# RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

**INTERROGATORY 29:**

**Reference(s): Exhibit 2A, Tab 1, Schedule 2, App. 2-BA, pp.5-6**

In the above reference, retirements and derecognition of gross costs are shown for 2014 and 2015 under MIFRS. Retirements are shown as $3.6 million in 2014 and $32.4 million in 2015. Derecognition is shown as $83.1 million in 2014 and $101.9 million in 2015.

a) Please explain how THESL differentiates between the two categories of retirements and derecognition;
b) Please identify and describe the capital projects that give rise to these retirements and derecognition of fixed assets which are or were presumably in service;
c) Please state where in the application the cost recovery of these amounts is shown;
d) Please state whether or not it is expected that more than $100 million of fixed assets will be stranded per year during the test period 2015-2019;
e) In these schedules, additions and transfers of gross cost are shown. Please explain what are the transfers and to whom or to what they are transferred.

**RESPONSE:**

a) Retirements relate to the disposal of rolling stock and properties. The gain or loss on disposition is calculated as the difference between the net disposal proceeds and the carrying amount of the item of PP&E and any related asset retirement obligation. The gains from the disposition of rolling stock and properties are recorded in profit or loss. The expected gain on disposition in 2015 has been deferred on the balance sheet.

# RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

Derecognition relates to the disposition of assets that are not individually identifiable.[1] Toronto Hydro does not expect any proceeds from the disposition of these assets. Losses resulting from the disposition of assets with a carrying amount are recorded as depreciation expense as shown in Exhibit 4B, Tab 1, Schedule 1, Appendix A.

b) In 2014, the retirement amounts relate to the disposal of two properties, 10 Gamble Avenue and 1255 York Mills Rd, and the reversal of the Asset Remediation Obligation assets for certain properties ($1.7 million) and wooden poles ($1.2 million). As part of ongoing efforts to improve operational efficiency, Toronto Hydro determined that the effort required to maintain Asset Remediation accounting for these assets does not justify the results obtained. Toronto intends to charge minor remediation costs to OM&A as they are incurred going forward. Large value and long-term remediation costs continue to be accrued.

In 2015, the retirement amounts relate to the forecasted disposal of two properties, 5800 Yonge Street and 28 Underwriters Road.

Please refer to Toronto Hydro's response to interrogatory 9-OEBStaff-92 part (a) for a description of capital projects that give rise to derecognition of fixed assets.

[1] Accounting Procedure Handbook ("APH") Article 410: Accounting for Specific Items – Property, Plant & Equipment and Intangible Assets, Pages 13-17.

# RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

c) The expected gain from the retirements of land and buildings has been deferred on the balance sheet. The derecognition loss is recorded as depreciation expense as shown in Exhibit 4B, Tab 1, Schedule 1.

d) It is not expected that more than $100 million of fixed assets will be stranded per year during the test period 2015-2019. Please refer to Exhibit 4B, Tab 1, Schedule 2, Table 1 for the forecasted losses on derecognition for the years 2014 to 2019.

e) The 2014 transfers relate to the reclassification of ICM in-service assets from PP&E to Regulatory Assets. In 2015, the transfers relate to the reclassification from PP&E to Regulatory Assets of Eligible Investments and Hydro One Capital Contributions. For more information regarding all of these accounts, please refer to Exhibit 9, Tab 1, Schedule 1, Sections 5.9 (Hydro One Capital Contributions), 6.2 (GEA / eligible investments), and 6.5 (ICM Assets).

# RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

**INTERROGATORY 30:**

**Reference(s):** **EB-2009-0180/-0181/-0182/-0183, Decision and Order, August 3, 2011, pp. 14-15 and**
**Exhibit 2A, Tab 5, Schedule 1, pp. 17-19**

The first reference is from the Board's findings in what THESL refers to as the "Valuation Decision". In that Decision, the Board found that the proposed transfer price for streetlighting assets of $28.938 million was reasonable and that the rate base, revenue requirement and rate consequences of the subject transfer should be determined in the context of THESL's next cost of service based rates application. The Board does not appear to make reference to any further revaluation of these assets in the Decision.

In the second reference, THESL explains why it believes that it is appropriate that the proposed 2014 NBV of the former streetlighting assets of $39.8 million be used rather than the original amount approved by the Board in the Valuation Decision of $28.9 million and states that:

> …it is still the case that the proxy value of $28.9 million provided at the time was the result of two simplifying assumptions that had to be made due to the lack of more precise information. .. However, the detailed analysis does not increase the value of the overall asset; rather, it changes the proportion of the unchanged total amount that is transferred to Toronto Hydro.

a) Please state whether or not and why THESL would view its detailed analysis as a revision of the asset valuation, rather than an update of the Board approved level given its comments related to the two simplifying assumptions in the second reference above;

# RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

b) If THESL views its detailed analysis as a revision of the asset valuation, please state why it believes its proposed approach would be in compliance with the Valuation Decision;

c) Please provide further explanation of the statement above that the detailed analysis does not increase the value of the overall asset.

**RESPONSE:**

a) Toronto Hydro views its detailed analysis as an <u>update</u> to the OEB-approved level. The OEB concluded in the Valuation Decision that the rate base, revenue requirement, and rate consequences of the street lighting transfer would be determined in the context of Toronto Hydro's next cost of service based rate application.[1] Because Toronto Hydro's 2012 cost of service application (EB-2011-0144) was dismissed, the OEB has not made final determinations of the amounts and assets to be transferred. All of these determinations are directly connected to and dependant on the value of the transferred assets, which was updated by Toronto Hydro to: 1) address the simplifying assumptions that had to be made in the context of the Valuation Decision, using better information that became available to Toronto Hydro through the detailed analysis, and 2) account for the natural evolution of the assets since the Valuation Decision.

b) Toronto Hydro views the detailed analysis as an update to the asset valuation, and believes that the updated value better adheres to the principles of the OEB's Decisions.[2] In particular, Toronto Hydro considers that the new information derived

[1] EB-2009-0180 et al., Decision and Order (August 3, 2011), at page 15 ["Valuation Decision"].
[2] EB-2009-0180, et al., Decision and Order (February 11, 2010) ["Classification Decision"]; and the Valuation Decision, *supra* note 1.

# RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

from the detailed analysis described in Exhibit 2A, Tab 5, Schedule 1, provides a better approximation for the depreciated historic cost method ("DHC") of the transferred assets, which the OEB found to be a more appropriate valuation methodology.[3] This conclusion was independently confirmed by PricewaterhouseCoopers LLP ("PWC") in the report filed at Exhibit 2A, Tab 5, Schedule 2.

c) Toronto Hydro refers to the combined Net Book Value (NBV) of both the transferred and un-transferred assets as the '*value of the overall assets*'. The purpose of the detailed analysis was to decompose the value of the overall assets into transferrable and non-transferrable amounts, consistent with the OEB's Decisions and the additional information that became available to Toronto Hydro through the detailed analysis. The overall value of the assets was held constant throughout, and therefore did not change as a result of the detailed analysis.

[3] Valuation Decision, *supra* note 1, at page 14.

# RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

**INTERROGATORY 31:**

**Reference(s): Exhibit 2A, Tab 5, Schedule 1, p. 22**

Table 4 of the above reference "Revenue Requirement from Streetlighting Assets ($ millions)" shows a service revenue requirement for the 2015 Test year of $8.1 million, which is offset by a "Revenue Offset – Contract Revenue" amount of $8.1 million producing a base revenue requirement of zero.

THESL's explanation of this adjustment is that:

> Under existing agreements between TH Energy and the City of Toronto, TH Energy receives service fees for the maintenance and operation of the street lighting assets. Given the transfer of a portion of these assets into Toronto Hydro's rate base as distribution assets, Toronto Hydro proposes to allocate a portion of the revenue that it expects to receive to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

a) Please state whether the existing agreements between TH Energy and the City of Toronto will be transferred over to THESL and, if so, whether they will be transferred unchanged, or if any modifications will be made. If modifications are anticipated, please state what they will be;
b) THESL states that it proposes to allocate a portion of the revenue it expects to receive. Please state what the anticipated total amount of expected revenue would be;

# RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

c) If THESL was not to make the revenue offset shown in Table 7, please state what the impact would be.

**RESPONSE:**

a) The existing agreements between TH Energy and the City of Toronto will not be transferred to Toronto Hydro. Rather, to meet its obligations under the existing agreements, insofar as they relate to the transferred portion of the assets, TH Energy has sub-contracted the performance of the services to Toronto Hydro.

b) The total amount of revenue that Toronto Hydro expects to receive from the City Contract is $8.1 million, consistent with the revenue requirement calculation outlined in Exhibit 2A, Tab 5, Schedule 1, Table 7. For greater clarity, the $8.1 million figure represents a portion of the total revenue under TH Energy's contract with the City of Toronto. Toronto Hydro proposes to allocate this entire $8.1 million amount to offset the revenue requirement costs associated with the transferred assets.

c) If Toronto Hydro did not include $8.1M from the Streetlighting contract as a directly allocated revenue offset, then $8.1M of additional Base Revenue requirement would need to be collected through Base Distribution Rates charged to all customers.

# RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

**INTERROGATORY 32:**

**Reference(s): Exhibit 2A, Tab 8**

As per the Filing Requirements for Electricity Rate Applications for 2015 Rate Applications, section 2.5.2.5, relating to renewable enabling investments, provincial rate recovery, please provide a draft accounting order for the requested variance account to track IESO payment revenues against the actual spending.

**RESPONSE:**

Please see Appendix A.

**Renewable Enabling Investments Provincial Rate Protection Variance Account – Draft Accounting Order**

Toronto Hydro is planning a number of Renewable Generation Connection investments which may be eligible for rate protection under the provisions of O. Reg. 330/09 (Cost Recovery Re Section 79.1 of the [OEB] Act. Eligible investments are as described under section 79.1 of the Ontario Energy Board Act, 1998.

In accordance with the Board's Filing Requirements for Electricity Distribution Rate applications (dated July 17, 2013) Chapter/Section 2.5.25 and Appendices 2-FA, 2-FB and 2-FC regarding Costs of Eligible Investments for the Connection of Qualifying Generation Facilities, Toronto Hydro shall establish a variance account to track the variance between Toronto Hydro's revenue requirement required to support the portion of the investments that are eligible for rate protection, and the rate protection payments collected from the Independent Electricity Systems Operator (IESO).

Toronto Hydro will calculate and record as a debit to the variance account, the revenue requirement associated with the portion of the capital costs that are eligible for provincial rate protection, as incurred by the utility for eligible renewable enabling investments for the period of 2015 through 2019.

Toronto Hydro will record as a credit to the variance account, the amounts collected from the IESO as a result of any OEB order directing such payments from the IESO to Toronto Hydro.

The balance in the account will not attract carrying charges.

Toronto Hydro will establish the following variance account to record the amounts described above:

- Account XXXX (TBD upon OEB approval, note 1) - Renewable Enabling Investments (REI) Provincial Rate Protection Variance Account

The sample accounting entries for the Variance Account are provided below.

a. To record the Renewable Enabling Investments (REI) capital expenditures:
    - DR 2055 Construction Work in Progress - Electric
    - CR 1005 Cash

b. To transfer the REI expenditures to Property, Plant and Equipment (PP8E) (Electric Plant in Service) :
    - DR Various Accounts Property, Plant and Equipment - Renewable Enabling Investments (PP*E)
    - CR 2055 Construction Work in Progress – Electric

c. To record amortization for the Renewable Energy Investments PP*E capital costs:
   - DR 5705 Depreciation Expense – Property, Plant and Equipment
   - CR 2105 Accumulated depreciation of Electric Utility Plant – Property, Plant and Equipment (REI)

d. To record amounts collected from the IESO for the Provincial Rate Protection Payments, to fund the Renewable Enabling Investments:
   - DR 1005 Cash
   - CR 4080 Distribution Services Revenue – Sub-account, REI Revenue Requirement

e. To record the annual true-up for the Renewable Enabling Investments Provincial Rate Protection revenue requirement variance: (the variance as defined in note 2. below)
   - DR/CR XXXX (TBD, note 1) REI Provincial Rate Protection Variance Account
   - CR/DR 4080 Distribution Services Revenue – Sub-account, REI Revenue Requirement

Notes:

1. There is no OEB prescribed Variance Account in the OEB APH for the "Renewable Enabling Investments (REI) Provincial Rate Protection Variance Account, specifically defined for the purpose described above. The OEB account is TBD upon OEB approval.

2. REI Provincial Rate Protection Variance Account calculation:
   Record the net of:
   i. The revenue requirement associated with the portion of the capital costs that are eligible for provincial rate protection, as incurred by the utility for eligible renewable enabling investments;
   AND
   ii. The amounts collected from the IESO as a result of any OEB order directing such payments from the IESO to Toronto Hydro.

# RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

**INTERROGATORY 21:**

**Reference(s): Exhibit 2A, Tab 10, Schedule 2 Page 11 Table 2**

Preamble:

Table 2 provides the percentage contribution of Defective Equipment to SAIFI & SAIDI.

a) Please provide a further breakdown of the causes of Defective Equipment that make up the percentages shown in Table 2.

**RESPONSE:**

a) Please see table below:

| Equipment | Contribution % to SAIFI | Contribution % to SAIDI |
|---|---|---|
| Underground Cables | 39.3% | 39.5% |
| Poles and Pole Hardware | 21.1% | 19.5% |
| Switches | 16.4% | 11.4% |
| Overhead Conductors | 7.7% | 6.9% |
| Others | 6.6% | 6.4% |
| Transformers | 5.0% | 7.7% |
| Stations Equipment | 3.8% | 8.6% |

# RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

**INTERROGATORY 22:**

**Reference(s): Exhibit 2A, Tab 10, Schedule 2**

a) Please complete the following table excluding loss of supply.

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|
| Number of Interruptions | | | | | | |
| Number of Customers Interrupted | | | | | | |
| Customer Hours Interrupted | | | | | | |

b) Please provide THESL's SAIDI and SAIFI targets for the 2015 to 2019 period.

**RESPONSE:**

a) Please see table below. Please note that Toronto Hydro is unable to provide a 2014 year-end forecast as it is unable to forecast the impact of MEDs. Please also refer to the response to Interrogatory 2A-EP-8.

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014F* |
|---|---|---|---|---|---|---|
| Number of Interruptions | 1,885 | 2,153 | 1,915 | 1,669 | 2,352 | N/A |
| Number of Customers Interrupted | 1,176,735 | 1,070,057 | 1,045,478 | 1,048,668 | 1,726,330 | N/A |
| Customer Hours Interrupted | 1,900,573 | 828,500 | 968,876 | 1,039,886 | 12,885,642 | N/A |

# RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

b) Please refer to the response to Interrogatory 2B-OEB-33 for the SAIDI and SAIFI projections for the proposed CIR scenario. Please note that these projections are not targets for the CIR period.

# RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

**INTERROGATORY 23:**

**Reference(s): Exhibit 2A, Tab 9, Schedule 1, p. 2**

"Toronto Hydro does not expect to be able to determine the required 2014 actual expenditures or ISAs in concordance with the likely timeframe of this proceeding. Toronto Hydro therefore submits that the true-up of the 2012-2014 ICM activities is most appropriately undertaken in a separate proceeding from this application, following the determination of actual expenditures and ISAs for the full 2012-2014 ICM period."

a) The OEB decisions for the 2012-2014 IRM rate case EB-2012-0064 were provided in 2 phases. The first being the Partial Decision of April 12, 2013 dealing only with 2012 and 2013 as well as the Settlement Agreement of December 18, 2013. Please provide a rationale for why the ICM cannot be trued up on actuals for 2012-13 and on the best available actuals for 2014 (to be updated when the 2014 audit is complete in the second quarter of 2015) in this proceeding.

**RESPONSE:**

a) Toronto Hydro believes that an early True-Up process is inconsistent with the OEB's decision in EB-2012-0064, as well as impracticable and inefficient for reconciling Toronto Hydro's ICM expenditures over the 2012-14 period against revenues generated through the approved ICM rate riders. In particular, Toronto Hydro believes that it is not possible to conduct a meaningful true-up of 2012-13 actual data alone or using a combination of 2012-13 actuals and estimates for 2014.

# RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

Toronto Hydro expressly stated in the ICM proceeding that it expected ICM jobs within approved segments would be advanced, deferred, or substituted during the three year ICM period in order to respond to externally-driven factors (e.g., weather) and maintain prudent work program execution.[1,2]

In its Partial Decision of April 2, 2013, the OEB expressly allowed for variances among actual jobs executed within approved ICM segments.[3] Furthermore, Toronto Hydro believes that the OEB contemplated a single true-up on the basis of the *complete* ICM program, through its wording in the Accounting Order: "At the time of true-up, THESL will recalculate the revenue requirement impacts …based on the actual in-service assets….to determine the revenue requirement on an actual basis for each applicable period (e.g., 2013 and 2014)."

Toronto Hydro has been tracking its ICM work program in detail and intends to provide robust and detailed information to the OEB and intervenors regarding that work program for the purposes of true-up. However, that work program is not yet completed. Until it is, the underlying detailed tracking information cannot be assembled, organized and summarized for meaningful presentation to the OEB.[4] This process will not be completed until sometime in the second quarter of 2015, which is well after the anticipated completion of the hearing in this proceeding.

[1] EB-2012-0064, Application and Evidence (August 19, 2013), at Tab 9, Schedule 1, page 10 (2014 Evidence Update – Manager's Summary).
[2] EB-2012-0064, Application and Evidence (October 31, 2012), at Tab 2, pages 4-6 (Addendum to 1 Manager's Summary – Summary of Updated Evidence).
[3] EB-2012-0064, Decision and Reasons (April 2, 2013), at pages 75-76.
[4] See Toronto Hydro's response to interrogatory 2B-OEBStaff-39 for more detail regarding the practical constraints on providing detailed true-up data in advance of the completion of the 2014 portion of the ICM work program and the appropriate compilation of the full three-year ICM work program data.

# RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

In addition, undertaking a true-up of just 2012 and 2013 would not properly take into account of the shifting of jobs between years, as some of this work was moved to the 2014 work program, which is not yet complete.

In summary, Toronto Hydro believes that undertaking the determination of the final true-up amount later in 2015 will allow for a full and efficient determination, and is preferable to a piece-meal or early partial true-up.

Please also see Toronto Hydro’s response to interrogatory 2B-OEB-39.

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

**INTERROGATORY 8:**

**Reference(s):** **Exhibit 2A, Tab 10, Schedule 2, pages 1-2, Figures 1 and 2**

Preamble:

Scenarios 1 and 2 provide SAIFI and SAIDI in the filing manner required by OEB Appendix 2-G (Exhibit 2A, Tab 10, Schedule 3). Scenarios 3 and 4 provide SAIFI and SAIDI values by excluding additional externalities and controllable outages, to give a more normalized reflection of total system reliability. Each of these values provides valuable information as to the causes, duration, and frequency of outages within Toronto Hydro's distribution system.

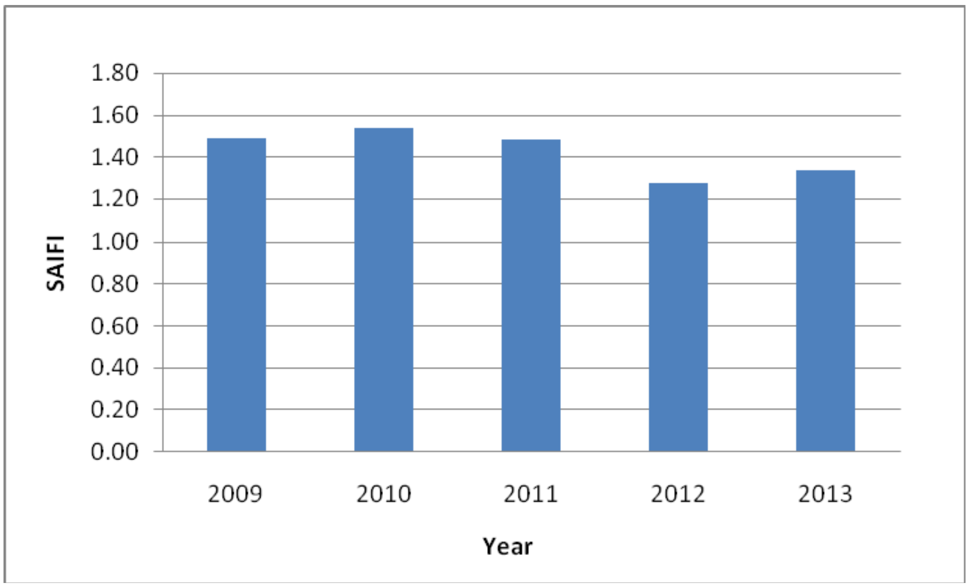
a) Confirm SAIDI and SAIFI are Metrics contained in the new OEB RRFE Scorecard for Electricity Distributors.
b) Please provide a historic SAIDI, SAIFI and CAIDI charts without LOS and MEDS, but including SOs
c) Provide a forecast of SAIDI, SAIFI and CAIDI for the period 2014-2019 including the CIR period 2016-2019, excluding LOS and MEDs, but including SOs.
d) Please provide the 5 year average SAIDI and SAIFI for the CIR Plan and Compare to Appendix 2-G historical Average

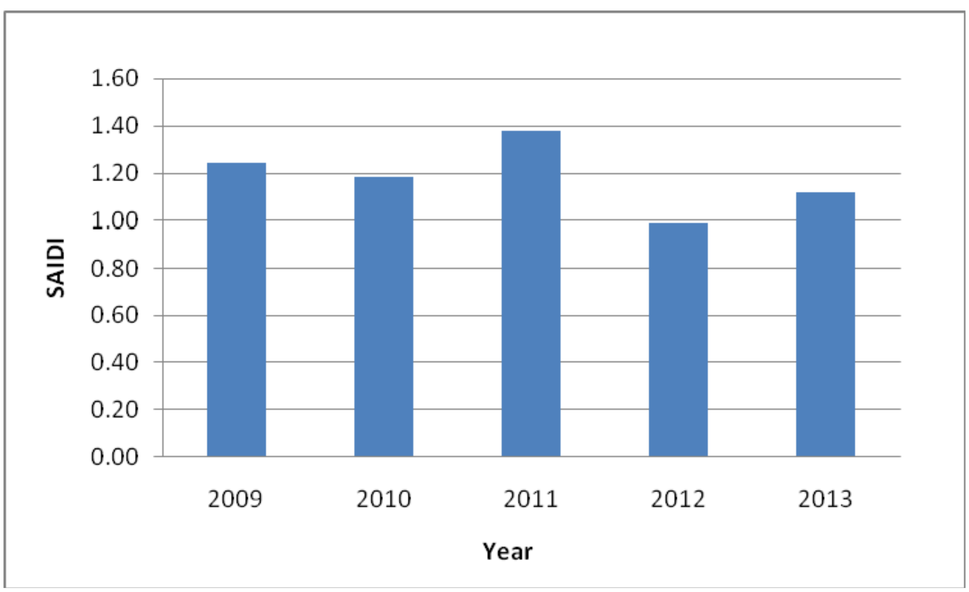
**RESPONSE:**

a) Confirmed.

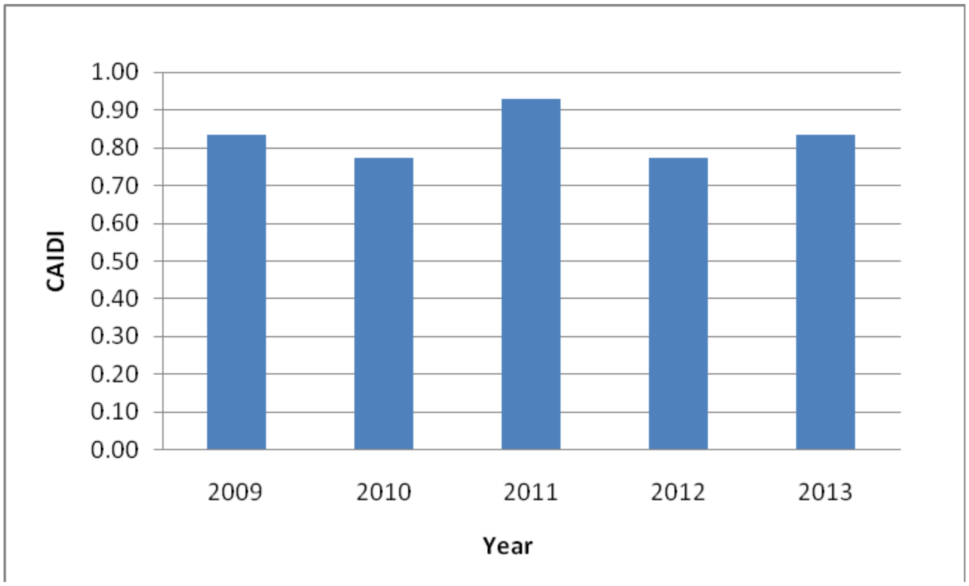
# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

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



# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES




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

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

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

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

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

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

**INTERROGATORY 9:**

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

Preamble:

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

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

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

**RESPONSE:**

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

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

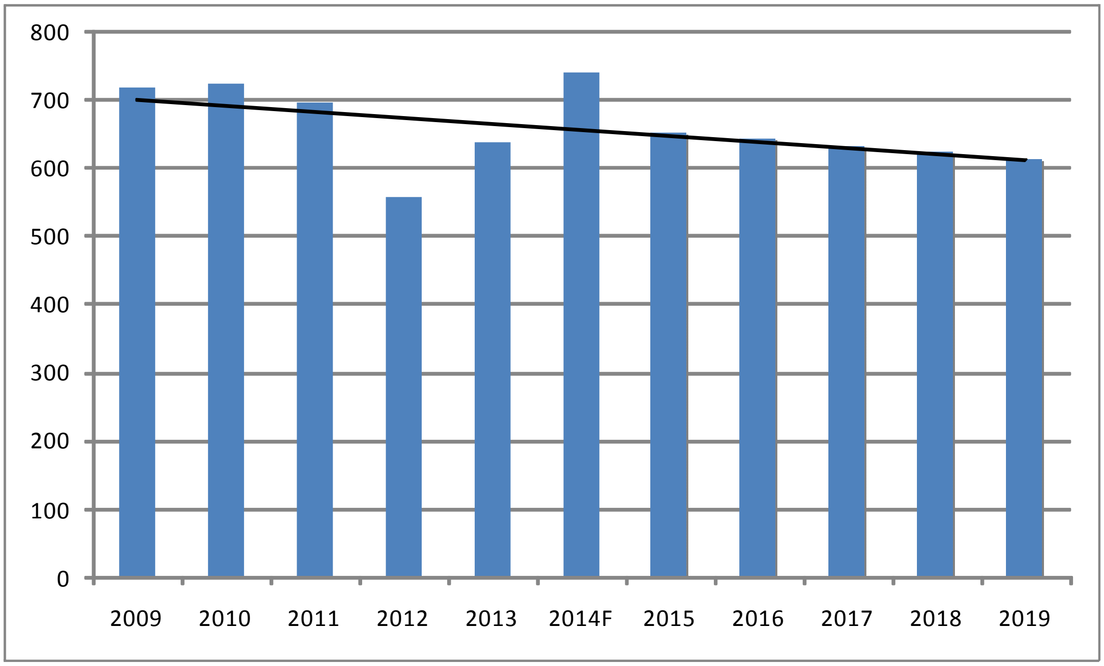
b) The following table shows the historic and forecast contributions to SAIFI and SAIDI from Tree Contacts (excluding MEDs).

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

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

d) Please see the chart on the following page.

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES




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

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

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

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

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

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

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

the area of capital performance measurement on the part of the OEB and the utility, the DSP metrics as described in Exhibit 2B, Section C were advanced for the purposes of ongoing monitoring to track continuous improvement, rather than performance standards to be used against pre-determined targets.

f) As discussed in Exhibit 2B, Section C Toronto Hydro expects to measure its performance throughout the plan term and take mitigation steps, where warranted and/or possible and practicable with respect to the performance measures advanced in this application. This should provide the OEB and Toronto Hydro with meaningful insights that could potentially be applied towards a more prescriptive performance measurement framework in the future.

g) See the response to (f) above.

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

**INTERROGATORY 10:**

**Reference(s):** **Exhibit 2A, Tab 10, Schedule 1, page 2, Table 1**

Preamble:

The Distribution System Code outlines certain obligations regarding missed and rescheduled appointments with customers in section 7.5.1.

Section 7.5.2 of the Code requires that distributors meet that obligation 100 percent of the time. It requires that if the appointments are to be missed, a distributor must attempt to inform the customer beforehand and reschedule the appointment.

a) Confirm THESL has not met this requirement in three of the past 5 years and in 2013 dropped to a 93% Rescheduling ESQR.
b) Please provide an explanation of factors under control of THESL and those that are not.
c) What remedial actions is THESL going to undertake (summary and timing)?
d) Has THESL considered asking for an exception to Sections 7.5.1 and 7.5.2?
e) If so, provide parameters of this.

**RESPONSE:**

a) Toronto Hydro confirms that it has not met the 100% target in three of the past five years. However, in preparing this response, Toronto Hydro discovered an error in the data reported. Specifically, in 2013 Toronto Hydro scheduled a total of 14,677 appointments, of which it missed 61. Of these 61, it failed to correctly reschedule 1

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

(not 4, as originally reported). This 1 missed appointment corresponds to a 98.4% Rescheduling ESQR (not 93.5%, as originally reported). Toronto Hydro intends to submit a revision request to the OEB in order to update its RRR records accordingly.

b) Factors under Toronto Hydro’s control include resource and capacity planning, resource scheduling, appointment management, vendor management, and contingency planning. Factors outside of Toronto Hydro’s control include inclement or severe weather conditions, unexpected emergencies encountered by the employee/contractor (illnesses, witness to a vehicle accident, encounter a safety risk en-route, etc.), or high-level emergencies requiring Toronto Hydro to divert resources to other priority tasks.

c) As explained in detail on pages 1 and 2 of Exhibit 2A, Tab 10, Schedule 1, Toronto Hydro believes that the results under this ESQR are more a function of the mathematical data rather than an underlying performance issue. Toronto Hydro has only incorrectly rescheduled a single missed appointment in each of the three affected years (2009, 2012, and 2013). As a result, Toronto Hydro does not believe that these small numbers (three affected customers over a five year period) warrant a specific remedial action, other than a continuous effort on the part of Toronto Hydro to attempt to comply with the requirements.

d) Toronto Hydro has not considered asking for an exception or exemption to section 7.5.1 or 7.5.2, as Toronto Hydro does not believe the inherent difficulties in meeting an ESQR with a 100% target are unique to its circumstances. However, given the effort required to track it, the very small number of customers affected by missed appointments, and the even smaller number of customers affected by incorrectly

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

rescheduled appointments, Toronto Hydro believes that this measure may benefit from review by the OEB. Toronto Hydro has noted these concerns to the OEB in the past, and would support a generic review of this ESQR by the OEB.

e) See d) above.

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

**INTERROGATORY 11:**

**Reference(s):** **Exhibit 2A, Tab 10, Schedule 3, Page 1**
**OEB Appendix 2-G, Service Reliability Indicators 2009-2013**

a) Please provide a forecast for the SQRS for the period 2014-2019.
b) Please provide explanation/commentary on any SQRS that exhibit significant differences from the Minimum Standard.
c) Please provide explanation of significant changes/trends over the CIR period.

**RESPONSE:**

a) Toronto Hydro expects results for 2015-2019 to largely be in line with historical averages, with the exception of an expected improvement to the Emergency Response ESQR. Toronto Hydro is unable to provide a specific forecast for each ESQR for this period. The 2014 YTD values (up to September 2014) are provided in the table below.

| ESQR Measure | 2014 YTD |
|---|---|
| Service Connections <750 V | 91.60% |
| Service Connections >750 V | 100% |
| Reconnections | 100% |
| Micro-Embedded Generation Facilities | 100% |
| Appointment Scheduling | 95.89% |
| Appointments Met | 99.70% |
| Appointment Rescheduling | 91.18% |
| Telephone Accessibility | 70.92% |

# RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

| ESQR Measure | 2014 YTD |
|---|---|
| Telephone Call Abandon Rate | 1.90% |
| Written Inquiry Response | 94.44% |
| Emergency Response | 94.66% |

b) Historic variances from minimum standards are discussed in detail in Exhibit 2A, Tab 10, Schedule 1. Toronto Hydro is not expecting any metrics to be below the minimum standard over the 2015-2019 period.

c) See a) above. Toronto Hydro expects an improvement in the Emergency Response ESQR as a result of increased availability of resources to perform emergency response functions. Please refer to Exhibit 4A, Tab 2, Schedule 3 for additional details.

# RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

**INTERROGATORY 11:**

**Reference(s):** **Exhibit 2A, Tab 9, Schedule 1, p.2**

Please provide the estimated amount that would be trued-up based on the Applicant's 2014 forecasted in-service additions.

**RESPONSE:**

Please see Appendix A to the response to interrogatory 2B-OEBStaff-39 for the actual and forecast in-service additions for Toronto Hydro's Total ICM Projects for 2012 to 2014.

# RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

**INTERROGATORY 12:**

**Reference(s): Exhibit 2A, Tab 1, Schedule 1**

Please provide all assumptions used in determine 2014 in-service additions.

**RESPONSE:**

The 2014 in-service addition assumptions for System Access, System Renewal, and System Service investments were based on the forecasted 2014 capital expenditures including prior year construction work-in-process. The planned attainment (i.e., project completion) date was used to determine if the projects would go in-service in 2014. Where projects were forecasted to be attained in December 2014, it was assumed they would go in-service in 2015 due to a timing lag with respect to the financial validation and close-out process. Other items (such as design, AFUDC, EAR) are integrated among the programs and follow the same in-service assumptions as the underlying project to which these other items relate.

The forecasted in-service additions assumptions for General Plant, Copeland, and HONI were based on the latest projections related to the specific programs. As an example, the IT Hardware Refresh (Exhibit 2B, Section E8.4), a program within General Plant, is comprised of discrete projects with varying completion dates. Each discrete project is assigned an estimated completion date based on the best information available at the time of the forecast. Where the project is estimated to be completed in 2014, it was included in the forecasted in-service additions for 2014.

# RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

**INTERROGATORY 13:**

**Reference(s):** **Exhibit 2A, Tab 3, Schedule 2**

Please provide the curriculum vitae for each of the Navigant employees responsible for the *Working Capital Requirements of Toronto Hydro Electric System Limited's Distribution Business.*

**RESPONSE:**

The curriculum vitae for each of Ralph Zarumba, Jodi Amy and Andy Tam are attached as Appendices A, B and C to this Schedule.

NAVIGANT

# Ralph Zarumba

Ralph Zarumba
Director

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Professional History

- Director, Navigant Consulting
- Director, Science Applications International Corporation
- President, Zarumba Consulting
- Management Consultant, Sargent & Lundy Consulting Group
- President, Analytical Support Network, Inc.
- Manager, Pricing Practice, Synergic Resources Corporation
- Senior Analyst – San Diego Gas & Electric Company
- Senior Analyst – Wisconsin Electric Power Company
- Analyst 4 – Eastern Utilities Associates
- Analyst – Illinois Power Company

Education

- MA, Economics, DePaul University, Chicago, IL
- BS, Economics, Illinois State University, Normal, IL

Ralph Zarumba is a Director in the Energy Practice with 29 years of experience specializing in regulatory issues and economic analysis in North America, Europe and Asia. Mr. Zarumba has appeared as an expert witness in a number of regulatory and legal proceedings addressing electric generation, transmission and distribution issues, unregulated operations of utility holding companies, asset valuation and regulatory treatment of Smart Grid investments. He has also assisted clients in other matters including Depreciation Studies, Transfer Pricing Mechanisms and evaluation of the results of competitive bidding for electric generation services.

Mr. Zarumba has testified as an expert witness before the Ontario Energy Board, the Nova Scotia Utility Review Board, the U.S. Federal Energy Regulatory Commission ("FERC"), the Massachusetts Department of Public Utilities, the Rhode Island Public Utilities Commission, the Illinois Commerce Commission, the Wisconsin Public Service Commission, the New York Public Service Commission as well as a number of other venues. Mr. Zarumba has provided a number of papers and presentations on various regulatory and market analysis issues.

## Recent Whitepapers

» White Paper Prepared for the Ontario Energy Board on Approaches to Rate Mitigation for Transmitters and Distributors

http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0378/EB-2010-0378_Navigant_Report.pdf

» White Paper Prepared for the Ontario Energy Board Cost addressing Distributor Efficiency

http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2012-0397/Navigant_Report_Elect-Dist-Efficiency_20130225.pdf

» White Paper Prepared for the Ontario Energy Board Cost addressing Cost Assessment Models for Regulators

http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/319593/view/Cost%20Assessment%20Model%20Report_Jan%2013%202011_20120116pdf.PDF

» Economic Issues Related to Tariff Development (with Thomas Welch)

http://www.erranet.org/index.php?name=OE-eLibrary&file=download&id=6052&keret=N&showheader=N

## Recent Publications

Public Utilities Fortnightly "Pricing Social Benefits - Calculating and allocating costs for non-traditional utility services" Ralph Zarumba, Benjamin Grunfeld and Koby Bailey, August 2013

American Gas "Modernization: The Quest for 21st Century Utilities" Ralph Zarumba and Peter Haapaniemi, November 2012

Public Utilities Fortnightly "Pre-Funding to Mitigate Rate Shock" Sherman Elliot and Ralph Zarumba, September 2012

**Regulatory and Pricing**

- » Currently assisting the Ontario Energy in formulating a regulatory process and pricing design for Revenue Decoupling.
- » Prepared a white paper on rate mitigation mechanisms for the Ontario Energy Board.
- » Prepared a white paper for the Ontario Energy Board on apportion of regulatory commission costs to various stakeholders.
- » Prepared a number of working capital studies for various distributors and transmitters in the Province of Ontario.
- » Prepare a functional cost separation study for a regulated electric utility in Ontario.
- » For a confidential client prepared a benchmarking analysis of the costs of regulatory proceedings associated with the introduction of new electric generation.
- » Prepared and sponsored before the FERC a cost-of-service filing supporting a Reliability Must-Run filing on the Cayuga Operating Company.
- » Prepared an analysis of the pricing of voluntary renewable energy products for a Midwestern public power association.
- » Prepared a number of working capital studies for various distributors and transmitters in the Province of Ontario.
- » Managed a project team which completed a Remaining Life Study for the Western Minnesota Municipal Power Agency.
- » Led a team that prepared a cost of service, rate design, legal evaluation and financial analysis for the Puerto Rico Electric Power Authority.
- » Performed a Pricing Strategy for the South Carolina Public Service Company (Santee Cooper).
- » Prepared a financial plan, electric rate design and phase-in plan for a new electric generation plan for Fayetteville (North Carolina) Public Works Commission.
- » Assisted Commonwealth Edison Company in their Electric Rate Request (Illinois Commerce Commission Docket No. 10-467).

- Prepared proposals for Retail Conjunctive Billing Pricing filed in Illinois and Wisconsin which were filed before the Illinois Commerce Commission and the Wisconsin Public Service Commission.

- Developed the Wisconsin Electric Power Company's first Curtailable Electric Tariff available to commercial customers.

- Negotiated complex service contracts with thermal energy customers which led to a major expansion of the Wisconsin Electric Steam System.

- Assisted Indianapolis Power & Light in preparing a cost recovery plan for Energy Efficiency and Demand Side Management Expenditures.

- Trained regulatory staffs in the Republic of Macedonia, Bosnia and Herzegovina, Croatia and Albania.

- Prepared proposals for ancillary services pricing based upon market-based mechanisms for San Diego Gas and Electric Company.

- Completed the development of wholesale and retail rate designs for a southeastern G&T, an analysis of stranded cost exposure for a northeastern utility, and prepared a strategic plan for a large municipal utility.

- Developed a proposal for electric generation transfer pricing that would be used as a transition mechanism between the existing vertically integrated utility and a deregulated environment.

- Filed testimony in Wisconsin proposing that state's first Demand Response Program.

**Demand Response**

- Assisted the Building Owners and Managers of Chicago (BOMA/Chicago) develop a program where they can bid demand response based ancillary services into the PJM market.

- Prepared a presentation for the Public Utilities Commission of Ohio on Commercial and Industrial Dynamic Pricing and Demand Response in an unregulated regulatory environment.

**Electric Transmission**

- Assisted the Long Island Power Authority to purchase distribution, transmission and regulatory assets and prepared its non-jurisdictional open-access transmission tariff.

- Prepared the pricing portion of a FERC open access tariff (Docket No. ER96-96-43.000) for San Diego Gas and Electric Company; testified on revenue requirements and pricing including opportunity costs.

**Generation Market Analysis**

- For a major public power generation owner prepared a strategy of internal coal versus natural gas generation dispatch protocols including the treatment of liquidated damages.
- Co-authored a report for Nalcor on the feasibility and economics of the proposed development of the Lower Churchill Hydroelectric project.
- Prepared a number of electric market price forecasts for many regions of the United States and Central America.
- Supported the electric pricing and infrastructure analysis for a Least-Cost Resource Plan for San Diego County.
- Prepared an analysis of the saturation of coal-fired electric generation technology in the Western Electric Coordinating Council.
- Developed a long-run electric expansion plan for the Railbelt System in Alaska.
- Managed a team that prepared a long-term capacity and energy forecast for a medium-sized municipal utility.
- For Manitowoc Public Utilities prepared a resource plan evaluating various generation expansion options.

**Merger, Acquisition and Divesture**

- On behalf of the Minnesota Public Service Commission, Mr. Zarumba co-authored an analysis of the merger savings associated with the proposed Primergy Merger (the proposed combination of Northern States Power and Wisconsin Energy). The analysis included a detailed review of cost savings that would emanate from the merger and regulatory commitments made by the companies to regulatory authorities in Minnesota.
- The Ontario Energy Board desired to identify factors that potentially impede the combination of regulated distributors in that province. Mr. Zarumba co-authored a study which identified those factors and discussed policies in other jurisdictions.
- For the Manitowoc Public Utilities prepared an analysis that evaluated the divesture of its transmission assets to the American Transmission Company.

» For a confidential client prepared a valuation to support a proposed acquisition of a Midwestern Electric and Natural Gas utility by a regional utility. The analysis included an analysis of a sale of the electric operations of the target utility to another regulated utility.

**International**

» Currently assisting the Israel Public Utility Authority is electric tariff reviews for the Israel Electric Company and the Jerusalem District Electric Company.

» Mr. Zarumba assisted the electric regulator in the Republic of Macedonia with various regulatory issues including pricing design, revenue requirements and privatization issues. Included in the assistance was the development of market designs for the electricity sector.

» Completed a tariff implementation plan proposal for the privatization of the distribution companies of the Bulgarian Electric Utility.

» Led a team to implement regulatory procedures and methodology for the electric power industry in Bosnia and Herzegovina.

» Conducted a study of the electric power market in El Salvador including a quantification of the level of generation market power using the Lerner Index.

NAVIGANT

Jodi Amy
Senior Consultant

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Professional History

- Senior Consultant, Navigant Consulting Ltd.
- Senior Business Analyst, Ontario Power Authority
- Sales and Trading Analyst/ Market Monitoring Analyst, Student, Ontario Power Generation
- Market Assessment Analyst, Student, Independent Electricity System Operator
- Development Student, Portfolio Risk Management, Bruce Power

Education

- University of Waterloo, Honours, BA, Economics

# Jodi Amy

Jodi Amy is a Senior Consultant in the Energy Practice in Navigant's Toronto Office. At Navigant, Ms. Amy has worked with individual utilities to complete studies for rate filings, to develop energy efficiency portfolio plans and developed tools to assess energy efficiency economics such as funding and cost effectiveness models. Ms. Amy has also developed, conducted, and performed analyses on participant surveys including a residential direct load control program and a portfolio of custom residential and commercial programs. Ms. Amy has performed analysis and developed Tools for generators in Ontario and provincial agencies including the OEB, IESO, and OPA. Prior to joining Navigant, Ms. Amy worked with the OPA in the Conservation division as a Senior Business Analyst. Jodi also gained broad experience across the industry through several co-op terms across the electricity industry at the IESO, OPG, and Bruce Power while studying economics at the University of Waterloo.

## Professional Experience

**Senior Consultant – Navigant:**

- **Line Loss Study – Hydro One Networks Inc.:** Using a macro approach, calculated the variance between actual and approved losses for Hydro One Network Inc.'s (HONI) rate filing. Analysed meter and bill data, reviewed internal processes, and interviewed with key staff. Drafted a report which included a recommended approach to complete entries in HONI's RSVA power and global adjustment accounts.

- **Lead-Lag Study – Toronto Hydro:** Conducted interviews with subject matter experts throughout an Ontario utility to calculate the working capital for the distributor's rate filing. Modeled the data provided and completed a report to concisely describe the methodology and results of the study.

- **Analysis Investigating Revenue Decoupling – OEB:** Analysed the electricity use of low income customers compared to standard residential customers from various perspectives and using various assumptions. Analysed consumption data and provided written and graphical summaries of key findings to OEB staff.

- **Review of OPA Demand Forecast – Ontario Ministry of Energy:** Completed a third party review of the OPA's long-term gross and net demand forecast. Reviewed residential and commercial load growth assumptions, interviewed key staff, and completed a summary presentation outlining the OPA's methodology and the results of the review process.

- **Conservation Planning and Analysis – Ontario Utility:** facilitated strategic planning sessions, provided jurisdictional research and benchmarking, developed conservation portfolio plans, and developed tools to understand conservation portfolio economics such as funding mechanisms and cost effectiveness for residential and commercial programs.

- **Custom Programs Evaluation – Greater Sudbury Hydro Inc.:** Completed Evaluation, Measurement and Verification of Greater Sudbury Hydro Inc. (GSHI) custom Conservation and Demand Management (CDM) programs, including a commercial parking lot plug controller program and commercial vending machine and self-service coolers efficiency program. Reviewed regulatory documents and tracking spreadsheets, interviewed key program staff and a sample of both residential and commercial program participants, and completed cost effectiveness analysis.
- **Cost Effectiveness Guide and Tool – Ontario Power Authority (OPA):** Developed a user-friendly, Excel-based Cost-Effectiveness Tool and Cost-Effectiveness Guide to plan and assess energy efficiency programs in Ontario. Provided training to OPA staff on cost-effectiveness basics, training on the cost-effectiveness Tool and how the Tool can be used to assess cost-effectiveness at the measure, program, and portfolio level.
- **Wind Bid Strategy Tool – Confidential client:** Developed a tool to predict a bidding strategy for a wind generator using an hourly forecast of surplus base load generation (SBG) and taking into account the actual level of intertie transactions during prior surplus events.

**Senior Business Analyst – Ontario Power Authority:** Analysed and forecasted Ontario conservation program performance and budgets for residential, commercial and industrial programs. Provided summary analysis of program results to the Environmental Commissioner of Ontario, Ontario Ministry of Energy, OEB, and all Ontario electric utilities. Presented reporting information and commercial program evaluation insights at LDC workshops and webinars. Provided lead analytics and project management support for the 2010/2011 Integrated Power System Plan.

**Sales and Trading Analyst/ Market Monitoring Analyst – Student – Ontario Power Generation:** Uncovered potential revenue opportunities through Excel-based analyses using calendar spreads for trade in an American market. Administered and enhanced a weekly report concerning fuel prices, imports and exports, spot and forward prices and risk limits.

**Market Assessment Analyst – Student – Independent Electricity System Operator:** Developed market models, programs and procedures to assess and enforce market rules. Investigated the effects of: loop flows, cascading hydraulic systems, and natural gas future and swap prices on bidding behaviour.

## Education

**University of Waterloo – Bachelor of Arts, Honours Economics:** Co-op program with International Trade Specialization. Relevant Coursework: Quantitative Finance, Accounting Information for Managers, Statistics for Economists, Econometrics, Business Finance.

NAVIGANT

# Andy Tam

Andy Tam
Managing Consultant

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Professional History

- Managing Consultant, Navigant Consulting
- Hydro One Networks Inc., Business/Finance Analyst

Education

- Queens University, Honours, BSc, Engineering (Electrical & Computer Option)
- Queens University, BA, Economics

Andy Tam is a Managing Consultant in Navigant's Energy Practice based out of Toronto. His experience spans projects with electric regulators, major transmission/distribution utilities, and various other energy related public/private sector entities. Within these engagements, Mr. Tam has primarily focused on electricity markets, utility financial modeling (working capital, cost of service, revenue requirement) and Smart Grid technologies through working with entities such as the Ontario Ministry of Energy (governmental entity), Hydro One Networks Inc. (Ontario's largest distribution & transmission utility) and the United States Navy and Marine Corps (military).

Most recently, Mr. Tam has participated in projects regarding technical and financial evaluations of Smart Grid and Micro Grid technologies. Furthermore, Mr. Tam has recently completed financial working capital evaluations for three of the largest utilities in Ontario. Prior to joining Navigant, Mr. Tam worked at Hydro One Networks Inc. as a business/financial analyst, completing a two year leadership rotation program where he worked on utility financial modeling, business planning, regulatory analysis and business process optimization. Throughout his career, Andy has developed a strong quantitative skill set and also brings forth software design experience from R&D at Nortel Networks. Mr. Tam received both his Bachelor of Science in Computer Engineering, and Bachelor of Arts in Economics degrees from Queen's University.

## Professional Experience

### Navigant Consulting – Managing Consultant

- Determination of working capital –financial modeling for local distribution companies to be filed with the Ontario Energy Board; quantifying the level of working capital in order to finance their ongoing business;

- Cost of service analysis – developed models and rates for local distribution companies (electric and natural gas) to determine the allocated and incremental cost of providing unregulated services;

- Revenue requirement analysis – developed financial revenue requirement models for local distribution companies (electric and natural gas);

- Development of energy and cost effectiveness strategies for military naval bases – identify underperforming facilities at naval bases and apply energy efficiency measures and smart grid strategies to determine project economics;

- Financial risk assessments for smart grid projects – analysis into financial risks and applicant capabilities to execute and commercialize proposed smart grid projects as part of the governmental smart grid fund;

- Technical risk assessments for smart grid projects – analysis into technical risks and applicant capabilities to advance the smart grid, stimulate economic development and reduce technical risk in the energy sector as part of the governmental smart grid fund;

- Financial modeling for energy storage project proposal – development of competitive energy storage bid price for client's proposal to the local electricity markets regulator; this included modeling of energy storage cost parameters as well as pro forma development for this project (balance sheets, income statements and cashflows)

- Evaluation services for micro grid demonstration project – provide technical advisory, project management and reporting services for a major distribution utility's micro grid demonstration project;

- Capital development / business planning – research and analysis to develop business planning long term strategies for local distribution companies, including bench marking analyses with other local distribution companies across Canada;

- Market assessments – conducted interviews, research and analysis for regulators, expert panels, and various electricity/natural gas entities regarding regulator cost assessment models, potential new product development areas, and jurisdictional/franchisee agreements between municipalities and local utilities;

- Electricity Market Pricing in Ontario – analysis on generator outputs, market pricing metrics, system operator restrictions, and transmission/distribution costs to develop forecasts and hedging strategies for various clients;

- Product Development Strategies – researched, benchmarked and analyzed global gas turbine segments and its counterparts in order to determine best product development and placement strategies for private industry clients;

- Demand Response Modeling – developed models for various clients regarding the impact of conservations/curtailment programs on total resource cost, load forecasts, and cost of power;

**Hydro One – Leadership Development Program**

**Responsibilities:**
- On 6 month rotations working through various lines of business within Hydro One

Financial Planning & Analysis – Corporate Finance
- Financial modeling and planning for Hydro One Networks and its subsidiaries; implemented updates of the revenue requirement model, quantified the impacts on distribution/transmission rates and presented financials to senior management
- Scenario analysis for other lines of business within Hydro One; provided 10 year financial outlooks on various scenarios (changes in return on equity/debt rates, capital structure allowances, project budgets etc.), which is required for project funding approvals

Investment Planning – Asset Management
- Facilitator of all Asset Management procurement procedures and contract management using SAP ECC & SRM modules
- Business planning analysis, provided reports on funding allocation of Transmission and Distribution segments of Hydro One's business plan

Regulatory Finance – Corporate Finance
- Prepared and analyzed financial information from all business units in support of the Ontario Energy Board (OEB) regulatory utility filings
- Developed Transmission & Distribution Financial Reference Base for use within Hydro One

Front End Planning – Engineering & Construction Services
- Created and designed business work processes using IBM's Line of Visibility Enterprise Modeling methodology
- Independently researched, analyzed and presented annual department metrics for management to gauge performance of group

**Education**

**Queen's University – Kingston, Ontario**
- Honours Bachelor of Science in Engineering (Electrical & Computer Option)
- Bachelor of Arts in Economics

# RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

**INTERROGATORY 14:**

**Reference(s):** **Exhibit 2A, Tab 3, Schedule 2**

Toronto Hydro has included inflation as a category of capital expenditures in its ‘Other Capital Expenditures’ investment category. It forecasts inflation for 2016-2019 to be 2.07% per year, consistent with the Statistics Canada Consumer Price Index for Toronto.

a) Why does the Applicant not build in the cost of inflation into each of its capital expenditure categories?
b) Footnote 3 references a web address which links to historic inflation information. Please provide the Statistics Canada information used to forecast inflation for 2016-2019.
c) Please explain why the Applicant believes it is appropriate to use the Statistics Canada Consumer Price Index for Toronto to measure inflation, instead of Gross Domestic Product Implicit Price Index (GDP-IPI)?

**RESPONSE:**

a) The inflation category was segregated for transparency; however, the inflation calculation was based on the underlying Distribution System Plan programs.

b) Refer to Appendix A of this Schedule for the Statistics Canada information. The forecasted rate of inflation rate for 2016 to 2019 was 2.07%. This inflation rate was the average year-over-year increase based on the Statistics Canada Consumer Price Index for Toronto.

# RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

c) Toronto Hydro believes that is appropriate to use the Statistics Canada Consumer Price Index for Toronto to measure inflation on the basis that the Toronto index provides a more accurate reflection of the inflation cost pressures of doing work in a mature urban environment like Toronto.

# Statistics Canada

Home > Summary tables >

Related tables: Consumer price indexes.

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## Consumer Price Index, by city (Index)

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| | 2002=100 | | | | |
| St. John's (N.L.) | 114.7 | 117.4 | 121.3 | 123.8 | 125.8 |
| Charlottetown and Summerside (P.E.I.) | 117.1 | 119.2 | 122.4 | 124.7 | 127.2 |
| Halifax (N.S.) | 115.3 | 117.6 | 121.7 | 123.8 | 125.2 |
| Saint John (N.B.) | 113.7 | 116.3 | 120.2 | 122.1 | 122.9 |
| Québec (Que.) | 113.2 | 114.8 | 118.2 | 120.8 | 121.9 |
| Montréal (Que.) | 113.5 | 114.8 | 118.0 | 120.4 | 121.4 |
| Ottawa-Gatineau, (Ont. part) | 113.7 | 116.6 | 120.1 | 121.7 | 122.9 |
| Toronto (Ont.) | 113.6 | 116.5 | 120.0 | 121.8 | 123.3 |
| Thunder Bay (Ont.) | 110.5 | 112.8 | 116.3 | 117.4 | 118.4 |
| Winnipeg (Man.) | 113.9 | 114.8 | 118.1 | 119.9 | 122.6 |
| Regina (Sask.) | 117.2 | 118.9 | 122.4 | 124.6 | 126.7 |
| Saskatoon (Sask.) | 118.2 | 119.6 | 122.6 | 124.4 | 125.7 |
| Edmonton (Alta.) | 121.6 | 122.9 | 126.0 | 127.4 | 129.0 |
| Calgary (Alta.) | 121.7 | 122.7 | 125.4 | 126.7 | 128.8 |
| Vancouver (B.C.) | 112.9 | 114.9 | 117.5 | 119.0 | 119.2 |
| Victoria (B.C.) | 111.9 | 113.1 | 115.5 | 116.7 | 116.3 |
| Whitehorse (Y.T.) | 113.8 | 114.7 | 118.1 | 120.8 | 122.8 |
| Yellowknife (N.W.T.) | 115.9 | 117.9 | 121.6 | 124.3 | 126.2 |

**Note:** Annual average indexes are obtained by averaging the indexes for the 12 months of the calendar year.
**Source:** Statistics Canada, CANSIM, table 326-0021.
Last modified: 2014-01-24.

To learn more about the Consumer Price Index, see Your Guide to the Consumer Price Index.

Find information related to this table (CANSIM table(s); Definitions, data sources and methods; *The Daily*; publications; and related Summary tables).

Date modified: 2014-01-24

# RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

**INTERROGATORY 15:**

**Reference(s):** **Exhibit 2A, Tab 6, Schedule 2, p.1**

Please add a column to Appendix 2-AA showing 2014 year-to-date actuals.

**RESPONSE:**

Please see Appendix A for a revised Appendix 2-AA schedule to include a column for 2014 June YTD capital expenditures.

# Capital Projects Table

| Projects | 2010 | 2011 | 2012 | 2013 | 2014 BRIDGE | 2015 TEST | 2016 TEST | 2017 TEST | 2018 TEST | 2019 TEST | 2014 Actual (YTD June) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Reporting Basis** | **CGAAP** | **CGAAP** | **USGAAP** | **USGAAP** | **USGAAP** | **MIFRS** | **MIFRS** | **MIFRS** | **MIFRS** | **MIFRS** | **USGAAP** |
| Metering | 28.4 | 22.1 | 12.1 | 12.2 | 14.0 | 24.7 | 16.6 | 14.7 | 11.7 | 13.7 | 6.8 |
| Customer Connections | 15.2 | 31.2 | 31.0 | 53.4 | 52.1 | 39.3 | 53.8 | 64.9 | 56.9 | 46.6 | 23.4 |
| Externally-Initiated Plant Relocation & Expansion | 0.7 | 5.0 | 9.8 | 18.6 | 8.8 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 3.9 |
| Load Demand | - | - | 0.3 | 2.4 | 1.1 | 12.0 | 13.9 | 14.0 | 15.7 | 19.2 | 0.0 |
| Generation Projects Protection and Control | - | - | - | - | - | 6.1 | 5.2 | 3.3 | 2.1 | 2.0 | - |
| **System Access Investments Sub-total** | **44.4** | **58.3** | **53.2** | **86.6** | **76.0** | **86.1** | **93.5** | **100.9** | **90.4** | **85.5** | **34.1** |
| Underground Circuit Renewal | 108.4 | 90.3 | 53.8 | 68.8 | 108.1 | 96.0 | 80.1 | 84.0 | 99.7 | 99.5 | 43.0 |
| Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers | - | 5.5 | 1.5 | 2.4 | 4.7 | 3.5 | 1.4 | 0.7 | 0.8 | 0.5 | 2.7 |
| Underground Legacy Infrastructure | - | - | - | - | - | 2.1 | 6.7 | 6.6 | 6.5 | 5.5 | - |
| Overhead Circuit Renewal | 25.8 | 28.3 | 23.2 | 49.0 | 53.3 | 44.0 | 23.0 | 24.9 | 25.3 | 30.3 | 30.1 |
| Overhead Infrastructure Relocation | - | - | - | - | - | 0.7 | 1.4 | 1.8 | 2.3 | 3.6 | - |
| Rear Lot Conversion | 6.9 | 16.6 | 17.5 | 23.8 | 22.7 | 17.0 | 8.1 | 10.3 | 10.3 | 13.6 | 7.3 |
| Box Construction Conversion | 5.7 | 7.1 | 0.8 | 13.8 | 23.3 | 16.8 | 20.7 | 21.1 | 21.6 | 22.7 | 9.7 |
| SCADAMATE R1 Renewal | - | - | - | 1.9 | 2.6 | 6.2 | 4.1 | 2.7 | - | - | 0.5 |
| Network Vault Renewal | 1.7 | 0.9 | 3.6 | 10.8 | 0.9 | 4.0 | 10.4 | 10.3 | 10.3 | 10.2 | 0.9 |
| Network Unit Renewal | 7.3 | 4.4 | 5.1 | 7.3 | 3.6 | 5.2 | 7.4 | 7.3 | 7.3 | 7.3 | 1.6 |
| Legacy Network Equipment Renewal (ATS & RPB) | 0.4 | 0.0 | 0.1 | 1.6 | 0.2 | 0.4 | 1.0 | 1.1 | 0.9 | 1.1 | 0.2 |
| Network Circuit Reconfiguration | - | - | - | - | - | - | 2.3 | 2.3 | 2.3 | 2.3 | - |
| Stations Switchgear Renewal | 14.9 | 12.9 | 11.6 | 7.9 | 24.6 | 11.9 | 18.9 | 25.5 | 27.6 | 22.4 | 3.4 |
| Stations Power Transformer Renewal | 1.8 | 4.0 | 2.7 | 1.7 | 1.3 | 1.7 | 2.6 | 2.6 | 2.7 | 2.7 | 0.9 |
| Stations Circuit Breaker Renewal | 0.0 | 0.9 | 0.2 | 1.0 | 2.1 | 1.7 | 1.8 | 1.8 | 2.1 | 1.8 | 0.1 |
| Stations Control & Monitoring | - | - | 0.1 | 0.5 | 0.2 | 0.1 | 0.9 | 1.1 | 1.5 | 1.4 | 0.2 |
| Stations Ancillary Systems | 0.1 | 0.1 | 0.2 | 0.6 | 0.2 | 0.7 | 0.6 | 0.4 | 0.3 | 0.4 | - |
| Station Buildings | - | - | 0.5 | 0.0 | 0.2 | 0.5 | 2.5 | 2.3 | 2.6 | 3.3 | - |
| Stations DC Battery Renewal | 0.2 | 0.2 | 0.4 | 0.3 | 0.6 | 0.3 | 0.7 | 0.7 | 0.7 | 0.7 | 0.2 |
| Reactive Capital | 25.1 | 28.6 | 29.2 | 37.4 | 32.1 | 31.9 | 32.7 | 33.1 | 33.6 | 34.2 | 17.6 |
| Worst Performing Feeder | 16.7 | 19.3 | 6.7 | 1.2 | 4.8 | 1.2 | 1.8 | 1.8 | 1.8 | 1.8 | 1.2 |
| Distribution System Communication Infrastructure | - | - | - | - | - | - | - | - | - | - | - |
| Telecom Program | - | - | - | 1.0 | 0.9 | 6.1 | 6.0 | 4.0 | - | - | - |
| **System Renewal Investments Sub-total** | **215.0** | **219.3** | **157.2** | **231.1** | **286.4** | **251.7** | **235.0** | **246.3** | **260.1** | **265.5** | **119.5** |
| Contingency Enhancement | - | - | - | - | - | 10.0 | 5.9 | 9.7 | 9.7 | 13.5 | - |
| Design Enhancements | - | - | - | - | - | 0.4 | 1.7 | 1.7 | 1.7 | 1.7 | - |
| Feeder Automation | 3.3 | 0.9 | 6.2 | 8.8 | 0.8 | 11.1 | 15.1 | 9.4 | 10.0 | 8.5 | 0.3 |
| Overhead Momentary Reduction | - | - | - | - | - | - | - | 0.6 | 0.6 | 0.6 | - |
| Handwell Upgrades | 21.1 | 32.9 | 12.6 | 11.7 | 16.2 | 5.0 | - | - | - | - | 4.0 |
| Polymer SMD-20 Renewal | - | - | - | 0.8 | 2.8 | 4.8 | - | - | - | - | 0.7 |
| Downtown Contingency | 1.1 | 4.7 | 0.1 | 1.1 | 1.0 | - | 0.7 | 0.7 | 1.0 | 0.9 | 0.5 |
| Customer Owned Station Protection | - | - | - | - | - | 0.6 | 1.0 | 1.0 | 0.8 | 0.6 | - |
| Stations Expansion | 6.9 | 32.5 | 18.6 | 61.2 | 82.2 | 54.2 | 28.5 | 36.5 | 22.0 | 44.0 | 28.6 |
| Energy Storage Systems | - | - | - | - | 1.0 | 0.5 | 1.1 | 2.2 | 3.2 | 3.8 | - |
| Local Demand Response | - | - | - | - | - | 0.2 | 2.4 | 0.6 | 0.5 | 0.3 | - |
| Grid Intelligence | 3.0 | 4.8 | 0.8 | 0.1 | - | - | - | - | - | - | - |
| EV | - | - | 0.0 | 0.0 | - | - | - | - | - | - | - |
| **System Service Investments Sub-Total** | **35.3** | **75.6** | **38.4** | **83.7** | **104.1** | **86.8** | **56.5** | **62.5** | **49.5** | **73.9** | **34.2** |
| Fleet and Equipment Services | 10.6 | 11.8 | 0.8 | 2.2 | 2.6 | 3.9 | 3.2 | 3.7 | 3.5 | 3.6 | 0.5 |
| Facilities | 12.1 | 25.3 | 6.6 | 14.5 | 90.3 | 53.8 | 24.2 | 2.0 | 2.0 | 1.9 | 41.8 |
| IT Hardware | 10.6 | 9.4 | 7.4 | 6.0 | 5.2 | 5.9 | 8.0 | 7.4 | 9.8 | 5.6 | 2.1 |
| IT Software | 22.2 | 21.2 | 14.5 | 9.6 | 10.1 | 15.5 | 16.2 | 15.8 | 16.8 | 16.8 | 3.8 |
| Radio Project | - | - | - | - | - | 6.7 | 13.7 | - | - | - | - |
| ERP* | - | - | - | 1.5 | 0.9 | 17.7 | 33.6 | - | - | - | 0.3 |
| Program Support | - | - | - | - | 0.4 | 1.2 | 0.5 | - | - | - | - |
| **General Plant Investments Sub-Total** | **55.5** | **67.7** | **29.3** | **33.8** | **109.5** | **104.6** | **99.4** | **28.9** | **32.1** | **27.9** | **48.6** |
| Miscellaneous | 12.3 | (4.2) | 4.5 | 5.4 | 3.2 | 0.9 | 1.2 | 1.2 | 1.2 | 1.2 | 2.0 |
| AFUDC | 3.5 | 5.2 | 2.3 | 3.3 | 7.1 | 6.1 | 4.3 | 4.5 | 4.6 | 4.6 | 2.3 |
| Roadcuts | - | - | 3.1 | 1.8 | 3.0 | 3.3 | 4.1 | 4.1 | 4.1 | 4.1 | - |
| EAR | 34.5 | 23.6 | - | - | - | - | - | - | - | - | - |
| Inflation | - | - | - | - | - | - | 10.2 | 18.9 | 28.0 | 39.5 | - |
| **Other Sub-Total** | **50.4** | **24.6** | **9.9** | **10.5** | **13.3** | **10.3** | **19.8** | **28.6** | **37.9** | **49.4** | **4.3** |
| **Total** | **400.6** | **445.5** | **288.0** | **445.7** | **589.2** | **539.6** | **504.2** | **467.4** | **470.0** | **502.2** | **240.7** |
| **Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)** | - | - | - | - | - | (6.3) | (5.9) | (5.1) | (5.0) | (5.4) | - |
| **Total** | **400.6** | **445.5** | **288.0** | **445.7** | **589.2** | **533.4** | **498.3** | **462.3** | **465.0** | **496.7** | **240.7** |

# RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

**INTERROGATORY 16:**

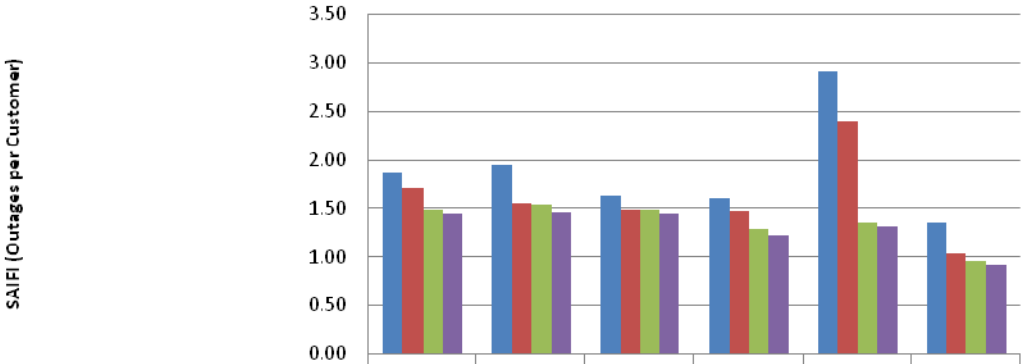
**Reference(s):** **Exhibit 2A, Tab 10, Schedule 2**

Please revise Figure 1-2, 10-11 to show 2014 year-to-date reliability information. If the Applicant is able to forecast 2014 end of year reliability information based on year-to-date actuals, please do so.

**RESPONSE:**

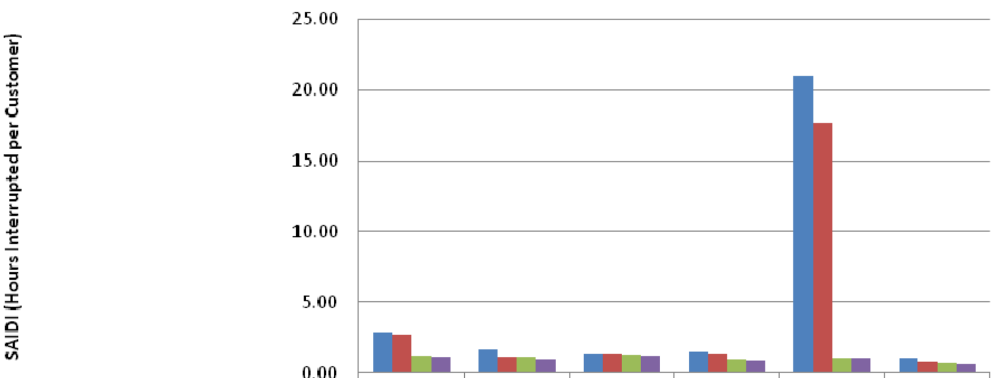
Year-to-date and forecast year-end projections for Figures 1-2 and 10-11 are provided below. However, due to the unpredictability of storms, Toronto Hydro is unable to provide any year-end projections for SAIFI or SAIDI categories that include the effects of MEDs.

# RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES




| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014YTD |
|---|---|---|---|---|---|---|
| Total SAIFI | 1.86 | 1.95 | 1.62 | 1.60 | 2.91 | 1.34 |
| SAIFI Excluding LoS | 1.71 | 1.54 | 1.48 | 1.47 | 2.38 | 1.03 |
| SAIFI Excluding MED's and LoS | 1.49 | 1.53 | 1.48 | 1.28 | 1.34 | 0.95 |
| SAIFI Excluding MED's, LoS and Planned Outages | 1.44 | 1.46 | 1.44 | 1.22 | 1.30 | 0.91 |

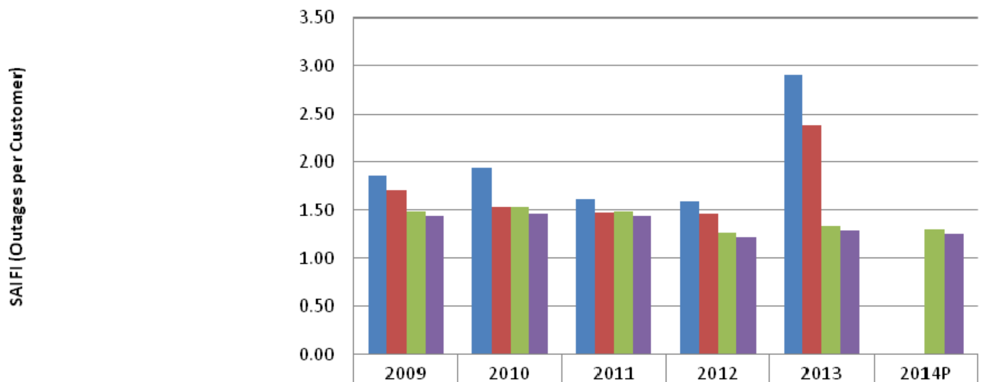
**Figure 1: Exhibit 2A, Tab 10, Schedule 2, Figure 1 reflecting 2014 Year-to-date Reliability Information**




| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014YTD |
|---|---|---|---|---|---|---|
| Total SAIDI | 2.91 | 1.66 | 1.43 | 1.50 | 21.07 | 1.11 |
| SAIDI Excluding LoS | 2.77 | 1.19 | 1.38 | 1.46 | 17.70 | 0.84 |
| SAIDI Excluding MED's and LoS | 1.24 | 1.18 | 1.38 | 0.99 | 1.12 | 0.72 |
| SAIDI Excluding MED's, LoS and Planned | 1.21 | 1.02 | 1.29 | 0.94 | 1.05 | 0.68 |

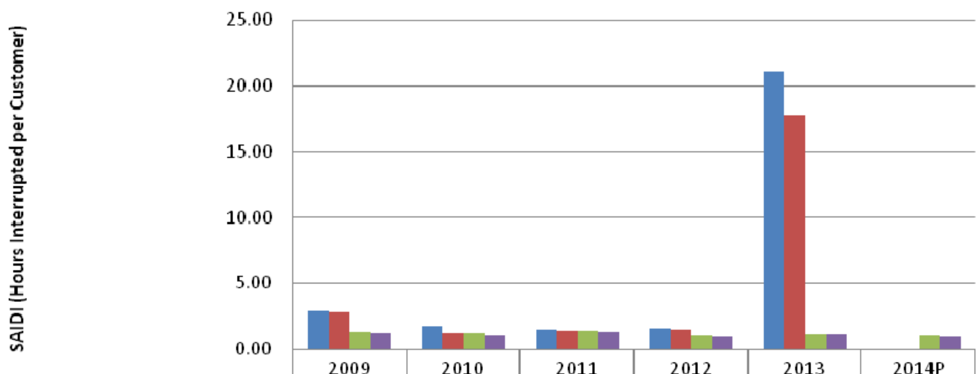
**Figure 2: Exhibit 2A, Tab 10, Schedule 2, Figure 2 reflecting 2014 Year-to-date Reliability Information**

# RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES




| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014P |
|---|---|---|---|---|---|---|
| Total SAIFI | 1.86 | 1.95 | 1.62 | 1.60 | 2.91 | |
| SAIFI Excluding LoS | 1.71 | 1.54 | 1.48 | 1.47 | 2.38 | |
| SAIFI Excluding MED's and LoS | 1.49 | 1.53 | 1.48 | 1.28 | 1.34 | 1.31 |
| SAIFI Excluding MED's, LoS and Planned Outages | 1.44 | 1.46 | 1.44 | 1.22 | 1.30 | 1.26 |

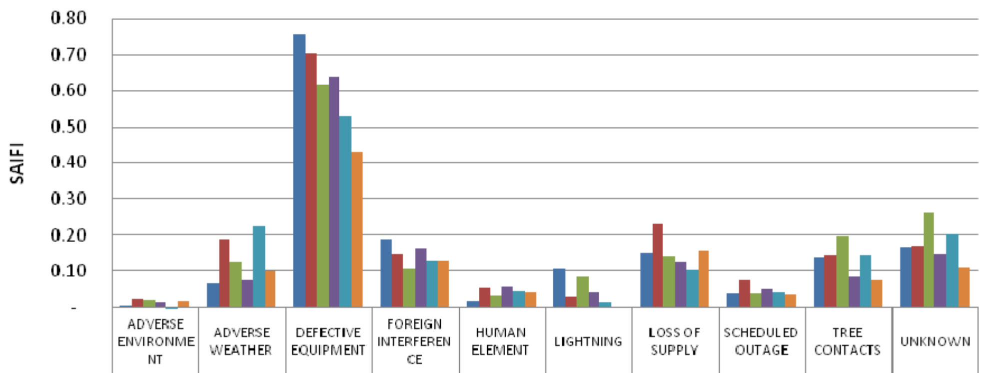
**Figure 3: Exhibit 2A, Tab 10, Schedule 2, Figure 1 reflecting 2014 Year-End Projections (Where applicable)**




| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014P |
|---|---|---|---|---|---|---|
| Total SAIDI | 2.91 | 1.66 | 1.43 | 1.50 | 21.07 | |
| SAIDI Excluding LoS | 2.77 | 1.19 | 1.38 | 1.46 | 17.70 | |
| SAIDI Excluding MED's and LoS | 1.24 | 1.18 | 1.38 | 0.99 | 1.12 | 0.97 |
| SAIDI Excluding MED's, LoS and Planned Outages | 1.21 | 1.02 | 1.29 | 0.94 | 1.05 | 0.92 |

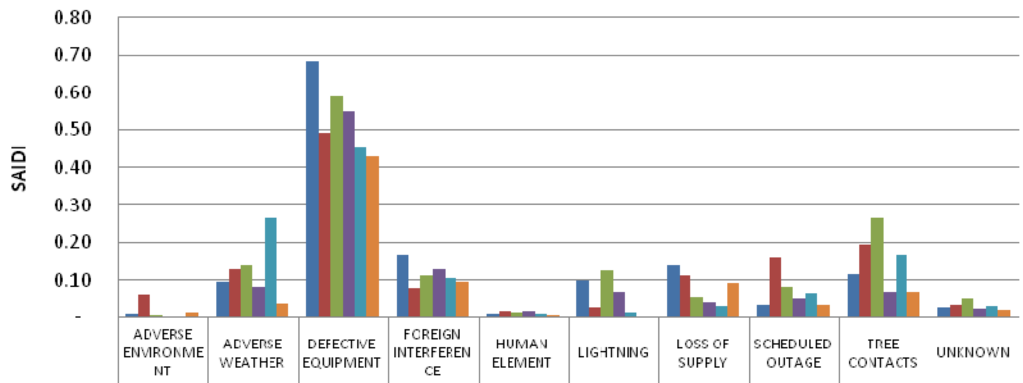
**Figure 4: Exhibit 2A, Tab 10, Schedule 2, Figure 2 reflecting 2014 Year-End Projections (Where applicable)**

# RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES




| | ADVERSE ENVIRONMENT | ADVERSE WEATHER | DEFECTIVE EQUIPMENT | FOREIGN INTERFERENCE | HUMAN ELEMENT | LIGHTNING | LOSS OF SUPPLY | SCHEDULED OUTAGE | TREE CONTACTS | UNKNOWN |
|---|---|---|---|---|---|---|---|---|---|---|
| 2009 | 0.01 | 0.07 | 0.75 | 0.19 | 0.02 | 0.11 | 0.15 | 0.04 | 0.14 | 0.17 |
| 2010 | 0.02 | 0.19 | 0.70 | 0.15 | 0.05 | 0.03 | 0.23 | 0.07 | 0.14 | 0.17 |
| 2011 | 0.02 | 0.13 | 0.62 | 0.11 | 0.03 | 0.08 | 0.14 | 0.04 | 0.19 | 0.26 |
| 2012 | 0.01 | 0.08 | 0.64 | 0.16 | 0.06 | 0.04 | 0.13 | 0.05 | 0.09 | 0.15 |
| 2013 | 0.00 | 0.23 | 0.53 | 0.13 | 0.05 | 0.02 | 0.10 | 0.04 | 0.14 | 0.20 |
| 2014YTD | 0.02 | 0.10 | 0.43 | 0.13 | 0.04 | 0.00 | 0.16 | 0.04 | 0.07 | 0.11 |

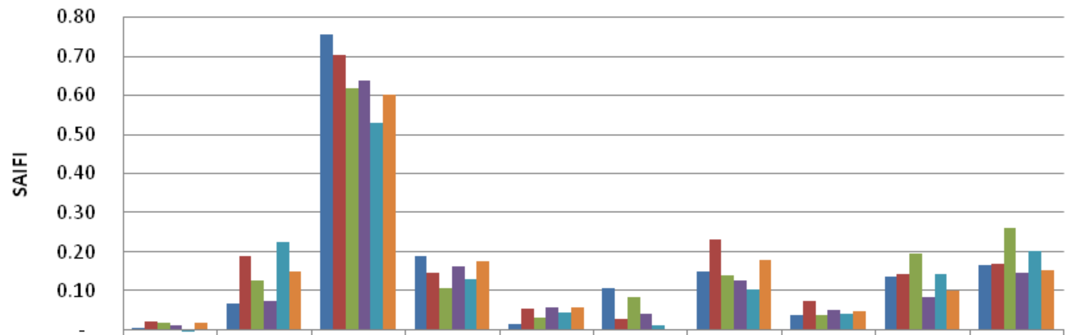
**Figure 5: Exhibit 2A, Tab 10, Schedule 2, Figure 10 reflecting 2014 Year-to-date Reliability Information**




| | ADVERSE ENVIRONMENT | ADVERSE WEATHER | DEFECTIVE EQUIPMENT | FOREIGN INTERFERENCE | HUMAN ELEMENT | LIGHTNING | LOSS OF SUPPLY | SCHEDULED OUTAGE | TREE CONTACTS | UNKNOWN |
|---|---|---|---|---|---|---|---|---|---|---|
| 2009 | 0.01 | 0.09 | 0.69 | 0.17 | 0.01 | 0.10 | 0.14 | 0.03 | 0.12 | 0.03 |
| 2010 | 0.06 | 0.13 | 0.49 | 0.08 | 0.02 | 0.03 | 0.11 | 0.16 | 0.19 | 0.03 |
| 2011 | 0.01 | 0.14 | 0.59 | 0.11 | 0.01 | 0.13 | 0.05 | 0.08 | 0.26 | 0.05 |
| 2012 | 0.00 | 0.08 | 0.55 | 0.13 | 0.02 | 0.07 | 0.04 | 0.05 | 0.06 | 0.02 |
| 2013 | 0.00 | 0.27 | 0.46 | 0.11 | 0.01 | 0.01 | 0.03 | 0.06 | 0.17 | 0.03 |
| 2014YTD | 0.02 | 0.04 | 0.43 | 0.10 | 0.01 | 0.00 | 0.09 | 0.04 | 0.07 | 0.02 |

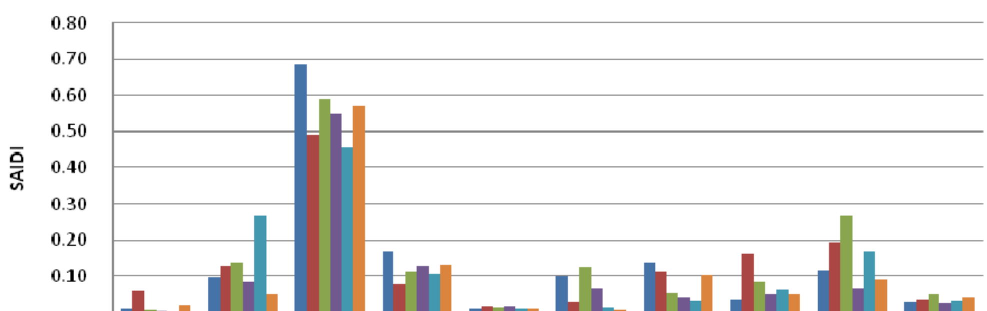
**Figure 6: Exhibit 2A, Tab 10, Schedule 2, Figure 11 reflecting 2014 Year-to-date Reliability Information**

# RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES




| | ADVERSE ENVIRONMENT | ADVERSE WEATHER | DEFECTIVE EQUIPMENT | FOREIGN INTERFERENCE | HUMAN ELEMENT | LIGHTNING | LOSS OF SUPPLY | SCHEDULED OUTAGE | TREE CONTACTS | UNKNOWN |
|---|---|---|---|---|---|---|---|---|---|---|
| 2009 | 0.01 | 0.07 | 0.75 | 0.19 | 0.02 | 0.11 | 0.15 | 0.04 | 0.14 | 0.17 |
| 2010 | 0.02 | 0.19 | 0.70 | 0.15 | 0.05 | 0.03 | 0.23 | 0.07 | 0.14 | 0.17 |
| 2011 | 0.02 | 0.13 | 0.62 | 0.11 | 0.03 | 0.08 | 0.14 | 0.04 | 0.19 | 0.26 |
| 2012 | 0.01 | 0.08 | 0.64 | 0.16 | 0.06 | 0.04 | 0.13 | 0.05 | 0.09 | 0.15 |
| 2013 | 0.00 | 0.23 | 0.53 | 0.13 | 0.05 | 0.02 | 0.10 | 0.04 | 0.14 | 0.20 |
| 2014P | 0.02 | 0.15 | 0.60 | 0.18 | 0.06 | 0.00 | 0.18 | 0.05 | 0.10 | 0.16 |

**Figure 7: Exhibit 2A, Tab 10, Schedule 2, Figure 10 reflecting 2014 Year-End Projections**




| | ADVERSE ENVIRONMENT | ADVERSE WEATHER | DEFECTIVE EQUIPMENT | FOREIGN INTERFERENCE | HUMAN ELEMENT | LIGHTNING | LOSS OF SUPPLY | SCHEDULED OUTAGE | TREE CONTACTS | UNKNOWN |
|---|---|---|---|---|---|---|---|---|---|---|
| 2009 | 0.01 | 0.09 | 0.69 | 0.17 | 0.01 | 0.10 | 0.14 | 0.03 | 0.12 | 0.03 |
| 2010 | 0.06 | 0.13 | 0.49 | 0.08 | 0.02 | 0.03 | 0.11 | 0.16 | 0.19 | 0.03 |
| 2011 | 0.01 | 0.14 | 0.59 | 0.11 | 0.01 | 0.13 | 0.05 | 0.08 | 0.26 | 0.05 |
| 2012 | 0.00 | 0.08 | 0.55 | 0.13 | 0.02 | 0.07 | 0.04 | 0.05 | 0.06 | 0.02 |
| 2013 | 0.00 | 0.27 | 0.46 | 0.11 | 0.01 | 0.01 | 0.03 | 0.06 | 0.17 | 0.03 |
| 2014P | 0.02 | 0.05 | 0.57 | 0.13 | 0.01 | 0.01 | 0.10 | 0.05 | 0.09 | 0.04 |

**Figure 8: Exhibit 2A, Tab 10, Schedule 2, Figure 11 reflecting 2014 Year-End Projections**

# RESPONSES TO SUSTAINABLE INFRASTRUCTURE ALLIANCE OF ONTARIO INTERROGATORIES

**INTERROGATORY 5:**

**Reference(s):** **Exhibit 2A, Tab 4, Schedule 1**

In THESL's Smart Meter Clearance Application (EB-2013-0287), in response to Board Staff Interrogatory 12, THESL estimated the value of its stranded meters as $13.04 million. In this application, the value is presented as $15.8 million. Please explain the variance between these two forecasts.

**RESPONSE:**

The differences in the forecasted stranded meters net book value between the response to Board Staff Interrogatory 12 (EB-2013-0287) and Exhibit 2A, Tab 4, Schedule 1 are a result of an increase in the identified quantity of stranded meters between the two applications. The response to Board Staff Interrogatory 12 (EB-2013-0287) provided a forecast value based on the best available information at that time. Exhibit 2A, Tab 4, Schedule 1 incorporates subsequent actual information, resulting in an identified increase in the quantity of stranded meters.

# RESPONSES TO SUSTAINABLE INFRASTRUCTURE ALLIANCE OF ONTARIO INTERROGATORIES

**INTERROGATORY 6:**

**Reference(s):** **Exhibit 2A, Tab 5, Schedule 1, page 4**

With regard to the transfer price of the Streetlighting Assets, THESL states that "At that time an Agreement of Purchase and Sale (the "Sale Agreement") was executed between the parties which initially provided for a transfer price of $28.5 million, subject to a detailed analysis of the NBV of the transferred assets, which analysis would then underpin an adjustment to the transfer price, if necessary." Does THESL believe that the OEB decision allows for an "adjustment to the transfer price"?

**RESPONSE:**

Please refer to Toronto Hydro's response to interrogatory 2A-OEBStaff-30 part a.

# RESPONSES TO SUSTAINABLE INFRASTRUCTURE ALLIANCE OF ONTARIO INTERROGATORIES

**INTERROGATORY 7:**

**Reference(s):** **Exhibit 2A, Tab 5, Schedule 1, page 17**

With regard to the value of the Streetlighting Assets, THESL states "However, it is still the case that the proxy value of $28.9 million provided at the time was the result of two simplifying assumptions that had to be made due to the lack of more precise information."

Did THESL at any time prior to this application indicate to the OEB that the $28.9 was intended only as a "proxy value" that would require subsequent adjustment? If not, why not?

**RESPONSE:**

In its Additional Evidence Regarding the Transfer of Streetlighting Assets, Toronto Hydro indicated to the OEB that,[1]

> should the Board approve the transaction as described herein, and subject to obtaining all necessary approvals, the Applicants intend to proceed with a transaction which is substantially similar to the transaction evidenced in the Initial Applications, except that the Asset Purchase Agreement will be updated, amended and restated to, among other matters, exclude all non-distribution assets, and the purchase price for the assets will be revised as described herein.

Please also refer to Toronto Hydro's response to interrogatory 2A-OEBStaff-30 part a.

[1] EB-2009-0180 et al., Application and Evidence (January 31, 2011), at pages 20-21.

# RESPONSES TO SUSTAINABLE INFRASTRUCTURE ALLIANCE OF ONTARIO INTERROGATORIES

**INTERROGATORY 8:**

**Reference(s): Exhibit 2A, Tab 5, page 4**

As part of the Aug 3, 2011 Decision (EB-2009-0180) the OEB accepted a transfer value of $28.9 million, stating "THESL proposed to pay $29.418 million in return for the transfer of the SEL System Assets classified as distribution assets" and concluding that "the Board finds the proposed transfer price of $28.938 to be reasonable". In its EB-2011-0144 rate application (which was ultimately dismissed), THESL relied on the original OEB decision and "proposed a slightly lower transfer price for the assets of $28.46 million, reflecting the forecast evolution of the assets (principally additions and depreciation) over 2011" (Exhibit 2A, Tab 5, Page 4)

a) Please explain why THESL accepted the OEB's Decision on the valuation of the streetlighting assets as part of its EB-2011-0144 filing, but finds it necessary to present an alternative valuation as part of this proceeding.
b) Please explain why THESL did not complete "the detailed analysis of the NBV of the transferred assets" (Exhibit 2A, Tab 5, Page 5) prior to the original OEB valuation decision.

**RESPONSE:**

a) The detailed analysis that resulted in the updated value of the assets on February 2012 was completed after Toronto Hydro submitted its pre-filed evidence in EB-2011-0144.
b) As noted at page 18 of the pre-filed evidence (Exhibit 2A, Tab 5, Schedule 1),

# RESPONSES TO SUSTAINABLE INFRASTRUCTURE ALLIANCE OF ONTARIO INTERROGATORIES

> It was necessary for Toronto Hydro to perform the detailed analysis resulting in the revised valuation in order to properly implement the OEB's Valuation Decision, and provide an accurate basis for Toronto Hydro's and TH Energy's ongoing accounting and financial reporting obligations.

As noted above, Toronto Hydro performed the detailed analysis in order to properly implement the OEB's Decisions and provide an accurate basis for Toronto Hydro's and TH Energy's ongoing accounting and financial reporting obligations. It would have been premature for Toronto Hydro to conduct the detailed analysis while the Board's Decision was still outstanding, since Toronto Hydro could not anticipate the content of that Decision.

# RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

**INTERROGATORY 8:**

**Reference(s): Exhibit 2A, Tab 1, Schedule 1, pp.7-8**

a) Please provide a breakdown of the $66.7 in capital additions that were above the Board approved in 2011 (i.e., Stray Voltage equipment/715 Milner/Other).

b) Please explain why this amount Stray Voltage Equipment and Milner Property purchase were unknown at the time of the 2011 rebasing application.

**RESPONSE:**

a) The table below details the 2011 capital additions that were above the OEB-approved amount:

| **Category** | **2011 Capex ($M)** |
|---|---|
| 715 Milner | 17.3 |
| Civil & Underground | 36.0 |
| Canadian Power Survey Corporation Lease | 13.4 |
| **Total** | **66.7** |

b) Amounts associated with the Stray Voltage Equipment were unknown at the time of the 2011 rebasing application because the capital lease with Canadian Power Survey Corporation was signed in the third quarter of 2013.

Amounts associated with the Milner Property were unknown at the time of the 2011 rebasing application because Toronto Hydro had not yet made the decision to acquire a property in the eastern part of Toronto.

# RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

**INTERROGATORY 9:**

**Reference(s): Exhibit 2A, Tab 1, Schedule 2, Continuity Schedule**

a) In 2011 through 2013 THESL shows significant additions and retirements to its Transportation Equipment (Account 1935). In 2014 no retirements are forecast and notwithstanding the forecast addition of 4.4 million in such equipment. Please explain why there are not retirements forecast for Transportation Equipment in 2014?

b) Please explain why there are no Transportation Equipment Retirements in 2015.

**RESPONSE:**

a) As shown in Exhibit 2A, Tab 1, Schedule 2 and summarized in the table below, the historical net book value amounts for retirement/transfers for Transportation Equipment are immaterial.

| | | 2011 CGAAP | 2012 UGAAP | 2013 UGAAP |
|---|---|---|---|---|
| Cost | Retirement | ($7,257,634) | ($7,623,507) | ($832,365) |
| Accumulated Depreciation | Retirement | $7,185,827 | $7,039,462 | $773,987 |
| **Net Retirement** | | **($71,806)** | **($584,045)** | **($58,377)** |

Toronto Hydro did not forecast retirements for Transportation Equipment (Account 1930) in 2014 under the assumption that any retirements will occur at the end of asset useful lives resulting in zero net book value.

# RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

b) Please refer to the response above in part a). The assumption for Transportation Equipment retirements in 2014 also applies in 2015.

# RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

**INTERROGATORY 10:**

**Reference(s):** **Exhibit 2A, Tab 1, Schedule 2, Continuity Schedule**

a) THEL's forecast contribution & grants for 2014 and 2015 appear to be significantly lower than past actuals (see table below). Please explain how the 2014 and 2015 forecast for contributions is calculated. If it is calculated based on specific connection projects please show these.

| Description | Account | 2011 | 2012 | 2013 | 2014 (MIFRS) | 2015 |
|---|---|---|---|---|---|---|
| Capital Contributions | 1995 | 36,381,079 | 22,061,046 | 23,083,937 | 17,606,991 | 15,285,779 |

**RESPONSE:**

The capital contribution recoveries for 2014 and 2015 were forecasted using the average recovery for routine customer connection jobs during 2012 and 2013, excluding unique large projects such as Civil Install Cherry Street Realignment, West Don Lands Phase 1, and Sherway Gardens Connection that resulted in a $45.1 million recovery in 2012-2013. At this time, Toronto Hydro does not have any signed offers to connect large projects with substantial recovery factors[1] in the bridge and test years. Therefore, the capital contribution recoveries for 2014 and 2015 were forecast based on the normalized historical trends for 2012 and 2013. Toronto Hydro excluded 2011 recoveries because

[1] Substantial recovery occurs where the cost to expand the system to provide the customer with additional power is not offset by an increased in load revenue, therefore a higher contribution from the customer is requested to offset the cost of the expansion work.

# RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

the definitions of system enhancements and expansion in its Conditions of Service were revised in January 2011. This change affected the contributed capital that was payable in 2011 as a large portion of the projects in that year were based on agreements which were concluded under the previous definitions.

# RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

**INTERROGATORY 11:**

**Reference(s): Exhibit 2A, Tab 5, Schedule 1, pg. 17**

a) Please show the allocation of the $10.9 million difference in value of transferred street lighting assets (39.8-28.9) as between that due to normal asset evolution and that due to valuation changes.

**RESPONSE:**

a) Please see the table below for a breakdown.

| | | in millions |
|---|---|---|
| **Value of Assets Eligible to be Transferred as per Valuation Decision** | | **28.9** |
| **Valuation Changes** | | |
| Valuation Changes of 2010 Base Assets | 13.0 | |
| 2011-2014 Depreciation of 2010 Base Assets | (7.6) | |
| **Net Valuation Change** | | 5.4 |
| | | |
| **Normal Asset Evolution** | | |
| 2011-2014 Additions | 5.7 | |
| 2011-2014 Depreciation on New Additions | (0.2) | |
| **Net Asset Evolution** | | 5.5 |
| **Value of Transferred Streetlighting Assets** | | **39.8** |

# RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

**INTERROGATORY 12:**

**Reference(s):** **Exhibit 2A, Tab 6, Schedule 1, p. 2**

a) Why did THESL change the interest rate used for CWIP to the weighted average cost of borrowing (from Board approved rate)?

What is the cost difference in 2015 of these methodologies? Given the short-term nature of project financing why would THESL's (Board's) cost of short-term not be more appropriate than the weighted costs?

**RESPONSE:**

Toronto Hydro changed the interest rate used for CWIP on transition to MIFRS. The weighted average cost of debt was applied under MIFRS to comply with Article 410 of the Accounting Procedures Handbook for Electricity Distributors, which states:

> The Board will continue to publish interest rates for Construction Work in Progress (CWIP). Where incurred debt is acquired on an arm's length basis, the actual borrowing costs should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS.

The cost difference between these methodologies in 2015 is approximately $1.2 million. It would not be appropriate to use the OEB-approved rate because it does not comply with MIFRS requirements and the Accounting Procedures Handbook.

# RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

**INTERROGATORY 13:**

**Reference(s): Exhibit 2A, Tab 6, Schedule 2, Appendix 2-AA**

a) Please explain the category Contingency Enhancement that begins in 2015.

b) Please explain the category of General Plant costs called "Inflation" is included in the capital budget.

**RESPONSE:**

a) The objective of the Contingency Enhancement program is to make improvements to feeders in the existing distribution systems that are currently unable to quickly restore power to affected customers under a contingency situation. Please refer to Exhibit 2B, Section E7.1 for more information about this program.

b) As indicated in Exhibit 2B, Section E4.2.5 (Other Capital Expenditures Spending Profile), the inflation category captures inflation costs for expenditures in 2016 through 2019. Please also refer to Toronto Hydro's response to interrogatory 2A-SEC-14.

# RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

**INTERROGATORY 14:**

**Reference(s):** **Exhibit 2A, Tab 6, Schedule 2, Appendix 2-AA**
**Exhibit 2A, Tab 1, Schedule 1**

a) Please explain the reasons for the large drop in capital/additions/spending in 2012 as compared to the previous and subsequent years.

**RESPONSE:**

a) The drop in 2012 is attributable to the immediate ramp-down of the capital program following the OEB's decision in EB-2011-0144. This ramp-down had a direct impact on the scheduling and execution of the capital program, and the resulting spending levels, in 2012.

# RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

**INTERROGATORY 15:**

**Reference(s):** **Exhibit 2A, Tab 10, Schedule 2, page 4**

Pre-amble:

The purpose of these questions is to better understand how MEDs are defined and used by THESL.

a) Please explain how a Major Event Day ("MED) thunderstorm is delineated from a "regular" thunderstorm. Are there certain conditions under which equipment flooding is categorized as part of a MED and others when it is not? Please explain how THESL divines the difference between a "major event day" and "something major that happens on a day"

**RESPONSE:**

Toronto Hydro uses the IEEE Standard 1366-2012 2.5 Beta method for calculating an MED threshold, which is then used to determine which days are considered a "major event day". This method is a SAIDI-based threshold and each year's MED threshold would be based on the past five years of data. As an example, if Toronto Hydro's daily MED threshold is ten minutes, a day would be considered to be an MED if the sum of all the events for a single day exceeds a SAIDI of ten minutes.

# RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

**INTERROGATORY 16:**

**Reference(s):** **Exhibit 2A, Tab 5, Schedule 1, p.6**
**Exhibit 2B, Section D2, Overvew of Assets Managed, p.13 and**
**Exhibit 4A, Tab 2, Schedule 1, p.**

a) In the discussion regarding streetlighting assets it states that the OIP study shows approximately 27% of poles were older than 1970. The table at 2B/Section D2, page 13 appear to show wood poles with an age of about 40%. At Exhibit 4A its states that 31% of poles will exceed 45 years. Are the findings of the Distribution plan similar or different than those for similar assets done for the streetlighting transfer?

b) Does the estimate of pole age have a bearing on THESL's pole replacement program?

**RESPONSE:**

a) Toronto Hydro confirms that proportions of poles that exceed 45 years of age are relatively similar for distribution poles (i.e., 31% for Exhibit 4A, Tab 2, Schedule 1, page 8) and for poles that are part of the streetlighting transfer (i.e., 27% for Exhibit 2A, Tab 5, Schedule 1, page 6).

b) Yes, the estimate of pole age is one of the determining factors for pole replacement decisions.