

SCHOOL ENERGY COALITION INTERROGATORIES

L1.INTERROGATORY SEC-1

Reference: Exhibit M1 [p.7, 26]

Please calculate, if it is possible, the amount of X-factor that, if inserted in Toronto Hydro's proposal, and if it resulted in reduced spending on a dollar for dollar basis, would result in Toronto Hydro's total cost over the 2020-2024 period being 5.2% above the benchmark, the same as 2015-2017. Please provide all assumptions and calculations used to obtain the result.

Response to SEC-1: The following response was provided by PEG.

A response to this request is not possible because capital cost is calculated differently in the benchmarking work than in the revenue requirement calculations.

L1.INTERROGATORY SEC-2

Reference: Exhibit M1 [p.7]

Please provide an estimate of the total capex over the 2020-2024 period that would result in Toronto Hydro's capex being the same as the benchmark predictions, and advise the capital cost of Toronto Hydro for each of those years based on that assumed level of capex. If it is possible to extrapolate a C factor formula that achieves that result, please provide. Please provide all assumptions and calculations used to obtain these results.

Response to SEC-2: The following response was provided by PEG.

The table below presents Toronto Hydro's benchmark capex and the Company's proposed capex. The associated C factor is difficult to calculate accurately because the capital costs are different in ratemaking versus benchmarking. The calculations to compute capital cost in PEG's econometric research can be found in the Appendix of Exhibit M1.

Year	Benchmark Capex	Proposed Capex
2020	\$463,124,917.88	\$499,874,176.00
2021	\$472,194,253.36	\$501,526,144.00
2022	\$481,798,823.93	\$615,883,968.00
2023	\$489,340,785.05	\$595,385,920.00
2024	\$499,260,573.76	\$588,694,720.00
Total	\$2,405,719,353.98	\$2,801,364,928.00

L1.INTERROGATORY SEC-3

Reference: Exhibit M1 [p.10,13,63]

Please estimate the C-factor formula, or average amount, if all “conventional distribution capex” is excluded from the budget calculation.

Response to SEC-3: The following response was provided by PEG.

Toronto Hydro could, in principle, be permitted to request supplemental funding only for extraordinary capex not addressed by the Z factor mechanism. The C factor, like the ICM, takes the different approach of considering all proposed capex. PEG does not know the percentage increase in revenue that would be required to fund only Toronto Hydro’s extraordinary capex.

L1.INTERROGATORY SEC-4

Reference: Exhibit M1 [p.16; EB-2014-0116, Decision and Order, p.6]

Please provide the expert's comments on whether Toronto Hydro's current C-factor and supporting capital plan deal appropriately with the Board's comment in its previous Custom IR decision: "It is not clear that Toronto Hydro's proposals are necessarily aligned with the interests of its customers, as they are largely supported by an asset condition analysis rather than the impact of the proposed work on the reliability of the system."

Response to SEC-4: The following response was provided by PEG.

PEG was not retained in this proceeding to appraise Toronto Hydro's capital plan. However, they have ventured several criticisms of the current C factor mechanism in their direct testimony and suggested modifications.

L1.INTERROGATORY SEC-5

Reference: Exhibit M1 [p.22]

Please expand upon your concerns with respect to the Ontario dummy variable.

Response to SEC-5: The following response was provided by PEG.

The purpose of an Ontario dummy variable is to account for the typical differences between the costs of sampled Ontario and U.S. power distributors which are not explained by other model variables. In PSE's response to OEB Staff IR-43-a, PSE listed the following as possible reasons for cost differences which an Ontario dummy variable might capture: incentive regulation (Ontario) versus primarily cost of service regulation (U.S.), the presence of annual econometric benchmarking in Ontario, energy efficiency/renewable mandate differences, differences in currency, the input prices assigned to Ontario versus the U.S., pension and benefit differences between the countries, and other unknown differences.¹

PEG has the following further comments on the Ontario dummy issue.

- Differences between the sampled Ontario and U.S. distributors in *actual* cost performance or the *incentives* for cost efficiency due to incentive regulation and annual econometric benchmarking are not an appropriate reason to include a regional dummy in the cost model since the model is designed to measure cost efficiency.
- Energy efficiency/renewable generation mandate differences can matter since difference in CDM programs can produce differences in the use of a utility's system. However, the models under consideration in this proceeding only have ratcheted peak demand variables.
- The input price indexes PEG and PSE use for labor and capital capture differences in currencies. However, these may be inexact. Moreover, the input price index for materials and services uses purchasing power parities ("PPPs") as a price "patch," and this could be inaccurate.
- Regional dummies may also reflect the differential impact on Ontario and U.S. distributors of excluded relevant variables and inaccurate measurement of cost.

¹ EB-2018-0165 IR 1B-STAFF-43

L1.INTERROGATORY SEC-6

Reference: Exhibit M1 [p.25-6]

Please explain why it is not more appropriate for the Board to use a productivity factor for Toronto Hydro that is more similar to the 0.31% to 0.45% range seen in the expert's Lawrence Berkeley Labs report.

Response to SEC-6: The following response was provided by PEG.

PEG believes that the OEB should resume consideration of U.S. productivity trends in its decisions on X factors for Ontario power distributors, at least in Custom IR proceedings. Here are some salient arguments in favor of this practice.

- The data available for power distributor productivity research in Ontario have some limitations, although these have not prevented useful productivity studies. Salient concerns include the recent transition to MIFRS accounting, the relatively recent benchmark years that are feasible (1989 and 2002) to begin capital quantity calculations, and Statistics Canada's suspension of its Electric Utility Construction Price indexes. Available U.S. data make possible a much earlier benchmark year (1964). Power distribution construction cost indexes are available for all years, and there is less concern about changing accounting standards.
- There are several peers for Toronto Hydro in the United States [e.g., Boston Edison (dba Eversource Energy)], Consolidated Edison of New York, Duquesne Light, Indianapolis Power and Light, Philadelphia Electric, and Potomac Electric Power] and it is desirable to know their productivity trends.
- If power distributor productivity growth is more rapid in the U.S. than in Ontario for reasons other than different business conditions, this information should be considered in setting Ontario X factors.
- U.S. power distributor productivity trends have been used to set X factors in recent IRM proceedings in Alberta, British Columbia, and Québec.
- When econometric benchmarking studies of power distributor costs based on U.S. data are submitted in Custom IRM proceedings, the incremental cost to the researcher of calculating productivity trends is materially reduced.
- The OEB is currently considering U.S. transmission utility productivity trends in the proceeding to develop an IRM for Hydro One Sault Ste. Marie, and recently considered U.S. productivity trends when setting the X factor for the hydroelectric generation services of Ontario Power Generation.
- U.S. power distributor productivity trends are calculated with some regularity. In addition to the

studies submitted in evidence in Alberta and British Columbia, studies have recently been published by Lawrence Berkeley National Laboratory and submitted by witnesses in two Massachusetts proceedings.

The reason why PEG nonetheless does not favor basing the X factor for Toronto Hydro on the results of its Berkeley Lab study (or the recent studies submitted by PEG and another consultancy in Massachusetts proceedings) is that these studies have not been properly vetted in this proceeding.

L1.INTERROGATORY SEC-7

Reference: Exhibit M1 [p.31]

Please confirm that a utility with a substantial annual capital plan should normally not be expected to have long-term declines in its outage frequencies, relative to benchmark, as exhibited from 2005 to 2024 in this table, unless the capital spending of the comparator group was relatively higher on a sustained basis than Toronto Hydro.

Response to SEC-7: The following response was provided by PEG.

PEG's reliability benchmarking model suggests that Toronto Hydro's SAIFI performance has worsened modestly since the 2009-2014 period and will worsen gradually during the proposed new IRM. This result reflects in part PEG's -0.019 estimate of the trend variable parameter. This estimate indicates that the SAIFI of sampled utilities is typically falling by 1.9% annually for reasons other than changes in the values of identified drivers of reliability. A modest deterioration in reliability performance could reflect unusually low capex, a legitimate need to focus on capex that doesn't reflect reliability, or poor reliability management. PEG's capex benchmarking indicates that Toronto Hydro's proposed capex is high. However, the model addresses only total capex, and not the capex that is most closely related to managing outage incidences (i.e., outage frequency).

L1.INTERROGATORY SEC-8

Reference: Exhibit M1 [p.39]

Please advise the range of excluded CS&I costs relative to total costs (%) in the comparator group, and for Toronto Hydro. Please explain how increases in Toronto Hydro CS&I costs, relative to benchmark, are captured, if at all, in the PSE and PEG models.

Response to SEC-8: The following response was provided by PEG.

The following table reports the ratio of excluded CS&I expenses to total included costs for Toronto Hydro and the other sampled companies as calculated by PEG.

	Ratio of Excluded CS&I Cost to Total Included Cost					
	Other Sampled Companies			Toronto Hydro		
Period	Min	Mean	Max	Min	Mean	Max
1995-2017	-4.13%	8.05%	49.88%	-	-	-
2005-2017	-4.13%	8.82%	49.88%	3.19%	6.73%	10.49%
2005-2024	-	-	-	3.19%	6.24%	10.49%
2018-2024	-	-	-	3.85%	5.34%	7.92%

It can be seen that, over the full 2005-2017 sample period for which data are available for all utilities in the sample, the ratios of the mean values are fairly similar. By construction, increases in Toronto Hydro CS&I costs would not be captured in either the PSE or the PEG models.

L1.INTERROGATORY SEC-9

Reference: Exhibit M1 [p.39]

Please advise the range of excluded pension and benefit expenses relative to total costs (%) in the comparator group, and for Toronto Hydro. Please explain how increases in Toronto Hydro pension and benefit expenses, relative to benchmark, are captured, if at all, in the PSE and PEG models.

Response to SEC-9: The following response was provided by PEG.

The following table reports the ratio of excluded pension and benefit expenses to the total included cost for Toronto Hydro and the other companies in PEG's econometric sample.

	Ratio of Excluded Pensions and Benefits Expenses to Total Included Cost					
	Other Sampled Companies			Toronto Hydro		
Period	Min	Mean	Max	Min	Mean	Max
1995-2017	-9.74%	4.20%	20.63%	-	-	-
2005-2017	-9.74%	4.33%	20.63%	2.85%	3.96%	5.08%
2005-2024	-	-	-	2.83%	3.68%	5.08%
2018-2024	-	-	-	2.83%	3.16%	3.31%

It can be seen that, over the full 2005-2017 sample period for which data are available for all sampled companies, the mean values of the analogous ratios are fairly similar for Toronto Hydro and the U.S. utilities but a little lower for Toronto Hydro, as might be expected. By construction, increases in pensions and benefit expenses would not be captured in either the PSE or the PEG models.

L1.INTERROGATORY SEC-10

Reference: Exhibit M1 [p.49]

Please explain more fully the observation: “Capital cost was higher the greater was the share of the area served that was urban, but also higher the greater was the area served that was non-urban”.

Response to SEC-10: The following response was provided by PEG.

The statement refers to the positive and statistically significant parameter estimates for both the percentage of area that is congested urban and the square kilometers of area that is not-congested urban in the capital cost model presented in Table 6 of Exhibit M1 on page 46. Capital cost should increase with the size of a utility’s service territory area, both urban and non-urban. However, urban and non-urban area may have different magnitudes of impact on capital cost. The percentage of congested urban territory has a larger estimated impact on capital cost than the non-congested square kilometers of service territory, other things equal.

L1.INTERROGATORY SEC-11

Reference: Exhibit M1 [p.52]

Please provide data showing that Toronto Hydro provides higher reliability in its downtown office district than a) other parts of its service territory, and b) the downtown areas of smaller Ontario distributors. Please provide all information available to the expert on the empirical relationship between that higher downtown reliability and higher costs to serve.

Response to SEC-11: The following response was provided by PEG.

PEG has gathered no disaggregated reliability data that could address this issue empirically but believes, based on its experience, that it is generally true that the reliability of power distributors is higher in large downtown office districts than in other areas that utilities serve. This notion is consistent with the results of PEG's econometric SAIFI research, which found that the share of the service territory that is congested urban has a statistically significant and negative parameter estimate. PEG's (and PSE's) econometric cost research of CAIDI found that the share of the service territory area that is congested urban has a statistically significant and positive parameter estimate. However, the research does not readily yield estimates of the effect of higher downtown reliability on cost. It is unclear, for example, how much the higher cost of urban congestion is due to the necessity of extensive vaulted undergrounding rather than the higher reliability that is demanded and required for key customers located in these urban cores (e.g., hospitals, major financial institutions, stock exchanges, colleges and universities, public transit and railway stations and lines).

L1.INTERROGATORY SEC-12

Reference: Exhibit M1 [p. 53]

Please provide any information available to the expert on the relationship, if any, between Toronto Hydro's annual capital cost performance over the 2005-2024 period, and the regulatory model applied by the Board to Toronto Hydro for each year.

Response to SEC-12: The following response was provided by PEG.

PEG's assessment of Toronto Hydro's capital cost performance is summarized in the Attachment to Exhibit L1/Tab 1/Schedule 26 (d). From these documents, it can be seen that Toronto Hydro's capital cost performance deteriorated in each year of PEG's sample period. The largest declines occurred in 2007-2008, 2010-2011, and 2013-2018. PEG believes that this deterioration in performance was due in part to changes in Toronto Hydro's regulatory system during this period.

PEG's understanding is that 2005 was the last of several years under which Toronto Hydro operated under a rate freeze that was preceded by a year of 1st GIRM. The Company's rates were rebased in 2006 and escalated by the 2GIRM price cap index in 2007. Between 2008 and 2011, Toronto Hydro's rates were adjusted on the basis of cost of service forecasts, due largely to the Company's claims that they had a need for capex in excess of what IRM would provide.

For the 2012-2014 period, Toronto Hydro requested a three-year stairstep attrition relief mechanism on the grounds that 3GIRM would not allow it to earn its rate of return while implementing its capex and workforce renewal plans. The Company presented several analyses showing that under incentive regulation, it would underearn or would need to cut its capex rates to "survival levels". The Company further maintained that a deferral of capex now would lead to a "snowplow effect" wherein capex would be immensely higher after the plan expired.

The OEB's response to Toronto Hydro's request to operate outside the I-X mechanism was noteworthy in several respects. First, the Board found that Toronto Hydro's financial scenarios were not credible because distributors:

... are expected to manage their resources in light of customer growth and system priorities and to seek out efficiencies and productivity improvements aggressively, and where warranted make applications using the additional 3GIRM tools of the ICM, or z-factor, or off-ramp . . . [and that the] 3GIRM framework is designed to instill cost management discipline through shareholder incentives for the benefit of ratepayers. [Toronto Hydro's] scenario assumes that the company can only respond by spending less with no prospect of productivity improvements to do the same (or more) with less. It also implies that [Toronto Hydro] would refuse to expend capital beyond the level of depreciation even though the company claims this could lead to a deterioration of its system. Good utility practice would necessitate a consideration of priorities and planning to

accommodate the needs of the system.¹

Second, the OEB noted that Toronto Hydro's productivity performance was not improving at a rate similar to other Ontario distributors and that benchmarking research indicated that they were a poor cost and bill performer. Third, the Board stated that Toronto Hydro:

... maintained that it could not conduct its business under IRM rates as that business has been planned for under an annual cost of service approach. But IRM is not intended to result in a status quo approach. The expectation is for changes in the way a distributor conducts business – not to do less – but to find efficiencies and drive productivity improvements.”²

From 2012 through 2014, Toronto Hydro's rates were instead set using 3rd GIRM. In each year, the Company requested supplemental capex funding via an Incremental Capital Module (“ICM”). In its ICM ruling on 2012 and 2013 projects, the Board broadened its ICM eligibility guidelines to include certain “business as usual” projects. The Board acknowledged that Toronto Hydro's aging infrastructure and associated capital needs were unusual in the context of the Ontario power distribution industry. However, the Board did “not expect that projects that are minor expenditures in comparison to the overall budget should be considered eligible for ICM treatment. A certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget.”³

Many of Toronto Hydro's proposed projects were nonetheless approved for ICM treatment. A separate proceeding was established to determine the degree to which forecasted capex would be trued up to actuals. Ultimately, Toronto Hydro's capex was not fully trued up to actuals, providing the company with some incentive to contain capex.

From 2015 through 2024, the Company has had and now proposes to have rates set by a Custom IR plan. C factors provide substantial supplemental revenue for capex and the benefit of capex underspends is returned to customers. The Board has struggled to appraise the need for high capex, as can be seen in both the prior Toronto Hydro Custom IR decision and the recent Custom IR decision for Hydro One Networks. Custom IR plans may encourage distributors to forecast higher levels of capex than necessary so as to justify the use of Custom IR, which does not have a mechanistic dead zone where supplemental capex funding is not provided.

This review suggests that since 2005 Toronto Hydro has not operated in most years under regulatory systems that give the Company a strong incentive to contain capex. With an aging system, the Company has been able to press a claim for supplemental capital revenue and it has been difficult for the OEB to fully reject this claim. Most capex underspends were returned to customers. Thus, relatively weak capex containment incentives may have been a contributing factor in Toronto Hydro's worsening capital cost

¹ Ontario Energy Board, Decision with Reasons and Order on the Preliminary Issue in proceeding EB-2011-0144, January 5, 2012, p. 20.

² *Ibid.*, OEB (2012), p. 17.

³ Ontario Energy Board, Partial Decision and Order, in proceeding EB-2012-0064, April 2, 2013, p. 19.

performance.