electric distribution indexes into Canadian
currency using the purchasing power parity indexes (PPPs) for Canada. Similarly, PSE
used U.S. employment cost indexes and a GDP price index to inflate OM&A related
costs, but adjusted these inflation measures using the Canadian PPP for the Ontario
distributors.
b) The table below illustrates the input price levels and trends for the Ontario distributors including in the PSE sample. As can be seen by the fact the growth rates are all the same, we used identical input price inflation assumptions for all seven distributors. The differences show up in the levelizations of labour and capital. Toronto Hydro and Enersouce have the same input prices in all years because we mapped each one to the city of Toronto to determine the levels of salaries and wages and capital construction prices. The other utilities were mapped to their respective headquarter cities.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Toronto Hydro</td>
<td>90,563</td>
<td>3.0%</td>
<td>1.40</td>
<td>2.0%</td>
<td>13.38</td>
<td>4.0%</td>
</tr>
<tr>
<td>Enersource</td>
<td>90,563</td>
<td>3.0%</td>
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<td>2.0%</td>
<td>13.38</td>
<td>4.0%</td>
</tr>
<tr>
<td>Horizon Utilities</td>
<td>85,546</td>
<td>3.0%</td>
<td>1.40</td>
<td>2.0%</td>
<td>13.04</td>
<td>4.0%</td>
</tr>
<tr>
<td>London Hydro</td>
<td>81,346</td>
<td>3.0%</td>
<td>1.40</td>
<td>2.0%</td>
<td>12.85</td>
<td>4.0%</td>
</tr>
<tr>
<td>Kitchener-Wilmont</td>
<td>85,236</td>
<td>3.0%</td>
<td>1.40</td>
<td>2.0%</td>
<td>12.32</td>
<td>4.0%</td>
</tr>
<tr>
<td>Hydro Ottawa</td>
<td>91,495</td>
<td>3.0%</td>
<td>1.40</td>
<td>2.0%</td>
<td>12.95</td>
<td>4.0%</td>
</tr>
<tr>
<td>EnWin</td>
<td>87,251</td>
<td>3.0%</td>
<td>1.40</td>
<td>2.0%</td>
<td>12.20</td>
<td>4.0%</td>
</tr>
</tbody>
</table>

c) The input price inflation assumed by PSE is looking at the historic industry inflation for each year, whereas the 1.2% is the recent escalation factor. Further, the industry

Panel: Expert Witnesses
inflation has been higher than the inflation factor, primarily due to the 4.0% growth in
capital prices and the 3.0% growth in utility employment cost indexes. We would
expect the industry-specific inflation to be different from the more general indexes
used in the inflation factor. In a benchmarking study, all utilities receive the same or
similar treatment regarding inflation assumptions, and this assumption will likely have
a small impact on the relative scores or rankings of the individual utilities being
benchmarked. The inflation assumptions are important when benchmarking
projected data. PSE believes we have used estimates that are conservative in those
projections. For example, rather than continuing the 4.0% capital inflation rate, we
instead used a capital inflation assumption of 2.18% for 2020 to 2024. PSE stayed on
the lower bound of what we would consider reasonable estimates for asset price
inflation in order to help address one of the three Board concerns cited in the Board’s
2015 Decision.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 28:
Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 20

Please explain why the %CU variable and the %UG*%CU variable do not measure similar or related effects.

RESPONSE (PREPARED BY PSE):
The congested urban variable (%CU) measures the cost impact of serving a highly congested urban service territory. This has been shown both empirically and through engineering analysis to be a significant driver of a distributor’s total costs.

The underground variable (%UG*%CU) measures the important cost differences between undergrounding power lines in congested urban areas relative to non-congested urban areas. It will tend to be far less costly to underground lines in suburban and/or rural areas. In fact, in many areas, utilities are able to direct bury power lines, and overall costs can be reduced relative to constructing overhead power lines (see the negative coefficient value on the %UG variable). By including the %UG*%CU variable, the model can disaggregate the vast cost differences between undergrounding in rural/suburban areas versus undergrounding lines in congested urban areas.

The added flexibility of distinguishing between the differences this variable provides is important to accurately evaluating Toronto Hydro’s total cost performance, given their high percent undergrounding and high percentage of congested urban service territory. If this variable were excluded, undergrounding costs in the model would combine the low-
cost rural/suburban undergrounding with the much higher cost urban undergrounding making the model less precise and accurate.

PSE stated the importance of disaggregating the underground costs on p. 20 of the PSE report:

The percent underground multiplied by congested urban variable provides the interaction between the percent underground variable and the congested urban variable. Constructing underground lines in urban settings is far more costly than in more rural settings. For example, underground lines in rural settings can be “direct buried” without the need for concrete-enclosed banks and other capital infrastructure. We would expect a positive coefficient on the variable.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 29:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 22

SEC is seeking to understand how the change in the maximum peak demand variable impacts the model results.

a) Please provide a table showing the maximum peak demand of Toronto Hydro for each year from 2002 onwards using the 2015 methodology and using the current methodology, and explain each year that there is a difference.

b) Please confirm that the new methodology assumes that, even if demand declines, that never, over time, reduces the costs of an electricity distributor. If not confirmed, please explain.

RESPONSE (PREPARED BY PSE):

a) The maximum demand variable is defined the same as the capacity variable included in the 4th Generation OEB benchmarking model. The difference in the annual peak demand and maximum peak demand is due to the maximum peak demand variable measuring the highest peak demand variable from either the current year, or from all past years since 2002, whereas the annual peak demand measures only the current year.
Table 1: Annual and Maximum Peak Demand for Toronto Hydro

<table>
<thead>
<tr>
<th>Year</th>
<th>Annual Peak Demand</th>
<th>Maximum Peak Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>4,771</td>
<td>4,771</td>
</tr>
<tr>
<td>2003</td>
<td>4,821</td>
<td>4,821</td>
</tr>
<tr>
<td>2004</td>
<td>4,521</td>
<td>4,821</td>
</tr>
<tr>
<td>2005</td>
<td>5,005</td>
<td>5,005</td>
</tr>
<tr>
<td>2006</td>
<td>5,018</td>
<td>5,018</td>
</tr>
<tr>
<td>2007</td>
<td>4,788</td>
<td>5,018</td>
</tr>
<tr>
<td>2008</td>
<td>4,564</td>
<td>5,018</td>
</tr>
<tr>
<td>2009</td>
<td>4,607</td>
<td>5,018</td>
</tr>
<tr>
<td>2010</td>
<td>4,786</td>
<td>5,018</td>
</tr>
<tr>
<td>2011</td>
<td>4,919</td>
<td>5,018</td>
</tr>
<tr>
<td>2012</td>
<td>4,830</td>
<td>5,018</td>
</tr>
<tr>
<td>2013</td>
<td>4,915</td>
<td>5,018</td>
</tr>
<tr>
<td>2014</td>
<td>4,274</td>
<td>5,018</td>
</tr>
<tr>
<td>2015</td>
<td>4,404</td>
<td>5,018</td>
</tr>
<tr>
<td>2016</td>
<td>4,592</td>
<td>5,018</td>
</tr>
<tr>
<td>2017</td>
<td>4,260</td>
<td>5,018</td>
</tr>
<tr>
<td>2018</td>
<td>4,217</td>
<td>5,018</td>
</tr>
<tr>
<td>2019</td>
<td>4,195</td>
<td>5,018</td>
</tr>
<tr>
<td>2020</td>
<td>4,165</td>
<td>5,018</td>
</tr>
<tr>
<td>2021</td>
<td>4,119</td>
<td>5,018</td>
</tr>
<tr>
<td>2022</td>
<td>4,069</td>
<td>5,018</td>
</tr>
<tr>
<td>2023</td>
<td>4,038</td>
<td>5,018</td>
</tr>
<tr>
<td>2024</td>
<td>4,052</td>
<td>5,018</td>
</tr>
</tbody>
</table>

b) A distributor’s actual total costs can still increase or decrease based on the actual cost levels incurred. It is true that the definition of the variable prevents the maximum
peak demand variable from decreasing over time. This is because the distribution system is required to be built to meet maximum peak demands over a multi-year period and not just the annual peak demand in each year.
RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 30:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 48, 50

With respect to the %CU business condition variable:

a) Please confirm that, for the %CU business condition variable, out of the 90 utilities in the full dataset, only one had a higher %CU than Toronto Hydro, i.e. Consolidated Edison Co. of New York.

b) Please confirm that the average %CU of the dataset is 0.06%, or less than one-thirtieth of the Toronto Hydro percentage.

c) Please confirm that only three of the 90 utilities had a %CU over 0.50%, and all of the utilities except New York City has a %CU of less than one-third that of Toronto Hydro.

d) Please explain how the %CU variable can be accurate in light of the following statement by PSE:

“The further a utility’s operating conditions are from the mean, especially if there are few sample observations “near” the utility (i.e. close in magnitude), the less accurate the cost benchmark based on the model will be.”

RESPONSE (PREPARED BY PSE):

a) Confirmed.
b) According to the average of Table 13 in the PSE report the average %CU is 0.095%.

This is not less than one-thirtieth of the Toronto Hydro percentage of 1.88%.

c) Confirmed. The variable value of Consolidated Edison of New York City has the highest congested urban value and Toronto Hydro has the second highest congested urban service territory in the sample. This illustrates the importance of including the congested urban variable to adjust for the cost challenges and service territory reality.

There are also two Ontario utilities (Enersource Hydro Mississauga and EnWin) with a %CU above 0.45%. See also the response immediately below.

d) Toronto Hydro serves a service territory that contains a high amount of congested urban service territory. Their level of service territory that is highly urban does put them at the high end with respect to this variable, with only Consolidated Edison of New York City having a higher percentage. This external condition will increase total costs and this condition must be adjusted for to accurately benchmark Toronto Hydro.

The parameter estimate on the %CU variable measures the impact of urban congestion on total cost for the available sample. PSE also included a quadratic term on the variable that estimates the “curvature” of the cost impacts as the size of the variable increases or decreases. While it is true that the precision of the estimate decreases as the variable value departs from the sample mean, given the available sample the estimates still remain the best possible estimators for the cost challenges of serving a congested urban service territory.
INTERROGATORY 2:

Reference(s): Exhibit 1B (Updated)

a) Please explain what, if any changes are being proposed for the 2020-24 rate frameworks as compared to the currently approved rate adjustment formula.

RESPONSE:

As noted in Exhibit 1B, Tab 4, Schedule 1, page 1, lines 18-24, the proposed rate framework is the same as that approved by the OEB in EB-2014-0116, however Toronto Hydro is proposing a custom stretch factor value based on custom econometric benchmarking.
RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

INTERROGATORIES

INTERROGATORY 3:

Reference(s): Exhibit 1B, Tab 4, Schedule 1

a) How is the annual growth rate shown in Table 4 calculated?

RESPONSE:

a) As described in Exhibit 1B, Tab 4, Schedule 1, page 11, lines 10-15, Toronto Hydro calculates the g-factor as follows. First, Toronto Hydro determines the annual revenue through applying the forecast of its billing determinants (including loads and customers) for the 2021-2024 period to the proposed 2020 rates for each class. Second, Toronto Hydro calculates the compound average annual growth based on the determined above revenue.
RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 4:

Reference(s): Exhibit 1B, Tab 4, Schedule 1

a) Using the continuity schedule information please provide a table for the 2019–2024 period which shows:
   i) The forecast average annual additions to rate base
   ii) The additions to accumulated depreciation;
   iii) Total PP&E net of CWIP

b) Using THESL’s 2019 weighted cost of capital (based on OEB November 2018 cost of capital report) please show for each year the annual cost increase related to the incremental capital in-service (i.e. net PP&E).

c) For each value calculated in b) please provide the increase in existing rates that would be required to recover each year’s net increase in PP&E. Please provide this value on a pre and tax grossed up basis.

RESPONSE:

a) Please see below as requested:
   i) Average annual additions to rate base
Table 1: Average Annual Additions to Rate Base

<table>
<thead>
<tr>
<th></th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Annual</td>
<td>262.1</td>
<td>185.3</td>
<td>209.8</td>
<td>248.1</td>
<td>288.3</td>
<td>269.7</td>
</tr>
<tr>
<td>Additions to rate base</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

ii) Additions to accumulated depreciation

Table 2: Additions to Accumulated Depreciation

<table>
<thead>
<tr>
<th></th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Additions to</td>
<td>(225.8)</td>
<td>(240.8)</td>
<td>(252.7)</td>
<td>(264.0)</td>
<td>(280.2)</td>
<td>(294.5)</td>
</tr>
<tr>
<td>Accumulated</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

iii) Total PP&E net of CWIP

Table 3: Total PP&E Net of CWIP

<table>
<thead>
<tr>
<th></th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total PP&amp;E Net of CWIP</td>
<td>4,269</td>
<td>4,490</td>
<td>4,690</td>
<td>4,986</td>
<td>5,266</td>
<td>5,526</td>
</tr>
</tbody>
</table>

b) See table 4 below for the increase in the revenue requirement assuming the weighted cost of capital is based on OEB November 2018 cost of capital report for the 2020-24 period.

Table 4: Incremental Revenue Requirement due to change in WACC

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Change in Capital-related RR</td>
<td>11.7</td>
<td>27.9</td>
<td>22.7</td>
<td>38.5</td>
<td>37.6</td>
</tr>
</tbody>
</table>
c) The annual growth in total revenue requirement associated with the scenario calculated in part (b), on a pre and post-tax basis is shown in Table 5.

**Table 5: Revenue Requirement Scenario**

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pre-Tax</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual</td>
<td>2.7%</td>
<td>3.2%</td>
<td>3.1%</td>
<td>4.1%</td>
<td>3.4%</td>
</tr>
<tr>
<td>Increase (%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Post-Tax</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual</td>
<td>1.5%</td>
<td>3.4%</td>
<td>2.7%</td>
<td>4.4%</td>
<td>4.1%</td>
</tr>
<tr>
<td>Increase (%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

INTERROGATORIES

INTERROGATORY 5:

Reference(s): Exhibit 1B, Tab 2, Schedule 1, p. 23

Figure 8: Toronto Hydro’s Cost Performance 2005-2024

a) Does the above analysis indicate that THESL is projecting a decline in its relative performance over the term of the proposed rate plan?

RESPONSE:

a) The relative total cost performance of Toronto Hydro is converging towards the benchmark costs during the projected CIR years. The company is projected to move from 18.6 percent below its benchmark costs in 2015-2017 to 6.0 percent below benchmark costs for the 2020-2024 CIR period. This convergence is primarily due to the capital spending needs identified by Toronto Hydro.
RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION
INTERROGATORIES

INTERROGATORY 6:
Reference(s): Exhibit 1B, Tab 2, Schedule 2, p. 22

“Internal project construction costs were on average [redacted] than the costs of the same projects had they been constructed externally using up to seven design and construction contractors over the 2013 to 2016 period.”

a) Were the average costs of internally constructed projects higher or lower than the average cost of similar externally constructed projects?

RESPONSE:
a) Toronto Hydro declines to provide the requested commercially sensitive information publicly on the basis that to do so, will harm ratepayers by applying upward pressure on Toronto Hydro’s costs and interfere in Toronto Hydro’s future negotiations with both external contractors and collective bargaining units. This information has been filed confidentially with the OEB (and accepted as such pursuant to its Decision issued on December 14th, 2018), and is accessible to participants in this proceeding through the OEB’s normal process for accessing confidential information. Please also see Toronto Hydro’s submissions on this issue filed with the OEB on November 27, 2018.
RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

INTERROGATORIES

INTERROGATORY 7:

Reference(s): Exhibit 1B, Tab 3, Schedule 1, Appendix A – Innovative Research Group Customer Engagement

a) Please provide the costs of the Innovative Customer Engagement study (including the Residential Ratepayer Survey and Key Accounts Engagement).

b) What specific changes were made to THESL’s CIR proposal as a result of this study?

RESPONSE:

a) Please refer to Toronto Hydro’s response to interrogatory 1B-BOMA-119.

b) The specific changes made to this Application as a result of Planning-specific Customer Engagement occurred as a result of both Phase 1 and Phase 2 of that work, discussed in detail in Exhibit 1B, Tab 3, Schedule 1, pages four and six in particular. Please also see Table 2 in Toronto Hydro’s response to interrogatory 2B-Staff-73 (a).