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TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

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PEG REPORT

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Toronto Hydro Electric System Limited Custom IR Application and PSE Report

Econometric Benchmarking of Toronto Hydro's Historical and Projected Total Cost and Reliability Levels

Assessment and Recommendations

December 2014

Pacific Economics Group Research, LLC

TORONTO HYDRO ELECTRIC SYSTEM LIMITED CUSTOM IR APPLICATION AND PSE REPORT

ECONOMETRIC BENCHMARKING OF TORONTO HYDRO'S HISTORICAL AND PROJECTED TOTAL COST AND RELIABILITY LEVELS

ASSESSMENT AND RECOMMENDATIONS

December 8, 2014

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1 Introduction and Executive Summary

Pacific Economics Group Research LLC (PEG) and Dr. Lawrence Kaufmann advised Board Staff on the Custom Incentive Rate-Setting ("Custom IR") application submitted by Toronto Hydro-Electric System Limited ("THESL," "Toronto Hydro" or "the Company") in July 2014. PEG was retained to review the overall Custom IR application, to assess the design of the Custom IR plan, and to analyze the Company's proposed stretch factor and custom capital factor. PEG was also asked to evaluate the technical work of Power Systems Engineering ("PSE"), which undertook benchmarking analyses of THESL's past and projected cost and service reliability performance. Where relevant, PEG was also asked to provide alternate cost and reliability benchmarking evidence.

This report presents: 1) the findings of PEG's review of the PSE work; 2) a brief analysis of the Company's proposed stretch factor and custom capital factor; and 3) PEG's ratemaking recommendations for THESL in light of these conclusions. PEG reviewed the prefiled evidence, updated evidence, and responses to interrogatories and technical conference questions before finalizing this report.

Overview

PEG's review indicates that PSE's conclusions regarding Toronto Hydro's cost and reliability performance are largely, but not entirely, unfounded. Based on an econometric analysis of THESL and 85 US utilities, PSE's analysis indicated that THESL's 2010-2012 costs were 31.1% below the costs expected for an average electric utility operating under the Company's business conditions. PEG's review identified a number of areas in which the costs of THESL and the US were not comparably defined or measured. After correcting and/or controlling for these differences, and eliminating an unwarranted "urban core dummy" variable from PSE's econometric cost model, PEG found THESL's costs were 9.7% *above* its expected costs. The Company's total costs are projected to be 34.7% above its expected costs in 2019, the final year of its Custom IR plan.

PEG's review partly confirmed PSE's reliability benchmarking conclusions. Based on an econometric analysis of THESL and 46 US utilities, PSE found the Company's SAIFI performance was 73% above its expected value but found THESL's SAIDI was 50% below its expected SAIDI. PEG believes the data PSE used for its reliability benchmarking are not suitable for regulatory application, so we compiled an alternative SAIFI and SAIDI dataset and used it to estimate alternate SAIFI and SAIDI benchmarking models. Using these data and models, PEG confirms PSE's finding that THESL's SAIFI is far above its expected level, but we find the Company's SAIDI is not statistically different from its expected level.

Overall, PEG finds THESL has been a sub-par performer with respect to cost and reliability. Given these findings, the proposed stretch factor of 0.3% in the Company's Custom IR plan is not warranted. PEG believes a stretch factor between 0.6% and 1% is appropriate and consistent with Toronto Hydro's historical and projected cost performance. We recommend that a stretch factor within this range be applied to the Company's capital and OM&A costs. In addition, the Company's proposed C factor should include an adjustment for the growth in THESL billing determinants to prevent the C factor from over-recovering capital cost. PEG's recommended C factor adjustment will eliminate over-recovery of capital costs and reduce THESL's price growth by an estimated 1.5% per annum in 2016 through 2019.

PEG also believes there may be value to ratepayers in extending the period of THESL's capital spending program. Doing so is consistent with the RRFE principles of pacing and prioritization of capital spending, while at the same time managing the pace of rate increases for customers. PEG therefore recommends that the capital expenditures in THESL's Custom IR plan be spread out over eight years (2015-2022) rather than concentrated in five years (2015-2019).

Below we present a chronological, chapter-by-chapter summary of PEG's main findings.

Interpretation and Regulatory Application of PSE Benchmarking

PEG believes PSE's interpretation of its technical benchmarking analysis is problematic. PSE's interpretations of its benchmarking results are sometimes not consistent with the actual statistical hypotheses they are testing. The cost benchmarking models PSE applies are specifically designed to assess the efficiency of cost performance. This is also how the Board currently applies statistical benchmarking in Ontario regulation. Using these models to benchmark the "reasonableness" of THESL's cost forecasts is tantamount to benchmarking THESL's cost efficiency during the period being forecast. However, PSE does not accept this interpretation, but at times attempts to use its benchmarking models to draw unwarranted conclusions about the impact of THESL's cost management on its SAIFI performance. There is no logical or empirical basis for these conclusions in PSE's benchmarking work.

PEG also has concerns with the regulatory application of PSE's benchmarking results. PSE has employed inconsistent and contradictory standards for evaluating THESL's performance. This creates ambiguity that would be avoided if the analysis focused on the hypotheses the benchmarking models are designed to test. PEG also believes that PSE's view on aligning utilities with external, average performance standards represents a misapplication of benchmarking and is likely to be incompatible with the Board's objectives for incentive regulation.

PSE's Cost Benchmarking

PEG reviewed PSE's cost benchmarking work in three steps. The first step addressed PSE's measure of costs for THESL. The starting point for PEG's cost benchmarking work in 4thGenIR study was the benchmark cost measure we developed for THESL and other Ontario utilities. However, PSE selected and used the more limited, TFP-based cost measure for THESL as the basis for its analysis. When the appropriate, benchmark-based costs for the Company are used in PSE's analysis, the difference between THESL's actual 2010-2012 costs and its predicted costs changes from the -31.1% reported by PSE to -21.3%.

THESL's costs were also not comparable to the costs of US utilities in several respects. PEG standardized the treatment of the costs of uncollectible accounts, DSM expenses, and contributions in aid of construction (CIAC) across THESL and the US sample. PEG also eliminated several US companies from PSE's US sample because of mergers during the sample period. When these changes are made, the difference between THESL's actual 2010-2012 cost and its predicted cost changes from -21.3% to -6.3%.

The third stage of PEG's review examined PSE's business condition variables. PEG made two necessary changes to PSE's selected business conditions. The first was adding a variable to reflect MVa of transformer capacity for stations with primary voltage levels at or above 50 kV. This variable is necessary to control for US utilities' costs of owning high voltage assets. The second was eliminating the urban core dummy variable from PSE's model because it is redundant, inappropriate in electricity distribution benchmarking, and appears to distort the estimated impact of other business condition variables (especially undergrounding). When these changes are made, the difference between THESL's actual and predicted costs changes from -6.3% to +9.7%. Over the term of the Company's Custom IR plan, the difference between THESL's projected and predicted costs rises further to 34.7% by 2019. The differences between the Company's projected and predicted costs are statistically significant.

PEG's review therefore finds that THESL is projected to be an inefficient cost performer when it is compared to US electric utilities. This differs from PSE's conclusion. However, making necessary changes to THESL cost data, modifying the data and business conditions to make THESL and US cost data more comparable, and eliminating an inappropriate urban core dummy variable changes the difference between the Company's actual and predicted costs from PSE's reported -31.1% to +9.7%. Most of this difference can be attributed to problems with the THESL and US utility data used by PSE. PEG's finding that THESL's projected costs exceed its expected, benchmark costs is consistent with PEG's benchmarking conclusion from Ontario, where THESL was an inferior cost performer compared with Ontario electricity distributors.

PSE's Reliability Benchmarking

PEG carefully reviewed the data that PSE assembled and used to estimate its reliability benchmarking models. We found that PSE could not identify the source of 22.1% of its SAIFI or SAIDI observations. PEG also found that 15.2% of PSE's SAIFI data and 17.6% of its SAIDI data were inaccurate.

PEG believes these are serious errors and omissions. Reliability benchmarking is still new in Ontario. The Board must have confidence in the data that are used to estimate reliability benchmarking models. This is particularly true since SAIFI and SAIDI data will differ among sampled companies for a variety of reasons. Because of its failure to document sources and data processing errors, PEG does not believe PSE's US dataset is suitable for regulatory application, and we recommend that the Board give no weight to PSE's reliability benchmarking.

PEG compiled its own reliability data and used these data to estimate SAIFI and SAIDI econometric models. Our sample period excluded the 2012 year because of the distorting impact of Hurricane Sandy. We found that measured SAIFI and SAIDI are both negatively related to the share of a utility's capital that is underground and are positively related to lighting strikes, variance in elevation, CDD and the amount of precipitation. SAIDI is also positively related to HDD and has a positive, statistically significant time trend.

PEG used these econometric models to benchmark THESL's SAIFI and SAIDI performance. In 2009-2011, we found THESL's SAIFI exceeded its benchmark value by 78.7%, and the difference was statistically significant. For SAIDI, we found THESL's SAIDI was below its benchmark by 20.6%, but the difference was not statistically significant.

Although PEG recommends that no weight be placed on PSE's reliability benchmarking, it is interesting to note that PEG and PSE both find THESL's SAIFI performance is far below what is expected. However, our findings differ somewhat with respect to SAIDI. PSE estimates that THESL's SAIDI is well below expected levels. PEG finds THESL's SAIDI is not statistically different from expected levels.

Simultaneous Cost and Reliability Benchmarking

Statistical analysis can be used to explore the relationship between electricity distributors' cost and reliability, instead of treating each as a stand-alone benchmarking exercise. Statistical tools can also quantify how this relationship is impacted by differences in business condition variables such as scale of outputs, customer density, and asset undergrounding. These are inherently empirical issues and therefore potentially amenable to statistical quantification and testing. While benchmarking cost and reliability simultaneously does pose a number of challenges, the simultaneous benchmarking of cost and reliability is in essence similar to the cost benchmarking analyses that the Board employed in 4thGenIR. Statistical methods and data sources are available to address the challenges involved with simultaneous cost and reliability benchmarking.

In fact, PSE has presented other evidence in this proceeding that addresses the cost-reliability relationship more directly. PSE has developed what it calls a "SAIDI impact benchmark model." This model was designed to address and evaluate the cost-effectiveness of reliability projects by examining the impact of utilities' capital spending on SAIDI, after controlling for the effects of other factors that influence SAIDI.

If the key result from the SAIDI impact benchmark model is applied to THESL, it shows that THESL's increase in capital spending is expected to lead to declines in SAIDI from 71.4 minutes in 2014 to 68.8 minutes in 2015, 66.4 minutes in 2016, 64 minutes in 2017, 61.7 minutes in 2018, and 59.5 minutes in 2019. In contrast, THESL projects smaller declines in SAIDI in each of these years. THESL's capital spending is therefore projected to lead to less SAIDI improvement than what PSE's SAIDI impact benchmark model predicts for an average utility investing the same amount as THESL.

PEG does not endorse the SAIDI impact benchmark model, but it is interesting because it shows statistical methods can be used to understand the interaction between distributors' cost and reliability performance. It is feasible to develop models that simultaneously benchmark cost and service reliability, and there may be merit in further research on this topic if the interaction between cost and reliability performance is expected to remain an important regulatory issue in Ontario.

THESL's Proposed Stretch Factor and C Factor

THESL and PSE both recommend a 0.3% stretch factor as part of the Price Cap Index in the Custom IR rate adjustment formula. This represents a reduction from the 0.6% stretch factor THESL would be assigned if it elected the Price Cap IR option. PSE explicitly bases this recommendation on the findings of its econometric research, since the difference between the Company's projected and expected costs under the Custom IR plan is within the +/- 10% band the Board established for the cohort of distributors that were assigned a 0.3% stretch factor.

PEG's review finds that PSE's recommendation is unwarranted. Our appraisal indicates that, in a US-only benchmarking study, THESL's costs are projected to be 34.7% above its expected costs under the Custom IR plan. A 34.7% difference between projected and benchmark costs would put THESL in the cohort of distributors assigned a 0.6% stretch factor in Price Cap IR. It is noteworthy that this finding supports PEG's conclusion regarding THESL's cost performance in our Ontario cost benchmarking study.

It should also be noted that the Company exhibits generally poor reliability performance. PSE and PEG agree that THESL's SAIFI is far greater than what is expected for a utility operating under its business conditions. PEG's analysis also indicates that THESL is an average SAIDI performer. Since THESL displays poor cost performance and average to poor reliability performance, PEG believes a stretch factor in excess of 0.6% may even be appropriate for THESL. There are precedents for stretch factors of 1% in North American incentive regulation. PEG therefore recommends that the stretch factor in THESL's Custom IR price cap index be no lower than 0.6% and no higher than 1%.

The C factor in THESL's Custom IR plan is designed to recover capital-related costs that exceed the funding for capital expenditures implicitly provided by the plan's "I – X" rate adjustment mechanism. THESL's C factor employs a sound method for ensuring that the C factor reflects only incremental capital spending, but the proposed C factor does not appropriately translate those cost changes into price changes. THESL's C factor will lead to revenue adjustments that exceed the change in capital costs because it does not account for the revenue growth resulting from changes in billing determinants. To ensure that the C factor recovers only the change in incremental capital spending, it should be modified to reduce the change in prices by the annual change in a revenue-share weighed average of THESL's billing determinants. This adjustment can be easily calculated and implemented using THESL billing data.

Concluding Remarks and Ratemaking Recommendations

Overall, PEG finds THESL has been a sub-par performer with respect to cost and reliability. Given these findings, and a broader review of the Company's Custom IR application and the record in this proceeding, PEG recommends the following changes to Toronto Hydro's Custom IR proposal:

1. Adopt a stretch factor of between 0.6% and 1% rather than THESL and PSE's recommended 0.3%
2. Apply the stretch factor to both OM&A and capital costs under the Custom IR plan
3. Apply an adjustment to the C_n factor in each year to net off the annual growth in billing determinants

4. Spread the Company's proposed capital expenditures over the eight year, 2015-2022 period rather than the proposed five year, 2015-2019 period

PEG's estimates that its recommendations will reduce growth in THESL prices over the 2016-2019 period from the Company's estimated 6.26% per annum to 2.07% per annum. About 40% of the reduction in THESL's price escalation can be attributed to the addition of the billing determinant adjustment. Just over 10% of the reduction in THESL's price escalation results from the increased stretch factor and the application of this stretch factor to capital as well as non-capital costs. The remainder is due to spreading the Company's capital expenditures over an eight-year period rather than a five-year period.

This report is structured as follows. After this introduction, Chapter Two discusses the interpretation and application of PSE's benchmarking results. Chapter Three presents our analysis of PSE's cost benchmarking work. Chapter Four discusses PSE's reliability benchmarking work and presents alternate results. Chapter Five considers the simultaneous benchmarking of cost and reliability. Chapter Six assesses THESL's proposed stretch factor and custom capital factor. Chapter Seven presents concluding remarks and recommendations.

There are also two appendices. Appendix One summarizes the data sources used in PEG reliability datasets. Appendix Two presents some technical details of PEG's econometric modeling.

2 Interpretation and Application of Benchmarking Results

Before addressing the technical details of PSE's benchmarking analysis, this chapter will consider how PSE has interpreted and applied its benchmarking results in THESL's Custom IR application. After briefly summarizing PSE's work, we assess how PSE has interpreted its findings. We then consider the application of PSE's results in light of the Board's objectives for incentive regulation.

2.1 Summary of PSE Benchmarking Results

PSE benchmarked Toronto Hydro's cost and reliability performance on a historical and forward-looking basis. For the cost benchmarking, PSE compared THESL's actual and forecast total costs to econometric projections of the Company's costs over the same periods. Similarly, PSE's reliability benchmarking compared THESL's actual and forecast values for SAIFI and SAIDI to econometric projections of those values.

PSE estimated its econometric models using samples from two broad jurisdictions. One was a "combined sample" of Ontario electricity distributors (including THESL) and US electric utilities. The second was a "US-Only" sample of US electric distributors plus THESL.[1] PSE expanded the sample beyond the Ontario database PEG used to benchmark costs in Fourth Generation Incentive Rate-setting ("4th Gen IR") because it claimed Toronto Hydro is an "extreme outlier" in the Province in size and because it serves Toronto's "urban core"/central business district.

PSE developed estimates of the "drivers" of cost performance, SAIFI performance, and SAIDI performance for the sampled utilities. Separate estimates of these cost and reliability drivers were developed using the combined sample and US-Only sample. Since PSE estimated three different econometric models using two different samples, the PSE report presents estimates for six different benchmarking models. The sample period in each model was 2002-2012.

[1] There were 85 US utilities and 71 Ontario utilities in the combined sample for the cost model, and 46 US utilities and 70 Ontario utilities in the combined sample for the SAIFI and SAIDI models. The US-Only samples therefore had 85 US utilities plus THESL for the cost model and 46 US utilities plus THESL for the SAIFI and SAIDI models. The number of US utilties differed across the cost and reliability models because fewer US utilities had available data on SAIFI and SAIDI.

For the combined sample, PSE finds that Toronto Hydro's historical costs are below those predicted by the econometric model.[2] PSE writes that "…prior to 2007 the company was consistently near 30% below benchmark expectations. This is suggestive that the company's capital was in need of investment."[3] In 2010-2012, PSE estimates that THESL's actual costs were 21.5% below the costs predicted by the econometric model, and the difference was statistically significant at the 10% level.

For the 2014 to 2019 period, PSE finds "the projected total cost levels during the Custom IR period remain below the benchmark predictions, although they do converge towards benchmark expectations, and the 'statistically below expectations' conclusion is no longer statistically significant at a 90% confidence level."[4] The fact that THESL's measured cost performance under the Custom IR plan is no longer significantly below expected cost is an indicator that its cost performance, as measured by PSE's "performance" definition and equation presented on p. 23 of its report, is deteriorating under the plan. PSE concludes that "nevertheless, they (the benchmarking models) indicate that the company's proposed spending levels are reasonable and well within the normal range of model expectations."[5]

For the reliability benchmarking, PSE finds that THESL's SAIFI values in 2010-2012 were 73% above those predicted by the econometric model. This indicates that the average THESL customer is experiencing about 73% more outages than would be expected for an average utility operating under the Company's business conditions. THESL's SAIDI, on the other hand, is 50% below the econometric prediction for the 2010-2012 period. Under THESL's Custom IR plan, SAIFI is projected to decline but still remain an average of 41% above the benchmark prediction for the 2015-2019 period. SAIDI is projected to decline even further under Custom IR and hence remain well below econometric forecasts for SAIDI.

Because THESL's total costs under Custom IR remain within benchmark projections, PSE concludes that THESL's spending under the Custom IR plan is reasonable from a benchmarking perspective. PSE also finds THESL's plan to address SAIFI is reasonable from a benchmarking perspective because SAIFI is projected to decline. Bringing these

[2] Although the quantiative values are different, PSE's analysis and conclusions for the combined sample also apply to its results from the US-Only sample.

[3] Power System Engineering (PSE), *Econometric Benchmarking of Toronto Hydro's Historical and Projected Total Cost and Reliabiilty Levels*, Report prepared on behalf of Toronto Hydro-Electric System Limited, p. 33.

[4] PSE, *op cit*, p. 5.

[5] PSE, *op cit*, p. 33.

conclusions together, PSE finds that “from a benchmark perspective, the projections to 2019 show that Toronto Hydro’s spending forecasts will converge the company’s SAIFI and total costs towards the benchmark expectations (red dot in Figure 6). SAIDI is projected to remain at a very strong level. Based on the projections, the projected spending will result in a utility more aligned with its externally-derived benchmark values from both a total cost and SAIFI perspective.”[6] Given PSE’s previously-stated conclusions that THESL’s costs and SAIFI under Custom IR are both reasonable from a benchmarking perspective, it follows logically that PSE believes “a utility more aligned with its externally-derived benchmark values” for total cost and SAIFI is also a reasonable outcome from a benchmarking perspective.

2.2 Interpretation of Benchmarking Results

PEG believes PSE’s interpretation of its technical benchmarking analysis is problematic. There are two main problems with these interpretations, both primarily stemming from PSE’s attempt to evaluate two aspects of THESL’s performance - cost and reliability - simultaneously. The first is PSE’s interpretations are sometimes not consistent with the actual statistical hypotheses they are testing. A second, related problem is that PSE draws conclusions that have no empirical basis in the benchmarking analysis it performs.

On the first issue, it must be recognized that PSE undertakes statistical cost benchmarking that, by its nature, is designed to address a specific hypothesis. The hypothesis addresses the difference between THESL’s actual (or projected) cost in a specific time period and the costs predicted for THESL. Predicted costs are equivalent to the costs of a utility with a sample-average level of cost efficiency operating under the same business conditions as THESL. The econometric benchmarking model is designed to test whether the subject utility’s cost is significantly different from its predicted cost. If so, the analyst has a rigorous basis for inferring that the subject utility is either a good cost performer (if cost is below predicted cost and the difference is statistically significant) or a bad cost performer (if cost is above predicted cost and the difference is statistically significant). This is equivalent to inferring that the subject utility exhibits efficiency with respect to cost management that is, respectively, above or below the average level of cost efficiency in the sample.

[6] PSE, *op cit*, pp. 8-9.

Analogous points apply to reliability benchmarking. When benchmarking SAIFI, the hypothesis is whether there is a statistically significant difference between THESL's actual (or projected) values for SAIFI and the values predicted for THESL. If so, there is a rigorous basis for inferring that THESL is either a good or bad performer with respect to managing its SAIFI performance. The same is true for SAIDI benchmarking.

PSE often draws conclusions from its benchmarking results that are not consistent with these hypotheses. For example, PSE's claim that THESL costs 30% below predicted costs are "suggestive that the company's capital was in need of investment" is not an appropriate inference. There is nothing in the structure of the statistical exercise or the hypothesis being tested that supports this conclusion. In fact, if PSE's statement is correct, an equally reasonable inference would be that the Company had been an *inefficient* rather than an efficient cost performer in recent years. The failure to invest when investment is needed could be an example of inefficient cost deferment, which the Board should want to discourage, rather than cost savings from efficiency gains. In addition, if PSE believes THESL has been inefficiently deferring costs, its benchmarking study provides no quantitative basis for discerning whether capital or OM&A expenditures are the costs that had been deferred. PSE's conclusion that "the company's capital was in need of investment" is simply speculation; this conclusion does not follow logically or empirically from the benchmarking studies it has presented.

It is also worth noting that PSE does not acknowledge that the purpose of its statistical cost benchmarking is to make inferences on THESL's cost efficiency. PSE instead claims that the purpose of its analysis "has been to evaluate the reasonableness of Toronto Hydro's historical and projected total cost amounts and system reliability metrics."[7] Indeed, PSE even says it "was not tasked with explicitly evaluating Toronto Hydro's efficiency."[8]

These interpretations are insupportable. PSE's statistical benchmarking model is similar in form and technical detail to the model PEG developed in 4thGen IR, although PSE has applied this model to other datasets and used different independent variables. The Board is using PEG's benchmarking model to assign stretch factors for Ontario distributors in 4thGenIR. The November 4, 2013 *Report of the Board: Ratesetting Parameters and*

[7] PSE, *op cit*, p. 1.
[8] Responses to Ontario Energy Board Staff Interrogatories, PSE response to Interrogatory 17 c).

Benchmarking Under the Renewed Regulatory Framework for Ontario's Electricity Distributors describes the Board's decision to use PEG's model for this purpose as follows:

> "the Board has determined that distributors will be assigned to one of five groups with stretch factors based on their efficiency as determined through PEG's econometric total cost benchmarking model."[9]

The Board's finding in 4thGenIR that efficiency is "determined through PEG's total cost benchmarking model" also applies logically to PSE's cost benchmarking model, because this model is identical in substance to the PEG model even though it differs in empirical implementation.

In sum, PSE's interpretation of its benchmarking results is often problematic. The cost benchmarking models PSE applies are specifically designed to assess the efficiency of cost performance. This is also how the Board currently applies statistical benchmarking in Ontario regulation. Using these models to benchmark the "reasonableness" of THESL's cost forecasts is tantamount to benchmarking THESL's cost efficiency during the period being forecast. PSE does not accept this interpretation, but instead attempts (at times) to use its benchmarking models to draw unwarranted conclusions about the impact of THESL's cost management on its SAIFI performance.

These are not pedantic issues or immaterial distinctions. It is important for analytical and statistical tools to be "fit for purpose" and for technical results to be interpreted appropriately. The relationship between THESL's cost and reliability performance may be relevant to the Custom IR application, but PSE would have to develop different benchmarking models to provide evidence on this topic. The statistical benchmarking models PSE employed are variants of PEG's cost benchmarking model, and PEG's cost benchmarking model has not been designed to explore this issue. Chapter Five will discuss some modelling issues associated with assessing cost and reliability simultaneously.

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[9] November 4, 2013 *Report of the Board: Ratesetting Parameters and Benchmarking Under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, p. 19.

2.3 Application of Benchmarking Results

PEG believes the regulatory application of PSE's results is problematic in at least two respects. First, PSE uses different criteria rather than a single standard to judge the "reasonableness" of THESL's cost and reliability performance under Custom IR. Second, PSE's application of "externally-derived benchmark values" is inappropriate and appears to be incompatible with the Board's objectives for incentive regulation.

On the first point, there is an inconsistency, and contradiction, in how PSE assesses the reasonableness of THESL's cost performance and its SAIFI performance. PSE finds THESL's costs to be reasonable because they are less than benchmark costs, even though THESL's costs under Custom IR are increasing over time relative to predicted costs. Conversely, PSE finds THESL's SAIFI to be reasonable because it is declining under Custom IR, even though SAIFI exceeds its benchmark level in every year of the plan. PSE's judgment on the reasonableness of THESL's cost therefore depends entirely on the *level* of cost compared to its benchmark; PSE's judgment on THESL's SAIFI depends entirely on the *change* in SAIFI relative to its benchmark.

There is no logical reason to judge the reasonableness of cost by one standard and the reasonableness of SAIFI by another. Doing so creates confusion and, more fundamentally, leads to ambiguities and contradictions in how performance is evaluated. For example, suppose PSE applied the "level" standard to both cost and SAIFI under Custom IR; its conclusion would now be that THESL's cost was reasonable but its SAIFI not. Alternatively, suppose PSE applied the "change" standard to both cost and SAIFI under Custom IR; now SAIFI would be deemed reasonable but cost would not. Finally, suppose PSE reversed the criteria, and cost under Custom IR was judged by the "change" standard and SAIFI by the "level" standard; in this case, neither cost nor SAIFI would be considered reasonable.

This ambiguity can be avoided by focusing directly on the hypotheses the benchmarking models are designed to test. Conclusions on the reasonableness of costs and reliability would then be determined by statistical tests that lead to rigorous inferences on whether THESL is an average, superior, or inferior performer with respect to cost and reliability performance. The temporal pattern of these test results can then be examined to evaluate how the Company's cost and reliability performance is (or is not) changing over time.

Instead of taking this approach, however, PSE's summary conclusion is that THESL's Custom IR plan will "result in a utility more aligned with its externally-derived benchmark values from both a total cost and SAIFI perspective." As previously discussed, PSE's statements preceding this conclusion imply that it views such an outcome as reasonable. PEG disagrees. We believe PSE's conclusion represents a misapplication of benchmarking models and is likely to be incompatible with the Board's objectives for incentive regulation.

It is important to remember that PSE's benchmark predictions for THESL reflect the average performance standards for cost and reliability within the samples used to estimate the econometric models. In general, incentive regulation should be designed to encourage superior performance by subject utilities, not average performance. Good incentive regulation also clearly encourages performance *improvements* by utilities subject to IR plans.

The desirability of a utility becoming "more aligned with its externally-derived benchmark values" therefore depends critically on the utility's performance at the outset of the plan. If the utility is a superior performer before the plan starts, then becoming more aligned with the average performance standards inherent in the econometric benchmark would represent a degradation in performance. Such an outcome is obviously contrary to good regulatory practice.

However, if PSE's cost benchmarking is (for now) taken at face value, it projects that this outcome would result from THESL's Custom IR plan. PSE finds THESL is a superior cost performer in 2010-2012, when its actual costs were 21.5% below benchmark costs (determined using the combined sample). This difference was statistically significant at the 10% level. The Custom IR plan is to take effect in 2015, and at its conclusion in 2019 PSE projects that THESL will be an average cost performer, with no statistically significant difference between THESL's projected and predicted costs. This trend is evident in Table 6 (millions of $ for actual and predicted cost) of the PSE report.

Year	Projected THESL Cost	Predicted THESL Cost	% Difference
2014	730	845	14.7%
2015	823	884	7.1%

2016	887	935	5.3%
2017	947	985	3.8%
2018	1001	1037	3.5%
2019	1064	1092	2.6%

The data in Table 6 can be re-expressed to show why THESL's cost performance declines under the Custom IR plan. If we examine the annual changes in THESL's projected costs, annual changes in benchmark costs, and the dollar value of this difference over the term of the IR plan, PSE's results (again, taken for now at face value) show the following:

Year	Change THESL Cost	Change Predicted THESL Cost	$ Difference
2015	93	39	-54
2016	64	51	-13
2017	60	50	-10
2018	54	52	- 2
2019	63	55	- 8
Cumulative			- 88

This table shows THESL's projected change in costs exceeds the Company's predicted change in costs in every year of the plan. PSE's results therefore imply THESL costs are growing more rapidly than the cost changes expected for a utility with average cost efficiency which faced the same projected business conditions as the Company in 2014-2019. As a result, PSE estimates that THESL's measured efficiency will decline (from 21.5% below the benchmark in 2010-12 to 2% below in 2019) under its Custom IR plan.

Even for a sub-par cost performer, the desired objective is not to become "aligned" with the average performance benchmark but instead move continuously in the direction of better performance each year. Benchmarking can support these incentives in various ways. For example, benchmarking models can set "stretch" goals that are embodied in regulation, with declining stretch factors as utilities become increasingly efficient.[10] The Board's

[10] This approach is consistent with establishing objective, above-average performance standards (but not "frontier" efficiency standards) for all utilities in the industry.

4thGenIR decision is an example of a well-designed regulatory framework that appropriately integrates benchmarking in this manner. Allowing superior cost performers simply to become "aligned" with externally-derived benchmarks is incompatible with the spirit and architecture of 4th Gen IR.

PSE's view is also likely to be inconsistent with the Board's desire to encourage continuous performance improvement in the RRFE.[11] This is evident from Figure 6 of the PSE report, which PSE references when it says "projections to 2019 show that Toronto Hydro's spending forecasts will converge the company's SAIFI and total costs towards the benchmark expectations (red dot in Figure 6)…Based on the projections, the projected spending will result in a utility more aligned with its externally-derived benchmark values from both a total cost and SAIFI perspective." Figure One below replicates PSE's Figure 6, but adds an arrow showing the movement from THESL's current cost and SAIFI performance to projected 2019 performance that "converge the company's SAIFI and total costs towards the benchmark expectations."

It can be seen that PSE projects THESL's performance will move in a northwest direction in this Figure. This is towards what PSE calls the "reliability better, cost worse" quadrant. The reason THESL moves in this direction is that, according to PSE's analysis, the company is in fact projected to display "reliability better, cost worse" performance under the Custom IR plan.

However, if THESL was exhibiting continuous improvement in its reliability and cost performance, it would be moving in a *southwest* direction on PSE's Figure 6, towards the "reliability better, cost better" quadrant. Indeed, it is straightforward to construct a "Zone of Continuous Improvement" for THESL relative to the Company's initial performance levels presented in PSE's Figure 6. This Zone of Continuous Improvement is incorporated into Figure Two below.

Figure Two illustrates why "converging towards benchmark expectations" is not a reasonable regulatory objective. Incentive regulation should be designed to encourage ongoing performance improvements. Encouraging continuous performance improvement is

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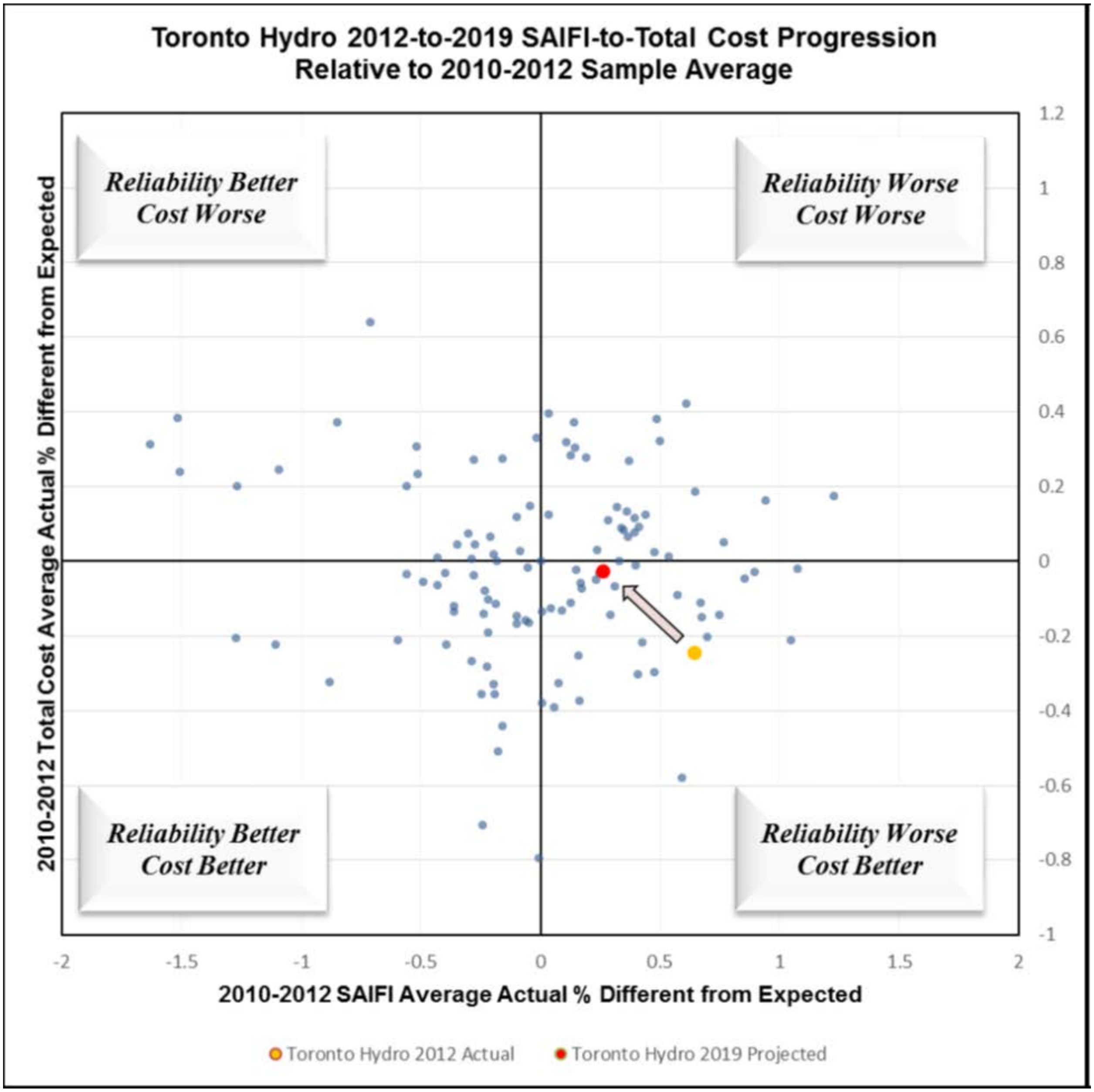
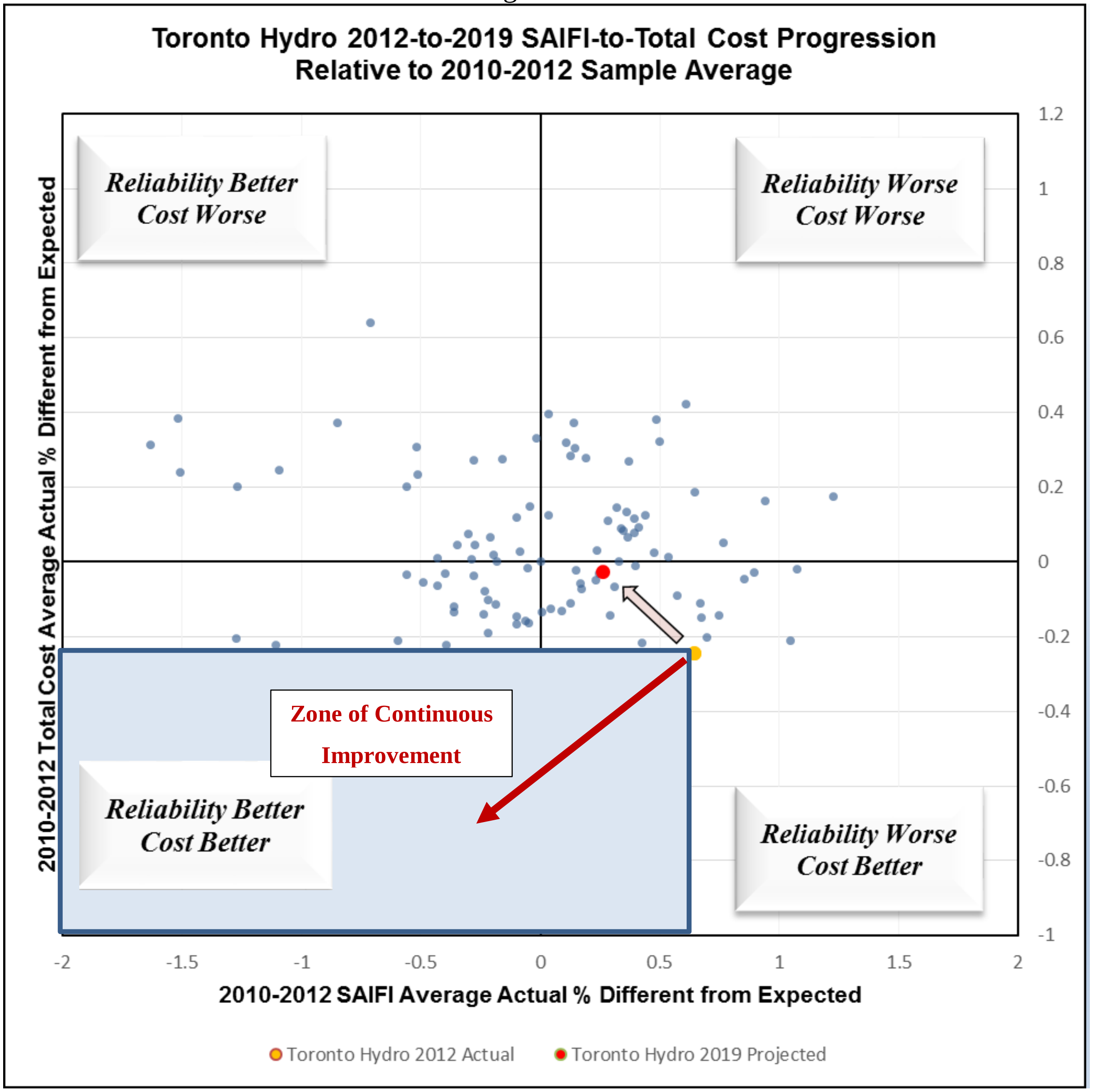
[11] Chapter Four of the RRFE report is titled "Performance Measurement and Continuous Improvement." Page 57 of the RRFE report also outlines performance outcomes that it expects distributors to achieve in four distinct areas. One of these outcomes is "continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives."

Figure One



Toronto Hydro 2012-to-2019 SAIFI-to-Total Cost Progression
Relative to 2010-2012 Sample Average
Reliability Better
Cost Worse
Reliability Worse
Cost Worse
Reliability Better
Cost Better
Reliability Worse
Cost Better
2010-2012 Total Cost Average Actual % Different from Expected
2010-2012 SAIFI Average Actual % Different from Expected
1.2
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
-1
-2
-1.5
-1
-0.5
0
0.5
1
1.5
2
Toronto Hydro 2012 Actual
Toronto Hydro 2019 Projected

Figure Two


Toronto Hydro 2012-to-2019 SAIFI-to-Total Cost Progression
Relative to 2010-2012 Sample Average
Reliability Better
Cost Worse
Reliability Worse
Cost Worse
Zone of Continuous
Improvement
Reliability Better
Cost Better
Reliability Worse
Cost Better
1.2
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
-1
-2
-1.5
-1
-0.5
0
0.5
1
1.5
2
2010-2012 Total Cost Average Actual % Different from Expected
2010-2012 SAIFI Average Actual % Different from Expected
Toronto Hydro 2012 Actual
Toronto Hydro 2019 Projected

also an explicit Board objective. As the two figures below show, converging to cost and reliability benchmarks is not necessarily consistent with continuous improvement. PEG therefore finds that PSE's summary conclusion that such an outcome is reasonable is both unwarranted and likely to be incompatible with the Board's policy objectives.

In sum, PEG has significant concerns with how PSE applied its technical benchmarking results in this regulatory setting. PSE has employed inconsistent and contradictory standards for evaluating THESL's performance. This creates ambiguity that would be avoided if the analysis focused on the hypotheses the benchmarking models are designed to test. PEG also believes that PSE's view on aligning utilities with external, average performance standards represents a misapplication of benchmarking and is likely to be incompatible with the Board's objectives for incentive regulation.

3 Review of PSE Cost Benchmarking

This Chapter summarizes PEG's evaluation of PSE's cost benchmarking work. As part of 4thGen IR, PEG undertook a cost benchmarking study of Ontario distributors for the same 2002-2012 period examined by PSE. The Board is currently using PEG's benchmarking results to set stretch factors for distributors who choose the Annual IR and Price Cap IR options in the RRFE.

The most notable aspect of PSE's cost benchmarking work for THESL is the expansion of its sample to include US utilities. PEG therefore confines our review to PSE results derived from the US-Only sample. This focus will streamline our review without any loss of substance, because PSE employed very similar benchmarking tools and obtained qualitatively similar results for its combined Ontario-US and US-only samples.

3.1 Data Issues

PEG's review identified significant concerns with the data used in PSE's cost benchmarking studies. In Section 3.1.1 we discuss data problems associated with PSE's cost measure for THESL. Section 3.1.2 considers problems with the cost measures for the US utilities in PSE's sample and their comparability with THESL costs.

3.1.1 Data Toronto Hydro

In our 4thGenIR work for Staff, PEG developed two different cost measures for each Ontario distributor. One cost measure was used to estimate TFP trends for the electricity distribution industry in the Province. The other cost measure was used to benchmark the cost performance of Ontario electricity distributors. The starting point for the latter, benchmarking cost measure was the total cost used in our TFP analysis. However, PEG undertook several cost adjustments in order to make the costs to be benchmarked more comparable across distributors.

One cost adjustment was made to make the costs of high-voltage (HV) transformation services (*i.e.* transformer substations greater than 50 kV) more comparable. If this was not done, the costs of the distributors that own HV equipment would be higher (all else equal) than the costs of the distributors who do not own high voltage equipment. PEG therefore excluded plant values explicitly identified by distributors as HV assets (in account 1815) and the OM&A accounts directly associated with HV transformation (accounts 5014, 5015, and 5112) from the total cost calculation.

These adjustments isolate most of the costs of HV ownership, but some costs cannot be readily distinguished in the Uniform System of Accounts. HV equipment capital is isolated in account 1815, but associated land and buildings capital is not categorized separately. Also, while HV-related O&M costs are booked in accounts 5014, 5015, and 5112, O&M for associated buildings are blended with other expenditures in accounts 5012 or 5110. Other HV-related costs are spread across multiple other accounts. Extracting these costs is problematic and not practical.

One other adjustment was made to make costs more comparable across distributors. PEG included some charges for low voltage (LV) services that were paid by distributors to their "host" distributors. These charges are regulated separately by the OEB but not included in the RRRs. The necessary data were obtained from two sources: (a) Hydro One provided a summary of LV Charges to distributors from 2002 to 2012, and (b) the Board's supplementary data request.[12]

PEG also included contributions in aid of construction (CIAC) and smart meter capital additions in the capital cost measure, as well as incremental OM&A associated with smart meters in the OM&A used in each distributor's benchmarking cost measure. CIAC payments are outside of the Board's IR rate adjustment formula, so it would not be appropriate to include them in the cost measure used to determine industry TFP trends that will be used to adjust allowed rates. However, CIAC additions are part of the capital stock that distributors use to provide service to their customers. Similarly, smart meters are part of this capital stock. Table 5 in PEG's November 2013 report to the Board summarizes the differences between the cost measures that PEG used to estimate TFP and to benchmark distributors' total costs.

The benchmark cost measure from PEG's earlier study should be used to benchmark THESL costs vis-a-vis US distributors. However, PEG's review indicated that PSE actually selected the more limited, TFP-based cost measure for THESL as the basis for its analysis.

[12] An Industry Workshop was held on October 7, 2013 to obtain guidance from the sector on which LV charges to include in total cost benchmarking. The Workshop Summary is posted on the Board's website (Summary of Hydro One Low Voltage Charges to Distributors 2002–2012 (07Oct13).xlsx).

As a first step, PEG therefore updated PSE's analysis to reflect THESL's correct, benchmark-based cost. We did not modify any data for the US utilities in PSE's sample, nor did we change any of PSE's selected independent variables or any aspect of the estimation procedure. PEG simply re-ran PSE's econometric model with the corrected THESL cost data, obtained new estimates of the econometric cost function parameters, and benchmarked THESL using this new cost model and THESL's corrected, benchmark cost. The first step of PEG's updated analysis therefore reflects the correction of THESL data errors only.

The econometric coefficients from this updated analysis are presented in Table One. PEG used the model in Table One to benchmark THESL's benchmark-based cost. For 2010-2012, PEG found that THESL's actual cost was 21.3% below its predicted cost. Using the same model but the incorrect cost measure for THESL, PSE found that THESL's 2010-2012 cost was 31.1% below its predicted cost. PEG therefore concludes that using the correct, benchmark-based costs for THESL reduces PSE's estimate of the difference between THESL's actual, 2010-2012 costs and its predicted costs from a reported -31.1% to -21.3%.

3.1.2 Data US Sample

PEG's review also identified several data concerns in PSE's US utility sample. One issue was that several sampled utilities underwent mergers during the 2002-2012 period. Mergers can impact a utility's reported cost data. Unless the business conditions are similarly updated to reflect those of the merged company, the statistical relationship between a utility's costs and business conditions can therefore be impacted. Appropriately controlling for mergers is often critical for obtaining accurate inferences on utilities' cost performance.

PEG's review indicated that PSE did not control for the impact of mergers that took place between 2002 and 2012 for seven of its sampled companies: Georgia Power; Green Mountain Power; Ohio Power; Potomac Edison; Public Service of New Mexico; Sierra Pacific Power; and Southwestern Electric Power. To avoid potential data errors associated with these utilities, PEG therefore eliminated these seven utilities from PSE's US sample.

PEG also identified several differences in the definition of costs for THESL and the US utilities. The benchmark cost measure for THESL excluded the costs of uncollectible accounts, while PSE's cost measure for the US utilities included the costs of uncollectible accounts. The benchmark cost measure for THESL also does not contain CDM expenses.

Table One

Econometric Cost Benchmarking Results:
Corrected THESL Data

VARIABLE KEY

K= Capital Price
N= Number Retail Customers
D= Peak Demand
UD= Urban Core Dummy
PRV= Percent Residential Deliveries in Total Deliveries
PCE= Percent Electric Customers in Gas & Electric Customers
PDE= Percent Distribution Plant in Total Electric Plant
UG= Percent Distribution Plant Underground
ED= Elevation Standard Deviation
PF= Percent Forestation
Trend= Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
K*	0.5591	143.028	0.0000
N*	0.7583	26.469	0.0000
D*	0.2075	7.494	0.0000
KxK*	0.0767	4.490	0.0000
NxN*	0.2993	3.282	0.0011
DxD*	0.2723	2.743	0.0062
KxN	-0.0191	-1.914	0.0559
KxD	0.0163	1.611	0.1075
NxD*	-0.2363	-2.572	0.0103
UD*	0.0211	6.417	0.0000
PRV	0.0130	1.217	0.2238
PCE*	0.2359	7.920	0.0000
PDE*	0.1038	5.590	0.0000
UG	0.0018	0.125	0.9006
ED*	0.0234	3.209	0.0014
PF*	0.0351	5.570	0.0000
Trend	-0.0015	-1.128	0.2596
Constant*	13.2016	910.034	0.0000
System Rbar-Squared	0.940		
Sample Period	2000-2012		
Number of Observations	880		

***Variable is significant at 95% confidence level**

PSE's cost measure for US utilities does include DSM expenses, which are considerable for many US utilities. Both of these differences tend to raise the cost of the US sample compared with THESL. All else equal, this lack of cost comparability leads to a more favorable benchmarking evaluation for THESL. To enhance cost comparability, PEG eliminated two sources of expenses from US utilities' cost measure: uncollectible bills, and customer service and information expenses (for which CDM often constitutes the largest single expense).

PEG also standardized the treatment of contributions in aid of construction (CIAC) across the sample. The benchmark-based costs for THESL and the other Ontario distributors include CIAC in the capital costs. The data PSE used to construct capital costs for the US distributors excluded CIAC. PEG therefore eliminated CIAC from THESL's costs to ensure greater comparability of costs between THESL and the US electric utilities.

PEG incorporated these changes into the dataset that includes the corrected THESL data. We then re-ran PSE's econometric model, obtained new estimates of the econometric cost function parameters, and benchmarked the Company using the new cost model and corrected/more comparable data for THESL and the US utilities. There were no changes to PSE's selected independent variables or the econometric estimation procedure. The second step of PEG's updated analysis therefore reflects corrected and/or more comparably-defined cost measures for both THESL and the US sample.

These results are presented in Table Two. Compared to Table One, it can be seen that these changes raise the estimated coefficient on the capital service price WK from 0.559 to 0.701. This is expected, because this coefficient will reflect the share of capital in the total cost measure. Because several O&M cost components were eliminated from US utilities' total costs while their capital costs were not modified, capital's share of cost is expected be higher in this econometric model than in previous models. A capital share of 70.1% is nevertheless reasonable and broadly consistent with PEG's econometric work elsewhere. It is also more consistent with THESL's own projected share of costs under its Custom IR plan than PSE's estimated capital cost share of approximately 56%.[13]

The coefficients on the outputs also differ somewhat. In the run correcting THESL and US data, the coefficient on customer numbers falls somewhat (from 0.758 to 0.613) while

[13] In Exhibit 1B, Tab 2, Schedule 3, p. 13, Table 5 includes Scap values for the 2016-2019 years. The average value of Scap during these years is 69.8%.

Table Two

Econometric Cost Benchmarking Results:
Corrected THESL and US Data

VARIABLE KEY

K= Capital Price
N= Number Retail Customers
D= Peak Demand
UD= Urban Core Dummy
PRV= Percent Residential Deliveries in Total Deliveries
PCE= Percent Electric Customers in Gas & Electric Customers
PDE= Percent Distribution Plant in Total Electric Plant
UG= Percent Distribution Plant Underground
ED= Elevation Standard Deviation
PF= Percent Forestation
Trend= Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
K*	0.7015	389.494	0.0000
N*	0.6132	20.643	0.0000
D*	0.2552	8.357	0.0000
KxK*	0.1150	18.592	0.0000
NxN*	0.5328	5.379	0.0000
DxD*	0.4781	4.821	0.0000
KxN*	0.0502	4.506	0.0000
KxD*	0.0471	4.217	0.0000
NxD*	-0.5012	-5.320	0.0000
UD*	0.0108	3.362	0.0008
PRV*	0.0268	1.993	0.0466
PCE*	0.1141	3.574	0.0004
PDE*	0.1500	8.248	0.0000
UG	-0.0213	-1.130	0.2587
ED	0.0097	1.302	0.1933
PF	0.0098	1.758	0.0791
Trend	0.0023	1.697	0.0901
Constant*	13.0269	832.749	0.0000
System Rbar-Squared	0.923		
Sample Period	2002-2012		
Number of Observations	805		

***Variable is significant at 95% confidence level**

the coefficient on peak demand increases (from 0.208 to 0.255). Peak demand therefore becomes a relatively more important "cost driver" in PEG's second econometric model.

PEG used the econometric estimates and updated data in Table Two to benchmark THESL's cost performance. The updated model showed that THESL's actual 2010-2012 cost was 6.3% below its predicted value. The difference was not statistically significant.

Recall that the benchmarking evaluation that corrected only the THESL data showed THESL's actual costs were 21.3% below predicted costs. The Company's efficiency score was reduced 9.8% (from -31.1% to -21.3%) when THESL's data were corrected. The current model corrects THESL data and corrects for costs that were: 1) included in the US data measure but not the THESL measure, or vice versa; or 2) potentially distorted by US utility mergers. PEG's results indicate that defining costs so that they are comparable across samples reduces THESL's efficiency score by a further 15.0% (i.e., the difference between the Company's actual and predicted cost changes from -21.3% to -6.3%).

3.2 Business Condition Variables

The third stage of PEG's review was to consider PSE's choice of business condition variables. We made only two minimal but necessary changes to PSE's business condition variables. The first was adding a variable to reflect MVa of transformer capacity for stations with primary voltage levels at or above 50 kV. The second was eliminating the urban core dummy variable.[14]

It is necessary to control for differences in distributors' high voltage transformation services. If this is not done, distributors with extensive high voltage transformation assets would be "penalized" for doing more work than distributors without such assets. PSE's current model includes the costs of high voltage transformation stations for US utilities, but it does not include a corresponding high voltage "network" or business condition variable.

[14] A "dummy" variable is a binary variable that takes a value of zero or one depending on whether certain specified criteria are satisfied. PSE's urban core dummy takes a value of one if a utility serves a city with a population of one million or more, and a value of zero if this condition is not true. A dummy variable is therefore a relatively blunt means of quantifying the impact of business conditions on a utility's operating cost because it does not measure the value of the posited business condition directly. A dummy variable also does not necessarily reflect the impact of the posited business condition, because it can capture a host of other company-specific effectes that are not explicitly included as independent variables in the model.

As explained in Section 3.1.1, controlling for differences in high voltage transformation was an important part of PEG's cost benchmarking work in Ontario. PEG eliminated all high voltage assets and OM&A costs that could feasibly be identified from our benchmark cost measures for Ontario distributors. The same should be done for US distributors, or the US utilities providing high voltage services will be unfairly disadvantaged in PSE's benchmarking analysis just as the Ontario distributors would have been in PEG's Ontario benchmarking study. Indeed, the importance of controlling for high voltage transformation appears to be at least as important in a THESL-US study as in an Ontario study. According to PEG's review, approximately 67.4% of the share of transformer stations for US utilities takes place at a primary voltage level of 50 kVA or above.

PSE did not control for differences in high voltage transformation between the US and THESL. The US FERC Form One accounts also do not provide separate data on the asset values or associated OM&A for utilities' high voltage assets. However, data are available to determine utilities' total MVa of capacity with primary voltage equal to or above 50 kV. PEG therefore included this variable in our econometric benchmarking model.

The second business condition issue concerns PSE's urban core dummy variable, which PEG believes should be eliminated from the model. Contrary to PSE's claims, PEG has never used an "urban core dummy" in our econometric benchmarking of electricity distribution. Some PEG studies have used this variable in gas distribution models, but the rationale for using such a dummy variable is much stronger for gas distribution than electricity distribution.[15] An urban core dummy is defensible for gas distribution because essentially all gas distribution assets are underground. A dummy variable is one means of distinguishing between the higher costs of installing and maintaining underground gas distribution assets in densely-populated, mature urban areas compared with "greenfield" suburban territories.

It is far less necessary to use the blunt approach of a binary dummy variable to capture these costs in electricity distribution. One important difference between electricity and gas infrastructure is that assets for the former are located both "overhead" and underground. Data on the share of lines, or plant values, that are overhead is a better and more direct measure of

[15] None of the studies Dr. Kaufmann has supervised has ever used an urban core dummy variable, for gas or electricity distribution.

the urbanization or ruralization of a service territory than a dummy variable. The share of plant *value* underground will also directly reflect the higher costs of installing and maintaining assets in a densely populated "urban core." While the OEB does not currently collect data on the value of plant underground, these data are available on the FERC Form One for US utilities, and PSE obtained the same data directly from THESL. Since PSE's model already includes a percent of plant underground variable, including an 'urban core dummy' would be redundant at best.

It should also be noted that when PEG has used urban core dummies in the past, the dummy variable was applied to most of the gas distributors in the sample. PSE, on the other hand, has applied its urban core dummy variable to only four of the 85 US utilities. Applying an urban core dummy to a larger share of the sample makes it more likely that the variable will reflect a systematic cost driver across the industry rather than idiosyncratic, utility-specific factors.

This issue is relevant to PSE's analysis because, in PEG's opinion, its urban core variable is not an accurate measure of the "urban cores" that exist throughout the US. As discussed, only four of the 85 utilities in PSE's sample are identified as having "urban cores": Consolidated Edison, which serves Manhattan and other parts of New York City; Commonwealth Edison, which serves Chicago; Arizona Public Service (APS) which serves Phoenix, AZ; and San Diego Gas and Electric (SDG&E), which serves San Diego, CA. Consolidated Edison and Commonwealth Edison clearly serve "urban cores," but the territories of SDG&E and APS can more fairly be characterized as suburban rather than densely urban. SDG&E serves a relatively normal mix of urban, suburban, and rural areas. APS's territory is overwhelmingly suburban but also contains a sizeable rural area and does not even include a significant part of Phoenix's central business district (which is served by the Salt River Project). A credible urban core dummy for the US electric utility industry would not include only these four American cities.

In addition, it must be recognized that a dummy variable can reflect a wide variety of company-specific factors, not just whether or not the selected utilities serve an urban core. One of those company-specific factors is the efficiency of company management. Using company-specific dummies is one method of estimating management efficiency.[16] It so happens that, collectively, the four utilities selected as serving urban cores tend to be average to poor cost performers. Including a dummy variable for these companies will effectively transfer some inefficiency from these utilities to the dummy variable. When this dummy variable is then used to develop econometric projections for other distributors, it effectively lowers the benchmark for the rest of the sampled firms.

There is also evidence that PSE's urban core dummy may be distorting other coefficients in PSE's cost model. Recall that the share of distribution plant underground already provides a measure of the degree of urbanization in a utility's service territory. Across a cross section of electric utilities, companies with a higher percentage of their plant underground will also tend to serve more urbanized territories. It is also well-known in the electric utility industry that it is more costly to build underground than overhead electricity distribution infrastructure. It is also not uncommon for utilities to request rate increases to recover the higher costs of undergrounding facilities. A good example is the System Modernization and Reliability Project (SMRP) proposed by Wisconsin Public Service (WPS), which specifically focused on undergrounding facilities in rural areas in an effort to improve reliability. In July 2013, WPS was allowed to increase rates by approximately 4.36% to recover the costs of the SMRP.[17]

PSE, however, finds that "undergrounding distribution capital *lowers* cost" (emphasis added) because the coefficient on the percent of distribution plant underground in its model is negative.[18] This result is contrary to the industry's experience and is not plausible.[19] Although it cannot be established definitively, this anomalous result may be due in part to the fact that the urban core dummy variable in the PSE model has a positive coefficient.

[16] However, PEG believes this benchmarking approach is not as robust or accurate as the methodology that the Board has used to benchmark costs for Ontario electricity distributors.

[17] Public Service Commission of Wisconsin, *Final Decision: Application of Wisconsin Public Service Corporation for its Electric Distribution System Modernization and Reliability Project*, Docket 6690-CE-198. It should be noted that the rate increase represents an approximate 4.36% increase in overall, bundled power rates.

[18] PSE, *op cit*, p. 37.

[19] PEG believes the estimated negative coefficient on the undergrounding variable in the US cost model conflicts with the statement on page 36 of its report that "parameter estimates have plausible signs and magnitudes." On page 18 of the report, PSE says that "the percentage of plant that is underground can raise the capital cost of distribution delivery, but lowers maintenance (and hence OM&A) expenses." While this is true, capital accounts for a greater share of electricity costs than OM&A, which means the OM&A cost savings would have to be a multiple of the initial capital costs for undergrounding to reduce overall distribution costs. Moreover, if undergrounding actually reduced electricity distribution cost, as PSE finds, one would expect utility proposals to underground assets to be coupled with rate reflief rather than requested rate increases. Industry experience indicates the opposite is true, which means the expected sign on PSE's undergrounding variable is positive.

Finally, the Board and stakeholders should not be left with the impression that urban conditions necessarily increase electricity distribution costs. Urbanization facilitates “economies of density” that can reduce the unit cost of performing a number of electricity distribution functions. Relatively concentrated service territories also decrease the quantity of “lines and poles” needed to deliver power to end-users, which directly reduces the costs of necessary infrastructure. This is not to deny that high density levels can raise other costs, but the relationship between electricity distribution cost and urbanization is complex, and it will not be fully captured in a binary, dummy variable.

In sum, PEG believes using dummy variables is a relatively crude and imprecise means of measuring “urban core” characteristics. While this is sometimes warranted for gas distribution, more accurate and direct measures of urbanization are available in electricity distribution. PSE’s specific “urban core” dummy is also not credible and is likely to reflect other company-specific factors (including management inefficiency) rather than specific aspects of an urban environment. Given these concerns, PEG eliminated the urban core dummy variable from the model used to benchmark THESL’s cost.

PEG incorporated these two changes in business conditions into the dataset that includes the corrected THESL data and the corrected and/or more comparably defined cost measures for THESL and the US utilities. We then re-ran PSE’s econometric model, obtained new estimates of the econometric cost function parameters, and benchmarked the Company using the new cost model. There were no other changes to the econometric estimation procedure. The third and final step of PEG’s updated analysis therefore reflects corrections to the THESL and US data, as well as changes in business conditions to control for US utilities’ costs of owning HV transformation assets and to eliminate the urban core dummy.

These results are presented in Table Three. The estimates on the outputs and business condition variables are all plausibly signed and statistically significant. The coefficient on the new HV transformer capacity variable has the expected positive sign, although it is not statistically significant. PEG used the econometric estimates and updated data in Table Three to benchmark THESL’s cost performance. The updated and final cost model showed that THESL’s actual 2010-2012 cost was 9.7% above its predicted value. The difference was not statistically significant.

Table Three

Econometric Cost Benchmarking Results:
Revised Data and Model

VARIABLE KEY

K=	Capital Price
N=	Number Retail Customers
D=	Peak Demand
CAP=	MVA of Capacity with Primary Voltage >= 50kV
PRV=	Percent Residential Deliveries in Total Deliveries
PCE=	Percent Electric Customers in Gas & Electric Customers
PDE=	Percent Distribution Plant in Total Electric Plant
ED=	Elevation Standard Deviation
PF=	Percent Forestation
Trend=	Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
K*	0.7024	390.050	0.0000
N*	0.6551	23.133	0.0000
D*	0.2207	7.209	0.0000
KxK*	0.1129	18.295	0.0000
NxN*	0.6856	7.053	0.0000
DxD*	0.5932	5.754	0.0000
KxN*	0.0446	4.003	0.0001
KxD*	0.0512	4.592	0.0000
NxD*	-0.6328	-6.628	0.0000
CAP	0.0009	0.451	0.6522
PRV*	0.0317	2.250	0.0247
PCE*	0.1374	4.473	0.0000
PDE*	0.1472	8.168	0.0000
ED*	0.0150	2.019	0.0438
PF*	0.0109	2.063	0.0394
Trend	0.0011	0.810	0.4180
Constant*	13.0373	740.885	0.0000
System Rbar-Squared	0.926		
Sample Period	2002-2012		
Number of Observations	805		

***Variable is significant at 95% confidence level**

PEG also used the econometric estimates in Table Three and THESL's projected business conditions to benchmark the Company's projected costs over the term of its Custom IR plan. In the first plan year of 2015, THESL's projected cost is 30.3% above its predicted cost. The difference between THESL's projected and predicted costs increases to 31.7% in 2016, 33.3% in 2017, 33.7% in 2018, and 34.7% in 2019. All of these 2015-2019 results for the Company are statistically significant at the 10% level.

Because THESL's projected costs are above its predicted costs and the differences are statistically significant, PEG finds that THESL under the Custom IR plan is projected to be an inferior cost performer compared with PSE's sample of 85 US electric utilities. This conclusion is similar to PEG's conclusion on THESL's cost efficiency in our benchmarking study for the Ontario electricity distribution industry. THESL was also identified as an inferior cost performer in Ontario, although the magnitudes of the Company's estimated inefficiency differ somewhat depending on whether THESL is benchmarked against US or Ontario samples.

3.3 Assessment of PSE Cost Benchmarking

The three steps in PEG's analysis of PSE's benchmarking results are summarized in Table Four. The "PSE Model" column shows PSE's estimates of the Company's efficiency in 2010-2012 and in each subsequent year from 2013 through 2019. The column immediately to the right shows how THESL's 2010-2012 estimated efficiency is impacted when THESL's cost data are corrected. This correction changes the difference between the Company's actual and predicted costs from -31.1% to -21.3%. The next column to the right shows the impact of correcting the data for US utilities as well, in order to enhance the comparability of the cost measures used for THESL and the US sample. These corrections further modify the difference between the Company's actual and predicted costs from -21.3% to -6.3%. The column on the far right of Table Four shows PEG's revised model, which incorporates the corrected THESL and US data, adds a variable to control for differences in high voltage ownership, and eliminates the urban core dummy. PEG's revised model shows that the difference between THESL's actual and predicted costs is +9.7% in 2010-2012. This difference rises further to +34.7% over the term of the Company's Custom IR plan.

Table Four

Comparison THESL Benchmarking Results

Year	PSE Model	PSE Model: Corrected THESL Data	PSE Model: Corrected THESL & US Data	Revised Model and Data
2010-2012	-31.1%	-21.3%	-6.3%	9.7%
2013	-24.6%			18.9%
2014	-21.8%			21.0%
2015	-13.1%			30.3%
2016	-11.4%			31.7%
2017	-9.9%			33.3%
2018	-9.5%			33.7%
2019	-8.5%			34.7%

PEG's review therefore indicates that PSE's conclusion that THESL was historically an efficient cost performer is unfounded. Using the appropriate cost data for THESL, adjusting the data and business conditions to make THESL and US cost data more comparable, and eliminating an inappropriate urban core dummy variable leads to a more than 40% increase in the difference between the Company's actual and predicted costs (*i.e.* 9.7% - (-31.1%) = 40.8%). Most of this difference can be attributed to the fact that PSE did not use comparable cost measures for THESL and the US utility sample. After cost measures are made more comparable and the inappropriate urban core dummy variable is eliminated, PEG concludes that THESL has been, at best, an average cost performer historically and is projected to be an inferior cost performer under the Custom IR plan.[20]

[20] It should be emphasized that PEG's analysis in this proceeding focused on reviewing PSE's work, not developing an econometric model explicitly designed to benchmark US electric utiliities. As a result, the econometric cost model presented in this chapter is somewhat circumscribed by the PSE model we were asked to review. There are several data and modeling assumptions in PSE's work that PEG would not retain in US cost benchmarking (*e.g.* a 1989 benchmark year for measuring capital cost), which it was nevertheless appropriate not to modify in the current analysis.

4 Review of PSE Reliability Benchmarking

This chapter presents PEG's evaluation of PSE's reliability benchmarking work, as well as alternate reliability benchmarking studies that PEG prepared. We begin by assessing the quality of PSE's reliability database. We then present alternate SAIFI and SAIDI benchmarking models, and associated benchmarking results for THESL, using service reliability data that PEG has collected.

4.1 Data Issues

While high quality data are important in any empirical analysis, concerns about data quality are particularly acute in service reliability benchmarking. One reason is that, unlike cost data, US utilities have traditionally not reported SAIFI, SAIDI and other reliability metrics to a single regulatory agency in a standardized format.[21] Some US utilities do report reliability to their state public utility commission, but these reports differ substantially from state to state. Reliability reporting differs in terms of the metrics reported, the definition of "sustained" outages, interruptions that are included in the reported measures and those that are excluded, and in other ways. Because state reliability reports can differ so significantly, care must to be taken to document and compile service reliability data in a manner that ensures they are as comparable as possible.

Utilities can also differ in how they measure and report outages. PEG described some of the factors that impact utilities' recorded reliability metrics in a 2010 jurisdictional survey of service reliability regulation to Board Staff. In that report, PEG noted:[22]

> These service reliability metrics must generally be collected directly within the utility itself. There is considerable variation in how reliability measures such as SAIFI and SAIDI are defined and calculated across utilities. Sources of difference include…
>
> - *Step restoration* When utilities restore power after widespread outages, restoration typically proceeds in "steps," where some phases of a circuit are restored before others. Companies vary in the extent to which they

[21] However, efforts to begin more standardized reporting are underway. The US Energy Information Agency (EIA) within the US Department of Energy is expected to begin reporting SAIFI and SAIDI for US utilities soon.

[22] Kaufmann, L., *et al*, (2010), *System Reliability Regulation: A Jurisdictional Survey*, Report to the Ontario Energy Board, pp. 10-13. The elipsed portion of this quotation included an extensive discussion of which interruption events are excluded from the reliability metrics, which is not relevant in the present context since PSE and PEG have examined unadjusted reliability data.

track customer minutes of interruption in response to partial restoration of circuits. This can affect both the "start" and "stop" times of a given interruption and the total minutes of the recorded outage.

- *Degree of automation* Companies differ in the extent to which they rely on manual or automated systems (such as outage management systems, or OMSs) to record reliability data. It is quite common for companies' measured frequency and duration of outages to rise substantially after they move to more automated recording systems. This implies that manual systems for measuring interruption data tend to miss or undercount the frequency and duration of outages.

For these and related reasons, there is often significant variation in how companies measure and record reliability indicators. In principle, reliability measurement can be standardized among electric utilities in a jurisdiction, but doing so is likely to take considerable effort. It would also lead to inconsistency between the past and standardized reliability measures for many utilities.

While it is not possible to redress many differences in how utilities measure outage events internally, this fact nevertheless underscores the sensitivity of reliability benchmarking to data quality and comparability issues. If US data are being used, analysts must compile their own reliability datasets from a variety of diverse sources. Because the quality and comparability of available US reliability data differ greatly, analysts must exercise care when compiling databases and should be as meticulous and transparent as possible in documenting the data used in the study.

PSE provided the reliability data used in its study to PEG. The data were provided subject to a confidentiality agreement, so PEG cannot discuss data points for any specific utility. However, we can report that PSE could not identify the source for 83 of the 376 observations it used for SAIFI. Similarly, PSE could not identify the source for 83 of its 376 SAIDI observations. This means PSE was not able to say where it obtained 22.1% (*i.e.* 83/376 = .221, or 22.1%) of the data used in its reliability benchmarking analyses.

PSE also provided PEG the source files used to compile PSE's reliability databases (for the observations where PSE could identify the source). PEG compared the SAIFI and SAIDI data contained in the PSE spreadsheets/databases with the data listed in the source files. Our review found 57 of the 376 data points entered into PSE's SAIFI data, and 66 of the 376 SAIDI data points, were erroneous and/or inconsistent with PSE's cited sources. When combined with our findings on PSE's data sourcing, PEG's review indicated that

35.9% of PSE's SAIFI database and 38.3% of PSE's SAIDI database was either inaccurate or obtained from an unknown source.

In PEG's opinion, these are serious errors and omissions. Reliability benchmarking is still new in Ontario.[23] The Board must have confidence in the data that are used to estimate reliability benchmarking models. This is particularly true since SAIFI and SAIDI data will differ among sampled companies for a variety of reasons. The uncertainties and data concerns that are inherent in reliability benchmarking should be mitigated to the greatest extent possible, not amplified by a failure to document sources and data processing errors.

In light of these concerns, PEG does not believe PSE's US dataset is suitable for regulatory application. PEG believes the quality of PSE's data are not of sufficiently high quality to assure the Board that econometric results developed from these data will be accurate. We therefore recommend that the Board give no weight to PSE's reliability benchmarking.

4.2 Alternate Reliability Benchmarking Models

To develop more accurate and robust service reliability benchmarking models, PEG compiled its own SAIFI and SAIDI databases. Appendix One shows the utilities and data sources PEG used to develop this database. Appendix One also provides further references on sources from which the data were extracted.

The sample period was 2002-2011. PEG eliminated 2012 from our sample because this was the year Hurricane Sandy led to unprecedented multi-day outages along much of the US East Coast. If 2012 data were used to estimate a model benchmarking reliability performance, the benchmarks would essentially build in a 1 in 11 probability of a Hurricane Sandy type event impacting the industry's measured reliability during the period to be benchmarked.[24] This is not reasonable, because Hurricane Sandy was by any measure a severe and unusual event, and it is highly unlikely to be repeated in the near future.

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[23] In our work advising Staff on setting reliability benchmarks, PEG undertook some statistical benchmarking of Ontario's SAIFI and SAIDI performance. The initial results were unsatisfactory, for a variety of data-related reasons, and we did not pursue the matter further.

[24] That is, 2012 was one of the 11 sample years in the 2002-2012 period. Using this period to estimate forward-looking benchmarks would essentially build the 2012 experience, which was dominated by Hurricane Sandy, into the SAIFI and SAIDI benchmarks.

PEG's benchmarking models investigated the environmental business conditions in PSE's datasets. We also examined the percent of capital that is underground, since it is widely known in the electricity distribution industry that underground assets are less prone to contact and interruption than overhead lines.[25] PEG found that whenever undergrounding and customer density were both included in an econometric model, the magnitude and statistical significance of the undergrounding coefficient was greater than that for customer density, and customer density would come in with a wrong (positive) sign. In light of its larger estimated effect and greater statistical significance, PEG therefore retained the undergrounding variable but excluded customer density from our SAIFI and SAIDI econometric models.

PEG also investigated other environmental variables that were not in the PSE models. These included heating degree days (HDD), cooling degree days (CDD), and precipitation. HDD and CDD are proxies for the severity of winter and summer weather, respectively. Severe winter weather can increase the frequency and duration of outages because of factors such as ice on lines, strong winds during winter storms, and conditions that increase the time it takes to respond to interruptions and restore power. Severe summer weather can cause conductors to sag and become more prone to contact, as well as increase the thermal loading of transformers and other assets. Precipitation is correlated with vegetation and wildlife, both of which are common causes of interruptions. For all three of these variables, the expected sign on the SAIDI and SAIFI coefficients are expected to be positive, because higher values for HDD, CDD, and precipitation are all expected to be associated with higher SAIDI and SAIFI values.

PEG's estimated econometric reliability model for SAIFI is presented in Table Five. Our estimated econometric model for SAIDI is presented in Table Six. Each table provides coefficient estimates and the t statistic on the hypothesis that the parameter value is equal to zero.

For SAIFI, PEG's econometric model finds:

[25] PSE has argued that it did not include undergrounding as an independent variable because it reflects management actions and is therefore not independent. While there is some merit to this claim, many undergrounding decisions also occur because of municipal regulations that mandate undergrounding of assets. Undergrounding is also so strongly correlated with observed SAIFI and SAIDI experience that if it was not included in an econometric model, there is a high probabiltity that the coefficients on the variables that were included would be characterized by ommited variable bias.

Table Five

SAIFI Benchmarking: PEG US Data

VARIABLE KEY

UG= Percent of Line Plant Underground
L= Lightning
E= Standard Deviation of Elevation
CDD= Cooling Degree Days
PCP= Precipitation

Trend= Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
UG*	-0.3131	-10.209	0.0000
L*	0.0910	7.148	0.0000
E*	0.1348	6.089	0.0000
CDD*	0.1346	4.697	0.0000
PCP*	0.2202	5.723	0.0000
Trend	0.0044	0.782	0.4349
Constant	0.0854	1.866	0.0629
R-Squared	0.273		
Sample Period	2002-2011		
Number of Observations	369		

***Variable is significant at 95% confidence level**

Table Six

SAIDI Benchmarking: PEG US Data

VARIABLE KEY

UG= Percent of Line Plant Underground
L= Lightning
E= Standard Deviation of Elevation
HDD= Heating Degree Days
CDD= Cooling Degree Days
PCP= Precipitation

Trend= Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
UG*	-0.4867	-7.522	0.0000
L*	0.1417	5.262	0.0000
E*	0.3115	5.378	0.0000
HDD*	0.1505	2.155	0.0318
CDD*	0.2951	3.548	0.0004
PCP*	0.4467	5.014	0.0000
Trend*	0.0380	3.195	0.0015
Constant*	-0.4527	-4.291	0.0000
R-Squared	0.248		
Sample Period	2002-2011		
Number of Observations	375		

***Variable is significant at 95% confidence level**

- Greater undergrounding is associated with fewer outages
- More lighting strikes are associated with more outages
- Greater variance in elevation is associated with more outages
- Higher values of CDD are associated with more outages
- Higher values of precipitation are associated with more outages

All estimates were statistically significant at the 1% level. For SAIDI, PEG's econometric model found:

- Greater undergrounding is associated with fewer minutes of outages
- More lighting strikes are associated with more minutes of outages
- Greater variance in elevation is associated with more minutes of outages
- Higher values of CDD are associated with more minutes of outages
- Higher values of HDD are associated with more minutes of outages
- Higher values of precipitation are associated with more minutes of outages
- A positive time trend, meaning a trend increase in minutes of outages that is unrelated to any of the business condition variables

All estimates were statistically significant at the 1% level, except HDD, which was statistically significant at the 5% level.

PEG used these models to benchmark THESL's SAIFI and SAIDI performance. For the 2009-2011 period, PEG found that THESL's actual SAIFI was 78.7% greater than its expected SAIFI. This means THESL customers were experiencing about 79% more outages than would be expected for a distributor operating under the Company's business conditions. This difference was statistically significant at the 1% level. For SAIDI, PEG found that THESL's actual SAIDI was 20.6% above its expected SAIDI. This difference was not statistically significant.

Although PEG recommends that no weight be placed on PSE's reliability benchmarking, it is interesting to note that PEG and PSE both find THESL's SAIFI performance is far below what is expected. However, our findings are somewhat different with respect to SAIDI. PSE estimates that THESL's SAIDI is well below expected levels. PEG finds THESL's SAIDI is not statistically different from expected levels.

5 Simultaneous Cost and Reliability Benchmarking

PSE has undertaken separate benchmarking analyses of THESL's cost and reliability performance. These analyses are entirely independent, yet PSE has used evidence from its cost benchmarking models to draw "suggestive" implications on THESL's SAIFI performance. As explained in Chapter Two of this report, these conclusions are unfounded, and PSE's cost benchmarking provides no empirical basis for assessing THESL's SAIFI or SAIDI performance or the need for capital investment to address reliability problems.

Indeed, PSE's benchmarking studies are tangential to the issue of how electricity distribution cost and reliability intersect. PSE relates these two dimensions of performance only rhetorically, by appealing to what might be called a general understanding of the electricity distribution industry. For example, PSE writes that, in its "opinion, it is certainly possible that the poor SAIFI performance (of THESL) is a symptom of the condition of the distribution network....poor SAIFI performance tends to be an indicator of old and failing infrastructure."[26] Since "old and failing infrastructure" can be remedied by purchasing and installing new infrastructure, PSE posits a relationship between changes in THESL costs (especially the investment costs associated with installing new capital) and future changes in its SAIFI.

PEG does not dispute this common-sense linkage, but we note that this understanding predates PSE's benchmarking studies, and these studies do nothing to illuminate or enhance parties' understanding of this relationship. For example, PSE's studies provide no evidence on the tradeoffs between cost and enhanced reliability, or how those tradeoffs may be related to the business conditions distributors face. PSE's studies for THESL also provide no evidence on the magnitudes of SAIFI or SAIDI improvements it is reasonable to expect THESL to achieve given its additional capital spending.

We believe these issues raise two points that are noteworthy and relevant to our review. First, the relationship between cost and reliability is central to THESL's Custom IR application, and this relationship may be amenable to statistical examination. Second, PSE

[26] PSE, *op cit*, p. 10.

has provided other evidence in this proceeding that explores the relationship between cost and reliability.

On the first point, the intersection between cost and reliability is clearly integral to THESL's Custom IR plan. THESL plans to increase its capital spending significantly under its Custom IR plan, and this spending is intended (in part) to maintain and/or improve service reliability. PSE's summary conclusion also assesses cost and reliability simultaneously (*e.g.* as represented in Figure 6 of its report) although, as discussed in Chapter Two, the benchmarking tools it employed were not designed or appropriate for this purpose.

However, statistical analysis can be used to explore the relationship between electricity distributors' cost and reliability, instead of treating each as a stand-alone benchmarking exercise. Statistical tools can also quantify how this relationship is impacted by differences in business condition variables such as scale of outputs, customer density, and asset undergrounding. These are inherently empirical issues and therefore potentially amenable to statistical quantification and testing. US utilities also operate under a wide variety of business conditions, and this diversity in operating environments facilitates robust statistical estimation and inference.

Of course, benchmarking cost and reliability simultaneously does pose a number of challenges. One involves the quality of the service reliability data. As discussed, the quality of these data vary, and care should be exercised when developing a service reliability sample. Second, while cost and reliability are inter-related, they are also both "endogenous" variables (and not "exogenous" or independent variables) that depend on management choices. This means that if cost and reliability are benchmarked simultaneously, cost will be a function of reliability, and reliability will also be a function of cost. Modeling these types of relationships can be complex, but simultaneous estimation approaches are available to address these complexities. Finally, there may be significant lags between changes in cost and associated changes in reliability. Quantifying these lag structures may also be challenging, but these difficulties become less pronounced with relatively long time series samples, such as those that exist for US electric utilities.

In sum, while the simultaneous benchmarking of cost and reliability does create some technical challenges, it is in essence similar to the cost benchmarking analyses that the Board employed in 4thGenIR. Statistical methods and data sources are available to address the challenges involved with simultaneous cost and reliability benchmarking. If the Board is asked in the future to assess the statistical relationship between cost and reliability in regulatory applications, effort should be directed towards developing appropriate simultaneous benchmarking models rather than relying on statistical tools that are not fit for this purpose.

In that regard, it should be noted that PSE has in fact presented other evidence in this proceeding that addresses the cost-reliability relationship more directly. This evidence was provided in response to Board Staff Interrogatory 11. That response included April 2013 testimony submitted on behalf of Wisconsin Public Service which referenced what PSE called a "SAIDI impact benchmark model." This model was designed to "address and evaluate the cost-effectiveness of reliability projects."[27] This is done through "a SAIDI benchmark model (that) examines the impact of utilities' capital cost levels on SAIDI values after controlling for the effects of other factors that influence SAIDI."[28] In response to the question "What did the models find relative to the *interaction* between SAIDI improvement and capital spending?" (emphasis added), the answer in the testimony is the following:

> The capital cost elasticity of SAIDI is -0.285, such that a one percent increase in the capital score (increased capital spending of one percent) results in a 0.285 percent reduction in SAIDI. In other words, when a utility increases its capital spending by one percent, it is expected to see a SAIDI improvement equal to approximately 0.285%. This finding is quite logical and is statistically significant at a 90 percent confidence level.[29]

Board Staff requested a copy of the dataset and computer program used to develop the SAIDI impact benchmark model. PSE responded that it "signed a confidentiality agreement that does not permit us to share these items with outside parties."[30] However, the PSE testimony states clearly and explicitly that "when a utility increases its capital spending by one percent, it is expected to see a SAIDI improvement equal to approximately 0.285%." This result can be used to "address and evaluate the cost effectiveness of reliability projects"

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[27] Toronto Hydro-Electric System Limited, EB-2014-0116 Interrogatory Responses, 1B-OEBStaff-11, Appendix A, p. 3 lines 5-6.

[28] Toronto Hydro-Electric System Limited, EB-2014-0116 Interrogatory Responses, 1B-OEBStaff-11, Appendix A, p. 3 lines 12-14.

[29] Toronto Hydro-Electric System Limited, EB-2014-0116 Interrogatory Responses, 1B-OEBStaff-11, Appendix A, p. 4 lines 12-19.

[30] Toronto Hydro-Electric System Limited, EB-2014-0116 Interrogatory Responses, 1B-OEBStaff-11, p.2, lines 14-16.

contained in the Custom IR application, by examining the changes in capital spending and SAIDI projected by THESL under the plan and comparing them to the SAIDI changes expected from this capital spending according to PSE's SAIDI impact benchmark model.

At Exhibit 1A, Tab 2, Schedule 1 page 15, THESL presents a summary of its historical and projected capital expenditures. This page indicates the Company's capital expenditures averaged $441 million per annum in 2012-2014. Projected capital expenditures under custom IR are $540 million in 2015; $504 million in 2016; $467 million in 2017; $470 million in 2018; and $502 million in 2019. Average capital expenditures over the custom IR plan accordingly average $496.6 million per annum.

PEG calculated the growth rate in THESL capital expenditures as the change in its average capital spending per annum over the Custom IR plan compared with the Company's average capital spending per annum over the 2012-2014 period just preceding the proposed Custom IR. These figures are $496.6 million per annum and $441 million per annum respectively. THESL's capital spending is therefore projected to increase by 12.61% per annum (*i.e.* 496.6/441 = 1.1261) over the term of the Custom IR.

PSE has written that, according to its SAIDI impact benchmark model, a one percent change in capital spending is expected to lead to a 0.285% improvement in SAIDI (*i.e.* a reduction in SAIDI of 0.285%). THESL projects capital spending in each year of its Custom IR plan to increase by an average of 12.61%. Given the estimated capital cost elasticity of -0.285, this implies that THESL's SAIDI should be expected to decline by 3.59% per annum in each year of its plan (*i.e.* 12.61% * -0.285 = -3.59%).

In Tables 15 and 16 of its report, PSE presents THESL's projected SAIDI value for 2014 as well as the Company's projected SAIDI in each year from 2015-2019. THESL expects its SAIDI in 2014 to equal 71.4. Taking this initial value as given, it is straightforward to compute the "SAIDI Impact" projection of THESL using the SAIDI impact benchmark model. This is done by decreasing THESL's 2014 SAIDI value of 71.4 minutes by 3.59% per annum in each of the five years of the Custom IR plan. These SAIDI Impact projections can then be compared with THESL's own projection of SAIDI over the Custom IR, as reported in PSE's report. These alternate projections for THESL's SAIDI under Custom IR, and the difference between them, are presented in Table Seven.

Table Seven

SAIDI Impact Benchmarking Projections

Year	THESL Actual SAIDI	THESL Projection SAIDI	"SAIDI Impact" Projection	Difference
2014	71.4			
2015		73.8	68.8	5.0
2016		70.2	66.4	3.8
2017		67.2	64.0	3.2
2018		64.8	61.7	3.1
2019		61.2	59.5	1.7

According to the SAIDI impact benchmark model, THESL's increase in capital spending is expected to lead to declines in SAIDI from 71.4 minutes in 2014 to 68.8 minutes in 2015, 66.4 minutes in 2016, 64 minutes in 2017, 61.7 minutes in 2018, and 59.5 minutes in 2019. These are the "benchmark" levels of SAIDI expected for an average utility investing the same amount of money as THESL is planning to invest.

Compared to these benchmarks, THESL projects smaller declines in SAIDI in each of these years. In 2015, THESL projects SAIDI of 73.8 minutes, falling to 70.2, 67.2, 64.8, and 61.2 minutes, respectively, in each of the four remaining years of the Custom IR plan. PSE's SAIDI impact model therefore implies that THESL's capital plan is delivering less SAIDI improvement than would be expected for an average utility investing the same amount of money.

PEG realizes this is a rough measure, and given our profound concerns with PSE's benchmarking work for THESL we certainly do not endorse its SAIDI impact benchmark model. Nevertheless, the model is interesting because it shows the type of work that could pursued in order to understand the interaction between distributors' cost and reliability performance. Work that simultaneously benchmarks cost and service reliability is feasible, and there may be merit in further research on this topic if the interaction between cost and reliability performance is expected to remain an important regulatory issue in Ontario.

6 Toronto Hydro's Stretch Factor and C Factor

This Chapter briefly addresses THESL's proposed stretch factor and custom capital factor, or C factor. The stretch factor is a component of the Company's proposed price cap index that will adjust rates in 2016 through 2019. The C factor is a component of the price cap index designed to recover capital-related costs that exceed the funding for capital expenditures implicitly provided by the plan's "I – X" rate adjustment mechanism.

6.1 Stretch Factor

THESL and PSE both recommend a 0.3% stretch factor in the Custom IR rate adjustment formula. This represents a reduction from the 0.6% stretch factor THESL would be assigned if it elected the Price Cap IR option in the RRFE.[31] PSE explicitly bases this recommendation on the findings of its econometric research, since the difference between the Company's projected and expected costs under the Custom IR plan is within the +/- 10% band the Board established for the cohort of distributors assigned a 0.3% stretch factor. PSE writes "total costs (of THESL) are projected to be well within the 0.3% stretch factor range of plus/minus 10% set in the November 2013 Board Report…based on these findings, reducing the stretch factor from 0.6% to 0.3% seems to be in line with the Board's intention of assigning a 0.3% stretch factor to utilities with "normal" total cost benchmark evaluations."[32]

PEG's review finds this conclusion is unwarranted. A more accurate appraisal indicates that, in a US-only benchmarking study, THESL's costs are projected to be 34.7% above its expected costs under the Custom IR plan. A 34.7% difference between projected and benchmark costs would put THESL in the cohort of distributors assigned a 0.6% stretch factor in Price Cap IR. This finding supports PEG's conclusion regarding THESL's cost performance in our Ontario cost benchmarking study.

It should also be noted that the Company exhibits generally poor reliability performance. PSE and PEG agree that THESL's SAIFI is far greater than what is expected

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[31] A stretch factor is not a necessary component of a Custom IR plan, although Custom IR plans can certainly contain stretch factors. PSE and THESL have elected to include a stretch factor in their proposal, and the PSE report and THESL application both link the magnitude of the proposed stretch factor to THESL's projected cost performance under the Custom IR plan, as measured by PSE's benchmarking analysis that includes data on US electric utilities.

[32] PSE, *op cit*, p. 11.

for a utility operating under its business conditions. PEG's analysis also indicates that THESL is an average SAIDI performer.

Since THESL displays poor cost performance and average to poor reliability performance, PEG believes a stretch factor in excess of 0.6% is defensible for THESL. While the Board has previously linked stretch factors to past cost performance, rather than past reliability performance, the latter may arguably be appropriate for at least two reasons.[33] One is to hold management accountable and establish consequences for sub-par reliability. A second is to compensate customers for the poor reliability they have been experiencing. Customers experience outage costs and/or lost value when their demands for continuous power deliveries are "unserved" because of power outages. Raising the stretch factor to reflect poor reliability performance would reduce the rate of price escalation customers experience and thereby partially compensate them for this lost value.

There are precedents for 1% stretch factors in North American incentive regulation. Based on the results from our cost and reliability benchmarking, PEG therefore recommends that the stretch factor in THESL's Custom IR price cap index be set no lower than 0.6% and no higher than 1%. A stretch factor at the upper end of this range would be more appropriate if the Board wishes to consider demand-side and value of service factors in addition to the cost efficiency considerations it has previously used as the basis for assigning stretch factors.

PEG also recommends that the stretch factor be applied to capital as well as non-capital costs. THESL has acknowledged that the formula for the price cap index (PCI) in the Company's Custom IR plan is equivalent to the following:[34]

$$PCI = (1 - S_{cap}) * (I – X) + C_n$$

In this formula, "PCI" refers to the growth in the price cap index for THESL; "S_{cap}" is the share of capital in the Company's total costs; "I" is the growth in the inflation factor; "X" is the value of the stretch factor (since the productivity factor component of the X factor is

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[33] The stretch factor is typically chosen to reflect the potential for incremental productivity gains (relative to the industry productivity trend) under IR. Because relatively inefficient utilities have more potential to achieve incremental productivity gains, all else equal, it is reasonable for the magnitude of assigned stretch factors to be inversely related to a utility's measured relative cost performance.

[34] EB-2014-0116, Interrogatory Responses, 1B-OEBStaff-6, page 2, response to part a).

zero); and "C_n" is the value of the C-factor, which recovers capital cost that is not otherwise recovered via the PCI.

The formula above shows that the stretch factor is applied only to non-capital costs. Because of this, the effective stretch factor in THESL's PCI is not the nominally proposed value of 0.3%. The formula shows that the stretch factor is actually equal to $(1-S_{cap}) * X$. The C_n factor stands outside of this product and provides dollar-for-dollar recovery of the Company's proposed capital costs, which do not embed an explicit stretch factor. Since the S_{cap} value for Toronto Hydro is about 0.7, the effective stretch factor in THESL's Custom IR is therefore actually 0.09% (*i.e.* (1-0.7) * 0.3% = 0.09%) rather than 0.3%.

PEG believes stretch factors should apply to both capital and non-capital costs. This is the norm in North American, index-based incentive regulation, and it is also how the Board has applied stretch factors in previous IR plans for electricity distributors. Moreover, PEG believes THESL's proposal is not compatible with the Board's Renewed Regulatory Framework for Electricity. In the RRFE Report, the Board writes that it "continues to support a comprehensive approach to rate-setting, recognizing the inter-relationship between capital expenditures and OM&A expenditures. Rate-setting that is comprehensive creates stronger and more balanced incentives and is more compatible with the Board's implementation of an outcome-based framework."[35] PEG does not believe the Company's PCI is consistent with the Board's support for a comprehensive approach to rate-setting that recognizes the inter-relationship between capital expenditures and OM&A expenditures. A comprehensive ratesetting approach would not exempt capital expenditures from stretch factor goals, nor would it separate capital from non-capital costs when implementing the plan's main benefit-sharing provision (*i.e.* the stretch factor). THESL has not addressed the important issue of how its Custom IR plan recognizes the inter-relationship between capital and OM&A expenditures. Indeed, its plan appears to specify distinct and independent ratemaking treatment for capital and non-capital costs.

PEG therefore recommends that the stretch factor be applied to all of THESL's costs, rather than non-capital costs as in the Company's proposal. Since THESL's effective stretch

[35] Report of the Board, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 9.

factor is (1 – S_{cap}) * (proposed stretch factor), this can be accomplished by subtracting a term from Toronto Hydro's PCI equal to S_{cap} multiplied by the Board's selected factor.

6.2 Custom Capital Factor

The C factor is designed to recover capital-related costs that exceed the funding for capital expenditures implicitly provided by the plan's "I – X" rate adjustment mechanism. THESL's C factor subtracts Scap * (1-X) from the percentage change in the capital costs to be recovered. This is a sound method for ensuring that the C factor reflects only incremental capital spending (*i.e.* capital spending in excess of that implicitly provided under the inflation minus X adjustment formula).

However, while THESL's proposed C factor does collect only incremental capital needs, it does not appropriately translate those cost changes into price changes. The C_n factor converts the percentage change in incremental capital costs into an equivalent percentage change in base rates. This approach will lead to revenue adjustments that exceed what is necessary to recover the change in capital cost because it does not take account of revenue growth from changes in billing determinants.

In cost of service proceedings, setting updated prices clearly considers changes in billing determinants as well as changes in costs.[36] The same principle applies when specific cost components are tracked and recovered in an incentive regulation plan. This principle is also reflected in the "indexing logic" that is used to set the terms of I – X, indexing plans. The following equations display this logic for a price adjustment specifically focused on recovering a change in capital costs.

The rate of growth in revenue (R) can be decomposed into the growth in a price index (P) and a revenue-weighted output index (Y^R) (a dot over a variable indicates the annual growth rate in that variable).

$$\dot{R} = \dot{P} + \dot{Y}^R \qquad [1]$$

Let C^N refer to the price changes specifically designed to recover incremental capital costs.

[36] More precisely, determining rate changes considers changes in cost and changes in billing determinatnts between the costs and billing determinants reflected in current, cost-based rates and the costs and billing determinants in the test year (or years) that is (are) used to set upated rates.

$$\dot{P} = C^N \qquad [2]$$

Assume the total revenue to be generated by the C_n charge just recovers the change in the utility's capital-related costs C_k.

$$\dot{R} = \dot{C}_k \qquad [3]$$

If we substitute [2] and [3] into [1] and rearrange terms, the following formula shows the price change that is just sufficient to recover the utility's change in capital costs:

$$C^N = \dot{C}_k - \dot{Y}^R \qquad [4]$$

It can be seen that, in general, the appropriate price change should be equal to the change in capital costs minus the change in a revenue-weighted output index.[37] For THESL, the latter term is equivalent to a revenue-share weighted average of annual growth in the Company's billing determinants. The formula in [4] subtracts the annual change in a revenue-share weighed average of billing determinants from the annual percentage change in capital costs to be recovered in that year. An adjustment for changes in billing determinants will prevent THESL's proposed C factor from over-recovering changes in the Company's incremental capital costs.[38]

The formula in equation [4] can be easily implemented using THESL billing data. This can be done using either projected billing determinants for the coming year (and truing-up those projections to actual billing determinants in the following year) or using the most recently observed rate of change in billing determinants for the adjustment. It is not problematic if THESL has not already provided forecasts of all billing determinants, as observed historical data already exist and forecasting billing determinants for the following year should not be unduly burdensome.

Although the impact of this adjustment depends on how billing determinants evolve in future years, THESL has provided some forecasts that can be used to approximate the impact of the billing determinant adjustment. The Company has projected that its customer numbers

[37] When prices are also adjusted by an I-X mechanism, the price change should also net off the implicit funds for capital investment provided by the indexing mechanism, as THESL's proposal does.

[38] An exception to this rule is if the C factor explicitly sets prices by allocating future costs to projections of future billing determinants, but PEG has seen no indication from the Custom IR application that the C factor will be implemented in this manner. In fact, the entire demonstration of how the C factor would be implemented in Exhibit 1B, Tab 2, Schedule 3, pp. 8 -13 makes no reference to changes in billing determinants or to billing determinants at all.

will grow at an average annual rate of 1.53% in the 2016-2019 period.[39] If kWh per customer and kW per customer remain constant for all customer classes over 2016-2019, then a revenue-weighted index of billing determinants will grow at approximately the same rate as customer growth, or by 1.53% per annum. If kWh per customer and kW per customer grow over the 2016-2019 period, then a revenue-weighted index of billing determinants will grow more rapidly than 1.53% per annum over this period. Conversely, if kWh per customer and kW per customer decline over the 2016-2019 period, then a revenue-weighted index of billing determinants will grow less rapidly than 1.53% per annum over this period.

Given the ongoing emphasis on energy conservation in the Province, PEG believes it is reasonable to expect modest declines in kWh per customer and kW per customer over the Custom IR period. However, provided these declines in consumption and demand are modest, and the forecasts in customer growth are accurate, the change in revenue-weighted billing determinants will still be close to1.5% per annum. PEG therefore estimates that the revenue-weighted change in the Company's billing determinants will grow by about 1.5% per annum during the term of the Custom IR plan. All else equal, this adjustment to THESL's C Factor will therefore reduce price growth by approximately 1.5% per year in 2016 – 2019.

[39] This growth rate is computed using data on the "Customers by Class" table presented in Exhbit 3, Tab 1, Schedule 1, Appendix C-1, page 1.

7. Concluding Remarks and Ratemaking Recommendations

PEG's review indicates that PSE's conclusions regarding Toronto Hydro's cost and reliability performance are largely, but not entirely, unfounded. Based on an econometric analysis of THESL and 85 US utilities, PSE's analysis indicated that THESL's 2010-2012 costs were 31.1% below the costs expected for an average electric utility operating under the Company's business conditions. PEG's review identified a number of areas in which the costs of THESL and the US were not comparably defined or measured. After correcting and/or controlling for these differences, and eliminating an unwarranted "urban core dummy" variable from PSE's econometric cost model, PEG found THESL's costs were 9.7% above its expected costs. The Company's total costs are projected to be 34.7% above its expected costs in 2019, the final year of its Custom IR plan.

PEG's review partly confirmed PSE's reliability benchmarking conclusions. Based on an econometric analysis of THESL and 46 US utilities, PSE found the Company's SAIFI performance was 73% above its expected value but found THESL's SAIDI was 50% below its expected SAIDI. PEG believes the data PSE used for its reliability benchmarking are not suitable for regulatory application, so we compiled an alternative SAIFI and SAIDI dataset and used it to estimate alternate SAIFI and SAIDI benchmarking models. Using these data and models, PEG confirms PSE's finding that THESL's SAIFI is far above its expected level, but we find the Company's SAIDI is not statistically different from its expected level.

Overall, PEG finds THESL has been a sub-par performer with respect to cost and reliability. Given these findings, and a broader review of the Company's Custom IR application and the record in this proceeding, PEG recommends the following changes to Toronto Hydro's Custom IR proposal:

1. Adopt a stretch factor of between 0.6% and 1% rather than THESL and PSE's recommended 0.3%
2. Apply the stretch factor to both OM&A and capital costs under the Custom IR plan
3. Apply an adjustment to the C_n factor in each year to net off the annual growth in billing determinants
4. Spread the Company's proposed capital expenditures over the eight year, 2015-2022 period rather than the proposed five year, 2015-2019 period

Recommendations 1, 2 and 3 were presented and explained in Chapter 6. Below we explain PEG's fourth recommendation.

Spread the Company's proposed capital expenditures over eight years rather than five years

PEG believes there may be value to ratepayers in extending the period of THESL's capital spending program. Doing so is consistent with the RRFE principles of pacing and prioritization of capital spending, while at the same time managing the pace of rate increases for customers. PEG therefore recommends that the capital expenditures in THESL's Custom IR plan be spread out over eight years (2015-2022) rather than concentrated in five years (2015-2019).

Table Eight shows the projected increase in THESL's Custom PCI in 2016 – 2019 under the Company's original proposal, as well as the increase in THESL's Custom PCI with PEG's proposed adjustments to the plan. The inflation and S_{cap} components of the adjustment are identical for THESL and PEG. The Company's stretch factor is equal to 0.3%, and this scenario for the PEG alternative selects a 0.6% stretch factor, which is the lower end of our suggested stretch factor range. PEG's alternative also includes the Stretch factor * S_{cap} and Billing Determinant adjustments previously described, while the THESL plan does not. For simplicity, PEG has also multiplied THESL's C_n value in each year by (5/8), to reflect our recommendation that the Company's capital program be implemented over an eight-year rather than five-year time horizon. We recognize that this is a rough approximation of the impact of spreading capital expenditures over eight years, and other patterns of smoothing capital expenditures can certainly be contemplated.

It can be seen that PEG's recommendations reduce the 2016-2019 growth in the Company's prices from 6.26% per annum to 2.07% per annum. PEG's recommendations therefore reduce the change in THESL prices by 4.19% per annum in each year from 2016 to 2019 (*i.e.* 6.26% - 2.07% = 4.19%). Over the 2016-2019 period, THESL proposes to increase prices by a cumulative 27.4%. With PEG's recommended changes to the Company's Custom IR plan, THESL prices would rise by a cumulative 8.5% over the 2016-2019 period or 18.9% less than under the Company's proposal.

Table Eight

Comparison of Custom PCI Values between Toronto Hydro and PEG for Custom IR Period

	Toronto Hydro				PEG			
Year	2016	2017	2018	2019	2016	2017	2018	2019
Inflation	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
X = Stretch Factor	-0.3%	-0.3%	-0.3%	-0.3%	-0.6%	-0.6%	-0.6%	-0.6%
Cn	4.10%	7.56%	6.67%	5.01%	2.56%	4.73%	4.17%	3.13%
Stretch Factor * Scap	N/A	N/A	N/A	N/A	-0.40%	-0.41%	-0.42%	-0.43%
Billing Determinant Adjustment	N/A	N/A	N/A	N/A	-1.50%	-1.50%	-1.50%	-1.50%
Scap	67.10%	69.20%	70.80%	71.90%	66.90%	68.50%	70.22%	71.35%
Change in Custom PCI	4.56%	7.99%	7.08%	5.40%	1.03%	3.16%	2.58%	1.52%
Average Annual PCI Growth				**6.26%**				**2.07%**

Source of Toronto Hydro data: Toronto Hydro Updated Application Exhibit 1B, Tab 2, Schedule 3.

About 40% of this downward adjustment (*i.e.* 1.5% of the overall 4.19% annual reduction) results from the Billing Determinant adjustment, which is necessary to prevent the C_n factor from over-recovering capital cost. Approximately 10% of the downward adjustment (*i.e.* about 0.41% of the overall 4.19% annual reduction) is due to applying the stretch factor to capital as well as non-capital costs. Approximately 50% of the price reduction is primarily due to spreading the capital spending program over eight years rather than five years. This recommendation will likely defer rather than eliminate these rate changes for THESL, subject to Board review and approval of the Company's deferred, 2020-2022 capital expenditures.

Appendix One: Sources for Reliability Data

PSEID	Year	Source	SAIDI Page(s) and Table Name(s) or Number(s), if Given	SAIFI Page(s) and Table Name(s) or Number(s), if Given
8	2008	Document 8.2008	pdf page 4	pdf page 2
8	2009	Document 8.2009	pdf page 4	pdf page 2
8	2010	Document 8.2010	pdf page 4	pdf page 2
8	2011	Document 8.2011	pdf page 5	pdf page 3
12	2002	Document 12.2003	pdf page 8, chart 1.3 (estimate based on graphical representation)	pdf page 7, chart 1.1 (estimate based on graphical representation
12	2003	Document 12.2003	pdf page 8, chart 1.3 and pdf page 6, Major Event Day Table	pdf page 7, chart 1.1 (estimate based on graphical representation
12	2004	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2005	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2006	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2007	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2008	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2009	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2010	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2011	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
13	2002	Document 13.2002	doc page 1, section (1)(a)	doc page 1, section (1)(a)
13	2003	Document 13.2003	pdf page 1, section (1)(a)	pdf page 1, section (1)(a)
13	2004	Document 13.2004	pdf page 1, section (1)(a)	pdf page 1, section (1)(a)
13	2005	Document 13.2005	pdf page 1, section (1)(a)	pdf page 1, section (1)(a)
13	2006	Document 13.2006	pdf page 2, section (1)(a)	pdf page 2, section (1)(a)
13	2007	Document 13.2007	pdf page 1, section (1)(a)	pdf page 1, section (1)(a)
13	2008	Document 13.2008 and Document 13.2010DR	pdf page 1, section (1)(a), and pdf page 15, table in response to OPCDR2-11	pdf page 1, section (1)(a), and pdf page 15, table in response to OPCDR2-11
13	2009	Document 13.2009 and Document 13.2010DR	pdf page 1, section (1)(a), and pdf page 15, table in response to OPCDR2-11	pdf page 1, section (1)(a), and pdf page 15, table in response to OPCDR2-11
13	2010	Document 13.2012	pdf page 4, table titled "All interruption data"	pdf page 4, table titled "All interruption data"
13	2011	Document 13.2013	pdf page 3, row 2 of table	pdf page 3, row 1 of table
21	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
21	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
21	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
21	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
21	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
21	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33
21	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
21	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
21	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
21	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
23	2002	Document 23.2006	pdf page 11, Exclusion Criteria "None" column for SAIDI in table titled "System Performance Index Comparison"	pdf page 11, Exclusion Criteria "None" column for SAIFI in table titled "System Performance Index Comparison"
23	2003	Document 23.2006	pdf page 11, Exclusion Criteria "None" column for SAIDI in table titled "System Performance Index Comparison"	pdf page 11, Exclusion Criteria "None" column for SAIFI in table titled "System Performance Index Comparison"
23	2004	Document 23.2006	pdf page 11, Exclusion Criteria "None" column for SAIDI in table titled "System Performance Index Comparison"	pdf page 11, Exclusion Criteria "None" column for SAIFI in table titled "System Performance Index Comparison"
23	2005	Document 23.2006	pdf page 11, Exclusion Criteria "None" column for SAIDI in table titled "System Performance Index Comparison"	pdf page 11, Exclusion Criteria "None" column for SAIFI in table titled "System Performance Index Comparison"
23	2006	Document 23.2006	pdf page 11, Exclusion Criteria "None" column for SAIDI in table titled "System Performance Index Comparison"	pdf page 11, Exclusion Criteria "None" column for SAIFI in table titled "System Performance Index Comparison"
23	2007	Document From Files, Email from Ann L. Thierault, CMP Pricing and Analysis, dated 04/02/2009		
23	2008	Document From Files, Email from Ann L. Thierault, CMP Pricing and Analysis, dated 04/02/2009		
23	2009	Document 23.2009	pdf page 97, (27 of 74)	pdf page 97, (27 of 74)
23	2010	Email From Commission		
23	2011	Email From Commission		
27	2003	Attachment to Email from PUCO dated July 16, 2009		
27	2004	Attachment to Email from PUCO dated July 16, 2009		
27	2005	Attachment to Email from PUCO dated July 16, 2009		
27	2006	Attachment to Email from PUCO dated July 16, 2009		
27	2007	Attachment to Email from PUCO dated July 16, 2009		
27	2008	Attachment to Email from PUCO dated July 16, 2009		
27	2009	Document 27.2009	pdf page 2, table 2	pdf page 2, table 3
27	2010	Document 27.2010	pdf page 2, product of tables 1 and 2 values before exclusions	pdf page 2, table 2
27	2011	Document 27.2011	pdf page 3, product of tables 1 and 2 values before exclusions	pdf page 3, table 2

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PSEID	Year	Source	SAIDI Page(s) and Table Name(s) or Number(s), if Given	SAIFI Page(s) and Table Name(s) or Number(s), if Given
30	2003	Attachment to Email from PUCO dated July 16, 2009		
30	2004	Attachment to Email from PUCO dated July 16, 2009		
30	2005	Attachment to Email from PUCO dated July 16, 2009		
30	2006	Attachment to Email from PUCO dated July 16, 2009		
30	2007	Attachment to Email from PUCO dated July 16, 2009		
30	2008	Attachment to Email from PUCO dated July 16, 2009		
30	2009	Document FE.2009	pdf page 2, table 2	pdf page 2, table 3
32	2002	Document 32.2002	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
32	2003	Document 32.2003	doc page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	doc page 2, table 18a, value for system (rightmost column)
32	2004	Document 32.2004	doc page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	doc page 2, table 18a, value for system (rightmost column)
32	2005	Document 32.2005	doc page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	doc page 2, table 18a, value for system (rightmost column)
32	2006	Document 32.2006	doc page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	doc page 2, table 18a, value for system (rightmost column)
32	2007	Document 32.2007	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
32	2008	Document 32.2008	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
32	2009	Document 32.2009	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
32	2010	Document 32.2010	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
32	2011	Document 32.2011	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
36	2002	Document 36.2006	pdf page 7, table below chart 2	pdf page 8, table below chart 3
36	2003	Document 36.2007	pdf page 7, table below chart 2	pdf page 8, table below chart 3
36	2004	Document 36.2008rev	doc page 8, table attached to chart 2	doc page 8, table attached to chart 3
36	2005	Document 36.2009	pdf page 8, table attached to chart 2	pdf page 8, table attached to chart 3
36	2006	Document 36.2010	pdf page 8, table attached to chart 2	pdf page 8, table attached to chart 3
36	2007	Document 36.2011	pdf page 8, table attached to chart 2	pdf page 8, table attached to chart 3
36	2008	Document 36.2012	pdf page 8, table attached to chart 2	pdf page 9, table attached to chart 3
36	2009	Documents 36.2012 and 36.2013	pdf page 8, table attached to chart 2 and doc page 7, table attached to chart 2	pdf page 9, table attached to chart 3 and doc page 9, table attached to chart 3
36	2010	Documents 36.2012 and 36.2013	pdf page 8, table attached to chart 2 and doc page 7, table attached to chart 2	pdf page 9, table attached to chart 3 and doc page 9, table attached to chart 3
36	2011	Documents 36.2012 and 36.2013	pdf page 8, table attached to chart 2 and doc page 7, table attached to chart 2	pdf page 9, table attached to chart 3 and doc page 9, table attached to chart 3
40	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
40	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
40	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
40	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
40	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
40	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33
40	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
40	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
40	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
40	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
43	2002	Document 43.2011	pdf page 3	pdf page 3
43	2003	Document 43.2012	pdf page 3	pdf page 3
43	2004	Document 43.2013	pdf page 3	pdf page 3
43	2005	Document 43.2013	pdf page 3	pdf page 3
43	2006	Document 43.2013	pdf page 3	pdf page 3
43	2007	Document 43.2013	pdf page 3	pdf page 3
43	2008	Document 43.2013	pdf page 3	pdf page 3
43	2009	Document 43.2013	pdf page 3	pdf page 3
43	2010	Document 43.2013	pdf page 3	pdf page 3
43	2011	Document 43.2013	pdf page 3	pdf page 3
44	2005	Attachment to Email from PUCO dated July 16, 2009		
44	2006	Attachment to Email from PUCO dated July 16, 2009		
44	2007	Attachment to Email from PUCO dated July 16, 2009		
44	2008	Attachment to Email from PUCO dated July 16, 2009		
44	2009	Document 44.2009	pdf page 2, table 2	pdf page 2, table 3
46	2002	Document 46.2013	pdf page 4	pdf page 4
46	2003	Document 46.2013	pdf page 4	pdf page 4
46	2004	Document 46.2013	pdf page 4	pdf page 4

II

PSEID	Year	Source	SAIDI Page(s) and Table Name(s) or Number(s), if Given	SAIFI Page(s) and Table Name(s) or Number(s), if Given
46	2005	Document 46.2013	pdf page 4	pdf page 4
46	2006	Document 46.2013	pdf page 4	pdf page 4
46	2007	Document 46.2013	pdf page 4	pdf page 4
46	2008	Document 46.2013	pdf page 4	pdf page 4
46	2009	Document 46.2013	pdf page 4	pdf page 4
46	2010	Document 46.2013	pdf page 4	pdf page 4
46	2011	Document 46.2013	pdf page 4	pdf page 4
62	2005	Document FL.2005	pdf pages 17, 19, and 20	pdf pages 17, 19, and 20
62	2006	Document FL.2006review	pdf pages 29, table 2-1, and 67, table A-1	pdf pages 29, table 2-1, and 67, table A-1
62	2007	Document FL.2007review	pdf pages 30, table 2-1, and 72, table A-1	pdf pages 30, table 2-1, and 72, table A-1
62	2008	Document FL.2008review	pdf pages 26, table 2-1, and 68, table A-1	pdf pages 26, table 2-1, and 68, table A-1
62	2009	Document FL.2009review	pdf pages 30, table 2-1, and 82, table A-1	pdf pages 30, table 2-1, and 82, table A-1
62	2010	Document FL.2010review	pdf pages 33, table 2-1, and 84, table A-1	pdf pages 33, table 2-1, and 84, table A-1
62	2011	Document FL.2011review	pdf pages 32, table 2-1, and 84, table A-1	pdf pages 32, table 2-1, and 84, table A-1
63	2005	Document FL.2005	pdf pages 22, 23. and 24	pdf pages 22, 23. and 24
63	2006	Document FL.2006review	pdf pages 30, table 2-3 and 69, table A.5	pdf pages 30, table 2-3 and 69, table A.5
63	2007	Document FL.2007review	pdf pages 31, table 2-2 and 76, table A.5	pdf pages 31, table 2-2 and 76, table A.5
63	2008	Document FL.2008review	pdf pages 27, table 2-2 and 71, table A.5	pdf pages 27, table 2-2 and 71, table A.5
63	2009	Document FL.2009review	pdf pages 31, table 2-2 and 85, table A.5	pdf pages 31, table 2-2 and 85, table A.5
63	2010	Document FL.2010review	pdf pages 34, table 2-2, and 88, table A-5	pdf pages 34, table 2-2, and 88, table A-5
63	2011	Document FL.2011review	pdf pages 33, table 2-2, and 88, table A-5	pdf pages 33, table 2-2, and 88, table A-5
68	2005	Document FL.2005	pdf pages 28 and 30	pdf pages 28 and 30
68	2006	Document FL.2006review	pdf pages 32, table 2-7, and 62, table A-13	pdf pages 32, table 2-7, and 62, table A-13
68	2007	Document FL.2007review	pdf pages 33, table 2-4, and 80, table A-13	pdf pages 33, table 2-4, and 80, table A-13
68	2008	Document FL.2008review	pdf pages 29, table 2-4, and 74, table A-13	pdf pages 29, table 2-4, and 74, table A-13
68	2009	Document FL.2009review	pdf pages 33, table 2-4, and 88, table A-13	pdf pages 33, table 2-4, and 88, table A-13
68	2010	Document FL.2010review	pdf pages 36, table 2-4, and 96, table A-13	pdf pages 36, table 2-4, and 96, table A-13
68	2011	Document FL.2011review	pdf pages 35, table 2-4, and 96, table A-13	pdf pages 35, table 2-4, and 96, table A-13
78	2002	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2003	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2004	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2005	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2006	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2007	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2008	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2009	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2010	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2011	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
89	2002	Document 89.2006	pdf page 3, table/section D	pdf page 3, table/section D
89	2003	Document 89.2007	pdf page 3, table/section D	pdf page 3, table/section D
89	2004	Document 89.2009	pdf page 3, table/section E	pdf page 3, table/section E
89	2005	Document 89.2010	pdf page 4, table 1	pdf page 4, table 1
89	2006	Document 89.2010	pdf page 4, table 1	pdf page 4, table 1
89	2007	Document 89.2010	pdf page 4, table 1	pdf page 4, table 1
89	2008	Document 89.2011	pdf page 8, table 7	pdf page 8, table 7
89	2009	Document 89.2012	pdf page 7, table 7	pdf page 7, table 7
89	2010	Document 89.2013	pdf page 6, table 7	pdf page 6, table 7
89	2011	Document 89.2013	pdf page 6, table 7	pdf page 6, table 7
91	2008	Document 91.2008	pdf page 4, section 4, values under "Including MED"	pdf page 4, section 4, values under "Including MED"
91	2009	Document 91.2009	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
91	2010	Document 91.2010	pdf page 3, section 4, values under "Including MED"	pdf page 3, section 4, values under "Including MED"
91	2011	Document 91.2011	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
98	2008	Document 98.2008	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
98	2009	Document 98.2009	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
98	2010	Document 98.2010	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
98	2011	Document 98.2011	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
99	2002	Document WI.2007	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"
99	2003	Document WI.2007	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"
99	2004	Document WI.2007	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"
99	2005	Document WI.2007	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"

PSEID	Year	Source	SAIDI Page(s) and Table Name(s) or Number(s), if Given	SAIFI Page(s) and Table Name(s) or Number(s), if Given
99	2006	Document WI.2007	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"
99	2007	Document 99.2008	pdf page 2, table titled "Total Annual Statistics"	pdf page 2, table titled "Total Annual Statistics"
99	2008	Document 99.2009	pdf page 2, table titled "Total Annual Statistics"	pdf page 2, table titled "Total Annual Statistics"
99	2009	Document 99.2010	pdf page 2	pdf page 2
99	2010	Document 99.2011	pdf page 2	pdf page 2
99	2011	Document 99.2012	pdf page 2	pdf page 2
124	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
124	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
124	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
124	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
124	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
124	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33
124	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
124	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
124	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
124	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
126	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
126	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
126	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
126	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
126	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
126	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33
126	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
126	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
126	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
126	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
130	2002	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2003	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2004	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2005	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2006	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2007	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2008	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2009	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2010	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2011	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
135	2003	Attachment to Email from PUCO dated July 16, 2009		
135	2004	Attachment to Email from PUCO dated July 16, 2009		
135	2005	Attachment to Email from PUCO dated July 16, 2009		
135	2006	Attachment to Email from PUCO dated July 16, 2009		
135	2007	Attachment to Email from PUCO dated July 16, 2009		
135	2008	Attachment to Email from PUCO dated July 16, 2009		
135	2009	Document FE.2009	pdf page 2, table 2	pdf page 2, table 3
136	2003	Attachment to Email from PUCO dated July 16, 2009		
136	2004	Attachment to Email from PUCO dated July 16, 2009		
136	2005	Attachment to Email from PUCO dated July 16, 2009		
136	2006	Attachment to Email from PUCO dated July 16, 2009		
136	2007	Attachment to Email from PUCO dated July 16, 2009		
136	2008	Attachment to Email from PUCO dated July 16, 2009		
136	2009	Document AEP.2009	pdf page 2, table 2	pdf page 2, table 3
140	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
140	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
140	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
140	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
140	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
140	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33

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PSEID	Year	Source	SAIDI Page(s) and Table Name(s) or Number(s), if Given	SAIFI Page(s) and Table Name(s) or Number(s), if Given
140	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
140	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
140	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
140	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
142	2002	Document 142.2011	pdf page 3, Table 1	pdf page 3, Table 1
142	2003	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2004	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2005	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2006	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2007	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2008	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2009	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2010	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2011	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
148	2002	Document OR.2008	pdf page 10	pdf page 8
148	2003	Document OR.2008	pdf page 10	pdf page 8
148	2004	Document OR.2008	pdf page 10	pdf page 8
148	2005	Document OR.2008	pdf page 10	pdf page 8
148	2006	Document OR.2008	pdf page 10	pdf page 8
148	2007	Document OR.2013	pdf page 7	pdf page 9
148	2008	Document OR.2013	pdf page 7	pdf page 9
148	2009	Document OR.2013	pdf page 7	pdf page 9
148	2010	Document OR.2013	pdf page 7	pdf page 9
148	2011	Document OR.2013	pdf page 7	pdf page 9
150	2002	Document 150.2007	pdf page 132, table 2.3-D	pdf page 132, table 2.3-D
150	2003	Document 150.2008	pdf page 140, table 2.3-C	pdf page 140, table 2.3-C
150	2004	Document 150.2011	pdf page 223, table 2.4-E	pdf page 223, table 2.4-E
150	2005	Document 150.2011	pdf page 223, table 2.4-E	pdf page 223, table 2.4-E
150	2006	Document 150.2011	pdf page 223, table 2.4-E	pdf page 223, table 2.4-E
150	2007	Document 150.2011	pdf page 223, table 2.4-E	pdf page 223, table 2.4-E
150	2008	Document 150.2012	pdf page 343, table 2.4-E	pdf page 343, table 2.4-E
150	2009	Document 150.2013	pdf page 280, table 2.4-E	pdf page 280, table 2.4-E
150	2010	Document 150.2013	pdf page 280, table 2.4-E	pdf page 280, table 2.4-E
150	2011	Document 150.2013	pdf page 280, table 2.4-E	pdf page 280, table 2.4-E
152	2002	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2003	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2004	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2005	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2006	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2007	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2008	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2009	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2010	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2011	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
159	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
159	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
159	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
159	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
159	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
159	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33
159	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
159	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
159	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
159	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
163	2002	Document 163.2011	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2003	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2004	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2005	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"

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163	2006	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2007	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2008	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2009	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2010	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2011	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
169	2002	Document 169.2011	pdf page 3, table titled "Historical System Reliability (IEEE Std 1366-2003)"	
169	2003	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2004	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2005	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2006	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2007	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2008	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2009	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2010	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2011	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
171	2002	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2003	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2004	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2005	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2006	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2007	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2008	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2009	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2010	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2011	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
178	2005	Document FL.2005	pdf pages 25, 26, and 27	pdf pages 25, 26, and 27
178	2006	Document FL.2006review	pdf pages 31, table 2-5, and 70, table A-9	pdf pages 31, table 2-5, and 70, table A-9
178	2007	Document FL.2007review	pdf pages 32, table 2-3, and 78, table A-9	pdf pages 32, table 2-3, and 78, table A-9
178	2008	Document FL.2008review	pdf pages 28, table 2-3, and 72, table A-9	pdf pages 28, table 2-3, and 72, table A-9
178	2009	Document FL.2009review	pdf pages 32, table 2-3, and 86, table A-9	pdf pages 32, table 2-3, and 86, table A-9
178	2010	Document FL.2010review	pdf pages 35, table 2-3, and 92, table A-9	pdf pages 35, table 2-3, and 92, table A-9
178	2011	Document FL.2011review	pdf pages 34, table 2-3, and 92, table A-9	pdf pages 34, table 2-3, and 92, table A-9
186	2002	Document 186.2006	pdf page 10, chart IV-1.1	pdf page 11, chart IV-1.2
186	2003	Document 186.2007	pdf page 9, chart IV-1.1	pdf page 10, chart IV-1.2
186	2004	Document 186.2008	pdf page 9, chart IV-1.1	pdf page 10, chart IV-1.2
186	2005	Document 186.2009	word doc page 9, chart IV-1.1	word doc page 10, chart IV-1.2
186	2006	Document 186.2010	word doc page 14, chart IV-4.1	word doc page 15, chart IV-4.2
186	2007	Document 186.2011	word doc page 11, chart IV-4.1	word doc page 12, chart IV-4.2
186	2008	Document 186.2012	word doc page 8, chart IV-4.1	word doc page 9, chart IV-4.2
186	2009	Document 186.2013	word doc page 10, chart IV-4.1	word doc page 11, chart IV-4.2
186	2010	Document 186.2013	word doc page 10, chart IV-4.1	word doc page 11, chart IV-4.2
186	2011	Document 186.2013	word doc page 10, chart IV-4.1	word doc page 11, chart IV-4.2

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PSEID	Year	Source	SAIDI Page(s) and Table Name(s) or Number(s), if Given	SAIFI Page(s) and Table Name(s) or Number(s), if Given
195	2002	Document VA.2010	Row for DVP	Row for DVP
195	2003	Document VA.2010	Row for DVP	Row for DVP
195	2004	Document VA.2010	Row for DVP	Row for DVP
195	2005	Document VA.2010	Row for DVP	Row for DVP
195	2006	Document VA.2010	Row for DVP	Row for DVP
195	2007	Document VA.2010	Row for DVP	Row for DVP
195	2008	Document VA.2010	Row for DVP	Row for DVP
195	2009	Document VA.2010	Row for DVP	Row for DVP
195	2010	Document VA.2010	Row for DVP	Row for DVP
195	2011	Document 195.2012	pdf page 12	pdf page 14
198	2002	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2003	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2004	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2005	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2006	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2007	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2008	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2009	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2010	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2011	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
201	2002	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2003	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2004	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2005	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2006	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2007	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2008	Document 201.2008	pdf page 5, table titled "We Energies RELIABILITY INDICES"	pdf page 5, table titled "We Energies RELIABILITY INDICES"
201	2009	Document 201.2009	pdf page 5, table titled "We Energies RELIABILITY INDICES"	pdf page 5, table titled "We Energies RELIABILITY INDICES"
201	2010	Document 201.2010	pdf page 6, table titled "We Energies RELIABILITY INDICES"	pdf page 6, table titled "We Energies RELIABILITY INDICES"
201	2011	Document 201.2011	pdf page 5, table titled "We Energies RELIABILITY INDICES"	pdf page 5, table titled "We Energies RELIABILITY INDICES"
202	2009	Document 202.2013	pdf page 4, table titled "Historical Comparison"	pdf page 4, table titled "Historical Comparison"
202	2010	Document 202.2013	pdf page 4, table titled "Historical Comparison"	pdf page 4, table titled "Historical Comparison"
202	2011	Document 202.2013	pdf page 4, table titled "Historical Comparison"	pdf page 4, table titled "Historical Comparison"
203	2002	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2003	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2004	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2005	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2006	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2007	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2008	Document 203.2008	pdf page 7, table titled "2008 Electric Distribution Customer Interruptions"	pdf page 7, table titled "2008 Electric Distribution Customer Interruptions"
203	2009	Document 203.2009	pdf page 7, table titled "2009 Electric Distribution Customer Interruptions"	pdf page 7, table titled "2009 Electric Distribution Customer Interruptions"
203	2010	Document 203.2010	pdf page 7, table titled "2010 Electric Distribution Customer Interruptions"	pdf page 7, table titled "2010 Electric Distribution Customer Interruptions"
203	2011	Document 203.2011	pdf page 7, table titled "2011 Electric Distribution Customer Interruptions"	pdf page 7, table titled "2011 Electric Distribution Customer Interruptions"

VII

Appendix Two: Econometric Research

A.2.1 Form of the Cost Model

The functional form selected for this study was the translog.[40] This very flexible function is the most frequently used in econometric cost research, and by some account the most reliable of several available alternatives.[41] The general form of the translog cost function is:

$$\ln C = \alpha_0 + \sum_h \alpha_h \ln Y_h + \sum_j \alpha_j \ln W_j$$
$$+ \frac{1}{2}\left(\sum_h \sum_k \gamma_{h,k} \ln Y_h \ln Y_k + \sum_j \sum_n \gamma_{j,n} \ln W_j \ln W_n \right) \qquad \text{[A2.1]}$$
$$+ \sum_h \sum_j \gamma_{i,j} \ln Y_i \ln W_j$$

where Y_h denotes one of K variables that quantify output and the W_j denotes one of N input prices.

One aspect of the flexibility of this function is its ability to allow the elasticity of cost with respect to each business condition variable to vary with the value of that variable. The elasticity of cost with respect to an output quantity, for instance, may be greater at smaller values of the variable than at larger values. This type of relationship between cost and quantity is often found in cost research.

Business conditions other than input prices and output quantities can contribute to differences in the costs of LDCs. To help control for other business conditions the logged values of some additional explanatory variables were added to the model in Equation [A2.1] above.

The econometric model of cost we wish to estimate can then be written as:

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[40] The transcendental logarithmic (or translog) cost function can be derived mathematically as a second order Taylor series expansion of the logarithmic value of an arbitrary cost function around a vector of input prices and output quantities.

[41] See Guilkey (1983), et. al.

$$\begin{aligned} \ln C \; = \; & \alpha_o + \sum_h \alpha_h \ln Y_h + \sum_j \alpha_j \ln W_j \\ + \; & \frac{1}{2}\left[\sum_h \sum_k \gamma_{hk} \ln Y_h \ln Y_k + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n\right] \\ + \; & \sum_h \sum_j \gamma_{ij} \ln Y_h \ln W_j + \sum_h \alpha_h \ln Z_h + \alpha_t T + \varepsilon \end{aligned} \qquad \text{[A2.2]}$$

Here the Z_h's denote the additional business conditions, T is a trend variable, and ε denotes the error term of the regression.

Cost theory requires a well-behaved cost function to be homogeneous in input prices. This implies the following three sets of restrictions:

$$\sum_{h=1}^{N} \frac{\partial \ln C}{\partial \ln W_h} = 1 \qquad \text{[A2.3]}$$

$$\sum_{h=1}^{N} \frac{\partial^2 \ln C}{\partial \ln W_h \partial \ln W_j} = 0 \qquad \forall j = 1, \ldots, N \qquad \text{[A2.4]}$$

$$\sum_{h}^{N} \frac{\partial^2 \ln C}{\partial \ln Y_h \partial \ln Y_j} = 0 \qquad \forall j = 1, \ldots, K \qquad \text{[A2.5]}$$

Imposing the above $(1 + N + K)$ restrictions implied above allow us to reduce the number of parameters that need be estimated by the same amount. Estimation of the parameters is now possible but this approach does not utilize all information available in helping to explain the factors that determine cost. More efficient estimates can be obtained by augmenting the cost equation with the set of cost share equations implied by Shepard's Lemma. The general form of a cost share equation for a representative input price category, *j*, can be written as:

$$S_j = \alpha_j + \sum_i \gamma_{h,j} \ln Y_h + \sum_n \gamma_{jn} \ln W_n \qquad \text{[A2.6]}$$

We note that the parameters in this equation also appear in the cost model. Since the share equations for each input price are derived from the first derivative of the translog cost function with respect to that input price, this should come as no surprise. Furthermore, because of these cross-equation restrictions, the total number of coefficients in this system of equations will be no larger than the number of coefficients required to be estimated in the cost equation itself.

A.2.2 Estimation Procedure

We estimated this system of equations using a procedure first proposed by Zellner (1962).[42] It is well known that if there exists contemporaneous correlation between the errors in the system of regressions, more efficient estimates can be obtained by using a Feasible Generalized Least Squares (FGLS) approach. To achieve even a better estimator, PEG iterates this procedure to convergence.[43] Since we estimate these unknown disturbance matrices consistently, the estimators we eventually compute are equivalent to Maximum Likelihood Estimation (MLE).[44]

Before proceeding with estimation, there is one complication that needs to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[45] This does not pose a problem since another property of the MLE procedure is that it is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

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[42] See Zellner, A. (1962).

[43] That is, we iterate the procedure until the determinant of the difference between any two consecutive estimated disturbance matrices are approximately zero.

[44] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

[45] This equation can be estimated indirectly from the estimates of the parameters left remaining in the model.

X

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TAB 2

EB-2017-0049: HYDRO ONE DX 2018 CIR

PEG REPORT

APRIL 2018

IRM Design for

Hydro One Networks, Inc.

April 13, 2018

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1. Introduction and Summary

1.1. Introduction

Hydro One Networks, Inc. (“Hydro One” or “the Company”) filed a Custom Incentive Rate-setting (“Custom IR”) application for its power distributor services on March 31, 2017. Escalation of the proposed revenue cap index is slowed by an X factor. The Company retained Mr. Steven Fenrick of Power Systems Engineering (“PSE”) to prepare productivity and econometric benchmarking research and testimony in support the proposed X factor. PSE reported a total factor productivity (“TFP”) trend of -1.4% for Hydro One over the 2003-2015 period and an average trend of -0.91% over this period for a broader sample of Ontario power distributors. Hydro One also commissioned unit cost benchmarking studies addressing various Company programs such as pole replacement, substation refurbishment, and vegetation management. The application was updated on June 7, 2017, including updated analyses by PSE.[1]

Hydro One is Ontario’s largest power distributor. This increases the payoff from careful appraisal of its Custom IR proposal and supportive statistical cost research. Controversial technical work and IR provisions should be identified and, where warranted, challenged to avoid undesirable precedents for Hydro One and other Ontario utilities in the future. The Ontario Energy Board (“OEB”) has commented on productivity and benchmarking methods in past IRM proceedings for all rate-regulated utility sectors.

OEB Staff retained Pacific Economics Group Research LLC (“PEG”) to appraise and comment on the productivity and benchmarking research and testimony and if necessary prepare alternative studies. We were also asked to appraise and comment on aspects of the Company’s Custom IR proposal. This is the report on our work.

The plan for our report is as follows. We begin by providing pertinent background information. There follow critiques of PSE’s productivity and benchmarking evidence and the presentation of some results using alternative methods. We conclude by discussing other features of Hydro One’s Custom IR proposal. An Appendix addresses some of the more technical issues in more detail.

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[1] Further updates to the application were filed in October and December 2017, although these did not affect PSE’s evidence or Hydro One’s proposed rate adjustment plan.

1.2. Summary

Hydro One has proposed a Custom IRM that features a revenue cap index (“RCI”) featuring a 0% Custom Industry Total Factor Productivity Measure and a 0.45% Custom Productivity Stretch Factor. These proposals are supported by TFP trend and total cost benchmarking evidence prepared by PSE. PSE also attempted to update PEG’s calculations for the Board, in the fourth generation IRM (“4th Generation IRM”) proceeding, of the TFP trend of Ontario’s power distribution industry. PSE calculated the TFP trend of Hydro One using an American Handy Whitman construction cost index.

Since this filing is being made towards the end of OEB’s 4th Generation IRM plan, PEG understands the Company’s (and the OEB’s) interest in investigating whether productivity trends of Ontario power distributors have changed in recent years. In measuring the TFP of Hydro One and other distributors, a key issue is how to replace the Electric Utility Construction Price Index (“EUCPI”) that Statistics Canada no longer calculates. Mr. Fenrick is a former employee of PEG and his methods are more similar to ours than those of some other productivity witnesses in recent IR proceedings.

PEG nonetheless disagrees with some of the methods PSE used in its productivity research. Here are our biggest concerns.

- We do not recommend using an American Handy Whitman index as the new asset price deflator in Ontario, preferring instead the implicit capital stock deflator for the Canadian utility sector. When our preferred deflator is used, Hydro One’s recent historical TFP growth is found to be much slower.
- A study of the TFP trends of Ontario power distributors must control for their transition to International Financial Reporting Standards (“IFRS”).
- PSE improperly updated the TFP indexes we developed for the OEB for 4th Generation IRM with respect to metering costs and contributions in aid of construction.
- The TFP indexes developed in 4th Generation IRM are due for methodological upgrades. In addition to a new asset price deflator, a new labor price index should be considered. A different output index is needed to calibrate the X factor of Hydro One’s revenue cap index.

Our research using alternative methods suggests that Ontario’s recent power distribution TFP trend is fairly close to zero. Growth in the productivity of operation, maintenance, and administration (“OM&A”) inputs of Ontario distributors has been more brisk than growth in the productivity of capital inputs. The available evidence suggests that the 0.0% base TFP growth trend established in 4th Generation IRM is still reasonable.

PEG also has reservations about some of the methods PSE used in its benchmarking work. However, our alternative benchmarking runs with methods we prefer produced a similar benchmarking assessment. The total cost forecasting model we developed for 4th Generation IRM suggests Hydro One's cost was about 33% above the benchmark, on average from 2014-2016, but was improving, reaching 25.73% in 2016. Using our adaptations to PSE's model, we found that their performance continued to improve in 2017 and 2018. Hydro One's forecasted/proposed cost for the 2019-2022 period is 23.0% above the benchmarks. However, Hydro One has an incentive to understate its OM&A cost growth in the years after 2018.

On this basis, a 0.45% stretch factor seems reasonable for Hydro One provided that the Board is comfortable fixing the stretch factor for the full plan term. Combined with the recommended 0% base X factor, this would give a combined X factor of 0.45%. The RCI formula would then be growth IPI - 0.45% for the annual adjustment of OM&A, net of Z factors or of any growth factor as discussed below.

The Custom IR plan proposed by Hydro One is, in several respects, uncontroversial. The design is similar to that of the Custom IR which the Board approved for Toronto Hydro in EB-2014-0016. The revenue cap index escalates OM&A revenue, strengthening the Company's performance incentives and avoiding the need for an OM&A cost forecast. An earnings sharing mechanism would asymmetrically share with customers only surplus earnings outside a deadband. A capital in service variance account ("CSVA") would asymmetrically share with customers some capex underspends but not overspends. A Custom Capital Factor ensures recovery of proposed/forecasted capital cost in each year of the plan, but this cost is reduced by the 0.45% stretch factor.

We are nonetheless concerned about some features of Hydro One's proposal. Here are some of our concerns and suggested alternative plan provisions.

- The proposed ratemaking treatment of capital cost is problematic. The C factor would incent Hydro One to exaggerate its need for supplemental revenue, and substantially raises regulatory cost for the OEB and stakeholders. The Company is perversely incented to spend excessive amounts on capital to contain OM&A expenses. The kinds of capex accorded C factor treatment are similar to those incurred by distributors in the productivity studies. The RCI would effectively apply chiefly to revenue for OM&A expenses and provide only a floor for revenue growth even though it is designed to play neither of these roles. We discuss several possible upgrades to the capital cost treatment and conclude that a materiality threshold and dead zone should be added to the C factor mechanism.

- Revenue cap indexes in approved IRMs usually have an escalator for growth in the utility's output. Hydro One's proposed RCI does not. We recommend a customer growth escalator.
- The addition of revenue decoupling to the plan has merit but makes less sense if the LRAM continues.
- With pension and benefit expenses addressed by DVAs, Hydro One has a weak incentive to contain these expenses. This raises oversight costs. Many utilities operating under IRMs do not have DVAs for these costs. Incentive for Hydro One to contain pension and other benefit expenses can be strengthened by adding a materiality threshold and dead zone to the DVA mechanism.

1.3. Credentials

PEG is an economic consulting firm with home offices in Madison, Wisconsin USA. We are a leading consultancy on IR and the measurement of energy utility performance. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. The University of Wisconsin has trained most of our staff and is renowned for its economic statistics program. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given PEG a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry is the President of PEG. He has over thirty years of experience as an industry economist, most spent on utility issues. Author of numerous professional publications, Dr. Lowry has also chaired several conferences on performance measurement and utility regulation. He has provided productivity research and testimony in over 30 proceedings. His latest study on the productivity tends of US power distributors was published in 2017 by Lawrence Berkeley National

Laboratory ("Berkeley Lab").[2] He has played a prominent role in IR proceedings in Alberta, British Columbia, and Québec as well as Ontario. Dr. Lowry holds a PhD in applied economics from the University of Wisconsin.

[2] Mark Newton Lowry, Matt Makos, and Jeff Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory, July 2017.

2. Background

Hydro One's proposed Custom IR plan is similar to that which the Board approved in 2015 for Toronto Hydro.[3] The term would be the five years from 2018 to 2022. A revenue cap index applicable to years 2019-2022 would feature two inflation measures: Canada's gross domestic product implicit price index for final domestic demand ("$GDPIPIFDD^{Canada}$") and the average weekly earnings for all businesses in Ontario ("$AWE^{Ontario}$"). The RCI would also have a 0% Custom Industry Total Factor Productivity Measure and a 0.45% Custom Productivity Stretch Factor. Several costs would be addressed by deferral and variance accounts ("DVAs"), including pension and other benefit expenses. A lost revenue adjustment mechanism ("LRAM") would expedite compensation for load losses due to conservation and demand management ("CDM") programs.

A Custom Capital Factor (aka "C Factor") averaging about 2% per year would supplement revenue growth to correct for the Company's expectation that the RCI would otherwise undercompensate it for growth in its capital revenue requirement. The capital revenue requirement would be based on forecasted/proposed cost but adjusted downward for the 0.45% stretch factor.

An asymmetrical earnings-sharing mechanism ("ESM") would share only surplus earnings. An asymmetrical capital in-service variance account ("CSVA") would reduce rates for the bulk of any plant addition underspends. Verifiable productivity gains would be excluded from the CSVA pass-through. In response to Staff interrogatory 123(b), the Company explained that

> Hydro One's productivity governance and associated reporting processes are maintained by Finance. Hydro One has implemented a robust governance structure around productivity reporting to ensure productivity savings are accurately reflected on corporate scorecards and that there is continuity of savings in the Business Plan.
>
> **All productivity initiatives are approved by Finance prior to reporting any actual savings on corporate scorecards and are audited for compliance throughout the year. Approval by Finance ensures that each initiative is tracked using a detailed calculation methodology.**
>
> Finance reviews all productivity reporting to ensure each initiative meets the following criteria:
>
> - Consistently documented (detailed description/logic, identified systems/dependencies, clear calculation methodology/data source and reasonable exclusions/adjustments);
> - Auditable with an applicable baseline for reporting;

[3] EB-2014-0016

- **In line with Hydro One's definition of productivity ('hard' savings and not cost avoidance); and**
- Reviewed and approved by a VP or delegate.

Productivity achievement is reported to the Executive Leadership Team on a monthly basis and is included as a metric on Hydro One's Team Scorecard for management staff.[4] **[Emphasis added]**

[4] Exhibit I/Tab 25/Staff-123 b)

3. PSE Productivity Research

PSE calculated the total factor productivity trend of Hydro One over the 2003-2015 period.[5] It reported a -**1.4%** average annual growth rate (aka "trend") over the full sample period and a **-0.4%** trend in the five-year 2011-2015 period.[6] In response to an undertaking, PSE reported that Hydro One's productivity in the use of OM&A inputs averaged a 1.2% annual decline over the full sample period while capital productivity averaged a 1.5% decline. From 2011 to 2015, capital productivity growth averaged a 1.5% annual decline while O&M productivity growth grew at a brisk +2.0% annual pace.[7] In response to a data request, PSE also measured the TFP trend that is implicit in the Company's proposed cost of base rate inputs during the IRM. PSE reported that TFP will be about the same in 2022 as in 2015.[8]

Unexpectedly, PSE also calculated the TFP trend of a broader sample of Ontario distributors over the 2003-2015 period using a methodology similar to that which PEG used in its work for the Board to calibrate the X factor for 4th Generation IRM. PSE reported a **-0.91%** TFP trend over the full 2003-2015 sample period.[9] TFP declined substantially in all three years that PSE added to the sample.

PEG has reviewed PSE's direct evidence and working papers and has several concerns about the productivity research that PSE conducted. To facilitate the OEB's review of the complicated issues that arise in a productivity study, we highlight here our most serious concerns.

3.1. Asset Value Price Deflator

Power distributors use capital-intensive technologies, so the treatment of capital is a major issue when measuring their total factor productivity. TFP research in North America typically uses a "monetary" approach to capital cost and quantity measurement. Computation of capital quantity

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[5] The TFP indexes PSE calculated for this proceeding are more accurately described as "multifactor" productivity indexes since they track trends in several kinds of inputs but exclude other inputs such as the power and upstream transmission services purchased in the provision of merchant services.

[6] Fenrick, S., Power Systems Engineering (PSE), *Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry*, EB-2017-0049, Exhibit A-3-2, Attachment 1, March 31, 2017, p. 2.

[7] HONI_TC_Undertakings JT1.01-1.07, Undertaking JT 1.3, March 14, 2018, p. 10.

[8] HONI_IRR_B-Custom Application-Issues 7-16, Exhibit I/Tab 8/Staff-31b, February 12, 2018.

[9] Fenrick TFP Study, *op. cit*., p. 4.

trends using monetary methods involves deflation of asset values that utilities report (e.g., their gross plant additions) using price indexes. Further discussion of monetary methods can be found in the Appendix.

PSE used an American Handy Whitman Electric Utility Construction Cost Index ("HWI") for power distribution in North Atlantic States to deflate Hydro One's asset values. They attempted to make this index more relevant to Canada by adjusting it for the trend in US/Canadian purchasing power parities ("PPPs") obtained from the Organization for Economic Cooperation and Development ("OECD"). However, like PEG in the 4th Generation IRM proceeding, PSE used Statistics Canada's Electric Utility Construction Price Index ("EUCPI") for distribution systems to perform the same function in its research on the TFP of other Ontario power distributors. This is to our knowledge the first time that an Ontario witness has proposed an alternative asset value price deflator in an energy utility productivity study. PSE's choice of an alternative deflator is an important empirical issue in this proceeding.

In response to an information request, PSE provided some criticisms of the EUCPI, including a statement that it didn't apply only to distribution (there were in fact EUCPI sub-indices calculated for "distribution systems" and "substations") and a concern that the EUCPI includes financing costs (there are versions without financing costs and the trends of these indexes are similar).[10]

The HWI has tended to grow much more rapidly than the EUCPI, so use of the HWI to deflate plant values should reduce measured capital quantity growth and accelerate TFP growth. In response to another information request, PSE reported that the TFP trend of the Company was a substantial 90 basis points slower (more negative) if the EUCPI was instead used as the asset value price deflator for the Company's productivity calculation.[11]

The appropriate asset price deflator to use in power distributor productivity research is an issue of growing importance in North American IR. One reason is that Statistics Canada stopped computing EUCPIs after 2014. We also believe that HWIs are due for a critical review.

Since, additionally, PSE used an HWI in its research, PEG has spent considerable time and effort in this project reviewing alternative asset price deflators. We found that HWIs and EUCPIs both have drawbacks. Both were designed many years ago and have some cost-share weights and inflation

[10] Exhibit I/Tab 10/SEC-17.

[11] Exhibit I/Tab 10/SEC-15.

subindexes that are now quite dated. The labor price component of the distribution system EUCPI has for many years grown quite slowly. However, trends in prices of labor and other construction inputs in the North Atlantic states, with their many large urban areas, may not be appropriate for Hydro One and other Ontario utilities.

Alternative asset price indexes are available. Based on our review, our professional opinion is that the most promising replacement for the EUCPI in Ontario productivity research is Statistics Canada's implicit price index for the capital stock of the Canadian utility sector.[12] This is readily computed from Statistics Canada's data on Flows and Stocks of Fixed Non-Residential Capital. This program measures trends in the quantities of various capital assets using a monetary method. Statistics Canada generates this dataset by gathering investment data from the Annual Capital Repair and Expenditures Survey. Mr. Fenrick stated at the technical conference that he did not consider alternative deflators in his work for this proceeding.[13]

3.2. Ontario Industry Productivity Research

PSE's -0.91% TFP trend estimate for the broader Ontario sample from 2003 to 2015 is disappointing if true and would imply that Hydro One's proposed revenue cap index contains a sizable implicit stretch factor. By way of contrast, we reported a **0.23%** trend in the TFP of US power distributors over the 2001-2014 period in our 2017 study for Berkeley Lab.[14] OEB Staff have not commissioned an updated study of productivity trends of power distributors since the 4th GIRM proceeding. Acknowledgment by the Board of a -0.91% trend in this proceeding could complicate a future proceeding on 5th Generation IRM for provincial power distributors.

There are, furthermore, reasons to doubt the accuracy of PSE's -0.91% trend estimate and its relevance for calibration of Hydro One's X factor. Here are some important grounds for concern that the -0.91% estimate may be too low. The biggest driver of the result was TFP declines in excess of 4% in 2012 and 2013. These were chiefly due to sharp declines in *OM&A* productivity. Over the full sample

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[12] Statistics Canada, Table 031-0005, Flows and Stocks of Fixed Non-Residential Capital, CANSIM. The implicit price index is calculated as the ratio of current value of net stock to the corresponding quantity index.

[13] Transcript, OEB, EB-2017-0049, HONI_Technical Conference_Day 1_20180301, p. 30, line 21 to p.31, line 1.

[14] Mark Newton Lowry, Matt Makos, and Jeff Deason, *op. cit.*, p. 6.4.

period, OM&A productivity growth averaged only -0.8% annually despite widespread installation in Ontario of automated metering infrastructure ("AMI") that should have cut OM&A costs.[15] Our Berkeley Lab study found that the OM&A productivity of US power distributors averaged 0.40% annual growth from 2001 to 2014 while capital productivity growth averaged 0.18%.

One reason for the negative OM&A productivity growth in Ontario in recent years which PSE reports has been the adoption by many distributors of new accounting standards. The OEB undertook the necessary work to determine how IFRS should be implemented and the result was a modified IFRS ("MIFRS"). The new standard affected a wide range of issues, but the most important item that impacts this productivity work is the treatment of capitalized overheads. Under Canadian GAAP, distributors were permitted to capitalize more costs than are permitted under IFRS. Not all distributors adopted MIFRS at the same time, and adoption often coincided with cost of service rate applications. Adoption of the OEB's revised capitalization policy sometimes predated full adoption of MIFRS. PSE noted, in response to a data request, that it did little work to gauge the impact of this conversion on productivity results.[16]

PSE used data from the OEB's total cost benchmarking program for its 2013-2015 Ontario productivity update even though these data include contributions in aid of construction ("CIAC") while those for the 4th Generation IRM productivity study did not. This will also tend to slow TFP growth artificially.

Average weekly earnings in Ontario were used in PSE's labor price index, as in PEG's 4th Generation IRM research. There are reasons to believe that this index is inexact. Trends in average weekly earnings are sensitive to trends in overtime and the composition of the labor force such as the share of employees working part-time. This creates aggregation bias in the measurement of labor price trends. A *fixed weighted* index of average hourly earnings of all employees in Ontario is available from Statistics Canada which is less biased.[17] We believe that this alternative labor price index should be used

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[15] Exhibit I, Tab 8, Staff-33.

[16] Exhibit I/Tab 8/Staff-27a.

[17] Statistics Canada. Table 281-0039 - Survey of Employment, Payrolls and Hours (SEPH), fixed weighted index of average hourly earnings for all employees, by North American Industry Classification System (NAICS), monthly (index, 2002=100), CANSIM (database).

in any future Ontario productivity research. This would be more accurate and incidentally grow more rapidly, modestly increasing OM&A and total factor productivity growth.

The output indexes that PEG developed in the 4th Generation IRM proceeding and PSE used in its calculations are multidimensional, and summarize trends in distributor delivery volumes, peak demand, and the number of customers served using cost elasticity weights drawn from our econometric total factor productivity research for the OEB. Growth in volumes and peak demand have been slowed considerably in Ontario by CDM programs encouraged by government policies. The recent growth in system use may well be slower and increase capacity utilization less than was expected when many facilities were built. It may take time for slower growth in system use to produce material distribution capex economies.[18]

We note in the Appendix that elasticity-based scale indexes are useful when the goal of productivity research is to measure cost efficiency trends. However, as Mr. Fenrick notes in his report, the output index developed in 4th GIRM excludes other pertinent measures of output which drive cost. He developed a scale index that also encompasses trends in reliability and safety and describes this work in his productivity report.[19] The enhanced scale index is used to compute "adjusted TFP" results for Hydro One which he discusses on pp. 36-39 of his report. PSE found that the addition of reliability and safety variables to the scale index accelerated the estimated TFP trend of Hydro One over the full sample period by a substantial 90 basis points. We believe that system capabilities that depend on smart grid facilities (e.g., the quality of metering and the ability of distribution systems to handle 2-way power flows) are also legitimate candidates for inclusion in an elasticity-weighted output index. Thus, the scale indexes Mr. Fenrick uses to measure the productivity trends of other Ontario distributors are not ideal for measuring cost efficiency trends.

It is also unclear how appropriate the unadjusted scale index is for an X factor calibration exercise. Hydro One proposes a *revenue* cap index. We explain in the Appendix that the X factors of RCIs are typically calibrated with productivity indexes that use the number of customers to measure output.

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[18] It may, alternatively, be the case that many distributors have not trimmed capex to reflect lowered expectations of future system capacity utilization.

[19] Fenrick TFP Study, *op. cit.*, pp. 28-34.

Most other distributors in Ontario operate under *price* cap indexes. Scale indexes used in X factor calibration exercises for price caps should in principle be revenue-weighted. Usage variables sometime receive substantial weights in revenue-weighted indexes. However, Ontario power distributors are transitioning to more fully fixed rate designs for residential customers that cause revenue to be driven increasingly by customer growth. Ontario power distributors also have LRAMs to compensate them for load impacts of CDM programs. Thus, the scale indexes Mr. Fenrick uses to calculate productivity trends of Ontario power distributors may also be inappropriate for determining X factors in future price cap IRMs.

Some other concerns that we have about PSE's Ontario industry productivity research are also important but do not necessarily suggest a higher or lower Ontario TFP trend.

- The EUCPI must be replaced and our research suggests that it has grown too slowly in recent years. Alternative asset value deflators we are considering have grown quite a bit more rapidly than the EUCPI in *recent* years and this could slow recent TFP growth. However, the trend of these alternative indexes in *earlier* years (e.g., before 2002) also affects TFP growth. The net effect on TFP is an empirical issue that we address further below.
- Pension and other benefits expenses are included in PSE's calculations (as they were in PEG's 4th GIRM research), even though these expenses would be Y factored in Hydro One's proposal and Statistics Canada does not maintain a labor price index that includes pension and benefit expenses. It is difficult to properly remove these expenses from the data. One reason is that the OEB has never provided PEG with itemized data on these expenses from the RRR for the full sample period which would be needed to remove them from the study. We are also concerned that some distributors do not consistently itemize these expenses in their reports to the OEB.
- PEG's productivity work in the 4th Generation IRM proceeding excluded all costs of Ontario's extensive AMI buildout, which began in 2007 and ended in 2012. We adjusted reported metering expenses for 2007 and later years to remove those attributable to AMI. These expenses grew over time to constitute almost all metering OM&A expenses by 2012. PEG also removed all reported metering capex for 2007 and later years.

  PSE's productivity update, which started with 2013 data, included all metering and meter reading expenses, causing thereby an artificial surge in OM&A expenses. This is another reason for the plunge in OM&A and total factor productivity in that year. PSE also included all metering capex starting in 2013. Capital costs of AMI installed between 2007 and 2012 were, however, excluded from Mr. Fenrick's productivity research.

If not now, it will soon be time to incorporate the full cost of AMI into calculations of the productivity trends of Ontario power distributors. This complicated exercise is beyond the scope of this project. In any event, it is not clear what the *net* impact of this inclusion would be. Inclusion of AMI capex would accelerate the industry's capital quantity growth from 2007 to 2012, especially if the cost of the older meters is not removed as they were replaced. However, capital quantity growth would be slowed after 2012 if properly measured since the AMI assets, with their relatively short service lives, would briskly depreciate. Metering OM&A expenses would have a more positive trend were they included for all years, and this would also slow TFP growth. However, they would not surge in 2013 as they do in PSE's treatment. Output quantity growth would accelerate were the scale index revised to reflect improved metering capabilities.

- Exclusion of Haldimand and Woodstock from PSE's study of the Company's productivity means that the study does not reflect all distributor operations of Hydro One. The impact of this is not expected to be large.

3.3. Alternative Productivity Runs - Ontario

We did not undertake a full upgrade and update of our Ontario power distribution productivity work for this proceeding. Many issues are best resolved in the upcoming 5th Generation IRM proceeding. However, PEG has undertaken preliminary work to quantify the impact of some of the issues noted above. Starting with the results in the PSE working papers, we introduced adjustments step by step to test the robustness of PSE's productivity results.

Table 1 provides the estimated incremental and cumulative impact of our adjustments on the OM&A, capital, and total factor productivity trends of sampled Ontario distributors over the full 2003-2015 sample period. The table is divided into an area for adjustments and corrections for known inconsistencies with our previous work and another area for upgrades to the methods we used in the 4th Generation IRM proceeding.

Here is a list of adjustments and corrections that we made to PSE's calculations.

- Contributions in aid of construction were removed from data for 2013-2015.
- Smart meter OM&A and capital costs were also removed.

Table 1

Analysis of PSE's Ontario Productivity Study

	OM&A		Capital		TFP	
PSE Productivity Trend (2003-2015)		-0.83%		-0.96%		-0.91%
	Incremental Impact	Revised Trend	Incremental Impact	Revised Trend	Incremental Impact	Revised Trend
Adjustments and Corrections						
Data Comparability Issues						
CIAC	na	-0.83%	0.17%	-0.79%	0.09%	-0.82%
Smart Meter OM&A	0.21%	-0.62%	na	-0.79%	0.09%	-0.73%
Smart Meter Capital	na	-0.62%	0.08%	-0.71%	0.05%	-0.68%
Transition to IFRS Accounting Changes	0.82%	0.20%	na	-0.71%	0.35%	-0.33%
Sample and Merger Issues	-0.01%	0.19%	0.01%	-0.70%	0.00%	-0.33%
Exclude Norfolk	0.00%	0.20%	0.00%	-0.71%	0.00%	-0.33%
Include Lakeland/Parry	-0.01%	0.19%	0.01%	-0.70%	0.00%	-0.33%
Total Impact of Adjustments and Corrections [A]	**1.02%**	**0.19%**	**0.26%**	**-0.70%**	**0.58%**	**-0.33%**
Methodological Upgrades						
Labor Price Index [B]	0.12%	0.31%	na	-0.70%	0.05%	-0.29%
Asset Price Index: Replace EUCPI	na	0.31%	0.10%	-0.61%	0.04%	-0.25%
Use Utility Sector Capital Stock Deflator [D]	na	0.31%	0.10%	-0.61%	0.04%	-0.25%
Use Northeast HW index adjusted for PPP	na	0.31%	1.30%	0.60%	0.79%	0.51%
Output Quantity Adjustment	0.29%	0.61%	0.29%	-0.31%	0.29%	0.05%
Conservation adjustments to volumes and peaks	0.50%	0.81%	0.50%	-0.11%	0.50%	0.25%
Customer only index [C]	0.29%	0.61%	0.29%	-0.31%	0.29%	0.05%
Total Impact of Proposed Upgrades [E]=[B+C+D]	**0.42%**		**0.39%**		**0.38%**	
Total Impact of All Adjustments and Upgrades [A+E]	**1.44%**	**0.61%**	**0.65%**	**-0.31%**	**0.96%**	**0.05%**

- An adjustment was made for the transition to MIFRS accounting. We estimated the 2015 OM&A quantity in the absence of MIFRS transitions. Most companies that recently filed for rebasing have reported the amount by which their OM&A expenses were affected by MIFRS adoption. We were able to identify 14 distributors that clearly identified the impact. These companies as a group showed 12.5% higher OM&A expenses under MIFRS. We then attempted to identify distributors that had either adopted MIFRS by 2015 or indicated that they had previously changed their capitalization policy. We found that companies representing about 81% of OM&A cost had done so. As an adjustment, we therefore used an estimate of what the OM&A input quantity would have been in 2015 in the absence of MIFRS. Our 10.1% markdown is the product of a typical 12.5% reported increase in cost times 81% of costs affected by this issue.

- Adjustments were also made for two mergers.

Here is a list of the changes in our 4th Generation IRM methodology for measuring TFP which we considered.

- We replaced the AWE with the fixed-weight average hourly earnings in Ontario.

- We replaced the EUCPI in turn with two alternative deflators: the implicit price index for the capital stock of the utility sector from Statistics Canada and the Handy Whitman Index of Electric Utility Construction Costs for power distribution in the North Atlantic states.

- We considered replacing the elasticity-weighted output index developed for 4th Generation IRM with 1) the number of customers served and 2) an alternative elasticity-weighted index that includes CDM savings.

As can be seen in the above table, the impact of these issues on the TFP trends of Ontario power distributors varied in importance. Considering first the adjustments and corrections, the correction for the transition to IFRS accounting had the greatest impact. For the full sample period, the OM&A productivity trend accelerated by 82 basis points and the total factor productivity trend accelerated by 35 basis points. While based on valid concerns, adjustments for CIAC and the treatment of meters individually had smaller impacts on the TFP trend. Corrections for two mergers had very little impact. Taken together, all of these steps changed the estimated Ontario distributor TFP trend from -0.91% to -0.33% over the full sample period.

The impacts of the methodological upgrades on the TFP trend also varied. Use of the fixed-weighted labor price index for Ontario raised the OM&A productivity trend by 12 basis points and the TFP trend by five basis points.

Use of the implicit price deflator for the utility sector capital stock instead of the EUCPI raises the TFP trend by 4 basis points.[20] This leaves us at **-0.25%**. This is our best current estimate of the cost efficiency trend of Ontario power distributors. However, other drivers of cost such as reliability, safety, and metering capabilities are excluded from the analysis. If the number of customers were used to measure output, it can be seen that the output and TFP trends would be about 30 basis points higher.[21]

Taken together, our recommended methodological upgrades changed the Ontario TFP trend from -0.33% (after our corrections) to +0.05%, which is an increase of 0.38%. The +0.05% result is similar to the trend in the productivity of US power distributors over a similar period which we reported in our Berkeley Lab study. The total impact of corrections *and* improvements is to move the TFP trend from -0.91% to +0.05%, an increase of 96 basis points after rounding.

It is also interesting to compare the partial factor productivity indexes of OM&A inputs and capital. It can be seen that, after adjustments, corrections, and recommended methodological changes, the **+0.61%** growth trend in the OM&A productivity of Ontario distributors has been much more brisk than the **-0.31%** growth trend in the productivity of capital inputs. Our study for Berkeley Lab also found that the OM&A productivity growth of US power distributors exceeded their capital productivity growth, although by a smaller amount.

In summary, PSE's productivity evidence for Hydro One opens a complicated set of issues on how Ontario power distributor productivity research should be updated and methodologically improved. Our critique and alternative runs suggest that the TFP trend of Ontario power distributors has been much more rapid than -0.91%. However, finalization of many of these issues must await a future 5th GIRM proceeding. We recommend that the OEB not embrace PSE's -0.91% TFP trend estimate in this proceeding. The base TFP growth target of 0% that the Board established in 4th Generation IRM, and which Hydro One proposes, still seems reasonable pending more definitive research on Ontario industry TFP trends.

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[20] It can also be seen that a PPP-adjusted Handy Whitman Index would produce a much larger increase in the Ontario TFP trend, but we are not suggesting that this would be an improvement in the accuracy of the index. We note this result because PSE used a Handy Whitman Index in its Hydro One-specific productivity work.

[21] Adding the impact of CDM on system use had an even larger effect. According to the Ontario Ministry of Energy, the impact of conservation and load control programs has approximately doubled since the 2012 endpoint of the previous study. Should the MW and MWh be adjusted to add back the impact of these programs, the output and TFP trends would be approximately 0.50% higher than measured by PSE.

3.4. Alternative Productivity Runs – Hydro One

We also recalculated the productivity trends of Hydro One. We revised PSE's methodology to use the implicit price deflator for the utility sector capital stock and the fixed-weight average hourly earnings for Ontario. Results of this work are presented in Table 2. It can be seen that the Company's TFP growth declined at a 2.31% average annual growth rate over the full 2003-2015 sample period. This result is quite different from PSE's, and less favorable to Hydro One. Output grew at a sluggish 0.6% average annual rate while input growth averaged 2.9%. OM&A productivity averaged a 1.11% annual decline while capital productivity averaged a more substantial 3.03% annual decline. In the last five years of the sample Hydro One's TFP growth improved, averaging a 1.26% decline. OM&A productivity growth averaged 1.93% annually whereas capital productivity declined by a substantial 3.2% annually.

Table 2

Adjusted Hydro One Productivity Results

	Input Quantity (PEG Upgrade)			Output	Productivity					
					PEG Upgrade			PSE Methodology		
Year	Summary	OM&A	Capital	Quantity[fn]	TFP	OM&A	Capital	TFP	OM&A	Capital
2003	1.5%	-1.2%	3.2%	1.6%	0.1%	2.8%	-1.6%	0.4%	2.7%	-1.0%
2004	-0.8%	-6.3%	2.4%	0.7%	1.5%	7.0%	-1.6%	1.9%	7.2%	-0.9%
2005	3.4%	5.8%	2.0%	1.2%	-2.2%	-4.6%	-0.8%	-1.5%	-4.3%	0.0%
2006	6.1%	10.2%	3.6%	0.3%	-5.8%	-9.9%	-3.2%	-4.8%	-10.4%	-1.8%
2007	9.9%	16.2%	5.6%	1.0%	-9.0%	-15.3%	-4.6%	-7.2%	-15.3%	-2.4%
2008	0.6%	-4.6%	4.2%	0.6%	0.0%	5.2%	-3.6%	0.7%	4.6%	-1.6%
2009	5.0%	5.6%	4.6%	0.0%	-5.0%	-5.6%	-4.6%	-4.1%	-6.7%	-2.8%
2010	4.0%	4.2%	3.8%	0.4%	-3.5%	-3.7%	-3.4%	-2.3%	-3.8%	-1.6%
2011	1.4%	-1.2%	3.2%	0.5%	-1.0%	1.7%	-2.7%	-0.1%	1.5%	-1.0%
2012	0.2%	-4.0%	2.9%	0.5%	0.3%	4.5%	-2.4%	1.1%	4.5%	-0.7%
2013	6.3%	8.4%	4.8%	0.2%	-6.1%	-8.2%	-4.6%	-4.6%	-8.1%	-2.7%
2014	3.2%	3.7%	2.9%	0.0%	-3.2%	-3.7%	-2.9%	-2.1%	-3.5%	-1.4%
2015	-2.9%	-14.6%	4.0%	0.7%	3.6%	15.4%	-3.3%	3.9%	15.3%	-1.6%
2003-2015	**2.9%**	**1.7%**	**3.6%**	**0.6%**	**-2.31%**	**-1.11%**	**-3.03%**	**-1.45%**	**-1.25%**	**-1.49%**
2003-2010	**3.7%**	**3.7%**	**3.7%**	**0.7%**	**-2.97%**	**-3.00%**	**-2.93%**	**-2.12%**	**-3.25%**	**-1.51%**
2011-2015	**1.6%**	**-1.6%**	**3.6%**	**0.4%**	**-1.26%**	**1.93%**	**-3.20%**	**-0.36%**	**1.95%**	**-1.47%**

[fn] The output measure for these calculations was the multidimensional elasticity-weighted output index developed by PEG for the OEB in 4th GIRM.

4. Benchmarking Research

4.1. PSE's Total Cost Benchmarking

PSE also benchmarked the total cost of the Company's distribution base rate inputs. This study appraised Hydro One's historical costs over the 3-year 2014-16 period and its forecasted/proposed costs for the 2017-2022 period. An econometric cost model was used in the study with parameters PSE estimated using US data on power distributor operations of investor-owned utilities ("IOUs") and rural electric cooperatives ("RECs"). This model has a flexible translogarithmic ("translog") functional form that includes quadratic and interaction terms for the output variables.

PSE reported that Hydro One's cost was 24.7% above the model's prediction on average from 2014 to 2016. Its proposed costs during the years of the IRM were about 22.2% above the model's predictions on average. On this basis, and in conformance with the OEB 4th Generation IRM rules, Mr. Fenrick advocated and the Company embraced a fixed 0.45% stretch factor during the years of the plan. Cost performance would decline about 1.3% between 2018 and 2022.[22] Hydro One's component OM&A expenses, capital costs (e.g., depreciation and return on plant value), and capital *expenditures* ("capex") were not separately benchmarked.

We have a number of concerns about PSE's benchmarking study. We highlight first our biggest concerns to facilitate OEB review.

- PSE's benchmarking results are improved by an optimistic forecast of Hydro One's OM&A expenses. These expenses appear to have been forecasted using an inflation – 0.45% formula that includes no growth factor. In addition, the PSE work assumed OM&A input price growth of 2.26%. This would overstate future cost performance if the 2.26% figure is more rapid than the inflation assumption used to generate the cost forecast. It is noteworthy that Hydro One has an incentive to understate its OM&A cost growth for the out years of the IRM because this reduces the stretch factor under its proposal without affecting the base productivity trend or C factor.

[22] Fenrick, S., Power Systems Engineering (PSE), *Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network*, Exhibit A-3-2, Attachment 2, June 7, 2017, p. 6.

- The challenge posed by low customer density is a major issue when benchmarking the cost of Hydro One. The customer density variable that PSE used is service territory area/customer.[23] Service territory area is difficult to calculate accurately. A threshold issue in these calculations is whether the territory is the area which the utility must *stand ready* to serve if demand arises or the (often much smaller) area it *actually* serves. The former approach is easier to implement but less accurate. In the technical conference, Mr. Fenrick stated that PSE took the former approach.[24] Hydro One's customer density is reported to be far lower than the average for the rural electric cooperatives in the sample. The service territory estimate for Hydro One exceeds the entire land area of Ontario. Alternative density variables are available. PEG used overhead line miles per customer as the density variable in a recent power distributor cost benchmarking study for Alberta's Utilities Consumer Advocate ("UCA").[25] The value of this variable will tend to be high for distributors serving rural areas and low for distributors serving urban areas.

- One cost *advantage* of a rural distributor is extensive overheading of facilities, which saves on capital cost. Our research indicates that distributors with extensive overheading tend to have lower capital cost and total cost. There is no overheading variable in PSE's model.

- The PSE benchmarking study is unusual for including data from numerous US regional electric cooperatives in the sample, yet it excludes data for Ontario distributors that serve rural areas (e.g., Algoma Power) and report their costs in Canadian currency. REC data do have some advantages in a study of the cost performance of Hydro One.

  - RECs typically have low customer density like Hydro One. Inclusion of REC data in the sample to that extent increases the precision of forecasts of the cost of Hydro One. REC data are particularly desirable for estimating the parameter of the cost model's density variable.

  - Data on peak loads of RECs may be better than those available for US IOUs.

  The REC data also have noteworthy limitations. Three of these are especially important.

[23] Fenrick, Benchmarking Study, *op. cit*., p. 11.

[24] Transcript, Technical Conference, March 1, 2018, *op. cit.*, p.46, line 17-p.47, line 4.

[25] Pacific Economics Group Research (2018). *Benchmarking the Performance of Alberta Power Distributors*, for Utilities Consumer Advocate of Alberta, February 2018.

- RECs tend to be much smaller than Hydro One.
- REC data are publicly available only through 2011. Inclusion of REC data in the sample to that extent reduces the precision of the trend variable parameter and of cost forecasts for years after 2011. This makes these data less relevant for calculating cost benchmarks for Hydro One in future years. Five years from now, in a possible new benchmarking study, this limitation of REC data would loom even larger.
- Pension and other benefit expenses of RECs are not itemized, so it is necessary to include these expenses for all companies in the benchmarking study, even though itemized data on these expenses are available for Hydro One and the American IOUs. PEG usually excludes pension and other benefit expenses from its benchmarking studies (but did not exclude them from our 4th GIRM study) because they are sensitive to volatile external business conditions that are beyond the control of utility managers.[26] Additionally, Hydro One proposes continuation of existing DVAs for these expenses.[27] We mentioned above that Statistics Canada does not have a labor price index that includes pension and benefit expenses.[28]
- Mr. Fenrick noted during the technical conference that the processing of the REC data was a major cost of the project.[29]

Here are some less important but nonetheless notable REC data problems.

- As is the case for Hydro One (but not for the American IOUs), the OM&A salaries and wages of RECs are not itemized. This reduces the accuracy of the OM&A input price indexes that can be calculated for RECs and used in benchmarking.

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[26] One reason that we did not exclude these costs from our benchmarking study for 4th GIRM is that we did not believe that these had been properly itemized by all companies.

[27] HONI_Update_Ex_F_20170607, Exhibit F1/Tab 3/Schedule 1, p. 2.

[28] PSE addressed this problem by converting an employment cost index for *total* compensation that is obtained from the US Bureau of Labor Statistics (an index which *does* address benefits) to Canadian dollars using PPPs. An Ontario salary price index was, meanwhile, used in PSE's *productivity* research. See Fenrick TFP Study, *op. cit*., p. 21.

[29] Transcript, Technical Conference, March 1, 2018, *op. cit*., p. 50, lines 6-19.

- RECs are not investor-owned and may therefore have less incentive to contain cost than IOUs.
- RECs do not itemize net distribution plant value, so this must be estimated when computing the first year of the capital quantity index using crude formulas.

In view of all these deficiencies, it is questionable whether inclusion of REC data in the sample and PSE's exclusion from the sample of data for Ontario distributors like Algoma Power which serve rural areas was worthwhile.

- PSE used a 2002 benchmark year to calculate the capital cost of *all* utilities in the econometric cost sample, even though the requisite capital data are available since 1989 for most Ontario utilities, since 1995 for US RECs, and since 1964 for major US IOUs. Since capital cost typically accounts for more than 60% of the total cost of distributor base rate inputs in PSE's study, this substantially reduces the accuracy of the benchmarking work. Mr. Fenrick stated at the technical conference that a common 2002 benchmark year was necessary to avoid "bias," but did not explain the expected character of such bias.[30] It is not clear why making research more accurate makes it more biased. In our benchmarking and productivity research for the OEB, PEG has always measured capital quantities starting in the earliest year for which data are available, even though these years vary amongst Ontario distributors. PSE used a mix of benchmark years in its industry productivity update to maintain consistency with PEG's 4th GIRM study.[31]
- As in the productivity research, PSE uses a Handy Whitman construction cost index converted to Canadian dollars.[32]

Here are some smaller concerns we have with PSE's benchmarking study. We do not believe that these problems had a major impact on benchmarking results on balance. However, future benchmarking studies, by Hydro One and other utilities, which steer clear of these problems will have more credibility.

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[30] Technical Conference Transcript Vol. 1, *op. cit.*, p. 50, line 24-p.54, line 5.

[31] Fenrick TFP Study, *op. cit*., p. 23.

[32] *Ibid.*, p.13.

- In the benchmark year, for all US utilities PSE calculated net *distribution* plant value as net *total* plant value multiplied by the share of total *gross* plant value which is distribution.[33] This is needlessly inaccurate since the requisite net distribution plant value data are available for the American IOUs in the sample.
- PSE uses peak demand data as a variable in the cost model. Available US data overstate distribution peak demand, since they can include the demand of a utility's wholesale customers. PSE did not adjust these data to make them more accurate. This made the performances of US distributors look better than they actually were.
- Fixed 70/30 weights were assigned to labor and material and service expenses in the OM&A price index for US utilities even though flexible weights are available for the American IOUs in the sample and a 70/30 split between labor and M&S isn't typical for these companies. Thus, the OM&A input price indexes for American distributors were needlessly inaccurate.
- The labor price levelization for Hydro One uses Ontario-wide data whereas levelization for all other utilities in the sample used labor prices specific to their service territories. The percentage of Hydro One distribution employees that work in large urban areas of Ontario where labor prices are highest is likely lower than the Ontario norm.
- The decision to take the logarithm of business condition variables was done inconsistently.
- No controls were made for large transfers of costs that some companies report between their transmission and distribution operations.[34] This compromises the accuracy of the capital cost estimates for these companies.
- Exclusion of Haldimand and Woodstock from the benchmarking study means that the study does not reflect all distribution operations of Hydro One. Haldimand has been a good performer in the Board's total cost benchmarking studies while Woodstock's performance has been similar to Hydro One's. The effect of these exclusions should not be large.
- PSE uses the US gross domestic product price index, converted to Canadian dollars using PPPs, as the material and services ("M&S") price index for HON. The Canadian GDPIPIFDD was

[33] *Ibid*., p.13.

[34] These transfers can go either way.

meanwhile used to deflate M&S expenses in PSE's research on the productivity of other Ontario power distributors.

PEG's recently completed benchmarking study for the UCA provides the Board with an alternative notion of how a transnational benchmarking study for Hydro One could be conducted. Advantages of our methodology over PSE's include the following.

- There are separate econometric benchmarking models for OM&A expenses, capital cost, capital expenditures, and total cost.
- The sample used in the research includes data for four Alberta distributors and several Ontario distributors (e.g., Hydro One and Algoma Power) as well as numerous investor-owned US electric utilities. Two Alberta distributors (FortisAlberta and ATCO Electric) are good peers for Hydro One because they serve areas with low customer density.
- Pension and other benefit expenses were excluded.
- Weights in the OM&A input price index were company-specific.
- US distributors with large reported transmission/distribution cost transfers were excluded.
- The benchmark year for the capital cost of US utilities was 1964.
- A system overheading variable was included.
- The density variable was not based on service territory area estimates.

4.2. Alternative Benchmarking Results

Mr. Fenrick noted in a response to a data request that Hydro One recently reported high voltage ("HV") plant additions to the OEB that were erroneously high.[35] We recomputed benchmarking results for Hydro One using the corrected capital cost data reported by the company and the total cost econometric model we developed for the OEB in 4th Generation IRM. Results are presented in Table 3. It can be seen that the three-year average cost performance of Hydro One was almost 33% over predicted cost. This level of cost performance is consistent with a 0.60% stretch factor instead of the

[35] Exhibit I/Tab 8/Schedule Staff-23 c).

Table 3

Impact of Revised High Voltage Data on Hydro One Benchmarking Results Using the OEB's Econometric Total Cost Model

	Before Correction	After Correction
2014	28.93%	39.94%
2015	19.68%	33.09%
2016	15.56%	25.73%
Average	21.39%	32.92%

0.45% as previously measured.[36] However, cost performance improved considerably over these years. By 2016, the Company's cost exceeded the model's prediction by 25.73%. We also developed a new econometric model that relies primarily on PSE's data but makes several changes to PSE's methodology to make it more in line with PEG's total cost model in the UCA study. Here are some changes to PSE's methodology that we made.

- REC data were excluded from the sample used in model estimation.
- Since the peak load variable parameter estimate was not statistically significant when the REC data were excluded, we used an alternative measure of peak demand: the volume of power deliveries per residential customer in 2015. Peak demand will tend to be higher where residential use per customer is high. Commercial use per customer is also pertinent but is more difficult to accurately measure. Industrial demand is less pertinent because large industrial customers in the States often receive power directly from the transmission system.
- An overheading variable was included. The variable we used was the share of overhead facilities in the gross value of overhead and underground distribution line plant.

[36] It is the understanding of PEG that it is the policy of the OEB to not revise previously assigned stretch factors due to data revisions. This information is being provided as additional evidence of the cost performance of HONI with the best data currently available. The adjusted results may include other OEB approved data corrections provided by the Company in 2017 relating to years prior to 2016.

- An alternative density variable was used that does not rely on an estimate of the service territory area. This variable was overhead structure miles per customer.[37] The statistical significance of the parameter of our density variable was considerably higher than that for the density variable PSE developed.
- US utilities with large transmission/distribution cost transfers were excluded.
- Scale economies are important when benchmarking the cost of a large distributor like Hydro One. To capture scale economies, our model included quadratic terms for the customer, density, and average use variables. To preserve degrees of freedom, we did not include interaction terms between the scale variables in the model.

The model otherwise used PSE's data, including the forestation, customer service and information, extreme weather, and artificial surface variables that PSE developed.

Details of this new econometric total cost model are reported in Table 4. It can be seen that all of the variables have statistically significant and plausibly-signed parameter estimates. The 0.958 adjusted R-squared for the model is quite high. Note that the trend variable parameter estimate suggests that the cost of sample distributors declined in real terms at a 0.20% annual pace for reasons other than the trends in the model's business condition variables.

Table 5 presents results when our preferred model is used to benchmark the cost of Hydro One. It can be seen that the Company's cost was 24.8% above the model's prediction on average over the three years from 2014 to 2016. Cost performance was a little better on average for forecasted/proposed costs in 2017 and 2018 and averages 23.0% over the 2019-2022 period. These results are similar to those from PSE's model.

[37] The source of data on overhead structure miles is the Utility Data Institute. We computed the ratio of line miles to customers for a single year for each sampled utility. This ratio should be fairly stable over time for most distributors.

Table 4

Details of PEG's Alternative Total Cost Benchmarking Model

VARIABLE KEY

N = Number of Electric Customers Served
F = Percent Forestation in Service Territory
CSI = Percent Cost Customer Service and Information Expenses
XW = Extreme Weather
Art = Percent of Territory that is Artificial Surfaces
OHMILES = Overhead Structure Miles per Customer
PCTOH = Percentage of Line Plant that is Overhead
RESUPC = MWh Deliveries per Residential Customer, 2015
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.964	288.651	0.000
N*N	0.019	5.040	0.000
OHMILES	0.184	18.527	0.000
OHMILES * OHMILES	0.094	5.856	0.000
RESUPC	0.034	1.955	0.051
RESUPC * RESUPC	-0.474	-3.730	0.000
F	0.151	30.053	0.000
CSI	0.006	2.047	0.041
XW	0.00003	16.798	0.000
Art	1.926	12.735	0.000
PCTOH	-0.107	-6.212	0.000
Trend	-0.002	-2.531	0.012
Constant	11.670	1264.902	0.000

Rbar-Squared	0.958
Sample Period	2002-2015
Number of Observations	942

Table 5

Benchmarking Results for Hydro One Using PEG's Total Cost Model

[Actual - Predicted Cost (%)][1]

Year	*Efficiency Score*
2002	6.9%
2003	5.6%
2004	2.1%
2005	5.4%
2006	12.1%
2007	15.9%
2008	15.8%
2009	20.2%
2010	25.1%
2011	23.8%
2012	23.4%
2013	25.8%
2014	28.2%
2015	23.2%
2016	23.1%
2017	*21.9%*
2018	*22.1%*
2019	*22.6%*
2020	*23.0%*
2021	*23.0%*
2022	*23.3%*
Average 2014-2016	**24.8%**
Average 2019-2022	**23.0%**

[1] Results presented are the log of the ratio of actual cost to the cost predicted by the econometric cost model.

Note: Italicized results are for forecasted costs.

Summing up, the total cost forecasting model we developed for 4th Generation IRM suggests Hydro One's cost was about 33% above the benchmark on average from 2014-2016 but was improving, reaching 25.73% in 2016. Our adaptations to PSE's model reveal a continuation of improved performance after 2016 and a forecasted cost that averages 22.8% above the benchmark during the plan term. We believe that the 22.4% average result for the 2016-18 period is most pertinent for establishing the stretch factor because the incentive that Hydro One had to understate OM&A growth in the 2019-22 period. On this basis, a 0.45% stretch factor seems reasonable for Hydro One provided that the Board is comfortable fixing the stretch factor. Combined with the recommended 0% base X factor, this would give an X factor of 0.45%. The RCI formula would then be IPI - 0.45%, net of Z factors or of any growth factor as discussed elsewhere.

4.3. Program Benchmarking

Hydro One also filed several more granular or "program-based" unit cost benchmarking studies addressing components of its cost. Pole replacement, substation refurbishment, and vegetation management were notable focus areas.

PEG examined the First Quartile/Navigant report. Some advantages of the general approach to benchmarking that these consultancies use can be noted. Benchmarking specialists can confer with colleagues in other companies. Special data can be gathered if and when a need for better data is identified. Participants can learn about best practices.

Traditional peer group benchmarking also has special limitations. Companies outside Ontario will participate only on a voluntary basis and may insist on data confidentiality. Individual consultancies compete to create peer benchmarking groups, but each consultant typically has only 15-30 participants. The utilities that participate in these groups are often quite large (e.g., Southern California Edison) because this increases the cost-effectiveness of participation. It may therefore be difficult to establish appropriate peer groups for Ontario distributors. For example, only three good peers might be available and average results for these peers may not be representative of the norm for companies facing their business conditions. Statistical methods are often crude, due in part to the small size of data samples gathered. Econometric modelling and hypothesis testing are rare.

PEG examined the First Quartile/Navigant study and has several concerns.

- The authors claimed that their peer group was "reasonably representative and useful."[38] In fact, few utilities in the peer group are similar to Hydro One. The sample consisted mostly of US utilities serving large urban areas like Chicago, Dallas, Houston, Los Angeles, and Philadelphia. These utilities were probably easier for the consultants to recruit for the study because of their large size and participation in past First Quartile or Navigant studies. The authors of the report claimed in response to an information request that the peer group is representative of the "industry."[39] However, Hydro One's request for project proposals called, as it should, for peer groups facing business conditions like those of Hydro One.
- Statistical methods were basic and consisted chiefly of simple unit cost metrics adjusted for currency differences between the US and Canadian utilities. Exchange rates, not PPPs, were used to adjust for currency differences. PPPs are generally considered to be more accurate for making international price comparisons.
- Other differences in input prices faced by peer utilities were not considered. Yet many peers served large urban areas where input prices tend to be unusually high. Many Hydro One employees, in contrast, do not work in Ontario's two large metropolitan areas.
- The evidence is not transparent, since utility participation in the study was conditioned on confidentiality.[40] Some results were not made available for scrutiny.[41]
- The sample period for the First Quartile/Navigant study was 2012-2014, which is not very recent.

All in all, we believe it is constructive for Hydro One to participate in some studies of this kind. However, the value of the First Quartile/Navigant report in support of Hydro One's proposed stretch factor was quite limited.

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[38] Navigant Consulting, *Distribution Unit Cost Benchmarking Study Pole Replacement and Substation Refurbishment*, HONI_App_Ex_B_Part2_20170427, B1-1-1, Section 1.6, Attachment 1, p. 5.

[39] HONI_IRR_B-Custom Application-Issues 7-16, Exhibit I, Tab 10, Schedule Staff-51, p. 4.

[40] EB-2017-0049, Exhibit I, Tab 25, Schedule AMPCO-19, part j.

[41] EB-2017-0049, Exhibit I, Tab 10, Schedule SEC-25, part c.

5. Other Plan Design Issues

The IRM proposed by Hydro One is in several respects uncontroversial. The design is similar to that of the Custom IRM that the Board approved for Toronto Hydro-Electric System. A revenue cap index escalates OM&A revenue, strengthening performance incentives and sidestepping the need for an OM&A cost forecast. An earnings sharing mechanism would asymmetrically share with customers only surplus earnings outside the deadband. The CSVA would asymmetrically share with customers some capex underspends but not overspends. A Custom Capital Factor would ensure recovery of the proposed capital cost, but this cost is reduced by the proposed 0.45% X factor.

We are nonetheless concerned about some features of the Company's proposal. We discuss the major areas of our concern in this section and suggest alternative IRM provisions for the Board's consideration.

5.1. Revenue Cap Index

Revenue cap indexes in approved IRMs usually have an escalator for growth in the utility's output. Hydro One's proposed RCI does not. In response to a data request, the Company defended this design on the grounds that the cost of system expansion is addressed by the C Factor.[42] For reasons discussed further below, we believe that it is preferable not to address capital costs by a C factor if it is efficient to address these costs by other means. Adding a growth escalator to the RCI is an efficient way to fund growth-related capex, including the acquisition of utilities. It reduces C-factored cost without increasing regulatory cost or weakening the Company's performance incentives.

On the other hand, Hydro One is not compensated under its proposal for higher OM&A expenses that result from higher output. This constitutes an implicit stretch factor in the Company's proposal. The addition of a scale escalator to the RCI would likely increase Hydro One's allowed revenue for OM&A expenses since there would likely be no offsetting increase in the X factor.

Were the Board to decide that a scale escalator should be added to the Company's RCI, our discussion of alternative scale escalators in the Appendix is pertinent. One option is an elasticity-weighted output index featuring cost driver variables. PEG developed such an index for the Board in the

[42] HONI_IRR_B-Custom Application-Issues 7-16, Exhibit I, Tab 8, Schedule Staff-21, p. 2.

4th Generation IRM proceeding which featured delivery volume, peak demand, and the number of customers served as scale variables.[43] While fresh estimates of cost elasticities would be desirable, it is notable that the elasticity weights in this index are 0.106, 0.289, and 0.606, respectively.[44]

Table 6 considers how this index might serve as a scale escalator using Hydro One forecasts of billing determinants. These forecasts do not include the expected bump in customers when these acquired utilities are integrated into the Company during the plan term. The number of customers is forecasted to average 0.60% growth over the 4-year 2019-2022 period. The max peak is forecasted to be flat while the delivery volume is forecasted to average a 0.49% annual decline. The table shows that this output index would average a modest 0.31% annual growth during the plan term. Even if negative growth in subindexes weren't permitted, the index would grow by only 0.36%. In either case, OM&A revenue would grow by this additional amount. The C factor would fall but allowed capital revenue would likely be unaffected on balance.

Since this scale index tracks trends in volumes and peak load, its addition to the RCI would weaken Hydro One's incentive to encourage CDM. One solution to this problem is to escalate Hydro One's allowed revenue only for customer growth. There is ample precedent for this approach, including revenue cap indexes for Altagas and ATCO Gas in Alberta and a recent IRM of Enbridge Gas Distribution that indexed growth in allowed revenue per customer.[45] Hydro-Québec Distribution will soon begin operating under an RCI with a 0.75 x Customer growth escalator.[46] Many US gas and electric utilities operate under revenue decoupling systems that escalate allowed revenue each year for customer growth.

On balance, we believe that the RCI for Hydro One in this IRM should have a customer growth escalator. This escalator could have a % markdown like the 0.75 in the recently approved escalator for Hydro-Quebec. Setting aside the addition of the three utilities, escalation of allowed revenue for

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43 This index could, in principle, be expanded to encompass reliability, safety, and/or metering capabilities.

44 The cost elasticity weights for the two scale variables in PSE's cost benchmarking model for Hydro One are 89% for customers and 11% for peak demand.

45 Ontario Energy Board, Schedule A to Decision Dated February 11, 2008 Enbridge Gas Distribution Inc., filed in OEB Case EB-2007-0615, p. 8.

46 La Régie de l'Energie, R-3897-2014, D-2017-043, April 2017.

Table 6

Forecast of Hydro One Scale Variables[1]

	Customers[2]		Volumes[2]		Max Peak[3]		4th GIRM Output Index[4]	
Year	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	PEG	Non-Negative GR Only
2012	1,311,445	0.66%	36,823	0.64%	6.09	0.00%	0.47%	0.47%
2013	1,323,658	0.93%	36,113	-1.95%	6.09	0.00%	0.36%	0.56%
2014	1,323,660	0.00%	36,266	0.42%	6.09	0.00%	0.04%	0.04%
2015	1,331,222	0.57%	35,514	-2.10%	6.09	0.00%	0.12%	0.35%
2016	1,340,493	0.69%	34,732	-2.23%	6.09	0.00%	0.18%	0.42%
2017	1,347,322	0.51%	33,988	-2.17%	6.09	0.00%	0.08%	0.31%
2018	1,355,818	0.63%	33,987	0.00%	6.09	0.00%	0.38%	0.38%
2019	1,363,783	0.59%	33,566	-1.25%	6.09	0.00%	0.22%	0.35%
2020	1,371,760	0.58%	33,491	-0.22%	6.09	0.00%	0.33%	0.35%
2021	1,380,395	0.63%	33,353	-0.41%	6.09	0.00%	0.34%	0.38%
2022	1,388,694	0.60%	33,330	-0.07%	6.09	0.00%	0.36%	0.36%
Annual Average Growth Rate								
2012 - 2017		**0.56%**		**-1.23%**		**0.00%**	**0.21%**	**0.36%**
2019 - 2022		**0.60%**		**-0.49%**		**0.00%**	**0.31%**	**0.36%**

Notes

[1] All growth rates are computed logarithmically. For example, growth rate of X = $\ln(X_t/X_{t-1})$.

[2] Source: *OEB Staff Interrogatory # 219*

[3] Max peak values are taken from PSE's working papers.

[4] The following cost elasticity weights were used in index construction: 0.6057 for customer numbers, 0.1058 for volumes, and 0.2885 for system capacity. The resultant elasticity weights are estimates from PEG's *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario* , 2013.

customer growth would likely average 0.6% annually if there was no markdown.[47] Once again, the OM&A revenue requirement would rise a little more rapidly but the C factor would fall and capital revenue would be unaffected.

[47] EB-2017-0049, Exhibit I/Tab 46/Schedule Staff-219, Filed: February 12, 2018.

If a customer growth escalator were added to the Company's RCI, we demonstrate in the Appendix that supportive productivity research to calibrate the X factor should use the number of customers as the scale variable.[48] As we showed in Section 3, this would increase the appropriate base productivity trend by about 30 basis points were X based solely on Ontario experience. However, Hydro One's Custom Productivity Measure would likely remain at 0%.

5.2. Capital Cost Treatment

The proposed ratemaking treatment of capital cost is similar to that which the Board approved for Toronto Hydro but nonetheless raises several concerns. The C factor ensures that the Company recovers its proposed capital cost less a perfunctory X factor markdown. Hence, capital revenue is chiefly determined on a cost of service basis. Incentives to contain capex and OM&A expenses are imbalanced, creating perverse incentives to incur excessive capex to reduce OM&A costs. Notwithstanding the proposed claw back of some capex underspends, Hydro One still has some incentive to exaggerate capex needs since this strengthens the case for a C Factor and reduces pressure for capex containment.

Exaggeration of capex needs may reduce the credibility of Hydro One's forecasts in future proceedings. However, utilities can always claim that they "discovered" ways to economize under the force of stronger incentives. British distributors operating under several generations of IR based on cost forecasts have repeatedly spent less on capex than they forecasted.

Distributors are also incentivized to "bunch" their deferrable capex in ways that increase supplemental revenue. The data in Table 7 suggests that Hydro One may be pursuing this strategy now. The table shows that capital additions are forecasted to be higher than the norm for the 2013-2015 period after a three-year lull from 2016 to 2018. Hydro One proposes to build an Integrated System Operating Center right in the middle of the plan term when the impact on the C factor would be close to the greatest possible. The impact on the C factor would be much less if the center were finished in 2019 or 2022.

[48] Christensen Associates used the number of customers to measure output growth in its recent productivity research and testimony in support of a revenue cap index proposal by Eversource Energy, a large Massachusetts power distributor. Massachusetts Department of Public Utilities, DPU-17-05, Direct Testimony of Mark E. Meitzen, *Performance-Based Ratemaking Mechanism*, Exhibit ES-PBRM-1, January 2017.

Table 7

Actual, Forecasted, and Proposed In-Service Capital Additions 2013-2022 ($M)[49]

		Sustaining	Development	Operations	Customer Service	Common & Other	**Total**
Actual	**2013**	296.6	194.1	1.4	13.9	223.4	**729.4**
	2014	324.8	187.6	5	1.4	96.6	**615.4**
	2015	420.2	216.9	7	16.6	100.5	**761.2**
	2016	371.1	168.3	-0.3	6.5	109.3	**654.9**
Bridge	**2017**	310.7	179.1	12.7	12.7	136.7	**651.9**
Proposed	**2018**	292.5	194.4	2.2	30.2	121.5	**640.8**
	2019	335.6	268.9	10.3	0.2	160.6	**775.6**
	2020	361.5	218.9	68.9	0.2	118.6	**768.1**
	2021	384.2	219.2	1.6	0.2	129.1	**734.3**
	2022	427.3	221	20.2	0.2	146.5	**815.2**
Averages							
	2013-2015	**347.2**	**199.5**	**4.5**	**10.6**	**140.2**	**702.0**
	2016-2018	**324.8**	**180.6**	**4.9**	**16.5**	**122.5**	**649.2**
	2019-2022	**377.2**	**232.0**	**25.3**	**0.2**	**138.7**	**773.3**

Another problem with the proposal is that customers must fully compensate Hydro One for expected capital revenue shortfalls when capex is high, even though most of the capex in question is likely to be similar in kind to that incurred by distributors in the productivity research sample used to calibrate X.[50] Utilities can then be compensated twice for the same capex: once via the C factor and then again by a low X factor in this and future IRMs. A similar concern about "double dipping" arises concerning distribution capex costs that are Z factored due to exogenous events such as severe storms and highway construction programs. These costs are also incurred by distributors in the productivity research sample and slow their productivity growth. Customers are asked to provide supplemental compensation for a disadvantageous short term need for high capex but are not offered timely revenue reductions for expected cost reduction opportunities such as the acquisition of other utilities.

Given the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, and Hydro One's incentives to exaggerate capex requirements, stakeholders and the Board must be especially vigilant about the Company's capex proposal. This raises regulatory cost. The need for the

[49] OEB Proceeding EB-2017-0049, HONI_Update_Ex_D_20170607, Exhibit D1/Tab 1/Schedule 2, pp 1,3.

[50] Hydro One would not, however, be compensated for unexpected capex overruns.

OEB to sign off on multiyear total capex proposals complicates Custom IR proceedings and is one of the reasons why the Board now requires and reviews distribution system plans --- a major expansion of its workload and that of stakeholders. The regulatory cost of Hydro One's C factor proposal is further raised by the provision that it be permitted to keep legitimate capex productivity gains. The Company will be incentivized to pursue its claims under this provision energetically.

Despite the extra regulatory cost, OEB's staff and stakeholders are sometimes hard-pressed to effectively challenge distributor capex proposals. In essence, the OEB's Custom IR rules have sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements without making the same investment that Ofgem has made in the capability for appraising and ruling on capex proposals.[51]

In pondering this quandary, the following remarks of the OEB in its decision approving IR for Toronto Hydro resonate.

> The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.[52]

In light of these remarks, it seems desirable to consider how to make Custom IR more mechanistic, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient distributors.

Following an unhappy experience with capital cost trackers in Alberta's first generation IRMs for provincial power distributors, a number of possible reforms to the ratemaking treatment of capital were discussed in the recent Alberta Utilities Commission ("AUC") generic proceeding on second generation IRMs. Based on the record, the AUC eventually chose a means for providing supplemental capital

[51] Ofgem's own view of a power distributor's required cost growth is assigned a 75% weight in IRM proceedings. This view is supported by independent engineering and benchmarking research. Despite these investments, it is still unclear as to how accurate Ofgem's assessments are.

[52] OEB, *Decision and Order*, EB-2014-0116, Toronto Hydro-Electric System Limited, December 29, 2015, p. 2.

revenue which was less dependent on distributor capex forecasts.[53] Regulatory cost was reduced thereby, and capex containment incentives were strengthened.

Informed by our research and testimony for a consumer group in that proceeding, we believe that the following amendments to Hydro One's proposed ratemaking treatment of capital merit consideration.

- The C factor could, like the ICMs in 4th Generation IRM, be subject to materiality thresholds and dead zones. Dead zones could also be added to materiality thresholds for Z-factored capex.
- The X factor could be raised, in this and Hydro One's future IRMs, to reduce expected double dipping and give customers a better chance of receiving the benefits of industry productivity growth in the long run. This would be tantamount to having the Company borrow revenue escalation privileges from future plans. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Hydro One's capex containment incentives.
- Eligibility of capex for supplemental C factor revenue could be scaled back. For example, capex in the last year of the plan term could be declared ineligible because this involves only one year of underfunding.
- The C factor could be calculated using the (slower) productivity growth trend of capital, while the X factor for OM&A revenue could reflect the (faster) productivity trend of OM&A. This would reduce the need for C factors and make escalation of OM&A revenue more reflective of industry OM&A cost trends. However, there is no conclusive research available to the OEB in this proceeding on OM&A and capital productivity trends of power distributors.

If the OEB is prepared to deviate from Hydro One's proposed C factor treatment, we note that the establishment of a materiality threshold and dead zone for supplemental capital revenue in Custom IR plans is most in keeping with its current policies. This could be done in such a manner that the first 10% of unfunded capex (after the X factor markdown) is ineligible for C factoring. However, the materiality threshold and dead zones need not be modelled on those in the incremental capital modules used in 4th GIRM. For example, if proposed capex exceeded the materiality threshold, a set percentage

[53] PEG is not recommending this ratemaking treatment for Hydro One.

of *all* unfunded capex could be declared ineligible for C factoring. This would strengthen the Company's incentive to contain capex at the margin. A similar idea is for a set number of basis points (e.g., 50) of the otherwise appropriate C factor to be disallowed. The OEB disallowed a 10% share of Toronto Hydro's proposed capex in a recent proceeding.[54] Any of these dead zone approaches can make customers whole for the addition of a growth escalator to Hydro One's RCI.

5.3. Revenue Decoupling

Consider next that Hydro One's proposal includes a revenue cap index but not revenue decoupling. Decoupling is popular in US jurisdictions (and Great Britain) and is often paired with revenue caps. In the absence of decoupling there may be controversy in proceedings to review the billing determinant forecasts that Hydro One will be required to file each year to convert allowed revenue to rates. Decoupling would add a small step to the Company's IRM but would eliminate billing determinant controversy. The need for an LRAM would also be eliminated since revenue as adjusted would be insensitive to the impact of CDM. Decoupling would also encourage the Company to use its AMI to implement time-sensitive rates because it would reduce the risk of demand fluctuations and load shifting that these rates entail. Hydro One's proposed LRAM does not extend to demand management.

On the other hand, the importance of system use forecasts is diminishing in Ontario due to the transition of rate designs for residential customers to fully-fixed pricing. Ontario's government requires that lost revenues do not weaken distributor incentives to embrace DSM but does not require LRAMs to accomplish this.[55] However, the OEB has mandated LRAMs for the 2015-2020 period.[56] These considerations reduce the benefits of adopting decoupling.

5.4. Pension and Benefit DVAs

With pension and benefit expenses addressed by DVAs, Hydro One has a weak incentive to contain these expenses. There is a perverse incentive for the Company to contain salary growth but maintain or sweeten benefits. This increases the need for prudence oversight of these expenses by the

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[54] OEB, *Decision and Order*, EB-2014-0116, *op. cit.*, p. 29.

[55] Ontario Executive Council, *Order in Council*, approved and ordered March 26, 2014.

[56] Ontario Energy Board, *Conservation and Demand Management Requirement Guidelines for Electricity Distributors*, EB-2014-0278, December 19, 2014 (Updated August 11, 2016).

OEB and stakeholders, raising regulatory cost. Many IRMs in North America do not have DVAs for pension and other benefit expenses. For example, Enbridge Gas Distribution and Union Gas have not proposed a DVA for these costs in their current IRM proposal.

Incentive for Hydro One to contain pension and other benefit expenses can be strengthened by adding a materiality threshold and dead zone to the DVA mechanism. For example, the first 10% of annual variances can be declared ineligible for rate adjustments. Alternatively, a set percentage of the entire variance can be ineligible if the threshold is exceeded. PEG recently proposed a similar treatment of pension and other benefit expenses in an IRM for Hydro-Québec Distribution.[57]

[57] La Régie de l'Energie, R-4011-2017, Présentation de PEG, C-AQCIE-CIFQ-0057, February 9, 2018, p. 14.

Appendix

Productivity Research and its Use in Regulation

This Appendix considers some technical and theoretical issues that arise in productivity research to support X factor choices in IRMs. We emphasize issues that arise in our appraisal of Hydro One's productivity research and IRM proposal in this proceeding.

Productivity Indexes

<u>The Basic Idea</u>

A productivity index measures the efficiency with which firms use production inputs to achieve certain outputs. The trend in a productivity index is the difference between the trend in an output index ("Outputs") and the trend in an input quantity index ("Inputs").

trend Productivity = trend Outputs – trend Inputs. [A1]

Productivity grows when the output index rises more rapidly than the input index.

Productivity can be volatile but usually has a rising trend in the longer run. The volatility is typically due to fluctuations in outputs and/or the uneven timing of expenditures. The productivity growth of individual companies tends to be more volatile than the average productivity growth of a group of companies.

The scope of a productivity index depends on the array of inputs addressed by the input quantity index. *Partial* factor productivity ("*PFP*") indexes measure productivity in the use of particular kinds of inputs such as capital or labor. A *multifactor* productivity index measures productivity in the use of multiple kinds of inputs. In Ontario, these are usually called *total* factor productivity ("*TFP*") indexes even though such indexes rarely address the productivity of all inputs.

The output (quantity) index of a firm summarizes growth in its outputs. If the index is multidimensional, growth in each output dimension which is itemized is measured by a subindex. Growth in the summary index is a weighted average of the growth in the sub-indices.

In designing an output index, choices concerning sub-indices and weights should depend on the manner in which the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event, the sub-indices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of revenue.[58] A productivity index calculated using a revenue-weighted output index ("$Outputs^R$") will be denoted as $Productivity^R$.

$$trend\ Productivity^R = trend\ Outputs^R - trend\ Inputs. \quad \text{[A2a]}$$

Another possible objective of output research is to measure the impact of output growth on *cost.* In that event, the index should be constructed from one or more output variables that measure dimensions of "workload" that drive cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the operations of utilities. Such estimates provide the basis for elasticity-weighted output indexes.[59] These have been used on several occasions in our previous research for the OEB.[60] A productivity index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

$$trend\ Productivity^C = trend\ Outputs^C - trend\ Inputs. \quad \text{[A2b]}$$

This may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Economists have considered the drivers of productivity growth using mathematical theory and empirical methods.[61] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

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[58] This approach to output quantity indexation is due to the French engineer and economist Francois Divisia (1889-1964).

[59] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

[60] See, for example, Kaufmann, L., Hovde, D., Kalfayan, J., and Rebane, K., *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board*, in EB-2010-0379, (2013); Lowry, M., Getachew, L., and Fenrick, S., *Benchmarking the Costs of Ontario Power Distributors* in EB-2006-0268, (2008) and Lowry, M., Hovde, D., Getachew, L., and Fenrick, S., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities* in EB-2006-0606/0615, (2007).

[61] See, for example, Denny, Fuss and Waverman, *op. cit.*

Economies of scale are another important productivity growth driver. These economies are realized in the longer run if cost has a tendency to grow less rapidly than operating scale. Incremental scale economies (and thus productivity growth) will typically be lower the slower is output growth.[62]

A third driver of productivity growth is X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher is its current inefficiency level.

Productivity growth is also affected by changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for a power distributor is forestation. In a suburb or rural area where forestation is increasing, rising vegetation management expenses will cause OM&A and total factor productivity growth to slow.

System age can drive productivity growth in the short and medium run. Productivity growth tends to be greater to the extent that the initial capital stock is large relative to the need to refurbish or replace aging plant. If a utility requires unusually high replacement capex, capital productivity growth can be unusually slow. On the other hand, productivity growth tends to accelerate in the aftermath of unusually high capex as the surge capital depreciates, thereby reducing the rate of return component of capital cost.

A TFP index with a *revenue*-weighted output index ("TFP^R") has an important driver that doesn't affect a cost efficiency index. This is true since

$$\begin{aligned} \textit{trend } TFP^R &= \textit{trend Outputs}^R - \textit{trend Inputs} + (\textit{trend Outputs}^C - \textit{trend Outputs}^C) \\ &= (\textit{trend Outputs}^C - \textit{trend Inputs}) + (\textit{trend Outputs}^R - \textit{trend Outputs}^C) \\ &= \textit{trend } MFP^C + (\textit{trend Outputs}^R - \textit{trend Outputs}^C). \qquad [A3] \end{aligned}$$

Relation [A3] shows that the trend in TFP^R can be decomposed into the trend in a cost efficiency index and an "output differential" that measures the difference between the impact that trends in outputs have on revenue and cost.

[62] Incremental scale economies may also depend on the current scale of an enterprise. For example, there may be diminishing incremental returns to scale as enterprises grow in size.

The output differential is sensitive to changes in external business conditions such as those that drive system use.[63] For example, the revenue of a power distributor may depend chiefly on system use, while cost depends chiefly on system capacity. In that event, mild weather can depress revenue more than cost, reducing the output differential and slowing growth in TFP^R and earnings.

Use of Index Research in Regulation

Price Cap Indexes

Index logic supports the use of index research in price cap index design. We begin our demonstration by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[64] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\textit{trend Revenue} = \textit{trend Cost.} \qquad [A4]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in revenue-weighted indexes of its output prices ("*Output Prices*^{R}") and billing determinants ("*Outputs*^{R}")

$$\textit{trend Revenue} = \textit{trend Outputs}^R + \textit{trend Output Prices}^R. \qquad [A5]$$

The trend in cost can be shown to be the sum of the trends in a cost-weighted input price index ("Input Prices") and input quantity index ("Inputs").

$$\textit{trend Cost} = \textit{trend Input Prices} + \textit{trend Inputs} \qquad [A6]$$

It follows that the trend in output prices that permits revenue to track cost is the difference between the trends in the input price index and a total factor productivity index of TFP^R form.

$$\begin{aligned}\textit{trend Output Prices}^R &= \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) \qquad [A7]\\ &= \textit{trend Input Prices} - \textit{trend } TFP^R.\end{aligned}$$

The result in [A7] provides a conceptual framework for the design of PCIs of general form

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[63] Note also that companies can sometimes bolster their output differential with better marketing. For example, they can sell more products that have a higher margin between incremental revenue and cost.

[64] The assumption of a competitive rate of return applies to unregulated, competitively structured markets. It is also applicable to utility industries and even to individual utilities.

growth Rates = growth Input Prices – X. [A8a]

Here X, the "X factor," reflects a base productivity growth target ("$\overline{TFP^R}$") that is typically the trend in the TFP^R of the regional or national utility industry or some other peer group. A "stretch factor" is often added to the formula which slows PCI growth in a manner that shares with customers the financial benefits of performance improvements which are expected under the IRM.[65]

$X = \overline{TFP^R} + Stretch$ [A8b]

Since the X factor often includes *Stretch* it is sometimes said that the index research has the goal of "calibrating" (rather than solely determining) X.

Revenue Cap Indexes

Index logic also supports the design of *revenue* cap indexes. Consider first the following basic result of cost theory:

trend Cost = trend Input Prices – trend Productivity^C *+ trend Scale*^{C}. [A9a]

The growth in the cost of a company is the difference between the growth in its input price and cost efficiency indexes plus the trend in a consistent cost-based output index. This result provides the basis for a revenue cap escalator of general form

growth Revenue = growth Input Prices – X + growth Scale^C [A9b]

where

$X = \overline{TFP^C} + Stretch.$ [A9c]

Notice that a *cost*-based scale index should be used in the supportive productivity research.

PEG used an elasticity-weighted output index in its research for the OEB on the productivity growth of Ontario power distributors in the 4th GIRM proceeding. The output variables were delivery volume, peak demand, and the number of customers served. These variables are billing determinants as well as cost drivers. Equations [A9a-c] permit the expansion of an elasticity-weighted output index used

[65] Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

in RCI design to include outputs that are not billing determinants. For a power distributor these might include kilometers of line, reliability, safety, and metering capabilities of the system.

A scale escalator that includes volumes and peak demand as output variables diminishes a utility's incentive to promote CDM. This is a strong argument for excluding these variables from an RCI scale escalator. Note also that values of usage variables can decline, materially slowing RCI growth even though cost is largely fixed in the short run with respect to system use.

For gas and electric power distributors, the number of customers served is a sensible scale escalator for a revenue cap index. The number of customers is an important distributor cost driver in its own right and is also highly correlated with peak load. The customers variable typically has the highest estimated cost elasticity amongst the scale variables modelled in econometric research on distribution cost.

We can expand [A6] to obtain the result

$$\begin{aligned} \textit{trend Cost} &= \textit{trend Input Prices} + \textit{trend Input Quantities} + (\textit{trend Customers} - \textit{trend Customers}) \\ &= \textit{trend Input Prices} - (\textit{trend Customers} - \textit{trend Inputs}) + \textit{trend Customers} \\ &= \textit{trend Input Prices} - \textit{trend } TFP^N + \textit{trend Customers} \end{aligned}$$

where TFP^N is a TFP index that uses the number of customers to measure output. This result provides the rationale for the revenue cap index formula

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Customers} \qquad \text{[A10a]}$$

where

$$X = \overline{TFP}^N + \textit{Stretch}. \qquad \text{[A10b]}$$

An equivalent formula is

$$\begin{aligned} &\textit{growth Revenue} - \textit{growth Customers} \\ &\quad = \textit{growth } (\textit{Revenue/Customer}) = \textit{growth Input Prices} - X. \end{aligned} \qquad \text{[A10c]}$$

This is sometimes called a "revenue per customer" index, and we will for convenience use this expression to refer to revenue cap indexes which conform to either [A10a] or [A10c].

Revenue per customer indexes are currently used in the IRMs of ATCO Gas and AltaGas in Canada. The Régie de l'Energie in Québec has directed Hydro-Québec Distribution and Gaz Métro to develop IRMs featuring revenue per customer indexes. Revenue per customer indexes were previously featured in IRMs for Southern California Gas and Enbridge Gas Distribution, the largest gas distributors in the US and Canada, respectively. In the United States, many gas and electric utilities operate under revenue decoupling systems which escalate allowed revenue for customer growth between rate cases.

TFP Research Methods

Monetary Approach to Capital Cost and Quantity Measurement

Monetary approaches to the measurement of capital costs and quantities have been widely used in TFP research. The main components of capital cost are depreciation expenses, the return on investment, and taxes.[66] These approaches decompose the growth in capital cost into the growth in consistent capital price and quantity indexes such that

$$growth\ Cost^{Capital} = growth\ Price^{Capital} + growth\ Quantity^{Capital}. \qquad [A11]$$

The capital quantity trend is calculated using deflated data on asset values.

Several monetary methods are well established for measuring capital quantity trends. A key issue in the choice of a monetary method is whether plant is valued in historic dollars or replacement dollars. Another issue is the pattern of decay in the quantity of capital resulting from plant additions. Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and obsolescence.

Three monetary methods have been used in research to calibrate the X factors of IRMs.

- The geometric decay ("GD") method assumes a replacement (i.e., *current* dollar) valuation of plant and a constant rate of decay. Replacement valuation differs from the historical (aka "book") valuation used in North American utility accounting and requires consideration of capital gains. The GD specification involves formulae for capital price and quantity indexes that are mathematically simple and easy to code and review.

[66] The trends in these costs depends on trends in construction prices, tax rates, and the market rate of return on capital. A capital price index should reflect these trends. The capital price index is sometimes called the "rental" or "service" price index because, in a competitive market, the trend in the price of rentals would tend to reflect the trend in the cost per unit of capital.

Academic research has supported use of the GD method to characterize depreciation in many industries.[67] GD has also been widely used in productivity studies, including X factor calibration studies. The US Bureau of Economic Analysis ("BEA") and Statistics Canada both use geometric decay as the default approach to the measurement of capital stocks in the national income and product accounts.[68] PEG has used the GD method in most of its productivity research for the Board, including the research for 4th Generation IRM.

- The one hoss shay method assumes that the quantity of capital from plant additions in a given year does not decay gradually but, rather, all at once as the assets reach the end of their service lives. Plant is once again valued at replacement cost. We have found that productivity results using the one hoss shay method are unusually sensitive to the choice of an average service life. The one hoss shay method has nonetheless been used occasionally in research intended to calibrate utility X factors.
- The cost of service ("COS") method is designed to approximate the way that capital cost is calculated in utility regulation. This approach is based on the assumptions of straight line depreciation and historic valuation of plant. The formulae are complicated, making them more difficult to code and review. PEG has used this approach in several X factor calibration studies, including two for the OEB.[69]

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. It is therefore desirable when calculating capital quantities using a monetary method to rely

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[67] See, for example, C, Hulten, and F. Wykoff (1981), "The Measurement of Economic Depreciation," in *Depreciation, Inflation, and the Taxation of Income From Capital*, C. Hulten ed., Washington D.C. Urban Institute and C. Hulton, "Getting Depreciation (Almost) Right", University of Maryland working paper, 2008.

[68] The BEA states on p. 2 its November 2015 "Updated Summary of NIPA Methodologies" that "The perpetual-inventory method is used to derive estimates of fixed capital stock, which are used to estimate consumption of fixed capital—the economic depreciation of private and government fixed capital. This method is based on investment flows and a geometric depreciation formula."

[69] See Lowry, et. al., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities, op. cit.;* Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., and Moren, A., *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, in EB-2007-0673, (2008); and Lowry, M., Hovde, D., and Rebane, K., *X Factor Research for Fortis PBR Plans,* in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia (2013).

on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized depreciation treatment for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years, the desired gross plant addition data are frequently unavailable. It is then customary to consider the value of all plant at the end of the limited-data period and then estimate the quantity of capital it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

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Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Research specialty: role of storage in commodity markets.

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Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

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Research under Dr. Charles Cicchetti in two areas:

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- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

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Research on the behavior of inventories in metal markets.

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1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
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8. National Association of Regulatory Utility Commissioners, Columbus OH, September 1992
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15. Michigan State University Public Utilities Institute, Williamsburg VA, December 1996
16. Edison Electric Institute, Washington DC, December 1995
17. IBC Conferences, San Francisco CA, April 1996
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55. CAMPUT, Halifax NS, May 2004
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57. EUCI, Seattle, May 2006 [Conference chair]
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70. EUCI, Chicago, July 2008 [Conference chair]
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Journal Referee

Agribusiness
American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
Materials and Society

Association Memberships (active)

International Association of Energy Economist
Wisconsin Public Utilities Institute

FORM A

Proceeding: EB-2017-0049

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Mark Newton Lowry (*name*). I live at Madison (*city*), in the State (*province/state*) of Wisconsin.

2. I have been engaged by or on behalf of Ontario Energy Board (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date April 5, 2018

Signature

TAB 3

EB-2018-0165: THESL 2020 CIR

SELECT PEG IR RESPONSES

APRIL 2019

L1.INTERROGATORY M1-TH-018

Reference: *PEG Report, p. 42, "Scale Variables."*

a) In constructing the ratcheted peak demand, did PEG use different years for Toronto Hydro and for the U.S. sample in the calculation?

b) What is the start year for determining the maximum demand for the U.S. sample?

c) What is the start year for determining the maximum demand for Toronto Hydro?

Response to TH-018: The following response was provided by PEG.

a) PEG confirms that it used different starting dates in its ratcheted peak demand calculations for Toronto Hydro and the U.S. utilities in its sample.

b) The start year for the U.S. utilities was 1995.

c) The start year for Toronto Hydro was 2002.

L1.INTERROGATORY M1-TH-026

PEG uses the 2008 version of *R. S. Means Heavy Construction Cost Data* to calculate a 2008 capital levelization year for the U.S. sample that adjusts for the differences in construction costs between utilities serving different geographic areas.

a) Please describe how the 2008 capital levelization was calculated for each utility. Please include in the description what city location factors were mapped to each of the utilities and the city weights used in calculating the levelization for each utility.

b) Please provide the 2008 R. S. Means location factor for Toronto.

c) Please confirm that PEG used the Toronto location factor from the 2012 version of *R. S. Means Heavy Construction Cost Data* as the basis for Toronto Hydro's capital levelization.

d) Please confirm that PEG inadvertently used a different capital levelization year for Toronto Hydro (2012) and for the rest of the U.S. sample (2008) which produces a capital asset price that is not properly levelized for Toronto Hydro relative to the rest of PEG's sample in any year. If the difference was intentional, please provide the basis and rationale for using a different year for a comparative index and how the impacts of escalating the index in each year do not distort the levelization.

e) Please provide a revised Table 6, Table 8, Table 9, Table 10, Table 12, and Table 13 from the PEG Report where no other changes are made to PEG's data and models other than making the capital levelization year consistent for Toronto Hydro and the U.S. sample using 2008 as the levelization year.

f) Please provide a revised Table 6, Table 8, Table 9, Table 10, Table 12, and Table 13 from the PEG Report where no other changes are made to PEG's data and models other than making the capital levelization year consistent for Toronto Hydro and the U.S. sample using 2012 as the levelization year.

Response to TH-026: The following response was provided by PEG.

a) The 2008 capital price levelization for the U.S. companies in PEG's sample was done in a similar manner to that done by PSE. Both consultancies used the RSMeans city cost indexes for total cost. The principal differences are that PEG used multiple cities for each U.S. company and that PEG performed the levelization two years prior to the year listed on the cover of the RSMeans volume. This was done to be in alignment with the date RSMeans ascribes to the city cost indexes. PEG used the 2010 RSMeans volume which states on the page 512 introduction to the city cost indexes:

> *Index figures for both material and installation are based on the 30 major city average of 100 and represent the cost relationship as of July 1, 2008.*[1]

b) The value for Toronto in the 2010 RSMeans book is 110.7. As noted in the response to part (a), this should be the 2008 value.

c) PEG left the PSE data for THESL intact except for specific changes discussed in the report. This included the 2012 city cost index for Toronto used by PSE.

d) PEG confirms that for Toronto Hydro it inadvertently retained the PSE method of using the 2012 RSMeans value to levelize the THESL asset price in 2012. The value from the 2010 book should have been used to do this levelization in 2008 to be consistent with the other U.S. data in the PEG study. Correcting the error of PSE not doing the levelization in 2010 and the error of PEG using the 2012 city cost index instead of the 2008 value affects the PEG benchmarking results. Over the five-year 2020-2024 period, the average total cost benchmarking score for THESL moves from **20.6% to 15.9%,** the average capital cost benchmarking score moves from **43.0% to 36.1%**, and the average capex benchmarking score moves from **21.7% to 14.9%.** The OM&A and reliability models were not affected. These corrections produce no change in stretch factor recommendation. Please see Attachment PEG-TH-026e for the revised results.

   In preparing these responses, PEG also noted some inconsistencies in the plant additions data and methods it had used in its initial study and those used by PSE. After examining the differences, PEG did not find either approach completely suitable. PEG chose to upgrade its calculation of plant additions to address its concerns. The impact of these improvements on the benchmarking results was minor. The performance of THESL changed from 15.9% to 15.6% in the total cost model. The result in the capital cost model changed from 36.1% to 35.7%. The result in the capex model was virtually unchanged. Please see Attachment PEG-TH-026d for the revised results.

e) Please see Attachment PEG-TH-026e.

f) Please see Attachment PEG-TH-026f.

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[1] PSE used the 2012 book and does the levelization in 2012 which is two years too late if the relationship in the 2010 book holds for 2012.

L1.INTERROGATORY M1-TH-030

PEG uses a different asset price escalator for Toronto Hydro and the rest of the sample.

a) Please confirm that the capital service price ("wkod" in PEG's code) used by PEG for Toronto Hydro increases by an average of 0.5% per year from 2005 to 2017.

b) Please confirm that every other utility in PEG's dataset has a higher average annual growth rate for the capital service price than Toronto Hydro from 2005 to 2017.

c) Please confirm that Consolidated Edison's average annual growth rate for the capital service price in PEG's dataset from 2005 to 2017 is 4.8%.

d) Please confirm that Madison Gas and Electric's average annual growth rate for the capital service price in PEG's dataset from 2005 to 2017 is 4.4%.

e) Does PEG believe that capital cost increases have been dramatically higher in the United States relative to the City of Toronto? Please explain PEG's rationale for the large discrepancy in the capital price inflation assumptions for Toronto Hydro versus the rest of the sample used by PEG.

Response to TH-030: The following response was provided by PEG.

These answers reflect the upgrades noted in response to question M1-TH-026.

a) PEG confirms this statement is correct.

b) PEG confirms every other utility in its sample period had a higher average annual growth rate for the capital service price than Toronto Hydro from 2005 to 2017.

c) Not confirmed. Consolidated Edison's average annual growth rate of the capital service price from 2005 to 2017 was 7.2%. This reflects rapid growth in the construction cost index over the 2006-2008 period. The relevance of this to the benchmarking of Toronto Hydro's cost is reduced by the fact that the levelization of the asset price takes place in 2008 in the PEG work. The trend in the asset price for Consolidated Edison was 3.08% vs. 2.57% for THESL since 2008. In the capital price, any deviations from this trend due to capital gains are mirrored by adjustments to capital cost.

d) Not confirmed. Madison Gas and Electric's average annual rate of the capital service price from 2005 to 2017 was 6.8%. This reflects rapid growth in the construction cost index over the 2006-2008 period. The relevance of this to the benchmarking of Toronto Hydro's cost is reduced by the fact that the levelization of the asset price takes place in 2008 in the PEG work. The trend in the asset price for Madison Gas and Electric was 2.64% vs. 2.57% for THESL since 2008. In the capital price, any deviations from this trend due to capital gains are mirrored by adjustments to capital cost.

e) PEG has endeavored to use the best available plant addition deflator for each utility. Please see the response to M1-TH-008 for a discussion of its deliberations concerning these deflators.

TAB 4

STATE PERFORMANCE-BASED REGULATION USING MULTIYEAR RATE PLANS FOR U.S. ELECTRIC UTILITIES

JULY 2017

State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities

July 2017

MN Lowry
M Makos
J Deason
L Schwartz, Project Manager and Technical Editor

Table 4. How Productivity Growth of Central Maine Power Compared to That of Other U.S. Electric Utilities: 1980–2014*

Year	CMP			U.S. Average		
	MFP	PFP O&M	PFP Capital	MFP	PFP O&M	PFP Capital
1980	-0.17%	-2.17%	1.08%	-0.49%	-4.19%	1.24%
1981	0.45%	-3.00%	1.47%	0.17%	-2.42%	1.25%
1982	0.08%	-1.43%	1.84%	0.87%	-1.20%	1.53%
1983	0.42%	-2.22%	1.82%	0.51%	-0.38%	0.98%
1984	1.63%	1.28%	1.80%	1.27%	-0.22%	1.79%
1985	0.75%	-1.94%	1.94%	0.95%	-0.21%	1.37%
1986	2.08%	0.89%	2.57%	0.91%	0.88%	0.97%
1987	0.59%	-1.10%	1.28%	0.44%	-0.12%	0.68%
1988	-0.49%	-1.43%	-0.03%	0.57%	1.55%	0.24%
1989	-0.83%	-0.12%	-1.25%	0.26%	0.00%	0.23%
1990	-0.97%	0.24%	-1.79%	0.18%	0.64%	-0.05%
1991	-0.43%	1.04%	-1.39%	-0.03%	0.58%	-0.32%
1992	1.32%	2.51%	0.64%	0.48%	1.61%	0.10%
1993	-0.24%	-2.55%	1.04%	0.45%	1.19%	0.12%
1994	2.10%	2.87%	1.66%	0.94%	2.44%	0.29%
1995	1.80%	0.98%	2.30%	0.94%	3.58%	-0.04%
1996	1.67%	1.75%	1.62%	0.11%	0.67%	-0.13%
1997	1.08%	-0.40%	2.00%	1.53%	4.68%	0.39%
1998	0.17%	-2.94%	2.14%	0.67%	0.73%	0.71%
1999	2.03%	1.98%	2.05%	1.08%	2.24%	0.52%
2000	0.97%	-2.17%	2.18%	0.89%	0.86%	0.73%
2001	0.83%	-0.69%	1.80%	1.20%	2.73%	0.61%
2002	1.23%	1.28%	1.19%	0.79%	2.73%	0.33%
2003	1.35%	-0.49%	2.83%	-0.03%	-1.50%	0.43%
2004	-0.35%	-3.96%	2.56%	0.41%	0.76%	0.22%
2005	1.85%	1.27%	2.32%	-0.07%	-0.25%	0.09%
2006	1.02%	-0.48%	2.62%	-0.52%	-1.07%	-0.21%
2007	1.16%	-0.21%	3.12%	-0.12%	0.00%	-0.02%
2008	-1.51%	-2.67%	1.27%	-0.99%	-2.06%	-0.09%
2009	2.23%	2.57%	1.34%	1.01%	2.73%	-0.46%
2010	-0.51%	-1.65%	1.00%	-0.27%	-0.47%	0.05%
2011	3.54%	6.17%	0.85%	0.50%	0.05%	0.50%
2012	0.56%	1.86%	-0.63%	1.29%	2.90%	0.58%
2013	-0.73%	-2.31%	0.76%	0.03%	0.40%	-0.05%
2014	-1.61%	-4.74%	1.47%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.66%**	**-0.34%**	**1.36%**	**0.45%**	**0.53%**	**0.43%**
1980-1995	**0.51%**	**-0.39%**	**0.94%**	**0.53%**	**0.23%**	**0.65%**
1996-2013	**0.92%**	**-0.06%**	**1.72%**	**0.42%**	**0.90%**	**0.23%**
2008-2014	**0.28%**	**-0.11%**	**0.86%**	**0.22%**	**0.30%**	**0.15%**

*CMP operated under multiyear rate plans in the years for which results are shaded.

Table B-6. Power Distributor MFP Trends of Individual U.S. Electric Utilities

Distributor	Average Annual MFP Growth Rate 1980-2014	1996-2014	2008-2014
Alabama Power	-0.52%	-0.61%	-0.50%
ALLETE (Minnesota Power)	0.86%	1.32%	0.54%
Appalachian Power	0.12%	0.38%	-0.29%
Arizona Public Service	0.39%	0.88%	0.98%
Atlantic City Electric	0.37%	0.10%	-1.37%
Avista	0.41%	0.09%	-0.71%
Baltimore Gas and Electric	0.35%	-0.06%	-1.08%
Central Hudson Gas & Electric	0.81%	-0.04%	-0.45%
Central Maine Power	0.66%	0.79%	0.28%
Cleco Power	-0.14%	-0.35%	-0.42%
Cleveland Electric Illuminating	0.40%	0.49%	0.05%
Connecticut Light and Power	0.41%	-0.10%	0.03%
Consolidated Edison	0.06%	-0.45%	-0.44%
Dayton Power and Light	0.84%	0.35%	-0.93%
Delmarva Power & Light	0.60%	0.71%	-1.08%
Duke Energy Carolinas	-0.04%	1.09%	0.75%
Duke Energy Florida	0.64%	0.38%	1.00%
Duke Energy Indiana	0.58%	0.08%	-0.09%
Duke Energy Kentucky	0.35%	0.54%	-1.24%
Duke Energy Ohio	0.58%	0.81%	-0.87%
Duke Energy Progress	0.56%	0.65%	1.35%
Duquesne Light	0.64%	0.73%	0.04%
El Paso Electric	0.88%	0.45%	-0.17%
Empire District Electric	-0.09%	-0.26%	-0.65%
Entergy Louisiana	0.63%	0.71%	1.86%
Entergy Mississippi	-0.01%	-0.17%	0.40%
Entergy New Orleans	0.43%	-0.54%	4.37%
Fitchburg Gas and Electric Light	0.34%	0.22%	0.98%
Florida Power & Light	0.84%	0.66%	1.06%
Georgia Power	0.40%	1.11%	1.09%
Green Mountain Power	0.82%	0.52%	1.05%
Gulf Power	0.21%	0.28%	-0.39%
Idaho Power	1.29%	1.48%	1.23%
Indiana Michigan Power	0.30%	-0.02%	-0.46%
Indianapolis Power & Light	0.81%	1.17%	0.86%
Jersey Central Power & Light	0.68%	0.63%	0.84%
Kansas City Power & Light	1.01%	0.76%	0.37%
Kansas Gas and Electric	0.70%	0.57%	0.18%
Kentucky Power	-0.71%	-0.56%	-1.42%
Kentucky Utilities	0.18%	0.01%	-2.38%
Kingsport Power	0.46%	0.23%	-1.33%
Louisville Gas and Electric	0.33%	0.20%	-2.39%
Massachusetts Electric	0.96%	1.10%	0.72%
MDU Resources Group	0.61%	0.76%	1.01%
Metropolitan Edison	1.25%	1.42%	1.06%

Table B-6 (continued) Power Distributor MFP Trends of Individual U.S. Electric Utilities

Distributor	1980-2014	1996-2014	2008-2014
MidAmerican Energy	0.04%	1.22%	2.37%
Mississippi Power	-1.18%	-1.42%	0.65%
Monongahela Power	0.10%	0.57%	0.54%
Narragansett Electric	0.80%	0.57%	-0.03%
Nevada Power	0.99%	1.12%	1.67%
New York State Electric & Gas	1.02%	1.57%	1.51%
Niagara Mohawk Power	0.54%	0.81%	0.68%
Northern States Power - MN	0.73%	0.26%	1.06%
Northwestern Public Service	0.30%	0.68%	1.01%
Nstar Electric	0.40%	0.59%	1.14%
Ohio Edison	0.97%	1.34%	1.02%
Ohio Power	0.28%	0.45%	-0.20%
Oklahoma Gas and Electric	0.14%	-0.07%	-0.49%
Orange and Rockland Utilities	0.82%	0.32%	0.07%
Otter Tail Power	0.00%	0.04%	0.37%
Pacific Gas and Electric	0.24%	-0.04%	0.10%
PacifiCorp	0.08%	1.18%	2.26%
PECO Energy	0.91%	0.16%	-0.21%
Pennsylvania Electric	0.84%	0.94%	1.15%
Pennsylvania Power	0.60%	0.75%	0.51%
Portland General Electric	0.57%	-0.72%	0.10%
Public Service Company of Colorado	0.72%	0.01%	0.90%
Public Service Company of Oklahoma	0.00%	-0.43%	0.07%
Public Service Electric and Gas	0.80%	0.76%	0.49%
Rochester Gas and Electric	1.05%	0.64%	0.97%
San Diego Gas & Electric	-0.31%	-0.41%	0.21%
South Carolina Electric & Gas	0.16%	0.21%	0.02%
Southern California Edison	-0.08%	-0.45%	-1.47%
Southern Indiana Gas and Electric	0.29%	-0.03%	-1.19%
Superior Water, Light and Power	0.57%	0.31%	-0.40%
Tampa Electric	0.97%	0.80%	0.42%
Toledo Edison	1.07%	1.13%	0.94%
Union Electric	0.38%	0.25%	0.45%
United Illuminating	-0.72%	-1.51%	-5.50%
Virginia Electric and Power	0.65%	0.88%	0.64%
West Penn Power	0.83%	1.38%	1.73%
Western Massachusetts Electric	0.75%	1.01%	0.42%
Wheeling Power	0.11%	-0.19%	-1.06%
Wisconsin Electric Power	0.41%	0.11%	0.74%
Wisconsin Power and Light	-0.04%	-0.29%	-0.38%
Wisconsin Public Service	0.82%	0.57%	2.31%
Full Sample Averages	**0.45%**	**0.39%**	**0.22%**