CUSTOM IR APPLICATION SUMMARY

1.0 APPLICATION STRUCTURE AND RCI COMPONENTS

This Application is based on a Custom Incentive Rate-Setting (IR) approach for a 5-year period. The methodology is a Revenue Cap IR in which the revenue requirement for the test year t+1 is equal to the revenue requirement in year t inflated by the Revenue Cap Index (RCI). The methodology is similar for both the Transmission and Distribution businesses. This exhibit describes the elements of this methodology, and details regarding the specific parameters for the Transmission and Distribution businesses are provided in Exhibits A-04-02 and A-04-03, respectively.

The Custom RCI is expressed as follows:

$$RCI = I - X + C$$

Where:

- "I" is the Inflation Factor, based on a custom weighted two-factor input price index;
- "X" is the Productivity Factor, equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor; and
- "C" is Hydro One's Custom Capital Factor, designed to recover incremental revenue each year necessary to support Hydro One's proposed system plans, beyond the amount of revenue recovered through the I – X adjustment, but reduced by a supplemental stretch factor on capital of 0.15%.

The revenue requirement in the first year of the 5 year period (2023) is determined using a cost of service, forward test year approach, consistent with the OEB's Renewed Regulatory Framework (RRF) as more recently set out in the Handbook for Utility Rate Applications (the Handbook). The revenue requirement in each of the following years, 2024-2027, is determined using the RCI. The proposed methodology is generally consistent with the approach approved by the OEB in Hydro One's prior Transmission and Distribution proceedings (EB-2019-0082 and EB-2017-0049). Hydro One engaged an independent consultant, Clearspring Energy Advisors (Clearspring), to undertake various benchmarking analyses to support the specific parameters of Hydro One's Custom RCI. The Clearspring study is provided in Exhibit A-04-01-01.

1.1 CHANGES TO THE FRAMEWORK

Hydro One's overall approach is consistent with the RRF and with the Custom RCIs approved by the OEB for Hydro One Distribution in EB-2017-0049 and for Hydro One Transmission in EB-2019-0082. However, Hydro One is proposing the following additions or adjustments compared to the RCIs it proposed in those prior applications, to the benefit of ratepayers:

1. Hydro One is adding a supplemental stretch factor of 0.15% to the capital related revenue requirement (Supplemental Stretch);
2. The productivity factors which form the X-factor, as well as the Supplemental Stretch on capital, are being applied cumulatively to the capital related revenue requirement in each year of the Custom IR term; and
3. The C-factor will be updated annually to reflect any changes to inflation.

1.2 ELEMENTS OF THE CUSTOM RCI

The individual elements of Hydro One's proposed Custom RCI are described below.

1.2.1 INFLATION FACTOR

The proposed Inflation Factor (I) is based on the weighted average of the annual percent change of two labour and non-labour indices, namely:

- Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

The industry-specific weightings and pro-forma Inflation Factors for the Transmission and Distribution businesses are set out in Exhibits A-04-02 and A-04-03, respectively. The Inflation Factor will be updated annually to reflect the latest values issued by the OEB.

1.2.2 X-FACTOR

The X-factor is the sum of two productivity factors: a base productivity factor which reflects the long-term industry productivity trend, and a stretch factor which reflects the results of an independent total cost benchmarking study conducted by Clearspring, provided in Exhibit A-04-01-01. Consistent with the RRF, these productivity factors are explicitly included in the rate adjustment mechanism and provide an incentive for Hydro One to achieve capital and OM&A productivity improvements – this is in addition to sustained and ongoing productivity savings embedded in Hydro One's business plan during the Custom IR term, as described in SPF Section 1.4. Exhibits A-04-02 and A-04-03 detail the values for the X-factor, as derived from the Clearspring study in Exhibit A-04-01-01.

1.2.3 CUSTOM CAPITAL FACTOR

The C-factor is designed to ensure that the total revenue resulting from the Custom IR approach is appropriate for Hydro One's specific circumstances and will support the necessary capital investments in Hydro One's TSP, DSP and GSP, while also ensuring that appropriate incentives are in place with up front benefits to ratepayers.

The C-factor is the percentage change in the total revenue requirement attributable to new capital investment that is not otherwise recovered from customers through the I – X adjustment. It includes depreciation, return on equity, interest and taxes attributable to new capital investments placed in-service each year of the Custom IR term. The working capital allowance is not included in the derivation of the C-factor, consistent with the OEB's decision in Hydro One's most recent Custom IR proceedings (EB-2019-0082 and EB-2017-0049).

To incent further productivity and continuous improvement, and provide an upfront revenue requirement reduction to customers, Hydro One is proposing a Supplemental Stretch on capital of 0.15% in respect of both the Transmission and Distribution businesses. The Supplemental Stretch will align with Hydro One's recent Custom IR proceedings, in which the OEB ordered a 0.15% supplemental stretch on capital in order to further incent Hydro One to seek productivity gains.[1] Hydro One will use its productivity framework, described in SPF Section 1.4, to achieve this Supplemental Stretch (along with the X-factor), and to ensure Hydro One is meeting its planned deliverables and outcomes at a lower cost.

The Supplemental Stretch, along with the X-factor described above, will be applied in a cumulative manner in each year of the test period. This results in a significant upfront revenue requirement reduction for customers. Details on the calculation of the C-factor are provided in Exhibits A-04-02 and A-04-03.

1.3 ADDITIONAL CUSTOM IR FEATURES

Hydro One is proposing the following additional features to align its interests with those of customers and to provide additional elements of protection for customers.

1.3.1 EARNINGS SHARING MECHANISM (ESM)

Hydro One proposes to share with customers 50% of any earnings that exceed the OEB-allowed regulatory ROE by more than 100 basis points in any year of the Custom IR term for each of Hydro One Transmission and Hydro One Distribution. The customer share of the earnings will be adjusted for any tax impacts and will be credited to a deferral account for clearance at the time of Hydro One's next rebasing. The calculation of the actual ROE for a test year will use the OEB-approved mid-year rate base for that period to avoid double counting with amounts in the proposed capital in-service variance account, described below. Further details on Hydro One's ESM are provided in Exhibits G-01-01 and G-01-02.

[1] EB-2017-0049, Decision and Order, p. 32 and EB-2019-0082, Decision and Order, p 39

1.3.2 CAPITAL IN-SERVICE VARIANCE ACCOUNT (CISVA)

A CISVA is a mechanism to track the difference between the revenue requirement associated with the actual in-service capital additions and the revenue requirement associated with OEB-approved in-service capital additions.

Hydro One is proposing a CISVA with the following key features:

1. The account will track the impact on revenue requirement of any in-service additions[2] that, on a cumulative basis, are lower than 98% of the OEB-approved amount for each year of the Custom IR term;
2. For cumulative in-service additions that are lower than 98% of the OEB-approved level, the associated revenue requirement impact will be computed and reported on an annual basis in the variance account;
3. The CISVA for Hydro One Distribution will, as in the past, require that the sum of the variances in each year be disposed of to the benefit of customers at the end of the Custom IR term;
4. In the case of the CISVA for Hydro One Transmission, Hydro One requests that the CISVA be modified to enable the balance in the account to be calculated yearly using the cumulative in-service additions over the Custom IR term so as to provide an opportunity for Hydro One to "catch-up" in later years within the term on any shortfalls in in-service additions that may occur in earlier years, and thereby to reverse the applicable impact recorded in a prior year of under in-servicing to the extent it makes up for such a shortfall, as described in Exhibit G-01-02, Section 4.3. Thus, the final balance at the end of the Custom IR term will be disposed of to the benefit of customers; and

[2] As described in Sections 4.2, 7.2 and 7.4 of Exhibit G-01-02, the amounts used to calculate the balance in Hydro One's Externally Driven Distribution Projects Variance Account, AMI 2.0 Variance Account and Externally Driven Transmission Projects Variance Account will be excluded from the Capital In-Service Variance Account, as applicable.

5. The final balances for the Hydro One Transmission and Hydro One Distribution CISVAs, respectively, will be disposed of with the following conditions:
   - The revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation; and
   - The account will be asymmetrical, meaning that should the cumulative in-service additions in any year of the Custom IR term exceed 98% of the cumulative OEB-approved amount for that period, no amount will be recoverable from ratepayers.

Hydro One believes that a dead band continues to be appropriate for the CISVA in order to ensure alignment between the behaviours that are incented by the account and the outcomes that ratepayers value. A 2% dead band was approved for this account in EB-2017-0049 and EB-2019-0082.[3] Further details on the features of the CISVA are provided in Exhibit G-01-02.

2.0 Z-FACTOR

Hydro One is proposing, consistent with the Handbook, that the OEB's Z-factor mechanism be available during this Custom IR term. The criteria that Hydro One proposes to apply to the use of the Z-factor mechanism are those approved by the OEB in EB-2017-0049 and EB-2019-0082.[4] Specifically, Z-factor claims must be outside the control of Hydro One to manage, exceed a $3M materiality threshold on a revenue requirement basis, and meet all of the following criteria on an individual event basis:

---

[3] EB-2017-0049 Decision and Order, p 173; EB-2019-0082, Decision and Order, p 172
[4] EB-2017-0047 Decision and Order p 42; EB-2019-0082 Decision and Order, p 41

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must exceed $3M on a revenue requirement basis and have a significant influence on the operation of the utility; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the utility's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

3.0 OFF-RAMPS

Hydro One proposes to apply the OEB's existing policy with respect to off-ramps, in which a regulatory review may be triggered if a utility's performance falls outside of an equity dead band of plus or minus 300 basis points. This approach is consistent with the OEB's decisions in EB-2017-0049 and EB-2019-0082.

4.0 PROPOSED FRAMEWORK FOR UPDATES

Hydro One expects to file annual update applications from 2024-2027. Details regarding these applications are set out in Exhibits A-04-02 and A-04-03.

This page left blank intentionally.

Benchmarking and Productivity Research for Hydro One Networks' Joint Rate Application

PREPARED BY:

CLEARSPRING ENERGY ADVISORS

CONTACT: STEVE FENRICK

STEVE.FENRICK@CLEARSPRINGENERGY.COM

JULY 30, 2021

Clearspring Energy Advisors LLC

Contents

List of Tables and Figures

1 Executive Summary

Hydro One Networks ("Hydro One" or "Company"), through counsel, engaged Clearspring Energy Advisors, LLC ("Clearspring") to conduct benchmarking and productivity research for the Company's transmission and distribution joint rate application ("JRAP"). The lead researcher of the study is Mr. Steven A. Fenrick. Mr. Fenrick provided research reports and expert witness testimony on behalf of Hydro One in the Company's most recent transmission and distribution rate applications, and has extensive experience conducting these types of studies.[1,2] A copy of Mr. Fenrick's summary *curriculum vitae* is attached as Appendix D.

A new feature in this research and report is the calculation and industry comparison of the capital age of assets for Hydro One's transmission and distribution infrastructure. This calculation uses industry data going back to 1948 and is done independently of the total cost benchmarking and productivity trend research.

1.1 Research Study Components

The research conducted and described in this report includes studies for both the transmission and distribution businesses of Hydro One. These studies are:

- **Transmission and distribution total cost benchmarking of Hydro One**. This study – done for each of the transmission and distribution businesses – is the basis for our recommendation for stretch factors in the Company's custom incentive regulation ("CIR") proposal for each business.

- **Transmission and distribution capital age calculation**. This study – done for each of the transmission and distribution businesses – supports and helps explain the cost benchmarking scores of the Company and the transmission industry total factor productivity ("TFP") trend.

- **Transmission industry TFP trend**. This study is the basis for our recommendation for the transmission base productivity component of the X-factor in the Company's CIR proposal.

- **Relationship between capital spending and OM&A expenses**. This study is in response to a request by the OEB in the last Hydro One transmission decision.

1.2 Transmission Research Study Results

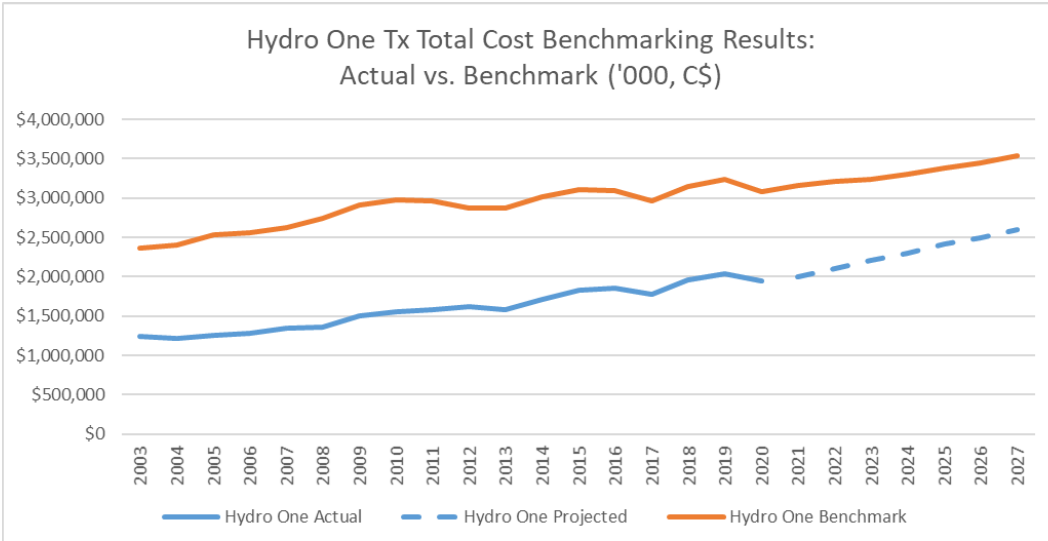
Clearspring benchmarked Hydro One's total transmission historical and forecasted costs from 2003 to 2027. Hydro One's transmission total cost benchmarking showed a forecasted total cost performance of

[1] The Transmission application was EB-2019-0082. The Distribution application was EB-2017-0049.

[2] Mr. Fenrick was an employee of Power System Engineering, Inc. ("PSE") and both prior Hydro One reports were produced when Mr. Fenrick was with PSE. Throughout this report, prior PSE benchmarking studies will be referred to as "Mr. Fenrick's studies" or "our" studies, as Mr. Fenrick was the primary researcher for all prior PSE benchmarking and productivity studies conducted in Ontario.

-34.5% during the CIR period of 2023 to 2027.[3] The Company's proposed transmission costs from 2023 to 2027 are 34.5% below the econometric transmission total cost model's benchmark, given the service territory conditions of Hydro One and the spending and variable forecasts of the Company.

Figure 1 Hydro One Transmission Total Cost Benchmarking



Hydro One's ranking among the transmission benchmarking sample substantiates this total cost performance benchmark score. Hydro One's benchmark score ranks in the top quartile.[4] The Company ranks 2nd out of the 60 utilities in the full transmission benchmarking sample.[5]

The capital age research conducted by Clearspring supports and helps to explain this transmission cost performance of the Company. The capital age compares the calculated age of assets at Hydro One to those of the industry at large. Older assets will tend to have lower capital costs, due to depreciation and capital asset inflation. A company with an older age would be expected, all else being equal, to have lower total costs and therefore a stronger benchmark score. Figure 2 shows that the Company's transmission capital age is materially older than the industry's transmission capital age in 2019.[6] This older capital age of Hydro One persists throughout the CIR period of 2023 to 2027 (based on the JRAP proposed capital investments and retirements).[7]

[3] This assumes the entirety of the proposed JRAP spending envelope is realized.

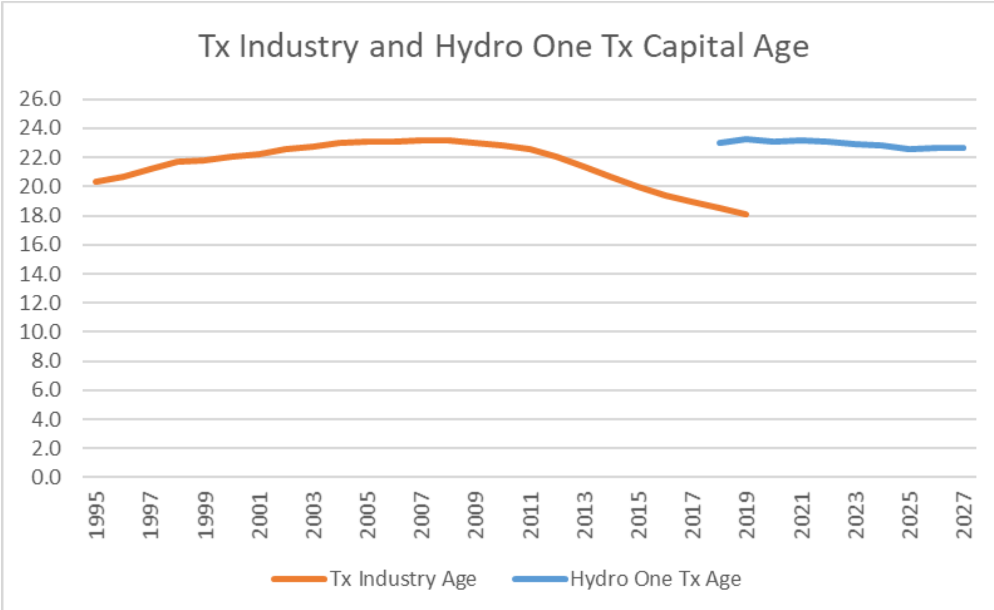
[4] The most recent three years for the sample are 2017 to 2019 for most of the utilities. This most recent three-year period is used to develop the sample ranking. Hydro One's benchmark score used is the average of 2023 to 2027. The Company would continue to rank 2nd in the entire sample if we used the 2017 to 2019 average for Hydro One.

[5] There are 59 U.S. transmission utilities in the sample; with Hydro One added, the full sample comprises 60 utilities.

[6] The industry's capital age is a weighted average of each utility's capital age in each year from the transmission benchmarking sample.

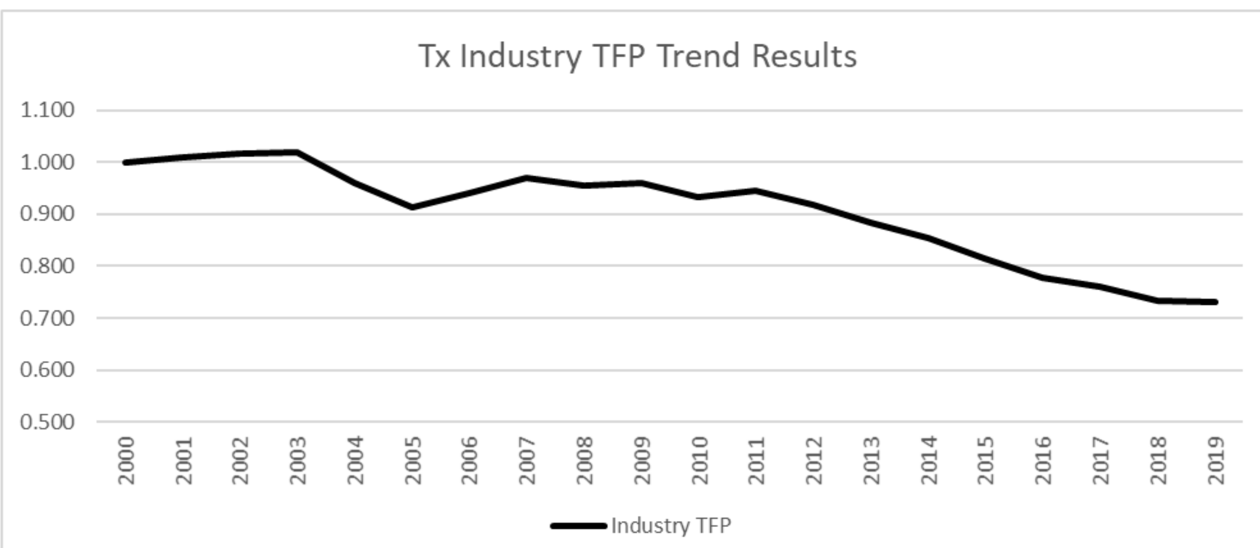
[7] Please see Section 5 and Appendix B for further details on the capital age variable.

Figure 2 Transmission Capital Age: Industry Historical vs. Hydro One



Clearspring also calculated the transmission industry TFP trend from 2000 to 2019 (see Figure 33 below), for purposes of the base productivity factor recommendation. We begin the TFP examination period in 2000, as that year immediately follows a time where a portion of the U.S. transmission industry restructured. We show that the industry TFP trend is clearly declining since 2000, and this decline has accelerated in recent years. From 2000 to 2019, the industry's TFP trend is an average annual decline of -1.66%. From 2010 to 2019, the average annual decline is -2.74%.

Figure 3 Transmission Industry TFP Trend

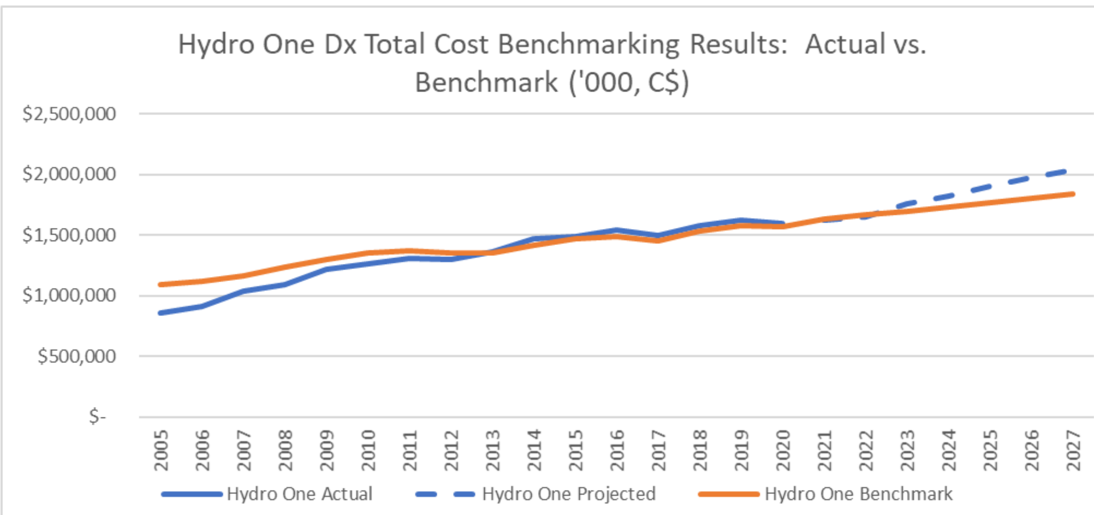


The industry's most pronounced TFP decline occurred during the period when the capital age of the industry became younger.[8] This is an expected result since it requires added capital investment to reduce the age of the system and this capital investment will also tend to lower the TFP trend. Interestingly, the industry TFP trend was also negative even during a period when the capital age of the industry became older (e.g., 2000 to 2010). This may be a result of the increasing challenges being placed on the industry (e.g., reliability, cybersecurity, DER) that is putting downward pressure on TFP not explained by the capital age.

1.3 Distribution Research Study Results

Clearspring benchmarked Hydro One's total distribution historical and forecasted costs from 2005 to 2027. Hydro One's distribution total cost benchmarking showed a forecasted total cost performance of +7.0% from 2023 to 2027.[9] The Company's forecasted distribution costs are 7.0% above the distribution total cost model's benchmark, given the service territory conditions of Hydro One and the spending and variable forecasts of the Company.

Figure 4 Hydro One Distribution Total Cost Benchmarking Results



Hydro One's ranking among the benchmarking sample substantiates this total cost performance score. Clearspring ranked the distribution sample using the three-year distribution cost performance

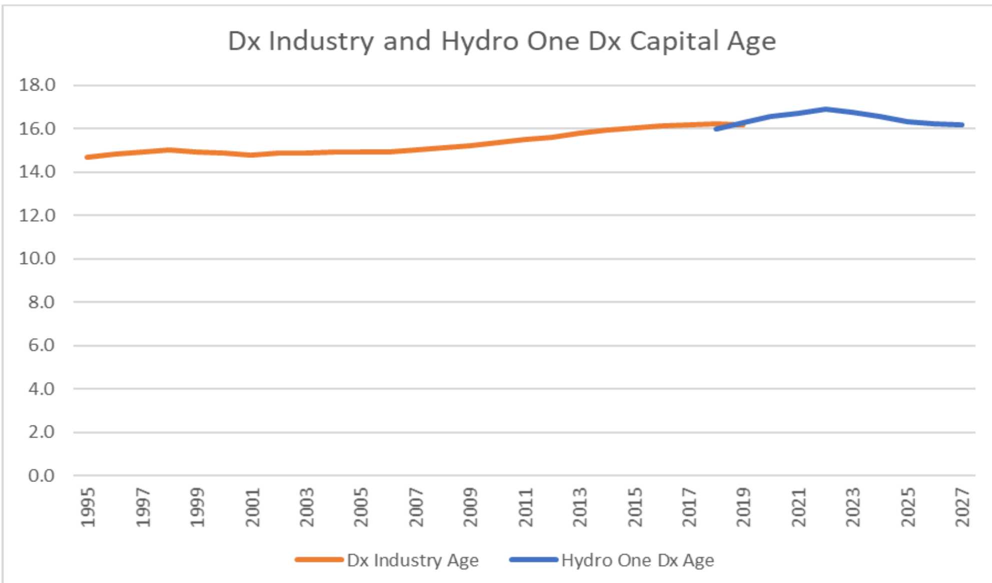
[8] A value below 1.0 in the TFP figure above indicates a negative productivity trend from the start year.

[9] This assumes the entirety of the proposed JRAP spending envelope is realized.

benchmarking score. Hydro One ranks in the third quartile.[10] The Company ranks 49th out of the 82 utilities in the full sample.[11]

The capital age research conducted by Clearspring further supports and helps to explain this cost performance of the Company (see Figure 5 below). The capital age compares the calculated age of assets at Hydro One to those of the industry at large. Older assets will tend to have lower capital costs, due to depreciation and capital asset inflation.

Figure 5 Distribution Capital Age: Industry Historical vs. Hydro One



Hydro One's distribution capital age in 2019 is near the industry's latest benchmark in 2019, which is the industry's oldest capital age level in the examined 25-year period. After 2019, Hydro One's distribution capital age is projected to slightly rise before declining back down near the 2019 level during the CIR period. This average capital age level and slight decline during the CIR period can, at least in part, be explained by Hydro One's AMI 2.0 project. AMI assets tend to have significantly shorter lives than traditional metering technology and other large distribution asset classes such as poles, conductors, and transformers. For context, if the AMI 2.0 project was not planned for during the CIR period, Hydro One's calculated capital age in 2027 would be more than a year older.[12] Absent AMI 2.0, Hydro One's distribution capital age would slightly increase during CIR and in 2027 would be 6.8% older than the industry's most recent benchmark in 2019.

---

[10] The most recent three years for the sample are 2017 to 2019 for most of the utilities. This most recent three-year period is used to develop the sample ranking. Hydro One's benchmark score used is the average of 2023 to 2027. The Company would rank 40th in the entire sample if we used the 2017 to 2019 average for Hydro One.

[11] There are 81 U.S. utilities in the sample and adding Hydro One makes 82.

[12] With AMI 2.0 it is 16.2 years, without AMI 2.0 it would have been 17.3 years.

1.4 Clearspring Recommendations

Our recommendations are as follows:

1. **Transmission base productivity component of the X-factor = 0.0%**. The industry TFP trend has declined since 2000, and this decline has continued to noticeably weaken in recent years for the industry.[13] While a negative base productivity factor would be reasonable, we recommend a 0.0% productivity factor, in recognition of OEB precedent in 4GIR and other CIR proceedings. However, it should be recognized that a 0.0% base productivity factor imposes a high implicit stretch factor onto the Company over 1.50%.[14] This is an extraordinary stretch factor, especially for a utility with such strong cost performance.

2. **Transmission stretch factor = 0.0%**. The transmission total cost benchmarking results of the Company indicate superior total cost benchmarking performance. The benchmark score of -34.5% shows that costs are significantly below benchmark expectations, and based on 4GIR precedent, a 0.0% stretch factor is indicated.[15] Hydro One's ranking in the top quartile among the sampled utilities, and the capital age result, further substantiate this finding. Given the following factors: (1) the superior transmission total cost performance score and ranking, (2) the transmission capital age results indicating Hydro One's capital age is substantially older than the sample, (3) the large stretch factor implicit in a 0.0% base productivity factor, and (4) the Company's proposed incremental stretch factor on capital of 0.15%, our takeaway is that a negative stretch factor should be considered and would be reasonable.

   A negative stretch factor would better reward the utility for its strong cost performance, which has provided significant cost savings to Ontario customers. Providing a strong signal and reward to utilities who are found to be superior cost performers aligns with the precepts of incentive regulation. Despite our opinion that a negative stretch factor would be reasonable in this case, we nonetheless recommend a 0.0% stretch factor in recognition of the OEB's 4GIR precedent of not allowing negative stretch factors.

3. **Distribution base productivity component of the X-factor = 0.0%**. This is based on the latest Ontario TFP study (conducted by Mr. Fenrick in the last Hydro One distribution application), and

[13] As discussed in Section 6, there may be good reasons for this decline in industry TFP. Increasing but unmeasured outputs such as increased reliability, cybersecurity, environmental, DER connections, geomagnetic protections, and other well-intentioned regulations may be placing higher requirements and cost challenges on utilities, without increasing the measured output growth that impacts TFP trends.

[14] Other jurisdictions have approved negative productivity factors. In Clearspring's opinion, negative productivity factors should be considered, as they would more accurately align the I-X framework with economic theory and empirical research, and substantially lessen the need for additional capital funding through other mechanisms.

[15] In the 4th Generation IR proceeding, five stretch factor groupings (cohorts) were established, based on the most recent average three-year total cost benchmarking scores. In that proceeding, a score better than -25% (i.e. costs were more than 25% below benchmark) received the lowest stretch factor of 0.00%. A score between -25% and -10% received a 0.15% stretch factor. Scores that were +/- 10% received 0.30%. Scores between 10% and 25% received a 0.45% stretch factor, and scores exceeding 25% (i.e. costs were 25% or more than benchmark) received the highest stretch factor of 0.60%.

on the 4GIR results, both of which show negative industry TFP trends.[16] The recommendation is also based on OEB decision precedents, where other CIR applications received a 0.0% base productivity factor.

4. **Distribution stretch factor = 0.3%**. The distribution total cost benchmarking results of the Company reveal average total cost benchmarking performance. The benchmark score of +7.0% indicates a 0.3% stretch factor, based on 4GIR precedent. This result is further substantiated by the distribution capital age comparison of the Company and the industry showing an average age level for the Company. In our opinion, a 0.3% stretch factor is a reasonable challenge for a utility that is estimated to be in the average cost performance range in both its benchmarking and capital age results, has already operated within incentive regulation, and is proposing a 0.15% incremental stretch factor on capital.

1.5 Reconciling Differences Between Methodologies

In several previous CIR applications, total cost benchmarking and productivity studies have been submitted by Mr. Fenrick, and OEB Staff has hired its own consultant, Pacific Economics Group ("PEG"), to conduct responding research. This reoccurring research by two benchmarking and productivity experts has produced a benchmarking methodology in Ontario that has improved and been refined over the years. This has included improvements in the service territory variables and the overall benchmarking framework. In Clearspring's opinion, the utilities in Ontario are subject to the most accurate and advanced utility benchmarking research in North America.

While some methodological differences between the experts have surfaced in past proceedings, it is important to recognize that these differences are relatively few. Clearspring has endeavored to further narrow or eliminate these differences in this current research. Clearspring examined past research and the methodological issues or questions that have been raised and has addressed these issues when that could reasonably be done without compromising the study. Please see Section 2.1 for a description of the specific methodological items addressed.

[16] In our opinion, an update to the 4GIR distribution industry TFP finding would be helpful but will require a substantial amount of effort and discussion given the accounting changes that occurred in Ontario, AMI investments, and other issues. We did not undertake to recalculate the distribution TFP trends in this application because this is best done, in our opinion, in a generic proceeding.

2 Total Cost Benchmarking Methodology

Clearspring used the same methodology for both the transmission and distribution total cost benchmarking studies. Other than the sample of utilities and the specific variables used, all other calculations and approaches are consistent. Both studies build upon prior benchmarking studies submitted in Ontario and are based on the best practices that have improved and evolved in the province.

The variables measure the impact of the variable on total cost; thus, some variables will impact transmission costs (e.g., transmission line lengths), others will impact distribution costs (e.g., customers served), and some variables will impact both costs (e.g., peak demand). Therefore, each model has its own variable specification. The samples are different because not all U.S. utilities serve both a transmission and distribution function. However, our prospective sample for each model started with the same sample "universe" of U.S. utilities, and each sample was then based on which utilities serve the applicable function and had plausible data observations for all included variables.[17]

The studies employed the econometric benchmarking approach. This is the most accurate and fair method when comparing utility cost levels because it explicitly adjusts for the quantifiable differences between utility service territories and business conditions. It is also the method preferred by the OEB in the 4GIR Report of the OEB and used for all our past CIR benchmarking research.[18]

Simple comparisons of "raw" (unadjusted) metrics such as rates, unit costs, or reliability indices do not typically allow regulators to compare utilities in a fair manner. For example, comparing a utility's costs or rates to those of a peer group utilities' costs or rates usually presents an inaccurate picture of the target utility's performance. Factors that cannot be controlled by the utility affect cost levels. Such factors include geographical size, regional wage levels, rural density, or serving a congested urban territory. It is often difficult or impossible to account for these factors using a peer group approach.

Adjusting for these and other influencing factors is necessary to accurately evaluate performance. With this concept in mind, Clearspring has estimated two econometric models (one for transmission and one for distribution) from a large sample of utilities, using variable parameters that statistically are drivers of transmission and distribution utility costs.[19] The econometric method adjusts for service territory conditions and other factors that affect total costs.

Using a large sample of utilities, the econometric model produces an industry-wide estimation of how the variables affect the studied metric (e.g., total costs). For the present research, the sample used to estimate the models includes U.S. observations from multiple utilities for multiple years.

[17] The U.S. sample is comprised of investor-owned utilities who are required to file a FERC Form 1. The Form 1 report includes expenses according to the Uniform System of Accounts, customers, peak demands, and plant information by function that allows us to ensure definitional consistency between Hydro One and the sample.

[18] EB-2010-0379.

[19] To "estimate" a model means, roughly, to examine the drivers or variables that affect the given metric (e.g., cost), and to use the data to create a model that measures how each variable affects that metric.

The model is then used to predict Hydro One's "expected" (benchmarked) costs, using the estimated relationship between the costs and the explanatory variables and Hydro One's values for the variables. The benchmark costs represent the costs that the model would expect a utility to have based on the actual operating conditions faced by that utility in that year.

The benchmark score is defined as the logarithmic percentage difference of the actual costs to the benchmark costs for a given year, as shown below.[20]

$$Benchmark\ Score = \text{Natural Log}\ \left(\frac{Historic\ or\ Projected\ Costs}{Benchmark\ Costs}\right)$$

The general approach of our benchmarking analysis is as follows:

1. Clearspring assembled the historical variables and costs of all utilities in the dataset.
2. Using the historical data, Clearspring estimated an econometric model that expresses the relationship between the variables and cost.
3. Using this model, Clearspring can then produce "benchmark" values for a given utility in each year. The benchmark values are determined from the model, using the specific variable values for a given year. In Hydro One's case, the benchmark represents the total cost amount expected for a utility with the same variable values as Hydro One.
4. We then compare the total costs that are expected by the model to Hydro One's actual historical and projected costs in each year, which allows us to: (1) evaluate the historical and projected cost performance, and (2) recommend a stretch factor.

For a more detailed description of the methodology, please see Appendix A.

2.1 Prior Methodological Differences Addressed

As discussed in the Executive Summary, Clearspring has reviewed the methodological issues raised in past CIR applications that have included econometric benchmarking. While PEG and Clearspring follow much of the same best practice research methods, some research differences have surfaced in past proceedings. While these differences are relatively few, we continued to narrow these differences in areas that do not compromise the research.

The following list summarizes past differences and the approach Clearspring has taken to address them.

- Sample Period: In the current research, Clearspring has a consistent sample period for both the transmission and distribution datasets; the sample period for each dataset begins in 2000 and

[20] We use the logarithmic percentage difference rather than the arithmetic percentage difference, because this is convention within the benchmarking profession, including in 4GIR and all other CIR applications we and PEG have been involved in. The approach provides a more intuitive result when averaging increases and decreases over time.

ends in 2019 (20 years).[21] In the last Hydro One transmission application, Mr. Fenrick used a sample period of 2004 to 2016 (13 years). In PEG's responding report, PEG used a sample period of 1995 to 2016 (22 years).

In the latest Hydro Ottawa distribution application, there was agreement on the sample period between the consultants. Clearspring put forth a sample period of 2002 to 2017 (16 years) and PEG put forth this same sample period. We also note that in PEG's latest transmission benchmarking research in Quebec, they used a sample period that began in 2004 and ended in 2019 (16 years).[22]

Mr. Fenrick had concerns regarding PEG beginning the sample in 1995 in the last transmission application because of the transmission industry structural change that began in the late 1990s with the creation of independent system operations ("ISOs") and far lower cost challenges in those earlier years relative to recent years that unduly influenced the benchmark scores of all utilities in the sample for recent or forecasted years.[23] The 1990s had considerably different and lower cost challenges than those now faced by transmission utilities; current challenges include cybersecurity, reliability enhancements and NERC requirements, distributed energy resource connections, and geomagnetic disturbances. These current cost challenges either did not exist or had far lower cost ramifications in the 1990s than now. Therefore, a sample that does not include and is not influenced by these systemically dissimilar observations from the 1990s provides a more accurate model and result when benchmarking 2023 to 2027 CIR cost projections.

For this current research, Clearspring is of the opinion that a sample period that begins in 2000 for both the transmission and distribution datasets strikes the right balance between these considerations. Starting in 2000 for both studies provides consistency in the studies and addresses PEG's desire for a somewhat longer sample period and our preference to begin the sample period after the transmission industry's restructuring and the markedly different cost challenges found in the 1990s.

- <u>Estimation Procedure</u>: Clearspring is using the same estimation procedure that we used in the last Hydro One transmission research and the previous Hydro Ottawa distribution research. This procedure is known as the Driscoll-Kraay ("DK") method, which uses the ordinary least squares ("OLS") coefficients and then adjusts the standard errors due to heteroscedasticity and

[21] This is for the U.S. sample. Hydro One has data beginning in 2003 and going through 2027, with future years using the proposed spending amounts.

[22] Please see p. 77 of PEG's report, "Transmission Productivity and Benchmarking Study," conducted in Hydro-Quebec Transmission's proceeding R-4058-2018 Phase 2, February 15, 2021.

[23] Please see the PSE Reply Report in EB-2019-0082 authored by Mr. Fenrick, "Reply to PEG's Report (Incentive Regulation for Hydro One Transmission)," October 15, 2019.

autocorrelation.[24] PEG had some questions regarding the DK method in those two applications. PEG used a generalized least squares ("GLS") estimation method in both of those applications; however, the GLS method appeared unstable when applied to Hydro One's transmission operations, given the large difference in benchmark results based on the exact GLS method used by PEG.[25]

In PEG's latest transmission benchmarking research conducted this year in Quebec, PEG states that they have adopted Clearspring's estimation approach and decided to use the OLS coefficients and then adjust the standard errors.[26] This appears to be the same (or very similar) estimation approach as the DK method that we use. PEG states in their Quebec report:

> The choice between these approaches has been debated several times in recent Ontario Energy Board proceedings. To diffuse controversy in this proceeding, we have adopted in this study the general approach that has been favored by utility witnesses in Ontario. Specifically, we have used an OLS estimator with robust standard errors available in the Stata statistical software package.

We support PEG on this effort to diffuse controversy on this methodological issue. This agreement on estimation approach will eliminate a major point of research difference between the consultants.

- <u>Model Specification</u>: Model specification is the process of determining which variables to include within the econometric models. There has been an evolution in these proceedings that has resulted in an improvement of the model specification as new or improved variables are developed and vetted.

  Regarding the distribution model specification, we reviewed the latest model specifications put forth by us and PEG in the Hydro Ottawa, Toronto Hydro, and last Hydro One distribution CIR applications. Hydro Ottawa's was the most recent. In the Hydro Ottawa proceeding, we put forth a model that PEG then modified in their responding report. Overall, PEG's modifications to our model specification we considered to be minor adjustments and the model specification is, in large part, similar to the one we put forth. This is especially true when applied to a non-urban

---

[24] Please see, Driscoll, J., and A. C. Kraay, 1998. "Consistent covariance matrix estimation with spatially dependent data," *Review of Economics and Statistics* 80: 549–560.

[25] Please see the PSE Reply Report in EB-2019-0082 authored by Mr. Fenrick, "Reply to PEG's Report (Incentive Regulation for Hydro One Transmission)". October 15, 2019.

[26] Please see p. 101 of PEG's report, "Transmission Productivity and Benchmarking Study," conducted in Hydro-Quebec Transmission's proceeding R-4058-2018 Phase 2, February 15, 2021.

utility like Hydro One, since one of the variables eliminated by PEG was a quadratic on the "congested urban" variable.[27]

Considering the preceding statements and to reduce differences, we have adopted PEG's distribution total cost model specification found in Hydro Ottawa's application.[28] We have added one new variable without any further model specification modifications. This variable is a measure of how much extra work a distribution utility is doing on voltage levels that some utilities may classify as transmission voltages.[29] This approach builds upon the prior research and improves the benchmarking research.

Regarding the transmission model specification, we have built upon the prior Hydro One transmission proceeding. The model specification changes we made to our model in that past proceeding include taking out the construction standards index variable, including a new ISO binary variable, and substituting the "transmission substation capacity" variable for a "number of transmission substations" variable.

The construction standards index variable that Mr. Fenrick put forth in the last application was a complex variable and was met with some criticism. This is cited on page 30 in the OEB's Decision in that proceeding. Given that this variable has not been vetted in multiple proceedings (unlike the urban core variable for the distribution model), its complexity, and questions that accompanied its first introduction, we have not included this variable in our transmission model specification.[30]

A new ISO variable has been added to the transmission model specification. In the last transmission proceeding, considerable discussion centered on the fact that the transmission industry restructured in the late 1990s by forming ISOs and RTOs. PEG excluded some cost categories based on this structural change within the industry. Mr. Fenrick began his sample period after a large portion of this structural change occurred. Starting the sample in 1995 created a noticeable influence in the results of later and forecasted observations in PEG's analysis, due

[27] Both PEG and Clearspring included the congested urban variable; our only difference was on whether to include the quadratic of that variable.

[28] PEG's distribution total cost model put forth in Hydro Ottawa's application (EB-2019-0261) can be found on p. 49 of their report titled, "Custom Incentive Rate Mechanism Design for Hydro Ottawa", June 19, 2020.

[29] This distribution work variable helps adjust for the different definitions of transmission versus distribution that utilities may have. If a transmission utility has a large portion of its line voltages below 50 kV, it is presumably lowering the costs of the distribution utility (which would otherwise need to make those investments). Including this variable allows the model to adjust for the transmission and distribution classification differences between utilities. We used the 50 kV cut-off since this is the defined cut-off in Ontario for high and low voltage.

[30] We would anticipate that including this variable would be beneficial to the benchmark score of Hydro One.

partly to this structural change.[31] Given all this, we believe the best approach is to include an explanatory variable into the model specification that allows the model to estimate the cost impacts of utilities operating within ISOs or RTOs and begin the sample period after a sizeable portion of this industry restructuring occurred.

The final modification from the prior model specification for the transmission total cost model is using the "number of transmission substations" variable instead of the "transmission substation capacity" variable. This change is due to the substation capacity variable coming in with the correct sign but statistically insignificant, whereas the number of transmission substations variable does come in correctly signed and statistically significant at a 90% confidence level.

- <u>Hydro One Distribution Service Area</u>: The variable value used for Hydro One's service area was discussed and mentioned in the OEB's Decision in Hydro One's last distribution application.[32] While the measured service area for the rest of the sample is the full licensed service area for each utility (including unserved areas), we recognize that Hydro One is unique in that it has a sizeable area that is not currently served. In recognition of this and to reduce research differences, Clearspring has adopted the variable value for Hydro One that PEG used in its Hydro Ottawa research. This variable value is substantially reduced relative to the variable value used by our team in the last Hydro One distribution proceeding.[33]

- <u>Peak Demand Variable Definition</u>: In the last transmission proceeding for Hydro One, PEG used a different data source for peak demands than our team did. PEG used system peak demands and we used transmission peak demand (both are data elements reported on the FERC Form 1 for U.S. utilities). There are advantages and disadvantages of using either one of these data sources; the primary advantage of using the system peak demand data is that the data series begins prior to 2004, whereas the transmission peak data does not. Since Clearspring's sample now begins in 2000, we have decided to use the system peak demand data in the current research.

  Another previous question has been the calculation of the peak demand variable for both the transmission and distribution studies. In past proceedings, we have used a peak demand definition that takes the maximum peak demand value up until that observation year as the variable value. This was called a "maximum peak demand" or "ratcheted peak demand" variable. The use of this definition became a concern of ours when PEG used a sample period starting in 1995, because Ontario utility data begins, generally, in 2002. Further, some intervenors had brought up the fact that the variable value, by definition, can never decrease, even if peak

---

[31] Other differences between the 1990s and current conditions also led to a model having worse scores for all utilities in later years if it included these earlier periods. Realities that are present today, such as cybersecurity, geomagnetic protections, distribution energy resources, environmental regulations, and enhanced reliability, were either not present, or far less costly, in the prior century than they are today.

[32] EB-2017-0049, Board Decision, p. 29.

[33] The variable value for Hydro One has been changed from 961,498 to 651,974 square kilometres.

demands decrease over time. We would also add that since we are benchmarking forecasted costs through 2027, the peak demand variable for Hydro One's 2021 to 2027 value is a forecasted one. By nature, forecasts represent what is expected and do not reflect non-normal weather. However, actual weather, and thus realized peak demands, vary considerably from year to year from their weather normalized values. Over several years, some years are likely to be extreme and other years are likely to be mild, and thus peak demand values will fluctuate around the forecasted expectation. Since we are using the forecasted values for the future years, these years are at their normal levels and not likely to produce a new maximum peak demand value.

Considering these issues, we have used a 10-year rolling average of annual peak demands for the peak demand variable definition for both the transmission and distribution studies. This resolves the question of some utilities having more years available in the sample than others. It also addresses the question about the variable never being able to decrease (with a 10-year rolling average, it now can). Lastly, basing the variable on an average eliminates the problem of benchmarking future years using forecasts that are forecasted based on normal weather assumptions.

- Capital Asset Price Levels: In the last Hydro One transmission application, PEG raised an issue about using city of Toronto data as the basis for determining the capital asset price levels of Hydro One. In that application we used the headquarter cities for all the price levels for the entire sample, including Hydro One.[34]

  The year that the capital asset price level is determined has also been a point of concern of ours regarding PEG's research. Clearspring is of the opinion that a recent year should be used to determine the asset price levels, since most of the focus from stakeholders is regarding the results for the recent and forecasted years. Using a recent year to determine the price levels between utilities also helps to mitigate differences in the asset price inflation indices chosen by the consultants.

  We have addressed these issues by using 2015 asset price level data and then weighting it based on population weights for the 3-digit zip codes of each U.S. utility in the sample. For Hydro One, we population-weighted all the Ontario cities available in the 2016 RSMeans Heavy Construction Cost Data book.[35] This population-weighting shifts the asset price levels of each utility from being based on the headquarter city to one that is based on the service territory of the utility. Using more recent 2015 data should help to mitigate any inflation assumption differences in the asset price used by either PEG or Clearspring. However, we have addressed the inflation assumption differences as well (see the next point).

[34] See PEG's report in EB-2019-0082, p. 24.

[35] We use the 2016 RSMeans publication and apply the values in 2015 since that is when the published data was gathered.

- Canadian Input Price Inflation for Hydro One: Regarding the capital asset price inflation assumption for Hydro One that escalates the asset price levels for inflation, we have adopted the compromise approach put forth by PEG in Hydro Ottawa's last application. In that application, PEG chose to give a 50% weight to our preferred index (the U.S. Handy-Whitman indices that are specific to transmission or distribution construction cost inflation) and a 50% weight to PEG's preferred index (the Canadian implicit capital stock price index for utilities; this index is specific to Canada).

  For the OM&A input prices, we have used the Canadian components of the Ontario average weekly earnings for the labour component and the Canadian GDP-IPI for the non-labour component. This assumption will have a negligible impact on the results, and while we generally continue to prefer using the same inflation indices for Hydro One as used for the rest of the sample, we do recognize the advantage of using Canadian indices and applying those to a Canadian utility. To reduce research methodology differences between Clearspring and PEG, combined with the negligible impact on the study, we have therefore applied the method of using the Canadian inflation measures and applying those to Hydro One.

- Transmission Depreciation Rate: In the last Hydro One transmission proceeding, PEG made the transmission depreciation rate approach a bit more detailed than the approach we took at the time. We used the Bureau of Economic Analysis (BEA) assumptions for electrical transmission, distribution, and industrial equipment as the basis for the depreciation rate assumption. This resulted in a transmission depreciation rate of 3.59%. PEG added the BEA's assumptions for electrical light and power structures and weighted transmission plant and general plant using cost share weights. All told, PEG's calculations led to a transmission depreciation rate assumption of 3.30%. We agree that PEG's approach is more detailed, and we use this 3.30% assumption in the current transmission research.[36]

- Older Capital Benchmark Year: The capital stock and cost calculations that are used by both Clearspring and PEG depend upon building up capital quantities and costs using the historical plant addition data for each utility. This method is called the perpetual inventory capital method.[37] PEG and Clearspring also apply a geometric decay assumption that uses a depreciation rate to depreciate historical capital additions in each year (see the prior point for the transmission depreciation rate assumption). In other incentive regulation proceedings, both inside and outside of Ontario, these capital quantity and costing assumptions can generate considerable debates, as some consultants make different assumptions on capital which can have large impacts on the

[36] For the distribution depreciation rate, we continue to use the 4.59% depreciation rate assumption that is used in all the CIR distribution applications submitted by our team and PEG.

[37] In Appendix A we provide more details on the perpetual inventory method, including the equations used.

study results. In our opinion, geometric decay is the proper assumption to use; it aligns best with theory and the realities of how a basket of utility assets depreciates over time for a utility.

Despite our agreement on that major issue, there have been a few minor differences regarding the treatment of capital that have been brought forth in past CIR proceedings. Our approach in the present application represents a compromise on the asset price levels, inflation, and depreciation rate assumptions (see prior discussion). The remaining difference is that the starting year that we have used for the perpetual inventory method for the U.S. sample has been 1989 in our prior research, whereas in a few past proceedings PEG has used a 1964 start year. This start year is called the "capital benchmark year". The capital benchmark year begins the perpetual inventory calculation in that start year, and then the capital stock is depreciated in subsequent years and plant additions are added to the capital stock to build the capital quantities and costs consistently over time for the entire sample.

The earlier the capital benchmark year is, the more actual plant addition data can be used to calculate the capital quantity and costs of each utility. Given the fact that PEG and Clearspring assume geometric decay, much of the capital quantity assumed in the capital benchmark year will have depreciated by the relevant years in the study. Despite our continued opinion that the capital benchmark year is a minor issue and that 1989 was a sufficient capital benchmark year, we have nonetheless collected all the necessary data to begin the capital benchmark year in 1947 for most of the U.S. utilities, and in 1959 for the rest that were missing data between 1947 and 1959.[38] We have therefore used the actual transmission or distribution plant addition data for the U.S. sample for the years 1948 to 2019 in the perpetual inventory capital method to calculate capital quantities and costs. This is over 70 years' worth of actual plant addition data.

- <u>Customized labour and non-labour OM&A weights</u>: For the OM&A input price index, an assumption as to the weights to use, between labour and non-labour, is required. In the 4GIR research conducted by PEG, a 70% labour and 30% non-labour assumption was used for the entire Ontario sample. In Mr. Fenrick's past CIR research, he has continued this 4GIR assumption of a 70/30 weight for all the sampled utilities. This enables consistent treatment between a U.S. sample and Ontario utilities, since Ontario utilities do not report labour/non-labour OM&A breakdowns. PEG has responded in past proceedings by saying that salary and wage data, while not publicly available for Ontario utilities, is available for the U.S. sample and should be used for the U.S. observations.

[38] In the data for 1947, the total utility net plant data is available but not the breakdowns for transmission or distribution net plant. However, breakdowns for gross plant in service are available. Therefore, we took the proportion of transmission gross plant in service to total gross plant in service to estimate the transmission net plant in service. We did the same for the distribution calculation. Any possible inaccuracy in this calculation will be miniscule by the time we consider the sampled years of the study and starting in 1947 allows us to use the actual plant additions for transmission and distribution in all years after 1947.

Modifying this treatment and assumption will have a negligible impact on the results and Hydro One was able to provide us with an estimate of Hydro One's labour/non-labour breakdown to be consistent with the U.S. sample. We have gathered the salaries and wages for the U.S. sample, located on the FERC Form 1s and requested Hydro One to estimate the labour and non-labour components within their OM&A expenses. We have used this estimate, along with the salary and wages data for the U.S. sample, to customize the labour and non-labour weights and to calculate the OM&A input prices for each sampled utility.

- Pensions and Benefits Treatment: Including or excluding pensions and benefits has been a topic of discussion in several CIR proceedings. Driving the issue is that Ontario distributors do not consistently report OM&A pensions and benefits expenses. Further, the different health care and other regulatory differences between the U.S. and Ontario can cause pensions and benefits to be higher in the U.S. than in Ontario, creating a small bias in favor of Ontario utilities when they are included. We believe it is fair to say that both consultants would prefer to exclude these expenses when it is possible to consistently do so. In the current research, we requested that Hydro One provide Clearspring with their OM&A pensions and benefits estimates for each year for transmission and distribution. This enabled us to exclude these expenses from both the U.S. sample and Hydro One.

2.2 Output and Business Condition Variables

In general, there are two types of variables used in econometric cost benchmarking: output variables and business condition variables. Output variables measure the output of the utility in question (i.e., what the utility "produces"). Business condition variables quantify the factors that drive costs in a particular service territory, such as regional input prices, lengths of line, highly congested urban areas, forestation, etc. Details of the output variables and business condition variables used for the transmission and distribution benchmark studies are described in Appendix A.

2.3 Benchmarks for Future Years

The same econometric model and its associated parameter values that are estimated using historical data (and used to develop Hydro One's historical benchmarks) are also used to calculate the Company's benchmarks for the forecasted years through 2027. These parameter values are combined with projected variable values to calculate the expected total costs of Hydro One in the future years of the Custom IR period.

Clearspring was provided OM&A expense, plant addition, physical asset, customer count, and peak demand projections from Hydro One. We used these projections to calculate variables for each future year, and then inserted these variable projections into the estimated econometric model.

2.4 Other Model Details

Other model details are provided in Appendix A. These details include the method used to calculate capital quantities and costs (perpetual inventory method), model estimation approach, model specification, and variable parameter hypothesis testing.

3 Transmission Cost Benchmarking

Clearspring undertook a total cost econometric benchmarking study of Hydro One's transmission costs. This study provides a comparison of Hydro One's actual and projected transmission total costs to the model-calculated benchmark costs after adjusting for the specific output levels, input prices, and business conditions that the Company operates within.

3.1 Transmission Variables

The two output variables used in the transmission benchmarking research are:

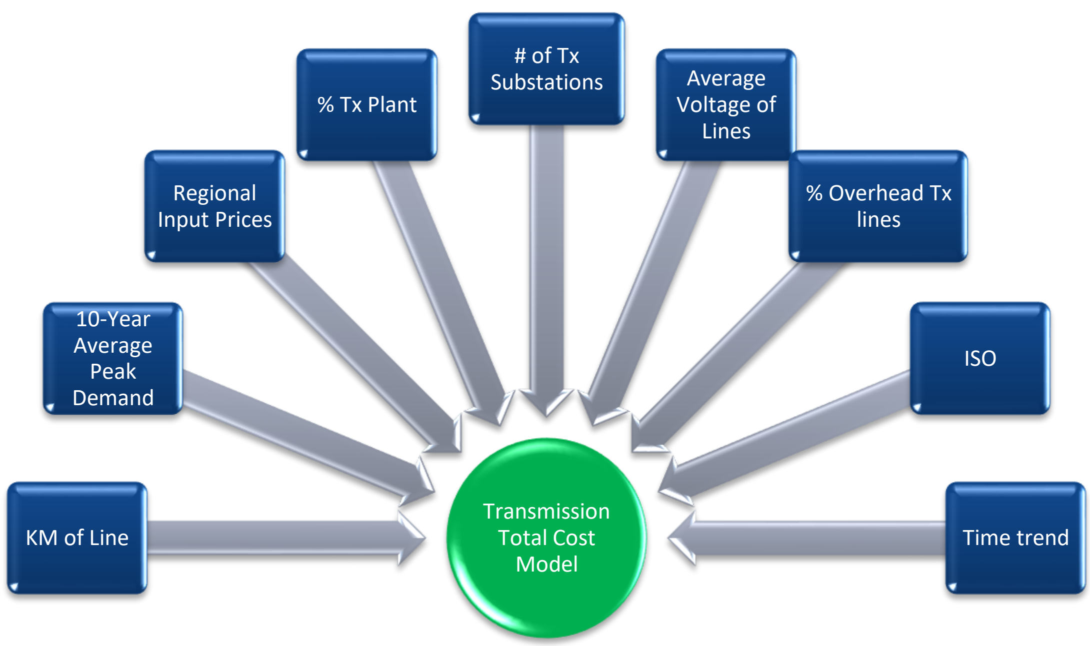
- Total kilometres of transmission line, and
- A 10-year rolling average of peak demand.

The business condition variables used in the transmission benchmarking research are:

- Regional input prices (total costs in the model are divided by the input price index),
- Percent of transmission plant in total electric utility plant,
- Number of transmission substations,
- Average voltage of transmission lines,
- Percent of transmission lines that are overhead,
- Independent System Operator (a binary value), and
- A time trend variable.

The variables included in the transmission benchmark analysis are shown in the figure below.

Figure 6 Variables in Transmission Cost Model



These variables provide a robust accounting of the varying service territory conditions faced by transmission utilities. All first order variables are statistically significant at a 99% confidence level and all variables are correctly signed (i.e., they are signed the way we would expect).

3.1.1 The Definition of Transmission Costs

Transmission OM&A and capital costs used in the benchmarking models for the U.S. transmission utilities are derived using FERC Form 1 filing data.[39] United States investor-owned utilities are required to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g., distribution, transmission, customer billing, administrative and general). Form 1s also include information regarding plant in service additions that are used in constructing capital costs.[40]

Clearspring used a definition of "cost" for Hydro One that allowed us to achieve comparability with the definition used for the U.S. sample. The cost of transmission services purchased by U.S. utilities from other utilities is removed from the transmission cost definition for the U.S. sample. Subtracting "transmission of electricity by others" expenses (Uniform System of Accounts category 565, on page 321 of FERC Form 1) creates a more comparable cost definition to Hydro One and, if not removed, would yield an unfair advantage to Hydro One, since certain U.S. utilities would have inflated expenses without commensurate output values. Clearspring also subtracted pensions and benefit expenses from the cost definition for both the U.S. and Hydro One.

The transmission cost definition also includes an allocated amount of administrative and general (A&G) expenses (see page 323 of FERC Form 1).[41] Some of the U.S. utilities own and operate power plants and/or conduct distribution functions. We allocated A&G expenses for those utilities based on the ratio of transmission expenses (minus transmission of electricity by others) to the total expenses of the utility minus the expenses of fuel, purchased power, transmission of electricity by others, regional market expenses, and A&G expenses. Similarly, general capital costs are allocated for the U.S. sample by the ratio of transmission gross plant in service to total plant in service minus general and intangible plant in service.

3.1.2 Transmission Output Variables

The transmission total cost model includes two output variables. The first is the total kilometres of transmission line, the second is the ten-year rolling average of peak demand for each utility. The output variables are gathered from FERC Form 1 data. The historical output data for Hydro One comes directly from the company. The peak demand variable is calculated based on taking the ten-year rolling average

[39] Some of the FERC Form 1 data was gathered using SNL Energy's database tool.

[40] Clearspring gathered plant addition data going back to 1947 for this study. Older data was collected from various EIA annual reports.

[41] The A&G expenses are after pensions and benefits expenses are subtracted.

of annual peak demand on the system in the sample that has occurred up to that observation's year. For years without ten years' worth of historical data, the years that are available are averaged.[42]

3.1.3 Transmission Business Condition Variables

Beyond the two output variables and the input price index, there are five business condition variables included in the model (plus a time trend). Each variable is discussed below.

The **percentage of transmission plant in total electric plant** uses gross plant in service information from FERC Form 1s. The variable measures the ability for a transmission utility to reduce costs through economies of scope: if the utility is also a generation and/or distribution utility, there may be cost savings to the transmission utility because of this added scope. The coefficient on the variable is expected to be positive: the higher the percentage of transmission plant in total electric plant, the higher we would expect total costs to be.

The **number of transmission substations** is based on FERC Form 1 data reported each year for the U.S. sample and based on asset information reported to Clearspring by Hydro One. We would expect a positive correlation between the number of transmission substations and total costs.

The **average voltage of transmission lines** measures the differences in voltage levels across transmission systems. This variable is constructed by calculating a weighted average by length of the different voltage levels found on each utility's transmission system. Serving higher voltages will be more costly than serving lower voltages, *ceteris paribus*. Therefore, we would expect a positive coefficient.

The **percentage of overhead lines** measures the percentage of overhead transmission lines to total transmission lines. Constructing underground transmission lines is costlier than constructing overhead transmission lines. As the percentage of overhead lines decreases, we would expect total costs to increase since this implies a higher percentage of lines that are underground. This implies a negative coefficient value is expected from this variable.

The **Independent System Operator (ISO)** variable indicates if the utility was operating under an ISO or Regional Transmission Operator (RTO) in the observed year. This variable is a binary variable that will equal "1" if in the observed year the utility is in an ISO or RTO and will equal "0" if this is not the case. We do not have an a priori expectation of the variable sign. While the ISO may take on some planning costs that the utility would have engaged in otherwise, the transmission utility may still be required to undertake some planning costs as well as added investments that the ISO may request to encourage a more efficient energy market. In the model, we find that the ISO parameter estimate is positive, indicating a positive relationship between being in an ISO and transmission total costs.

The **time trend** variable captures a general industry total cost level trend over the studied period. Time trend variables are often found in translog cost functions and econometric total cost benchmarking

[42] This is another advantage of the 10-year rolling average method. There is no bias if fewer than ten years for a utility are available since we are taking an average rather than a maximum of the peak demands.

research. In the present study, the variable is calculated by taking the current year of the observation and subtracting 1,999. For observations in the year 2000, the time trend variable equals 1. In 2019, the variable equals 20 (2,019 – 1,999). The coefficient value shows how adding an additional year increases or decreases total costs.

The estimated coefficient value on the trend variable is positive in our research, which aligns with our TFP trend research that indicates the industry has experienced negative TFP trends during the sample period.

3.2 Transmission Sample

The transmission benchmarking sample is comprised of 59 U.S. utilities plus Hydro One. The benchmark sample period begins in 2000 and extends to 2019. The sample is of an unbalanced panel form which allows utilities that do not have available and plausible data for all sampled years to still be present in the sample for the years in which they do have available and plausible data. There are 1,160 U.S. utility observations in the sample. Including Hydro One there are 1,185 observations. This large number of observations enables robust parameter estimates and a strong statistical model. Note that this sample is also used for the TFP analysis with the exceptions noted with an asterisk.

The sample of utilities within the sample is provided in the following table.[43]

[43] Data shown for the sample is from the most recently available year for each utility. For most of the sample this is for the year 2019. For Hydro One, it is 2027.

Table 1 Transmission Benchmarking and TFP Sample

Transmission Benchmarking and TFP Sample

Company	10-Year Average Peak Demand	Tx Line Lengths (KM)	Company	10-Year Average Peak Demand	Tx Line Lengths (KM)
Alabama Power Company	11,578	17,307	Kansas Gas and Electric Company	2,445	4,250
ALLETE (Minnesota Power)*	1,586	4,608	Kentucky Utilities Company	4,488	6,537
Appalachian Power Company	7,517	10,449	Louisville Gas and Electric Company	2,627	1,475
Arizona Public Service Company	7,159	10,106	MDU Resources Group, Inc.	568	5,446
Atlantic City Electric Company*	2,651	2,210	Mississippi Power Company	2,588	3,589
Avista Corporation	1,668	3,610	Monongahela Power Company	2,002	3,613
Baltimore Gas and Electric Company*	6,767	1,490	Nevada Power Company	5,781	3,060
Black Hills Power, Inc.	430	1,244	New York State Electric & Gas Corporation	2,947	7,317
Central Hudson Gas & Electric Corporation	1,129	964	Niagara Mohawk Power Corporation	5,960	17,611
Central Maine Power Company	1,586	4,677	Northern States Power Company - MN	7,604	9,239
Cleco Power LLC	2,471	2,204	Oklahoma Gas and Electric Company	6,657	9,665
Commonwealth Edison Company	21,525	8,015	Orange and Rockland Utilities, Inc.	1,401	889
Consolidated Edison Company of New York	5,070	837	PacifiCorp	10,148	28,350
Duke Energy Carolinas, LLC	17,526	13,329	PECO Energy Company	8,491	2,041
Duke Energy Florida, LLC	9,706	8,354	Potomac Electric Power Company	6,134	1,285
Duke Energy Indiana, LLC	5,885	8,548	PPL Electric Utilities Corporation	7,440	7,244
Duke Energy Progress, LLC	13,171	10,082	Public Service Company of Colorado	6,519	7,721
Duquesne Light Company	2,834	1,075	Public Service Company of New Hampshire	1,641	1,675
El Paso Electric Company	1,804	2,976	Public Service Company of Oklahoma	4,152	5,026
Empire District Electric Company	1,144	2,287	Public Service Electric and Gas Company	10,079	3,237
Entergy Arkansas, Inc.	5,402	8,350	Rochester Gas and Electric Corporation	1,594	1,761
Entergy Mississippi, Inc.*	3,134	5,041	San Diego Gas & Electric Co.	4,530	3,402
Entergy New Orleans, Inc.*	1,071	266	South Carolina Electric & Gas Co.*	4,776	5,915
Florida Power & Light Company	22,956	11,713	Southern California Edison Company	22,502	23,378
Gulf Power Company	2,521	2,739	Southern Indiana Gas and Electric Company	1,224	1,654
Hydro One Networks*	**21,830**	**20,788**	Southwestern Public Service Company*	4,821	12,473
Idaho Power Co.*	3,250	7,692	Tampa Electric Company	3,865	2,164
Indianapolis Power & Light Company	2,853	1,390	Tucson Electric Power Company	2,489	3,523
Jersey Central Power & Light Company*	6,079	4,181	Union Electric Company	7,716	4,115
Kansas City Power & Light Company	3,511	2,919	West Penn Power Company	3,941	3,510

*In Benchmark Sample but not TFP Sample

3.2.1 The Necessary Data is Not Available for Other Large Canadian Utilities

Other Canadian transmission utilities are not compelled to publicly file the information necessary to analyze consistently defined cost categories and consistently defined output and explanatory variables. Therefore, the only way to include these utilities in the sample is to directly request it from each utility and have them provide all the necessary information for the study.

Hydro One contacted several Canadian transmission utilities and asked if they would be willing to participate in the benchmarking study. Participation in the study would have required that the utilities give Clearspring the type of cost and variable information that was used in this report. None of the utilities chose to participate. Due to the absence of publicly available Canadian data, lack of voluntary participation on the part of utilities, and non-uniformity of cost categories in Canada even if the data were available, Clearspring has not used Canadian utilities in its dataset, other than Hydro One. This aligns with the prior transmission studies produced by our team and PEG which both used a sample comprised of U.S. utilities.

3.3 Transmission Model

The parameter estimates from the transmission total cost model are presented in the following table.

Table 2 Total Cost Model Estimates (Transmission)

Variable	Coefficient	Standard Error	T-Statistic	P-Value
Constant	10.6328	0.1407	75.5600	0.0000
KM of Transmission Lines (KM)	0.2929	0.0094	31.0000	0.0000
Peak Demand (D)	0.6475	0.0137	47.4000	0.0000
KM*KM	0.0204	0.0061	3.3600	0.0020
D*D	0.1111	0.0056	19.7600	0.0000
KM*D	-0.0098	0.0195	-0.5000	0.6200
% Tx Plant	0.3731	0.0414	9.0100	0.0000
# of Subs	0.0634	0.0074	8.5400	0.0000
Average Line Voltage	0.3465	0.0263	13.1800	0.0000
% Overhead	-1.3965	0.0570	-24.5100	0.0000
ISO	0.1216	0.0109	11.1300	0.0000
Trend	0.0075	0.0024	3.0800	0.0050

All the parameter estimates are plausibly signed and have reasonable magnitudes. The first order terms of all variables have the theoretically expected signs and are statistically significant at a 90% level of confidence. In fact, all the first order explanatory variables are statistically significant at a 99% confidence level. The adjusted R-Squared of the model equals a robust 0.942.

3.4 Transmission Results

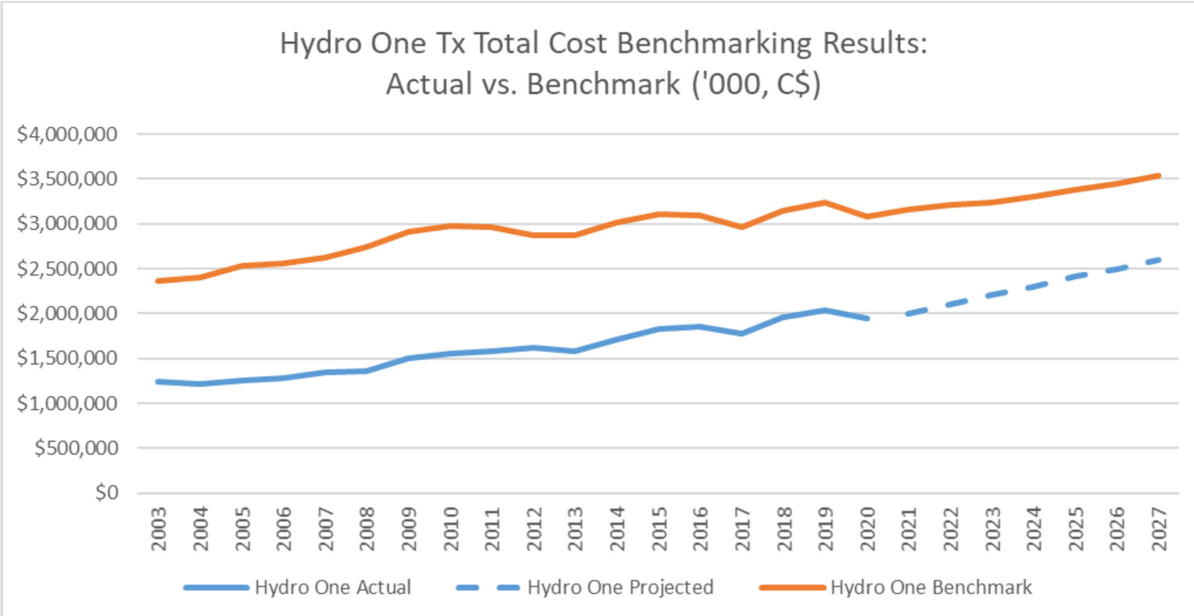
The following table breaks down the historical and forecast benchmark scores from 2003 through 2027. We note that the benchmark scores for future years assume that all the proposed spending will be incurred. If spending is less than the proposed amounts, the scores will improve; if spending is more than the proposed amounts, the scores will get worse.

Table 3 2003-2027 Transmission Total Cost Benchmark Score for Hydro One

Year	% Difference from Total Cost Benchmark
2003	-64.8%
2004	-67.9%
2005	-70.3%
2006	-69.9%
2007	-67.1%
2008	-69.6%
2009	-66.1%
2010	-64.7%
2011	-62.8%
2012	-57.8%
2013	-59.6%
2014	-56.9%
2015	-52.9%
2016	-51.0%
2017	-50.8%
2018	-47.3%
2019	-46.3%
2020	-46.1%
2018-2020 average score	**-46.6%**
2021	-45.5%
2022	-42.5%
2023	-38.4%
2024	-36.6%
2025	-33.9%
2026	-32.6%
2027	-30.9%
2023-2027 average score	**-34.5%**

The following graph displays how Hydro One's actual and projected transmission total costs have compared to the benchmark costs over time and through the Custom IR period, respectively.

Figure 7 Hydro One Transmission Total Cost Actual vs. Benchmark



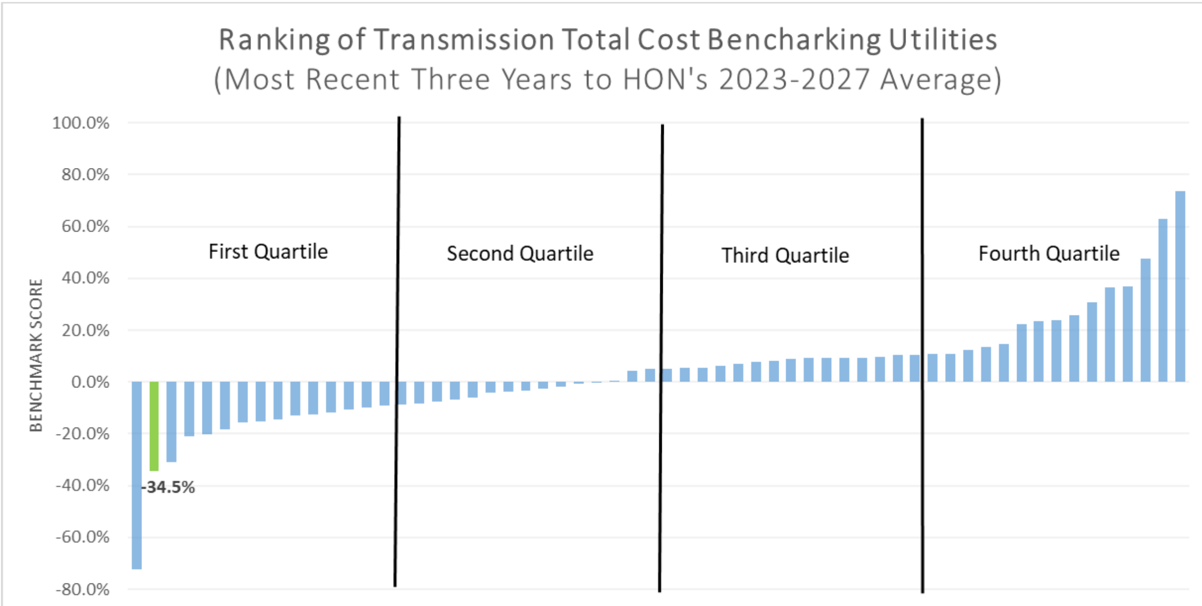
Hydro One's ranking among the transmission benchmarking sample substantiates this total cost performance benchmark score. Each utility in the sample received a transmission cost performance score; for every utility except Hydro One, the score was based on that utility's transmission costs in the most recent three years where data was available (compared to the model's expected costs for that utility in those years). For Hydro One, the score was based on the average of the CIR years of 2023 to 2027 proposed costs (compared to the model's expected costs for Hydro One in those years).[44] Hydro One's benchmark score ranks well in the top quartile.[45] The Company ranks 2nd out of the 60 utilities in the full transmission benchmarking sample.[46] Hydro One's position is noted in the green bar.

[44] If we instead ranked Hydro One's 2017 to 2019 cost performance relative to the sample's 2017 to 2019 cost performance, the Company would still rank 2nd among the entire sample.

[45] The most recent three years for the sample are 2017 to 2019 for most of the utilities. Hydro One's benchmark score is the average of 2023 to 2027.

[46] There are 59 U.S. transmission utilities in the sample; with Hydro One added, the full sample comprises 60 utilities.

Figure 8 Ranking of Utilities by Transmission Total Cost Scores



As noted, Hydro One's transmission total cost benchmarking scores indicate the Company's transmission costs have been significantly below benchmark expectations both historically and through the CIR period. We would expect a company who has a benchmark score as strong as Hydro One's historical score to eventually converge towards the mean of the sample. While Hydro One's score during the CIR period does moderate some, its overall ranking remains second throughout the CIR period and its benchmark score remains significantly below cost expectations. Further, Hydro One is not significantly lowering its overall capital age during the CIR period despite having relatively old assets. The research and CIR proposal indicates the Company can manage its assets at an older age than its industry peers.

4 Distribution Cost Benchmarking

Clearspring undertook a total cost econometric benchmarking study of Hydro One's distribution costs. This study provides a comparison of Hydro One's distribution total costs to the benchmark costs after adjusting for the specific output levels, input prices, and business conditions that the Company operates within. These comparisons are made for both historical and forecasted years through 2027. For more information on the benchmarking methods please see Chapter 2 and Appendix A.

4.1 Distribution Variables

The three output variables used in the distribution benchmarking research are:

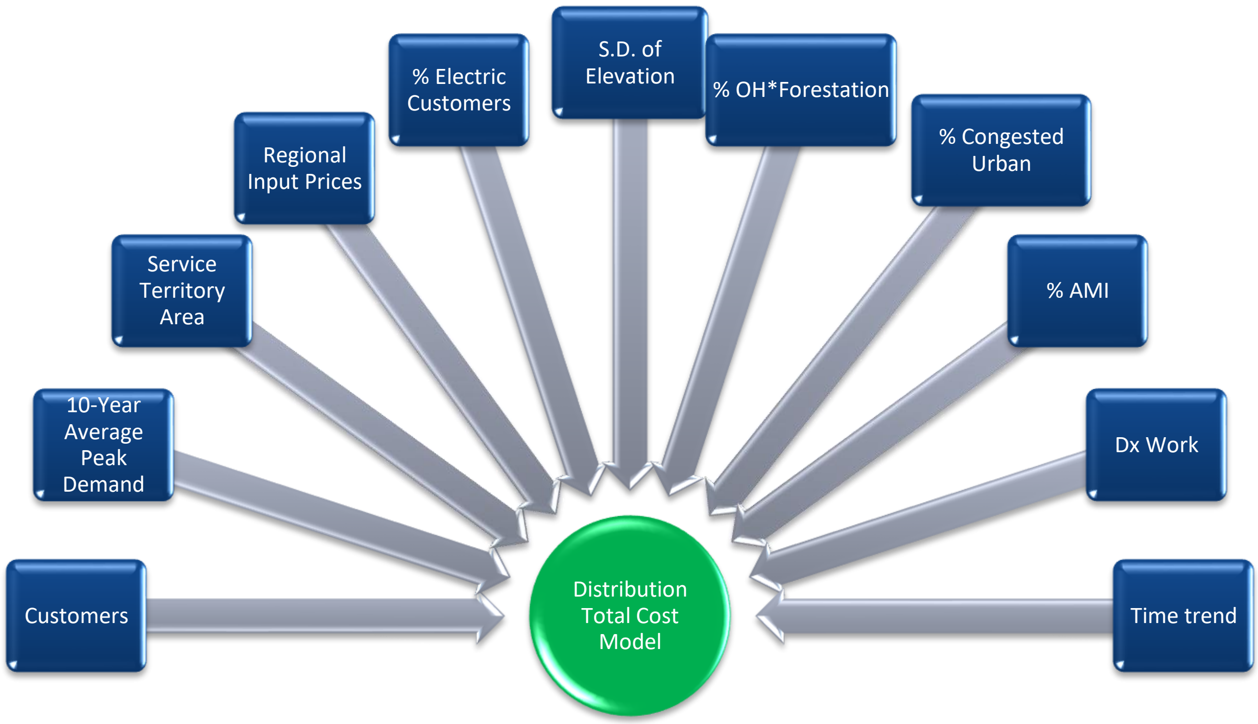
- Total customers served,
- A 10-year rolling average of peak demand, and
- The total distribution service territory of the utility.

The business condition variables used in the distribution benchmarking research are:

- Regional input prices (total costs in the model are divided by the input price index),
- Percent of electric customers in the total of electric and gas customers,
- Standard deviation of elevation,
- Percent of distribution plant that is overhead multiplied by the percent of forestation,
- Percent of congested urban area within each utility's service territory,
- Percent of AMI (smart meters) deployed by the utility in each year,
- The distribution work variable measures the percent of transmission lines classified as being served by transmission that are above 50 kV, and
- A time trend variable.

The variables included in the distribution benchmark analysis are shown in the figure below.

Figure 9 Variables in Distribution Cost Model



These variables provide a robust accounting of the varying service territory conditions faced by distribution utilities. All first order variables are statistically significant at a 99% confidence level and all variables are correctly signed (i.e., they are signed the way we would expect).

4.1.1 The Definition of Distribution Costs

OM&A and capital costs used in the benchmarking models for the U.S. distribution utilities are derived using FERC Form 1 filing data.[47] United States investor-owned utilities are required to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g., distribution, transmission, customer billing, administrative and general). Form 1s also include information regarding "plant in service" and accumulated depreciation that are used in constructing capital costs.[48]

We used a cost definition that is consistent between both the U.S. and Hydro One in the sample. The cost definition is the same as the latest one used in the Hydro Ottawa total cost benchmarking study led by

[47] Some of the FERC Form 1 data was gathered using SNL Energy's database tool.

[48] Clearspring gathered plant addition data going back to 1947 for this study. This data was collected from various EIA annual reports.

Mr. Fenrick, with the exception that we excluded pensions and benefits.[49] Clearspring began with the benchmark-based cost definition used by PEG in the 4GIR proceeding. To be consistent with the U.S. sample, we then added high-voltage expenses to the cost definition for Hydro One. The FERC Form 1 does not break down high- versus low-voltage distribution expenses, as Ontario reporting does. For the same reasons, contributions in aid of construction ("CIAC") have been excluded from Hydro One's cost definition, due to those expenses not being included in the U.S. Form 1 data. Bad debt expenses (called uncollectible expenses in the FERC Form 1) have been excluded for all utilities, to match the 4GIR benchmark-based definition.

The cost definition also excludes customer service and information ("CSI") expenses from total costs for all utilities. This is due to the possibility that the U.S. utilities include conservation demand management ("CDM") expenses in the CSI expense category. This assures cost consistency between the U.S. sample and Hydro One. The table below summarizes the cost definition treatment.

Table 4 Distribution Cost Definitions

Cost Element	Treatment
4th Generation IR Benchmark-Based Costs	This is the starting point for the sample.
Contributions in Aid of Construction (CIAC)	We subtracted from Hydro One distributor costs, since U.S. cost data does not include CIAC.
High Voltage Expenses	We added to Hydro One costs, since U.S. cost data includes distribution high voltage costs.
Customer Service and Information (CSI) Expenses	We excluded CSI expenses for both the U.S. and Hydro One, given the possible inconsistency in CDM reporting.
Pensions and Benefits	We excluded OM&A pensions and benefits from both the U.S. and Hydro One data.

4.1.2 Distribution Output Variables

The distribution total cost model includes three output variables.[50] The first is the total number of customers served, the second is the ten-year rolling average of peak demand for each utility, and the third is the total service territory area for each utility. The first two output variables are gathered from FERC

[49] This is because we can exclude these expenses as Hydro One is the only non-U.S. utility in the sample and we can directly request this data. Given higher health care costs in the United States, we would expect that excluding pensions and benefits from the cost definition would worsen Hydro One's benchmark score.

[50] This three-output specification matches PEG's latest distribution total cost model specification found in the Hydro Ottawa proceeding.

Form 1 data. The third uses GIS information on the utility service territory area; this variable uses the same values for the U.S. sample as found in the Hydro Ottawa research by Clearspring and PEG.[51] The historical output data for Hydro One regarding the number of customers and peak demands comes directly from the company. The peak demand variable is calculated based on taking the ten-year rolling average of annual peak demand on the system in the sample that has occurred up to that year. For years without ten years' worth of historical data, the years that are available were averaged.[52]

4.1.3 Distribution Business Condition Variables

Beyond the three output variables and the input price index, there are six business condition variables included in the model (plus a time trend). Each variable is discussed briefly below.

The **percentage of electric customers** measures the percentage of electric customers served by a utility out of total gas and electric customers. This variable measures the economies of scope available from serving both electric and gas customers. Billing and other customer-related activities can be shared between the gas and electric divisions when a utility serves its customers with both commodities. The value is set to 100% for Hydro One since they do not serve natural gas customers. We would expect a positive parameter estimate on this variable.

The **standard deviation of elevation** variable is calculated based on geographic information system ("GIS") elevation topography maps. A higher standard deviation of the elevation indicates increased elevation changes and variance within the utility's service territory. We would expect that a service territory with more hills, mountains, and other elevation changes would be more challenging and costly to serve, *ceteris paribus*. Therefore, a positive parameter estimate is expected (indicating a positive correlation between standard deviation of elevation and costs).

The **overhead percentage times percentage of forestation** variable is based on the overhead plant in service for each utility (for the percent overhead) and GIS land cover maps (for percent forestation). These maps used the GlobCover 2009 product produced by the European Space Agency ("ESA") and the Université Catholique de Louvain. These maps are matched with the areas served by each utility to create the forestation variable. We would expect that the higher the level of overhead lines and forestation, the higher OM&A costs required for right-of-way clearing and service restoration activities.

The **congested urban** variable measures the percentage of a utility's service territory that consists of a major urban load center that is "congested." Congested urban areas have physical constraints that necessitate complex and costly subterranean civil infrastructure for housing and operating electric distribution plant. Congested urban areas also often necessitate electrical equipment unique to such

[51] In the Hydro Ottawa research, Clearspring used a higher number for Hydro One's service area than PEG did. Clearspring used the value of the entire service area to match how the rest of the sample was calculated. PEG reduced this number substantially. We have used PEG's lower number to help reduce research differences and address one of the issues brought forth in the last Hydro One distribution proceeding.

[52] This is another advantage of the 10-year rolling average method. There is no bias if fewer than ten years for a utility are available since we are taking an average rather than a maximum of the peak demands.

subterranean infrastructure. The variable measures the percentage of service territory classified as "congested urban" area.[53]

We expect a utility that has a congested urban area within its service territory would experience substantial incremental costs as compared to a utility that does not have such an area within its service territory. The parameter value for this variable is expected to be positive, indicating a positive correlation of percent congested urban with total costs.

The **percentage of smart meters** variable measures the percentage of customers that have an installed smart meter. Smart meters enable hourly or sub-hourly interval use data to be collected from the meter. While installing more capable meters and the necessary infrastructure is expected to increase distribution costs, these meters enable time-of-use ("TOU") electricity rates that can create efficiencies mainly in the realm of power supply. Since this study is focused on distribution total costs, we would expect a positive coefficient on the percent smart meter variable.

The **distribution work variable** measures the percentage of transmission lines that are classified as transmission and are above 50 kV. This helps adjust for utilities classifying transmission and distribution assets differently. Some transmission utilities own lines that are below 50 kV and others do not. If the transmission system is taking on costs and serving lines that otherwise would be classified as distribution, this will tend to decrease costs for the distributor in that region relative to its peers. Likewise, if the distribution system is serving lines that would sometimes be classified as transmission for other utilities, this will tend to increase distribution costs for that utility relative to its sample peers. We use the 50 kV cut-off because this is the line used in the RRR reporting in Ontario between high voltage and low voltage. We would expect a positive correlation between distribution total costs and the percentage of lines above 50 kV served by the transmission utility.

The **time trend** variable captures a general industry total cost level trend over the studied period. Time trend variables are often found in translog cost functions and econometric total cost benchmarking research. In the present study, the variable is calculated by taking the current year of the observation and subtracting 1,999. For observations in the year 2000, the time trend variable equals 1. In 2019, the variable equals 20 (2,019 – 1,999). The coefficient value shows how adding an additional year increases or decreases total costs.

4.2 Distribution Sample

The distribution benchmarking sample is comprised of 81 U.S. utilities plus Hydro One.[54] The benchmark sample period begins in 2000 and extends to 2019. The sample is an unbalanced panel, which enables

[53] It is the same variable used in the most recent Toronto Hydro and Hydro Ottawa applications, with a few minor adjustments made in the Hydro Ottawa research. The variable is fully described in our Toronto Hydro report titled, "Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels". Our team, while at PSE, produced the report in EB-2018-0165. July 16, 2018.

[54] In Hydro One's prior distribution application, we included U.S. rural electric cooperatives in the benchmarking sample. However, to our knowledge, recent cooperative data is no longer being released publicly.

utilities that do not have available and plausible data for all sampled years to still be present in the sample for the years in which they do have available and plausible data. There are 1,572 U.S. utility observations in the sample. Including Hydro One there are 1,598 observations. This large number of observations enables robust parameter estimates and a strong statistical model.

The sample of utilities within the sample is provided in the following table.[55]

Table 5 Distribution Benchmarking Sample

Distribution Benchmarking Sample

Company	Number of Customers	Company	Number of Customers
Alabama Power Company	1,488,234	Madison Gas and Electric Company	156,833
ALLETE (Minnesota Power)	147,340	MDU Resources Group, Inc.	143,268
Appalachian Power Company	954,688	Metropolitan Edison Company	572,912
Arizona Public Service Company	1,260,115	Mississippi Power Company	188,342
Atlantic City Electric Company	558,559	Monongahela Power Company	391,968
Avista Corporation	390,059	Nevada Power Company	951,217
Baltimore Gas and Electric Company	1,299,421	New York State Electric & Gas Corporation	902,593
Black Hills Power, Inc.	73,084	Niagara Mohawk Power Corporation	1,396,454
Central Hudson Gas & Electric Corporation	258,977	Northern Indiana Public Service Company	473,221
Central Maine Power Company	639,993	Northern States Power Company - MN	1,491,047
Cleco Power LLC	287,921	Northern States Power Company - WI	261,093
Cleveland Electric Illuminating Company	752,471	Ohio Edison Company	1,052,921
Commonwealth Edison Company	4,048,298	Oklahoma Gas and Electric Company	854,128
Connecticut Light and Power Company	1,256,150	Orange and Rockland Utilities, Inc.	234,551
Consolidated Edison Company of New York	3,518,923	Pacific Gas and Electric Company	5,479,889
Consumers Energy Company	1,836,668	PacifiCorp	1,932,532
Delmarva Power & Light Company	529,284	PECO Energy Company	1,654,006
DTE Electric Company	2,208,925	Pennsylvania Electric Company	586,517
Duke Energy Carolinas, LLC	2,650,817	Pennsylvania Power Company	167,058
Duke Energy Florida, LLC	1,832,872	Portland General Electric Company	890,019
Duke Energy Indiana, LLC	840,116	Potomac Electric Power Company	889,380
Duke Energy Kentucky, Inc.	143,431	PPL Electric Utilities Corporation	1,450,006
Duke Energy Ohio, Inc.	722,911	Public Service Company of Colorado	1,499,395
Duke Energy Progress, LLC	1,590,969	Public Service Company of New Hampshire	520,866
Duquesne Light Company	600,804	Public Service Company of Oklahoma	557,421
El Paso Electric Company	429,191	Public Service Electric and Gas Company	2,285,737
Empire District Electric Company	174,520	Puget Sound Energy, Inc.	1,165,691
Entergy Arkansas, Inc.	713,080	San Diego Gas & Electric Co.	1,452,137
Entergy Mississippi, Inc.	450,377	South Carolina Electric & Gas Co.	739,385
Entergy New Orleans, Inc.	204,479	Southern California Edison Company	5,139,331
Florida Power & Light Company	5,061,510	Southern Indiana Gas and Electric Company	147,287
Gulf Power Company	464,882	Southwestern Public Service Company	394,669
Hydro One Networks	**1,420,879**	Tampa Electric Company	771,960
Idaho Power Co.	565,077	Toledo Edison Company	311,844
Indiana Michigan Power Company	596,731	Tucson Electric Power Company	428,626
Indianapolis Power & Light Company	507,576	Union Electric Company	1,230,246
Jersey Central Power & Light Company	1,138,696	Virginia Electric and Power Company	2,627,789
Kansas Gas and Electric Company	332,220	West Penn Power Company	727,552
Kentucky Power Company	165,461	Wisconsin Electric Power Company	1,138,054
Kentucky Utilities Company	556,129	Wisconsin Power and Light Company	476,494
Louisville Gas and Electric Company	415,853	Wisconsin Public Service Corporation	447,493

4.3 Distribution Model

The parameter estimates from the distribution total cost model are presented in the following table.

Table 6 Total Cost Model Estimates (Distribution)

Variable	Coefficient	Standard Error	T-Statistic	P-Value
Constant	13.0653	0.0235	555.8200	0.0000
Customers (N)	0.6319	0.0192	32.8500	0.0000
Peak Demand (D)	0.3392	0.0216	15.6800	0.0000
Area (A)	0.0547	0.0025	21.5400	0.0000
N*N	0.8638	0.0697	12.4000	0.0000
D*D	1.0755	0.0710	15.1400	0.0000
A*A	0.0392	0.0030	13.2800	0.0000
N*D	-1.8973	0.1413	-13.4300	0.0000
N*A	0.1254	0.0179	7.0000	0.0000
D*A	-0.1627	0.0200	-8.1300	0.0000
% Electric	0.1966	0.0169	11.6500	0.0000
Standard Deviation of Elevation	0.0221	0.0025	8.8600	0.0000
% OH*% Forest	0.0601	0.0021	28.6600	0.0000
% Congested Urban	13.7795	0.9436	14.6000	0.0000
% AMI	0.0729	0.0083	8.7600	0.0000
Dx Work (% Tx Lines Above 50 kV)	0.1148	0.0138	8.2900	0.0000
Trend	-0.0041	0.0011	-3.7200	0.0010

[55] Data shown is from the most recently available year for each utility. For most of the sample this is for the year 2019. For Hydro One, it is 2027.

All the parameter estimates are plausibly signed and have reasonable magnitudes. The first order terms of all variables have the theoretically expected signs and are statistically significant at a 90% level of confidence. In fact, all the first order explanatory variables are statistically significant at a 99% confidence level. The adjusted R-Squared of the model equals a robust 0.975.

4.4 Distribution Results

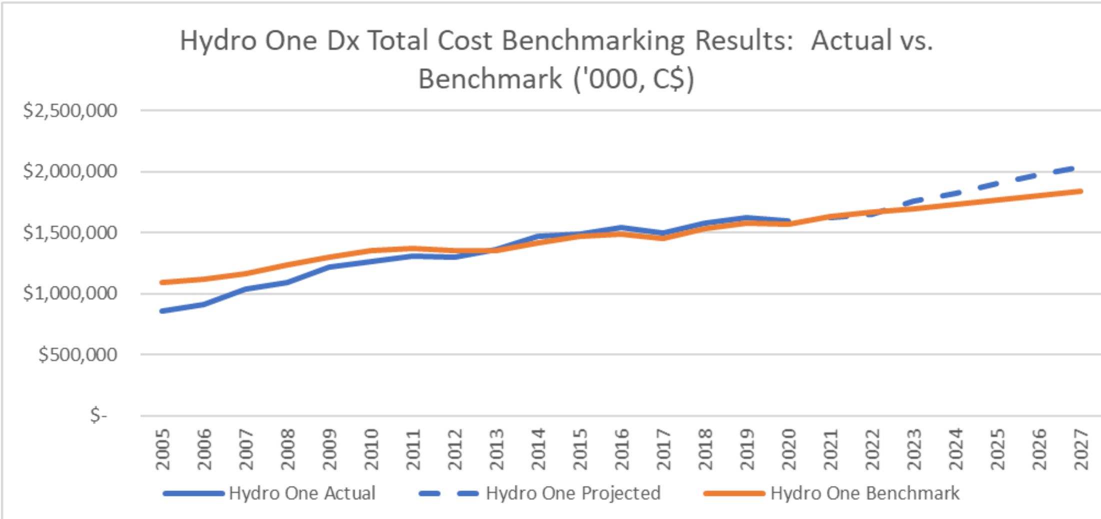
The following table breaks down the historical and forecast year benchmark and Company distribution total costs from 2005 through 2027. We note that the benchmark scores assume that all the proposed spending will be incurred. If spending is less than the proposed amounts, the scores will improve; if spending is more than the proposed amounts, the scores will get worse.

Table 7 2006-2027 Distribution Total Cost Benchmark Score for Hydro One

Year	% Difference from Total Cost Benchmark
2005	-24.4%
2006	-19.6%
2007	-11.3%
2008	-11.9%
2009	-7.0%
2010	-6.8%
2011	-4.7%
2012	-3.8%
2013	0.8%
2014	4.1%
2015	0.9%
2016	3.4%
2017	2.7%
2018	2.9%
2019	2.7%
2020	1.7%
2018-2020 average score	**2.5%**
2021	-0.6%
2022	-0.9%
2023	3.3%
2024	5.1%
2025	7.4%
2026	8.8%
2027	10.3%
2023-2027 average score	**7.0%**

The following graph displays how Hydro One's actual and projected distribution total costs have compared to the benchmark costs over time and through the Custom IR period, respectively.

Figure 10 Hydro One Distribution Total Cost: Actual vs. Benchmark



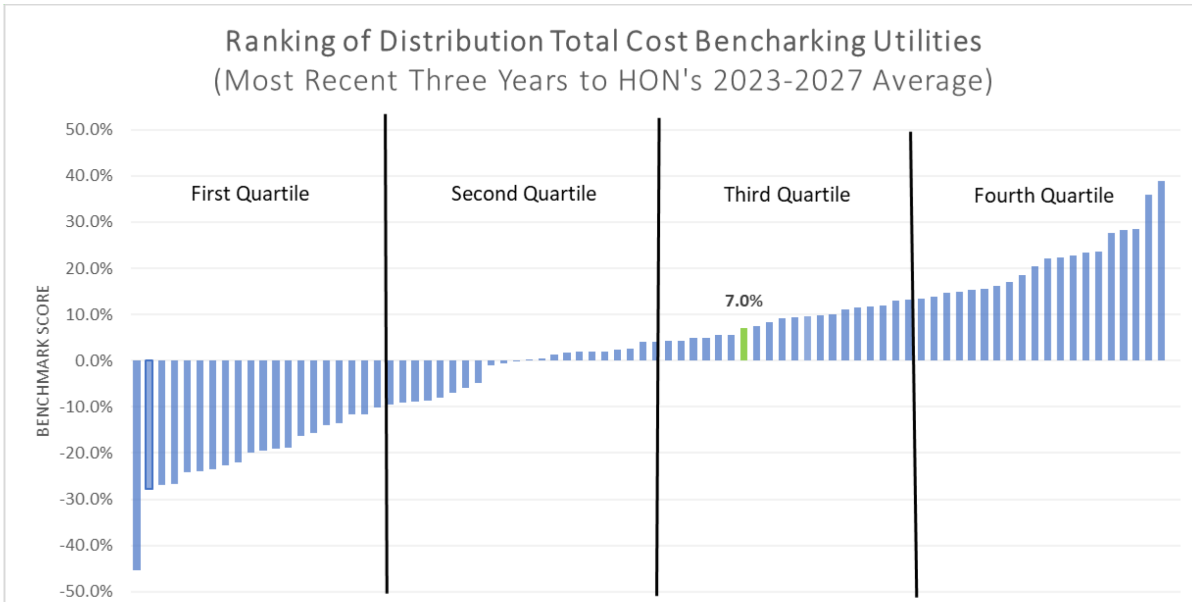
Hydro One's ranking among the benchmarking sample substantiates this total cost performance score. Clearspring ranked the distribution sample using the three-year distribution cost performance benchmarking score. Each utility in the sample received a distribution cost performance score; for every utility except Hydro One, the score was based on that utility's distribution costs in the most recent three years where data was available (compared to the model's expected costs). For Hydro One, the score was based on the average forecasted CIR costs from 2023 to 2027 (compared to the model's expected costs for those years). Hydro One ranks in the third quartile.[56] The Company ranks 49th out of the 82 utilities in the full sample.[57] Hydro One's position is noted with the green bar.

---

[56] The most recent three years for the sample are 2017 to 2019 for most of the utilities. This most recent three-year period is used to develop the ranking. Hydro One's benchmark score used is the average of 2023 to 2027. The Company would rank 40th in the entire sample if we used the 2017 to 2019 average for Hydro One.

[57] There are 81 U.S. utilities in the sample and adding Hydro One makes 82.

Figure 11 Ranking of Utilities by Distribution Total Cost Scores



4.5 Reasons for Different Transmission and Distribution Benchmark Results

In Hydro One's prior transmission application, the OEB Decision noted the different benchmark results for the transmission and distribution businesses of the Company and asked for an explanation for the different results to be provided at the next rebasing application.[58] A similar difference in benchmarking results persists through the current research found in this report. Hydro One's transmission operations have benchmark scores indicating a superior total cost performance, while Hydro One's distribution operations have benchmark scores that indicate a slightly above average level of total cost. The rest of this section provides some explanatory factors for this difference.

At a high level, Hydro One's transmission system is more similar to its peers and the benchmarking sample than the distribution system is with no available distribution model variables to adjust for this dissimilarity. The transmission system is vast and transmits electricity to rural, municipal, and urban centers. This is similar to many of the transmission utilities in the sample. However, Hydro One's distribution system is unique in serving remote areas, the density of its service territory, and having most of the lower-cost municipal and suburban areas not included within its service territory. This leaves Hydro One with the much higher-cost rural territories to which the Company is required to deliver electricity. This contrasts with its sampled peers whose service territories do include these lower cost suburban areas. Since Hydro One is the only utility with this disadvantage, we cannot develop a variable to adjust for this service territory condition present on the distribution system. Given this reality, we would expect the Company's transmission operations to score better than its distribution operations.

A further explanation of the differences in the benchmark results is the differences in the capital age results for transmission and distribution. Hydro One's transmission capital age is significantly older than

[58] OEB Decision in EB-2019-0082 at pg. 34.

the industry benchmark. Hydro One's distribution capital age is near the industry benchmark level. Older assets will be more depreciated and acquired at a lower cost level than newer assets. This difference in the capital age results helps explain the differences in the transmission and distribution total cost benchmark results.

Some additional underlying explanations for the differences in benchmark results could be the historical realities of Hydro One's distribution system. These historical facts of Hydro One's distribution system still may have a lasting impact on cost levels and, thus, the benchmark scores. In discussions with the Company, it is Clearspring's understanding that several mergers throughout the years (particularly at the turn of this century) meshed diverse systems together into one Company.

One challenge resulting from the historical mergers is that Hydro One has a distribution system that is comprised of many different voltage levels. Our understanding (based on information from the Company), is that these numerous voltage levels create cost challenges that would not otherwise exist (such as increased inventory requirements for station transformers and a need for a more diverse fleet of mobile unit substations). Most other distribution utilities in the sample do not have this historical challenge. This creates a disadvantage to Hydro One that is not being adjusted for within the benchmark model.[59] The transmission system does not have this same historical challenge of meshing different systems together on such a large scale; therefore, this could be a further explanation for the different performance results.

In its Decision in the last transmission application the OEB noted that it did not have the evidence to make conclusions on why the same company has different transmission and distribution benchmark scores,[60] and also noted that there are significant common costs allocated between the two operations. Although examining this allocation of common costs is outside the realm and scope of our research, we note that common costs are a relatively small percentage of the total costs being evaluated in our benchmarking research and are unlikely to be a significant reason for the benchmark score differences.

The benchmarking research deals with the transmission and distribution businesses of Hydro One independently. The models are separate, with a different sample, and a diverse set of variables in each model. However, if the transmission and distribution actual/proposed and benchmark costs for each study are summed to create a full Hydro One total cost benchmarking evaluation, the full Company has a strong total cost performance result of -18.2%. This result is despite the unadjusted cost challenges of having the low-cost service areas cut out of the Company's distribution service area and the historical challenges resulting from the turn of the century mergers.

[59] Distribution line voltage data is not available for the sample to create a variable that could adjust for this.

[60] See p. 33 of the Decision and Order dated April 23, 2020 in EB-2019-0082.

5 Capital Age

The capital age research examines plant addition and retirement data going back to 1948 to calculate and benchmark the capital age of assets, on an overall basis, within the transmission and distribution industries. Clearspring undertook this research to provide further information and context around both the cost benchmarking and TFP studies conducted and discussed throughout this report.

The age of assets will have a large impact on the costs and measured productivity of the utility and industry. A utility which runs its system with an older asset age, all else being equal, will tend to have lower costs due to depreciation and asset inflation. One probable explanation for Hydro One's strong transmission total cost benchmark score is that the Company has an older capital age than the industry.

Regarding the industry TFP trend, even when the transmission industry capital age remained at the same level during the years of 2000 to 2012, the TFP trend was still negative during that same period. This indicates that overall cost challenges for transmitters may be increasing over time. This negative TFP trend is more pronounced in the recent years when the industry has made investments to lower the capital age.

These calculations are conducted using the financial reporting data provided by utilities in the sample since 1947. This is different than using physical asset reports, which would report actual vintages and ages of assets. We use the financial reporting data, along with certain assumptions, to calculate and ascertain a comparison of the capital age of Hydro One to the industry, and the direction both are moving. The capital age calculations are conducted independently of the total cost benchmarking and TFP research.

The sample used for the industry capital age calculations is the same as the benchmarking sample for the corresponding industry (transmission or distribution).[61] To calculate the transmission industry capital age, we used the transmission total cost benchmarking sample, which includes 59 U.S. transmission utilities. For the distribution industry capital age, we used the distribution total cost benchmarking sample, which includes 81 U.S. distribution utilities.

5.1 Capital Age Methodology

There are three steps in the capital age methodology:

1. Calculate the plant in service amounts for each utility in each year in the applicable industry (transmission or distribution).[62] The vintages are calculated by using the additions for a given year as the value for plant in service in the year those additions were placed in service for all

[61] Both the transmission and distribution capital age calculations include an allocated portion of general plant. This is the same approach as the total cost benchmarking research. General plant will tend to have a lower capital age, thus lowering the measured transmission or distribution capital age.

[62] Like the benchmarking studies, the plant in service calculation includes an allocated amount of general plant for both transmission and distribution. This allocation is based on the ratio of transmission plant to total net of general plant for the transmission capital age study and on the ratio of distribution plant to total net of general plant for the distribution study. Both additions and retirements include this allocated portion of general plant.

calculations in subsequent years, and subtracting retirements recorded in that year from the earliest year that still has a remaining positive value of plant in service.

2. Transform the plant in service vintage estimates to capital quantity vintages by dividing by an asset price deflator in the same year as the plant in service (this is the same asset price deflator used in the benchmarking research). These capital quantity vintages are then used to calculate the average capital age of each utility in the year the calculation is being made.

3. Using the capital age estimates for each utility, an industry weighted average is calculated to determine the transmission or distribution industry age benchmark.

More details for each of these three steps are provided in Appendix B.

5.2 Capital Age Results

The capital age results provide a comparison of Hydro One's capital age, on an overall basis, for both transmission and distribution to the U.S. industry. They also provide a viewpoint in how the capital age is changing over time for Hydro One and the industry, and how the Company's capital age is projected to change based on the proposed investment levels during the CIR period. We note that Hydro One's capital age results will be the most comparable to the U.S. sample in more recent or projected years and less comparable in the earlier years. The same is true for examining the trend in the capital age variable for Hydro One.

5.2.1 Transmission Capital Age

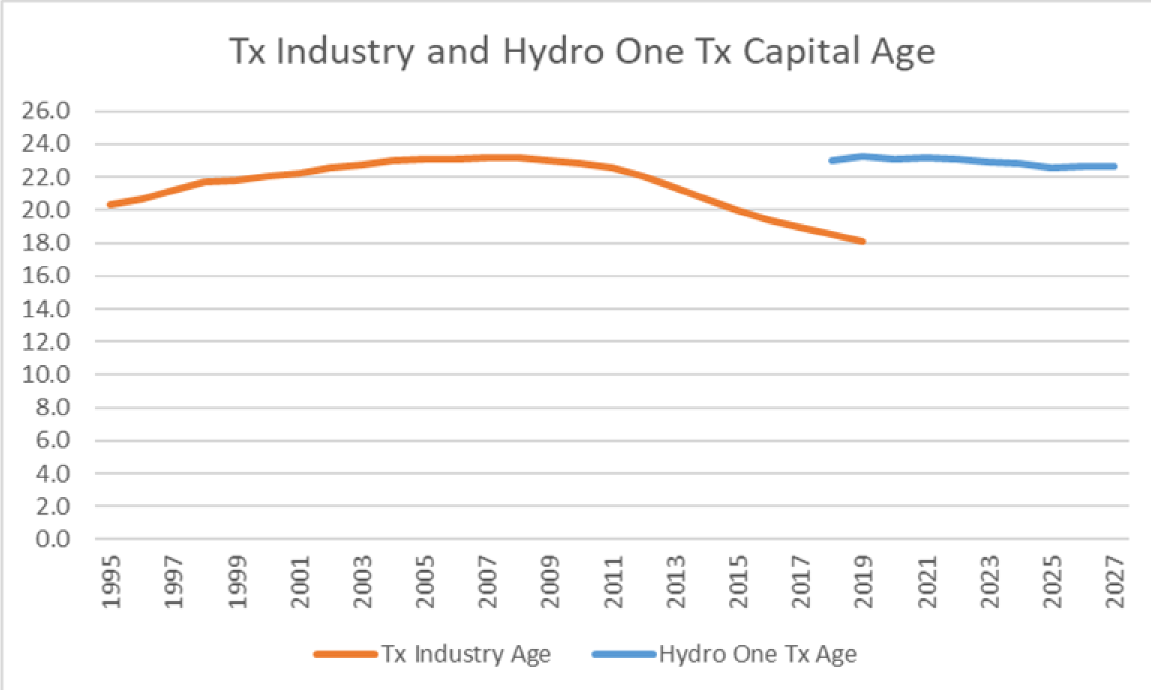
The following table and graph display the U.S. sample aggregate capital age for the transmission industry by year beginning in 1995 through 2019. The table also displays Hydro One's transmission capital age beginning in 2018 through 2027.[63]

[63] This provides 15 years for Hydro One's retirement and additions data to reduce the comparability issues resulting from using the 2003 vintage data to compensate for the lack of historical retirement/addition data prior to 2003.

Table 8 U.S. Sample and Hydro One Transmission Capital Age

Year	U.S. Transmission Industry	Hydro One
1995	20.3	
1996	20.7	
1997	21.2	
1998	21.7	
1999	21.8	
2000	22.0	
2001	22.2	
2002	22.5	
2003	22.7	
2004	23.0	
2005	23.1	
2006	23.1	
2007	23.2	
2008	23.2	
2009	23.0	
2010	22.8	
2011	22.6	
2012	22.0	
2013	21.4	
2014	20.7	
2015	20.0	
2016	19.4	
2017	19.0	
2018	18.5	23.0
2019	18.1	23.2
2020		23.1
2021		23.2
2022		23.1
2023		22.9
2024		22.8
2025		22.6
2026		22.7
2027		22.7

Figure 12 U.S. Sample and Hydro One Transmission Capital Age



Hydro One's transmission capital age during the CIR period is significantly older than the industry's latest capital age value in 2019. Throughout the CIR period, Hydro One's age is above 22.5 years compared to 18.1 years for the industry in 2019. The Company's older transmission capital age is likely one of the main contributors to the Company's strong transmission total cost benchmarking result. Thus far, the Company has been able to maintain this older capital age even while the industry at large substantially increased capital investments and has gotten younger. Combined with the total cost benchmarking results, this capital age result seems to indicate the Company's capital spending proposal is maintaining assets at a relatively older age than the industry can and is resulting in total cost levels considerably lower than our models expect.

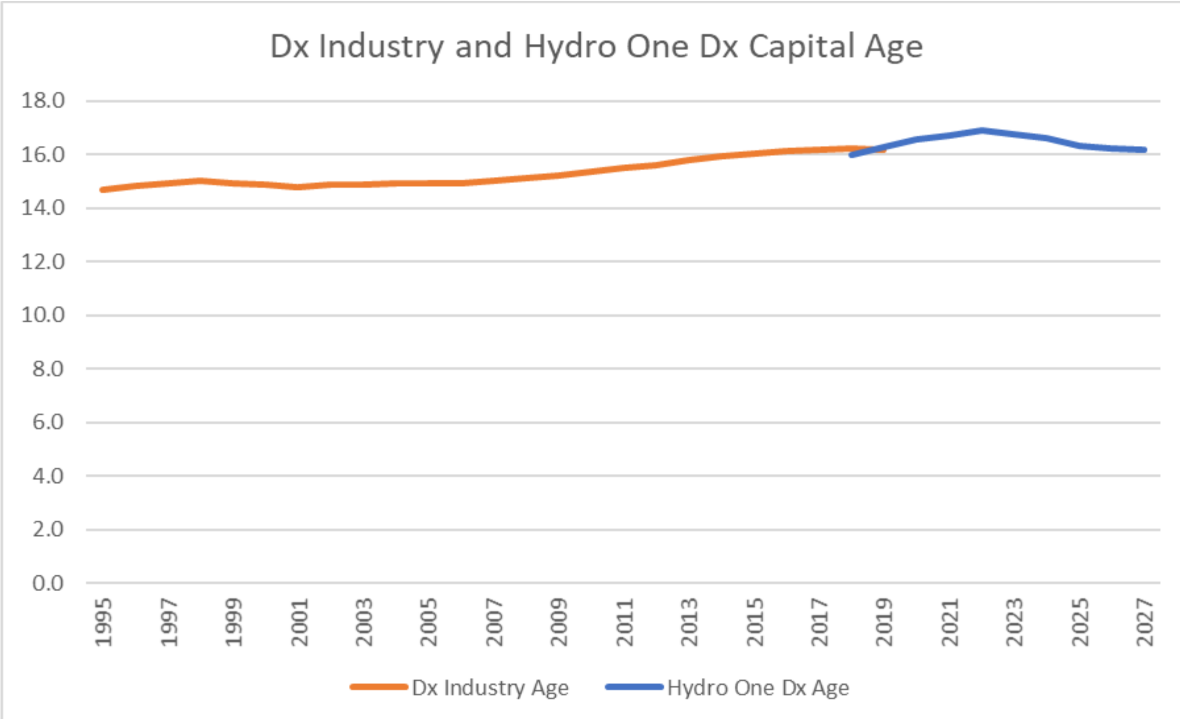
5.2.2 Distribution Capital Age

The following table and graph display the U.S. sample aggregate capital age for the distribution industry by year beginning in 1995 through 2019. The table also displays Hydro One's distribution capital age beginning in 2018 through 2027.[64]

Table 9 U.S. Sample and Hydro One Distribution Capital Age

Year	U.S. Distribution Industry	Hydro One
1995	14.7	
1996	14.8	
1997	14.9	
1998	15.0	
1999	15.0	
2000	14.9	
2001	14.8	
2002	14.9	
2003	14.9	
2004	14.9	
2005	14.9	
2006	14.9	
2007	15.0	
2008	15.1	
2009	15.2	
2010	15.4	
2011	15.5	
2012	15.6	
2013	15.8	
2014	15.9	
2015	16.0	
2016	16.1	
2017	16.2	
2018	16.2	16.0
2019	16.2	16.3
2020		16.6
2021		16.7
2022		16.9
2023		16.8
2024		16.6
2025		16.3
2026		16.3
2027		16.2

Figure 13 U.S. Sample and Hydro One Distribution Capital Age



Hydro One's distribution capital age during the CIR period is near the industry's latest capital age value in 2019. In 2027, Hydro One's age is equal to the latest available benchmark from the industry in 2019. This aligns with our distribution total cost benchmarking finding showing slightly above average cost.

Part of the explanation for the capital age result is the second generation of AMI being deployed during the CIR period. AMI meters tend to have lower service lives than their traditional counterparts and other assets found within the distribution industry. This results in higher proposed plant additions and retirements relative to utilities without AMI or utilities not investing in their second generation of AMI.[65] For context, if the AMI 2.0 project was not planned for during the CIR period, Hydro One's capital age in 2027 is estimated to be 17.3 compared to 16.2 with AMI 2.0. Absent AMI 2.0, Hydro One's distribution capital age would slightly increase during CIR and in 2027 would be 6.8% older than the industry's most recent benchmark in 2019.

---

[64] This provides 15 years for Hydro One's retirement and additions data to reduce the comparability issues resulting from using the 2003 vintage data to compensate for the lack of historical retirement/addition data prior to 2003.

[65] This is not to say that AMI investments are not economic from a societal perspective. AMI can have benefits to society that are not captured directly by the distribution utility. This includes TOU pricing and the impact on generation costs.

6 Transmission Industry Total Factor Productivity

External industry total factor productivity ("TFP") trends form the basis for the base productivity factor ("Base PF") used in the proposed CIR formula. The Base PF should be based on an external measure of the industry TFP trend. Hydro One should have no impact on the measured industry TFP trend. This is because incentive regulation seeks to decouple the link between a utility's costs to the allowed revenue escalation. If a utility's own TFP is used within the formula, it will weaken the incentives to enhance productivity and reduce costs.

Clearspring employed a sample of U.S. transmission utilities to calculate the TFP trends of the industry starting in a base year of 2000 and going through 2019. The sample is comprised of 50 U.S. transmission utilities and is shown in the table below.[66]

[66] This table shows both the transmission benchmarking and TFP samples. The TFP sample includes all of the utilities on this table except those with an asterisk. The reason the nine utilities (plus Hydro One) are excluded is because the TFP trend calculations require every utility to have a good observation for every year of the sample period, whereas the benchmarking research does not have this requirement. Hydro One is excluded from the TFP trend sample because excluding it will assure the TFP trend result is fully external to the performance of the Company and the Company does not have available data beginning in 2000.

Table 10 Transmission Benchmarking and TFP Sample

Transmission Benchmarking and TFP Sample

Company	10-Year Average Peak Demand	Tx Line Lengths (KM)	Company	10-Year Average Peak Demand	Tx Line Lengths (KM)
Alabama Power Company	11,578	17,307	Kansas Gas and Electric Company	2,445	4,250
ALLETE (Minnesota Power)*	1,586	4,608	Kentucky Utilities Company	4,488	6,537
Appalachian Power Company	7,517	10,449	Louisville Gas and Electric Company	2,627	1,475
Arizona Public Service Company	7,159	10,106	MDU Resources Group, Inc.	568	5,446
Atlantic City Electric Company*	2,651	2,210	Mississippi Power Company	2,588	3,589
Avista Corporation	1,668	3,610	Monongahela Power Company	2,002	3,613
Baltimore Gas and Electric Company*	6,767	1,490	Nevada Power Company	5,781	3,060
Black Hills Power, Inc.	430	1,244	New York State Electric & Gas Corporation	2,947	7,317
Central Hudson Gas & Electric Corporation	1,129	964	Niagara Mohawk Power Corporation	5,960	17,611
Central Maine Power Company	1,586	4,677	Northern States Power Company - MN	7,604	9,239
Cleco Power LLC	2,471	2,204	Oklahoma Gas and Electric Company	6,657	9,665
Commonwealth Edison Company	21,525	8,015	Orange and Rockland Utilities, Inc.	1,401	889
Consolidated Edison Company of New York	5,070	837	PacifiCorp	10,148	28,350
Duke Energy Carolinas, LLC	17,526	13,329	PECO Energy Company	8,491	2,041
Duke Energy Florida, LLC	9,706	8,354	Potomac Electric Power Company	6,134	1,285
Duke Energy Indiana, LLC	5,885	8,548	PPL Electric Utilities Corporation	7,440	7,244
Duke Energy Progress, LLC	13,171	10,082	Public Service Company of Colorado	6,519	7,721
Duquesne Light Company	2,834	1,075	Public Service Company of New Hampshire	1,641	1,675
El Paso Electric Company	1,804	2,976	Public Service Company of Oklahoma	4,152	5,026
Empire District Electric Company	1,144	2,287	Public Service Electric and Gas Company	10,079	3,237
Entergy Arkansas, Inc.	5,402	8,350	Rochester Gas and Electric Corporation	1,594	1,761
Entergy Mississippi, Inc.*	3,134	5,041	San Diego Gas & Electric Co.	4,530	3,402
Entergy New Orleans, Inc.*	1,071	266	South Carolina Electric & Gas Co.*	4,776	5,915
Florida Power & Light Company	22,956	11,713	Southern California Edison Company	22,502	23,378
Gulf Power Company	2,521	2,739	Southern Indiana Gas and Electric Company	1,224	1,654
Hydro One Networks*	**21,830**	**20,788**	Southwestern Public Service Company*	4,821	12,473
Idaho Power Co.*	3,250	7,692	Tampa Electric Company	3,865	2,164
Indianapolis Power & Light Company	2,853	1,390	Tucson Electric Power Company	2,489	3,523
Jersey Central Power & Light Company*	6,079	4,181	Union Electric Company	7,716	4,115
Kansas City Power & Light Company	3,511	2,919	West Penn Power Company	3,941	3,510

*In Benchmark Sample but not TFP Sample

6.1 Methodology

The output variables, input prices, and cost definitions used for the analysis match those used in the transmission total cost benchmarking research. The only major refinements from the prior transmission TFP research that we conducted in EB-2019-0082 includes modifying the peak demand output definition to the ten-year rolling average and moving the examined sample period back to 2000. Both modifications match the research methodology used for the transmission benchmarking study.[67]

Productivity is defined as the ratio of an output quantity index to an input quantity index. In the case of TFP, the Input Quantity Index includes both capital and OM&A inputs.

$$Productivity = \frac{Output\ Quantity\ Index}{Input\ Quantity\ Index}$$

[67] Please see Section 2.1 for a description of why these two modifications were made.

The output quantity index measures the level of output produced by the utility or industry. The input quantity index measures the level of resources used, such as labour, non-labour OM&A, or capital inputs. Clearspring employs commonly used indexing techniques to capture a comprehensive measure of outputs and inputs, which are in turn used to calculate the productivity term. We then examine how this productivity ratio changes over time to determine the productivity index trend.

The input quantity index is comprised of resources, such as OM&A labour, OM&A materials, and capital stock. The output quantity index in this study includes: (1) kilometers of transmission lines, and (2) 10-year rolling average of peak demand. These two outputs are combined into one output index using cost elasticity weights derived from the transmission total cost econometric model.

The TFP trend is the difference between the annual growth rate in the output quantity index and the input quantity index.

$$\boldsymbol{TFP\ trend = Output\ Quantity\ trend - Input\ Quantity\ trend}$$

It may be helpful to note that TFP trend measurement differs from total cost benchmarking. With cost benchmarking, utilities are compared relative to the average efficiency level of other utilities within the industry. Conversely, TFP trends measures how productivity is changing over time for that same industry or utility.

6.1.1 Output Quantity Index

This section describes the TFP output quantity index calculations. Clearspring used the same definition of outputs for the transmission TFP study as we did for the transmission total cost benchmarking study. There are two outputs: kilometers of transmission lines and 10-year rolling average peak demand.

The two outputs need to be combined into one output quantity index. We accomplished this using output weights derived from the econometric total cost model. The weights are 36.6% and 63.4% for KM of line and 10-year rolling average peak demand, respectively.

The two components of the output quantity index for the industry are provided in the following tables. After combining the components, the overall index is provided in the last column.

Table 11 Outputs for the U.S. Industry (Sum of Industry)

Year	KM of Line	Peak Demand	Output Quantity Index
2000	274,815	254,303	1.000
2001	277,846	256,766	1.010
2002	275,583	258,126	1.011
2003	279,327	261,779	1.025
2004	278,234	266,078	1.036
2005	279,193	271,584	1.051
2006	282,986	277,699	1.072
2007	285,486	283,377	1.090
2008	286,091	287,448	1.102
2009	285,843	289,767	1.108
2010	287,110	293,216	1.118
2011	288,316	296,114	1.127
2012	291,320	298,043	1.136
2013	292,641	298,898	1.140
2014	295,024	300,369	1.147
2015	296,872	300,093	1.148
2016	296,435	298,686	1.144
2017	299,331	296,179	1.141
2018	303,004	296,586	1.146
2019	305,952	296,977	1.151
Average Annual Growth Rate			
2000-2019	**0.6%**	**0.8%**	**0.7%**
2010-2019	**0.7%**	**0.1%**	**0.3%**

The transmission industry has experienced output growth around 0.7% per year for the entire output quantity index (2000 to 2019). However, since 2010, the peak demand component of output growth has experienced a slowdown. Over the last 9-year period, it has basically remained flat. This contrasts with transmission line lengths, which have shown relatively steady growth over the sample period.

6.1.2 Input Quantity Index

The input quantity index is comprised of the OM&A quantity and capital quantity. These two measures are then combined using Tornqvist indices based on using the cost shares of each input component. Tornqvist indices are a commonly used indexing methodology, and this is the same approach used in all our prior research.

The OM&A quantity used in the TFP calculation is derived by dividing annual OM&A expenses in year t by the OM&A input price index in year t. Clearspring used the same cost and price definitions for both the TFP and the benchmarking research.

$$OM\&A\ Quantity_t = \frac{OM\&A\ Expenses_t}{Input\ Price\ Index_t}$$

Clearspring used the same procedures in both the benchmarking and productivity research for the capital quantity index, using the Perpetual Inventory Method with a capital benchmark year of 1947 for most of the sample.[68]

The transmission industry's input quantity index is provided in the tables following. The table displays the industry capital quantity index, OM&A quantity index, and then the combined input quantity index from 2000 to 2019.

[68] Please see the section on the Perpetual Inventory Method found in Appendix A.

Table 12 Input Quantities for the U.S. Transmission Industry

Year	Capital Quantity Index	OM&A Quantity Index	Input Quantity Index
2000	955,067	1,702,118	1.000
2001	953,406	1,722,159	1.001
2002	947,164	1,707,804	0.994
2003	953,267	1,776,286	1.007
2004	953,688	2,408,508	1.080
2005	954,028	3,038,175	1.151
2006	964,467	2,868,448	1.141
2007	974,163	2,639,278	1.124
2008	985,250	2,817,461	1.153
2009	1,003,211	2,665,172	1.153
2010	1,028,740	2,878,763	1.197
2011	1,051,164	2,637,361	1.192
2012	1,099,639	2,671,856	1.237
2013	1,153,733	2,721,290	1.289
2014	1,216,944	2,721,180	1.343
2015	1,276,156	2,848,585	1.408
2016	1,325,140	3,036,530	1.470
2017	1,361,708	3,004,692	1.498
2018	1,406,083	3,250,116	1.563
2019	1,452,627	3,009,862	1.576
Average Annual Growth Rate			
2000-2019	**2.2%**	**3.0%**	**2.4%**
2010-2019	**3.8%**	**0.5%**	**3.1%**

The input quantity index has been growing at a faster rate than the output quantity index during the 2000 to 2019 period, and even more during the 2010 to 2019 period. The trend in the capital quantity index has been driving the recent TFP declines that the industry has been experiencing for the last decade. This aligns with the capital age research, showing that the industry is making large capital investments that are lowering the overall system age of the transmission systems.

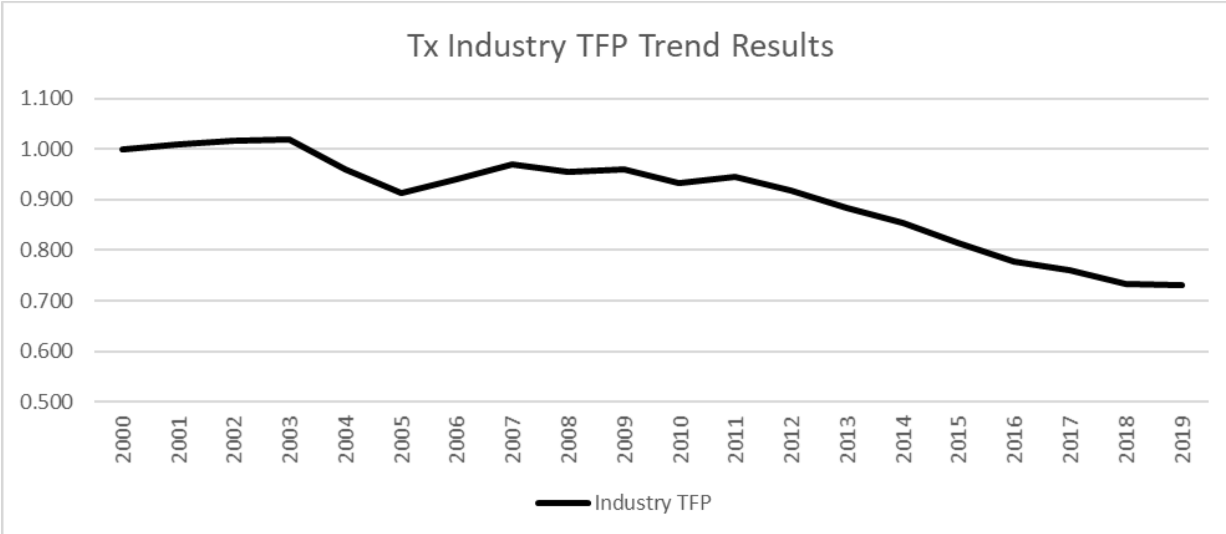
6.2 Transmission TFP Results

The transmission TFP trend results are provided in the following table and displayed graphically in the following figure.

Table 13 Transmission Industry TFP Results

Year	Industry TFP Index	Industry TFP Growth Rate
2000	1.000	
2001	1.009	0.9%
2002	1.017	0.8%
2003	1.018	0.1%
2004	0.959	-6.0%
2005	0.913	-4.9%
2006	0.940	2.8%
2007	0.970	3.2%
2008	0.956	-1.5%
2009	0.961	0.5%
2010	0.934	-2.8%
2011	0.946	1.3%
2012	0.918	-3.0%
2013	0.884	-3.8%
2014	0.854	-3.5%
2015	0.816	-4.6%
2016	0.778	-4.7%
2017	0.762	-2.1%
2018	0.733	-3.8%
2019	0.730	-0.4%
Average Annual Growth Rate		
2000-2019		**-1.66%**
2010-2019		**-2.74%**

Figure 14 Transmission Industry TFP Results



Clearspring calculated the total factor productivity trend for the industry from 2000 to 2019. This nineteen-year period resulted in an average annual decline in industry TFP, with an annual growth rate of -1.66%. Since 2010, the industry TFP has declined at an even higher rate, with an average annual growth rate of -2.74%. Based on OEB precedent, the Base PF is to be set at no lower than 0.0%. However, we note that a PF equal to 0.0% is tantamount to an exceptionally large stretch factor.

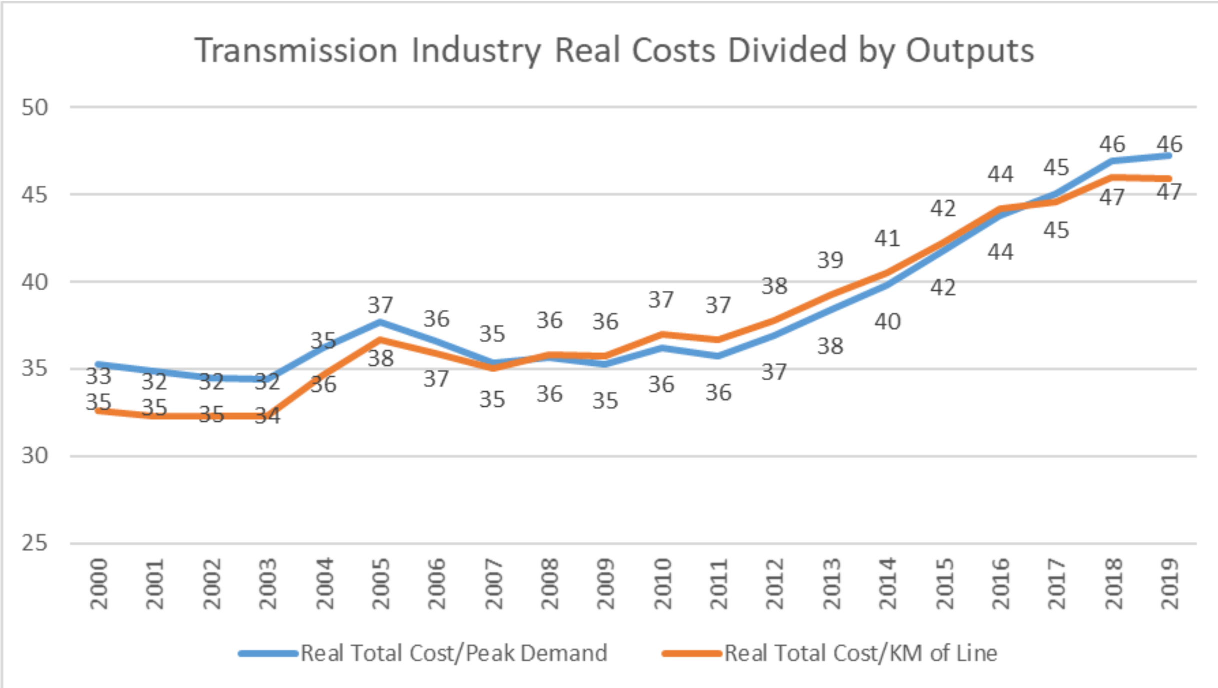
6.3 Interpretation of Negative TFP Growth

A negative industry TFP trend implies higher electricity costs for the industry (beyond inflationary cost increases). The OEB addressed this possibility in the Board's Decision dated November 21, 2013 in EB-2010-0379 (page 17):

> The Board acknowledges that achieved industry TFP may be negative due to unforeseen events and/or situations in which costs may be incurred with no corresponding increase in output.

The unit cost trends of the transmission industry may help to illustrate the negative TFP trends that are prevalent in the industry during recent years. In the following graph, we display the industry's sum of real transmission total costs (i.e., total costs adjusted for inflation) divided by the industry's sum of each of the two major outputs (peak demand and KM of line).

Figure 15 Transmission Industry Real Costs Divided by Outputs



The transmission industry's real unit costs have increased substantially from the early 2000s to now. There appears to be higher cost pressures on utilities now than twenty years ago. The most pronounced increase in real unit costs also occurred during a period when the capital age of the industry became younger. This is part, but not all, of the explanation.

It is important to note that a negative TFP growth rate does not necessarily indicate declining efficiency, at either the industry or the utility level. Recall that the TFP trend equals the Output Quantity Index trend minus the Input Quantity Index trend. Negative TFP trends indicate that measured outputs are growing slower than inputs.

While declining efficiency is certainly one possibility when observing negative TFP trends, there are several other possibilities. Systemic possibilities include:

1. The increasing of "outputs" that are not being measured within the TFP calculation. While Clearspring's output measure incorporated two key outputs of a transmission utility, there are other valued utility functions that are difficult, if not impossible, to incorporate and quantify. These other valued functions could include reliability, cybersecurity, safety, meeting increased regulatory requirements, increasing generation interconnections from wind or solar, providing enhanced environmental stewardship, geomagnetic disturbances, and increasing other aspects of power quality and security.

2. External circumstances can change over time. One circumstance often found in modern western economies is slower growth. For some countries, output growth has slowed due to more energy efficient appliances and machinery, and conservation programs. This has slowed the growth in

peak demands (in kW). Since the TFP trend is a function of the output index, this slower growth will tend to slow down TFP.

3. A common external circumstance that is changing across the electric industry, but is problematic to quantify, is the aging of capital infrastructure. Due to the post-World War II population boom and increasing use per customer during the 1950s, 60s, and 70s, utilities needed to heavily invest in capital infrastructure to meet the higher peak demands (unlike the current situation, in the past utilities were able to fund much of this investment through increasing billing determinants rather than higher prices). We notice in the capital age research for the transmission industry that capital expenditures have been made in recent years to lower the capital age of the industry. These added capital expenditures have lowered the TFP trend of the industry. However, we note that this does not fully explain the negative TFP trends since even during a period when the capital age of the industry was getting older, the industry was still experiencing slightly negative TFP trends.

7 Capital Costs Impact on OM&A Expenses

In the most recent Hydro One transmission application in EB-2019-0082, the OEB Decision stated in the Conclusion on p. 183: "Provide a high level assessment of the correlation, or lack of same, between capital investments and OM&A costs at the program level in future rate applications." Hydro One requested that Clearspring use the econometric model dataset to investigate if correlations are evident in the data between transmission or distribution capital investments and their corresponding OM&A costs.

There may be lengthy lags between when capital increases and when those investments result in OM&A cost savings. Further, increased capital investments may signal the utility doing more for its customers (i.e., increasing unmeasured outputs), and this increased output could translate into higher OM&A expenses rather than a reduction. As the capital age research can also show, increased capital investments do not necessarily mean that the overall capital age of the system is being lowered. If those increased capital investments are merely maintaining the system age, it would not be expected that OM&A expenses would decline since the capital age is not being reduced by the investments.

These realities complicate the development of models that estimate the relationship between capital and OM&A spending. While more research could be conducted to examine the empirical relationship between capital spending increases and OM&A impacts, we were not able to uncover a clear relationship in our initial research.

The table below summarizes the model results by showing the sign on the capital age variable and if the parameter value on it is statistically significant at a 90% confidence level. If OM&A levels decline as age declines, we would expect to see a positive coefficient value. For the full model details, please see Appendix C.

Table 14 OM&A and Capital Age Model Results

Model	Parameter Value on Capital Age	Significant at 90% Level?
Transmission 1: No Lag in OM&A	-0.197	No
Transmission 2: One-Year Lag in OM&A	-0.164	No
Transmission 3: Five-Year Lag in OM&A	+0.069	No
Distribution 1: No Lag in OM&A	-0.043	No
Distribution 2: One-Year Lag in OM&A	-0.092	No
Distribution 3: Five-Year Lag in OM&A	-0.058	No

7.1 Capital Costs Impact on OM&A Expenses Conclusion

The six models do not display a consistent empirical story and do not provide evidence that OM&A spending should be expected to decrease through increased capital spending, even as the capital age of the system starts to get younger. The only model that displays a positive correlation between OM&A changes and capital age changes was Transmission Model 3. All other models display an inverse relationship; that is as capital age decreases, OM&A increases. All the model coefficients for the capital age variable were found to be statistically insignificant from zero.

Therefore, with this initial research on this topic, Clearspring is unable to identify a consistent correlation in both the transmission and distribution datasets that aligns with the theory that as capital investments increase enough to reduce capital age, OM&A should decrease. In the case of Hydro One’s capital age and its proposed change during the CIR period, this may be a moot point, given that the proposed capital investment levels are not expected to reduce the Company’s overall system age to any significant degree.

Appendix A: Total Cost Benchmarking Methodology Details

Variable Types

In general, there are two types of variables used in econometric cost benchmarking: output variables and business condition variables. Output variables measure the output of the utility in question (i.e. what the utility "produces"). Business condition variables quantify the factors that drive costs in a particular service territory, such as regional input prices, highly congested urban areas, forestation, etc.

Output Variables

The two output variables for the transmission benchmark study are the length of transmission lines and a rolling ten-year average of peak demand. This matches the output variables used in the prior Hydro One transmission research, with the exception the peak demand variable definition is now defined as a rolling ten-year average. This change addresses concerns that as it was defined in previous studies, the peak demand could never decrease.

The three output variables for the distribution benchmark study are the number of customers, a rolling ten-year average of peak demand, and the service area of each utility. This matches the outputs specified in PEG's response to Clearspring's model in the last distribution application for Hydro Ottawa (again, with the modification of the peak demand variable).

For the U.S. utilities, the output variables are calculated from FERC Form 1s. The customers and line lengths are based on the reported data. The peak demand variable is defined for both studies using the annual peak demand value found on p. 401b of the FERC Form 1.[69] This variable consists of the distribution system peak demands plus the required sales for resale. For the transmission study, we did not modify the variable from what is reported in the FERC Form 1. For the distribution study, we adjusted the data to take out the proportion of the required sales for resale. This aligns with the treatment of peak demand that both Clearspring and PEG undertook in the Hydro Ottawa application.

The service area used for each utility is based on variables derived from GIS mappings of each utility's service area. For the U.S. utilities, the values used correspond to what both Clearspring and PEG used in the last Hydro Ottawa application. In the Hydro One Distribution application, one of the concerns brought forth by the intervenors and OEB Staff and mentioned in the Board Decision was the service area value used for Hydro One. In response to those concerns, we have reduced Hydro One's service area to the value used by PEG in its Hydro Ottawa benchmarking research. This reduced the service area variable

[69] In our prior study for Hydro One Transmission, we used the Transmission peaks listed on p. 400 of FERC Form 1. However, this data is not reported prior to 2004, and PEG used the p. 401b data as they thought that may be more suitable, given that some demands are not firm and would not correlate with costs. We see pros and cons with each approach. In an effort to reduce research differences, we use the peak demand data preferred by PEG. This also enables us to roll back the start year to 2000.

value from 961,498 square kilometres served to 651,974 square kilometres served.[70]

Business Condition Variables: Input Prices

Business condition variables are discussed in following sections. However, one important business condition variable merits detailed discussion: input prices. Input prices are divided into two categories: capital and OM&A. The capital input price calculation used in our research is called the Perpetual Inventory Method and is discussed in detail in a following section. The OM&A input price captures the regional market price level that each utility encounters when procuring OM&A inputs, such as employees or materials and services. There are two components used to construct the OM&A input price. These are labour and non-labour.

The labour component is calculated by taking wage levels of numerous job occupations and weighting them based on the U.S. Bureau of Labor Statistics ("BLS") estimates of job occupation weights in the Electric Power Generation, Transmission, and Distribution Industry. The BLS has estimates for wage levels for each job occupation by city and metropolitan area. For Hydro One, we gathered job occupation wage estimates from the 2011 Canadian Census, using wage data reported for Ontario, translated job occupations to match their U.S. counterparts, and then weighted the job occupation wages by the BLS estimates. This provides consistency from the U.S. and Ontario regarding labour input prices and also puts the input price in terms of each country's currency. We then escalated labour prices for U.S. utilities using BLS employment cost indices for the utility sector and escalated Hydro One prices using the Ontario average weekly earnings estimates.

The non-labour component of the OM&A input price uses the U.S. gross domestic product price index for the U.S. utilities. The Hydro One non-labour component uses the Canadian GDP-IPI in each year, but with a levelization adjustment using the purchasing power parity ("PPP") index in 2012. This translates the non-labour input price component into Canadian dollars.

To construct the overall OM&A input price we weighted each index using the customized labour and non-labour cost shares calculated from the FERC Form 1 data or based on data provided to us from Hydro One. We then took the OM&A input price and combined it with the capital price using the capital and OM&A cost shares. This produces the total input price index.

Total cost is divided by this comprehensive input price index to adjust for regional input price differences between utilities and to account for annual inflation. Dividing total cost by the input price index imposes the requirement that total costs display linear homogeneity with respect to input prices. As the prices of inputs increase by X%, total cost should increase by that same percentage. For example, if all utility input prices (including labour) increase by 10%, its costs would also increase by 10%. This is derived from economic production theory, which states that costs equal input quantity multiplied by input price.

[70] The rest of the U.S. sample includes all of the service territory, even if there are no customers within that area.

Other Business Condition Variables

Beyond the output variables and input prices, each model contains business condition variables that provide cost adjustments for given service territory conditions. These variables enable unique service territory conditions to be accurately benchmarked on an "apples to apples" basis. This ability to adjust for specific conditions is why the econometric benchmarking approach is more accurate and fair than unit cost approaches. Unit cost benchmarking tends to only reveal which utility has the most challenging service territory, rather than indicating cost performance. This is because service territory conditions have a profound impact on the cost levels of transmission and distribution utilities. Their capital assets are spread across the entire service territory, and the overall cost levels are thus highly influenced by the conditions the utility is faced with. These cost drivers and specific service territory conditions need to be accounted for to reveal and estimate the performance of the utility.

The business conditions used for the transmission and distribution total cost models are described in each model's specific Chapter.

Perpetual Inventory Method

Total cost is defined as the sum of the annual OM&A expenses plus capital costs. Clearspring's calculation of capital cost is based on the capital service price approach. This approach has a solid basis in economic theory; it is the same method used in all the Ontario benchmarking and productivity studies conducted by Mr. Fenrick, and is the same method chosen by PEG in its 4GIR research and its other studies in CIR applications.[71] The approach allows for a consistent way to account for differences between utilities with respect to historical plant additions and depreciation rates. The service price approach is also prominent in government-sponsored cost research. The Bureau of Labor Statistics of the U.S. Department of Labor uses the capital service price approach in computing multi-factor productivity indices for the U.S. private business sector and for several subsectors, including the utility services industry.

The cost of capital in each year *(t)* is the product of the capital service price index and capital quantity index at the end of the prior year (*t-1)*. The formula for this is given by:

$$CK_t = WKS_t \cdot XK_{t-1}$$

CK_t is the cost of capital, WKS_t is the capital service price index, and XK_{t-1} is the capital quantity index value in the prior period.

The capital quantity index (*XK*) is constructed based on the value of net plant in a benchmark year, and on gross plant additions in years subsequent to the capital benchmark year. In an effort to address past concerns of PEG regarding the start year (capital benchmark year) of this capital series, we put

[71] See Hall and Jorgensen (1967) for a seminal discussion of the use of service price methods for measuring capital cost.

considerable effort into gathering and processing U.S. utility data going back to 1947.[72] We use 1947 for most of the U.S. sampled utilities as the capital benchmark year. A few utilities only had consistent data beginning in 1959, for those utilities we used 1959 as the capital benchmark year. We used 2002 as the capital benchmark year for Hydro One, because this is the first year where data is available and can be readily verified.

A "triangulated weighted average" ("TWA") is used to divide the net plant value in order to adjust the net plant value for historical inflation.[73] This results in an estimate of the capital stock in 1947, 1959, or 2002 based on when the capital benchmark year begins for the utility. Subsequent years use the previous year's capital stock multiplied by one minus the depreciation rate and then escalated by that year's plant additions divided by the asset price in that year.[74] This same method is used both Hydro One and U.S. distributors. The formulas for the capital quantity index in 1947 and in subsequent years are provided below.[75]

$$XK^i_{1947} = \frac{Net\ Plant^i_{1947}}{TWA^i_{1947}}$$

$$XK^i_t = XK^i_{t-1} * (1 - d) + \frac{Add^i_t}{WKA^i_t}$$

The capital service price (*WKS*) has two components: opportunity cost and depreciation. The capital service price index is thus given by the formula:

$$WKS_t = r_t * WKA_{t-1} + d_t * WKA_t$$

Here, r_t is the allowed rate of return based on the Board's historical calculated returns. This same annual value is also used in the capital service price computation for the U.S utilities in the dataset. Setting the same rate of return for all distributors provides consistency in determining the capital costs, so that decisions by regulators do not enter the benchmark evaluation, which is attempting to assess the performance of the utility itself. The parameter d_t is the economic depreciation rate. For the transmission study, to reduce research differences, we used the same depreciation rate that PEG used in their responding research

[72] In our past studies, we used 1989 for the capital benchmark year, as that was the first year of electronically available data. We considered 1989 to be a sufficient start year for the capital series. However, to reduce the research differences, considerable efforts were invested into gathering and processing these data.

[73] For the U.S. sample, the 1947 or 1959 net plant value is for the total utility. To calculate a transmission or distribution net plant value we multiplied the total net plant value by the percentage of transmission or distribution gross plant in service to total gross plant in service, respectively. We note that any error in this net plant value calculation in 1947 or 1959 will have an extraordinarily minimal impact on the cost levels once the sample starts in 2000. This is because any possible small error in 1947 will have also depreciated for 53 years by the time it enters the sample period.

[74] The historical data going back to 1948 and forward all have plant in service additions disaggregated by transmission and distribution, enabling us to build up a robust capital quantity and cost estimate for each function.

[75] For the Ontario distributors, the subscripts would change to 2002 in the first equation.

during the Hydro One Transmission CIR application for Hydro One's depreciation rate. This value is 3.30%. For distribution, we use the same value as we have used in all our distribution CIR benchmarking applications and the same one PEG used in the 4GIR proceeding: 4.59%.

The asset price deflator (*WKA*) is an index of the price of capital assets in each year used in either transmission or distribution. In several CIR applications, this has been an area of contention between PEG and our research team. Historically, Clearspring uses the U.S.-based Handy-Whitman indices for both the U.S. sample and Canadian utilities, as these are well-known and provide asset inflation estimates that are specific to electric transmission or distribution.[76] Both Clearspring and PEG (at least historically) use the Handy-Whitman indices for the U.S. sample.

However, when estimating asset inflation for a Canadian utility, PEG has used Handy-Whitman indices in some of its prior research but has preferred a Canadian-specific asset inflation measure in some applications. The advantage of the latter approach is that it is specific to Canadian asset inflation; the disadvantage is that the measure is a comprehensive measure of water, sewer, gas, and electric utilities (including generation). In the Hydro Ottawa CIR research, PEG compromised between these two asset inflation measures and used a 50% weighting on the Handy-Whitman indices and a 50% weighting on their implicit capital stock index measure. For our current research, we have adopted this 50/50 weighting approach put forth by PEG in the Hydro Ottawa application.

For the U.S. sample, we compute this index using data on differences in the cost of constructing utility plant between regions over time. For U.S. distributors, we use the Handy-Whitman indices for total power distribution plant; these indices vary over time and across six geographic regions.[77] We do the same for the U.S. transmission utilities, except using the index for total power transmission plant. For Hydro One, we use the same Handy-Whitman index for total distribution or transmission plant in the North Atlantic region and then adjust for the Canadian purchasing power parity in the given year. This is for half of the weight in the index; for the other half, we use PEG's implicit capital stock deflator index found in the Capital Flows and Stocks data provided by Stats Canada.[78] For future years, we escalate the WKA index using a 50/50 calculation of the projections for the average weekly earnings in Ontario and the GDP-IPI index available from the Conference Board of Canada.

We determine the relative levels of utility plant asset prices for 2015 by using the City Cost Indices for electrical work in the 2016 edition of RSMeans' *Heavy Construction Cost Data*. These indices measure differences among cities in the cost of labour needed to install electrical equipment and differences in equipment prices. The construction service categories covered are: raceways; conductors and grounding;

[76] For Canadian utilities we adjust the Handy-Whitman for the purchasing price parity (PPPs) in each given year to put the inflation estimate into Canadian dollars.

[77] Handy-Whitman indexes are widely used throughout the U.S. utility industry. They measure the construction cost trends for specific utility functions in six different regional areas of the U.S. For more information, please see: https://wrallp.com/about-us/handy-whitman-index

[78] We note that at the time of the research, this Canadian index was only available through 2019. For 2020, we escalated the Hydro One index fully by the appropriate Handy-Whitman index.

boxes and wiring devices; motors, starters, boards, and switches; transformers and bus ducts; lighting; electric utilities; and power distribution.

We modified this calculation in response to concerns in prior Hydro One applications. The prior method was to calculate the level of the asset price index for each utility by the headquarter city in the service territory (or the closest available city). The concern was that Hydro One, while headquartered in Toronto, has most of its assets outside the City of Toronto, and Toronto tends to have relatively high price levels.

In response to this concern, we modified the asset price level calculation to be based on a population-weighted average of the RS Means value for each 3-digit zip code served by a given utility. This spreads the levelization across the entire service territory, rather than centering on the headquarter city. For Hydro One, we took a population-weighted average of all the Ontario values in the RS Means book. This spreads the levelization across all of Ontario rather than centering on Toronto. The index is already adjusted for currency differences between the two countries.

Model Estimation Procedure and Specification

We assume that the relationship between a utility's cost and the conditions that affect it, called "cost drivers," can be quantified and captured by a statistical function. This function, called a "cost function," allows Clearspring to specify cost as a dependent variable that can be explained by relevant independent or explanatory variables and associated parameters; the latter capture the effect of the independent variables on cost. Such a cost function is estimated using econometric techniques that rest on certain fundamental assumptions.

As implied by the term "independent," one of these assumptions is that the explanatory variables used in the model are factors that are outside the control of utility decision-makers. For instance, the wage paid to labour is driven by market conditions in the service territory and is largely outside the control of a firm's managers. On the other hand, the number of employees hired is within management's control, and thus should not serve as an independent variable.

The data used to estimate this cost relationship can be from a single firm with multiple time observations (time series data), from many firms observed at a single time period (cross-sectional data), or from many firms with multiple time observations (cross-sectional time-series or panel data). The estimation procedure used to estimate model parameters is affected by the type of data used to estimate the model. In our present study, we have a panel dataset with cost data from multiple firms with observations starting in 2000 and extending to 2019.[79] For benchmarks of past years, we use the model to produce benchmarks for each year and compare Hydro One's benchmark costs with its actual costs.

Additionally, for future years we can take Hydro One's cost projections through 2027, allowing us to also

[79] The data extends to 2027 for Hydro One.

benchmark those forecasts "out of sample."[80] We use the model (which is based on historical data) and apply the estimated coefficients and projected independent variable values for Hydro One to calculate a predicted benchmark value. This predicted benchmark value is then compared to Hydro One's projected total cost amount.

Statistical Tests on Parameter Estimates

The precision of parameter estimates is an important dimension of the cost estimation exercise. It identifies business condition variables that have a statistically significant effect on cost. Standard errors of parameter estimates, which measure the precision with which a parameter is estimated, are used to construct a test of a relevant hypothesis. The hypothesis to be tested is "the explanatory variable in question has no statistically significant effect on cost." This procedure is called the *t*-test. A variable is statistically significant if this hypothesis is rejected at a pre-specified level of confidence. We use a 90% confidence threshold in our research for all first order terms. This restriction is not placed on the quadratic and interaction output terms that comprise the translog cost function.

A cost model with plausibly signed and statistically significant parameter estimates is ultimately used to assess the cost performance of each firm in the sample. By "plausibly signed" we mean that its sign (positive/negative) accords with our intuitive understanding of the relationship between that parameter and the variable. For example, we would expect to see distribution costs rise as the number of customers served increases (i.e. we expect that the customer parameter would be positively signed).

Once the industry cost model is estimated, the cost model with estimated parameters is fitted with the business conditions of each utility to generate cost benchmarks, against which actual cost is evaluated. A cost benchmark for a particular utility reflects the performance we would expect from an average hypothetical utility facing the business conditions of that utility.

If a given utility's actual cost is below the benchmark cost, its cost performance is better than average—it spent less than a hypothetical utility (with the same particular characteristics) would be expected to spend. If its actual cost is above the benchmark cost, its cost performance is worse than average. A statistical test of a cost efficiency hypothesis, based on the *t*-test, can also be constructed to identify whether the cost performance identified by the above exercise is statistically significantly different from average.

Model Specification

A translog function is selected for the total cost model estimated in this study. The translog cost function was the same functional form we have used in all our prior CIR research, and the one chosen by PEG in its 4GIR benchmarking research. The function's general form, after suppressing time and firm subscripts, is given by:

[80] For Hydro One's OM&A, Clearspring Energy was given projections until 2023 and then we applied the I-X formula to escalate OM&A amounts in years 2024 to 2027. The I-X formula matches how the Company is proposing to escalate OM&A revenue during those years.

$$ln\left(\frac{C}{W}\right) = \propto_0 + \sum_i \alpha_i \, ln\, Y_i + \sum_j \alpha_j lnZ_j + \frac{1}{2}\left[\sum_{i,k} \propto_{ik} \, lnY_i * ln \; Y_k\right] + \alpha_t t + \varepsilon$$

In this specification, $\alpha's$ are model parameters, and ε is the random noise term. In addition, Y_i quantifies output, W is the input price, Z_j is the other business condition variables, and *t* is a time trend term. This form has been widely used in cost function research.[81] A major advantage is its flexibility, which permits it to provide a good approximation for the wide range of functional forms that the data can reflect.[82]

Estimation Approach

As discussed earlier, the estimation approach has generated considerable discussion between benchmarking consultants in prior CIR proceedings. This is especially difficult for intervenors and the Board, due to the intricacies and difficulties for non-econometricians to evaluate these different approaches. However, PEG, in its latest benchmarking research conducted in Quebec, appeared to use the same estimation approach that Clearspring has used in the past, and is using in this report. Our hope is that PEG will continue to use this same estimation approach (which uses the OLS parameter estimates but then adjusts the standard errors) in any possible benchmarking research in this application. Clearspring believes this would best serve the Ontario industry for the benchmarking consultants to use consistent and pre-determined estimation approaches for all CIR benchmarking research.

The estimation procedure used to estimate model parameters is affected by the type of data used to estimate the models. In our present two benchmarking studies, we have an unbalanced panel dataset with cost data from multiple utilities with multiple observations starting in 2000 and extending to 2019 (or 2027 for Hydro One).

In multivariate regression analysis, the constructed model is designed to use a set of independent (often called explanatory or right-hand-side) variables to "explain" movement in the dependent (often called the left-hand-side) variable. The numerical relationship between an independent variable and the dependent variable is provided through an estimated coefficient value. Under the assumptions of the model, this coefficient value is considered an unbiased estimator of the relationship. Multivariate regression analysis also makes statements about the precision of each coefficient value. Precision in this context is a statement about how confident or statistically valid the coefficient value is. When all the assumptions of multivariate regression are satisfied, the coefficient values are the best (or most precise) unbiased estimators that are available.

Two common issues arise in multivariate regression using real world data: heteroscedasticity and autocorrelation. Neither of these issues causes the coefficient values to be biased or less precise. This is important because it means the researcher does not need to worry about correcting the coefficient values: they are not misleading. However, both conditions render the standard error estimates which

[81] In their Monte Carlo studies of functional forms' performance, Gagne and Ouellette (1998) use the translog as a benchmark because "it is the most widely used" functional form.

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

measure precision problematic. Specifically, the problem with heteroscedasticity and autocorrelation is that they increase the regression variance calculations, which means the researcher is less confident in the calculated coefficient values. For decades, the standard correction procedure involved trying to figure out the nature of each problem and strategically weighting the regression to render heteroscedasticity and autocorrelation less of a problem. One key issue with this strategy is that the researcher may have a hard time truly understanding how to reweight the regression. Additionally, the coefficient values will be different after the reweighting.

More recent treatments for dealing with heteroscedasticity and autocorrelation focus the correction procedures on methods that do not alter the regression or the coefficient values. Instead of reweighting the regression itself, these strategies leave the regression unaltered and focus on altering the way the variances of the coefficients are calculated. These procedures are systematic and do not depend on understanding the underlying reason for the heteroscedasticity and autocorrelation.

For our analysis, we have chosen to estimate the precision of our coefficients using Driscoll-Kraay standard errors.[83] Driscoll-Kraay standard errors have been coded and available in the STATA software suite since 2007.[84] The computer software calculates information crucial to understanding whether each relationship (as described by each coefficient) can be supported statistically.

[83] Driscoll, J., and A. C. Kraay, 1998. "Consistent covariance matrix estimation with spatially dependent data," *Review of Economics and Statistics* 80: 549–560.

[84] Hoechle, Daniel, 2007 "Robust standard errors for panel regressions with cross-sectional dependence," *The Stata Journal* 7(3): 281-312.

Appendix B: Capital Age Calculation Details

As stated in Section 5, there are three steps in the capital age methodology:

1. Calculate the plant in service amounts for each utility in each year in the applicable industry (transmission or distribution).[85] The vintages are calculated by using the additions for a given year as the value for plant in service in the year those additions were placed in service for all calculations in subsequent years, and subtracting retirements recorded in that year from the earliest year that still has a remaining positive value of plant in service.

2. Transform the plant in service vintage estimates to capital quantity vintages by dividing by an asset price deflator in the same year as the plant in service (this is the same asset price deflator used in the benchmarking research). These capital quantity vintages are then used to calculate the average capital age of each utility in the year the calculation is being made.

3. Using the capital age estimates for each utility, an industry weighted average is calculated to determine the transmission or distribution industry age benchmark.

Plant in Service Vintage

The capital age calculation begins in the year 1947 for most of the U.S. sample. The entire amount of the transmission or distribution total plant in service is first assumed to have been put in service in that start year of 1947. In each subsequent year, the reported plant in service additions are recorded in the year that they were reported in (e.g., 1970 plant additions are placed in 1970 and, for example, in the 2000 calculation would be 30 years old) and the reported plant retirements are subtracted from the earliest year that still has positive plant in service value.[86] This calculation continues for every year up through 2019 for the sample.

This calculation is done in every year after 1947 for every utility in the sample.[87] In each new year t, the remaining plant for all prior years is examined. The retirements reported in year t are subtracted from the earliest year that still has a positive value of plant in service. The plant additions reported in year t are assumed to be the amount of new plant in service for year t.

[85] Like the benchmarking studies, the plant in service calculation includes an allocated amount of general plant for both transmission and distribution. This allocation is based on the ratio of transmission plant to total net of general plant for the transmission capital age study and on the ratio of distribution plant to total net of general plant for the distribution study. Both additions and retirements include this allocated portion of general plant.

[86] By the start of 1995, most utilities in the sample have zero remaining plant in service by the start year of 1947, and retirements in years after 1995 were subtracted from additions in years after this start year. This is important, since 1947 assumed all plant in service at that time was added in 1947. This assumption will have a minimal impact on capital age values after 1995 for the sample.

[87] These calculations are done separately for transmission and distribution.

The additions reported in 1948 are recorded and placed in the 1948 value for plant in service, retirements in 1948 are subtracted from 1947's value to formulate the vintages of plant in service in 1948. The same process is conducted in 1949, the 1949 additions are placed in the 1949 value for plant in service, retirements in 1949 are subtracted from what was left from 1947 after the prior year's calculation. In all subsequent years, retirements will keep being subtracted from 1947 until all of the plant in service in 1947 is depleted, then the retirements will be taken from 1948 until that year is depleted and so forth.

An example of the mechanics of this calculation may be helpful. Let us assume year t is 1990 and a specific utility reports $1,000 in transmission plant retirements and $10,000 in new transmission plant additions in 1990. Let us also say that due to the calculations in 1989, there is assumed to be no plant remaining in 1980, but there is still $500 of plant remaining in 1981 and $2,000 of plant remaining in 1982.[88,89] For this illustrative example, additions increase by $1,000 in years subsequent to 1982.

Table 15 Sample Plant in Service Calculation

Year	Plant Vintages as a Result of 1989 Calculation	1990 Reported Retirements	1990 Reported Additions	Plant Vintages as a Result of 1990 Calculation
1979	0			0
1980	0			0
1981	**$500**			**0 (subtracted $500 to bring value to 0)**
1982	**$2,000 (1982 additions)**			**$1,500 (Subtracted off remaining $500 from 1990 retirements)**
1983	$3,000 (Adds in 1983)			$3,000 (Adds in 1983)
1984	$4,000 (Adds in 1984)			$4,000 (Adds in 1984)
1985	$5,000 (Adds in 1985)			$5,000 (Adds in 1985)
1986	$6,000 (Adds in 1986)			$6,000 (Adds in 1986)
1987	$7,000 (Adds in 1987)			$7,000 (Adds in 1987)
1988	$8,000 (Adds in 1988)			$8,000 (Adds in 1988)
1989	$9,000 (Adds in 1989)			$9,000 (Adds in 1989)
1990		$1,000	$10,000	$10,000 (1990 Additions)

In the example calculation above, the $10,000 in additions in 1990 is placed in the 1990 bucket for plant in service. In 1990, $1,000 of plant was retired. We assume that the oldest remaining plant is retired first. In the example, this was the $500 remaining in 1981. However, each year's value cannot go below zero, so only $500 of the $1,000 retired in 1990 is assumed to come from plant constructed in 1981. This leaves

[88] In reality, the remaining plant for utilities will be from years longer than 10 years ago. We say 10 years ago just to simplify the example and reduce table size.

[89] The 1982 value will equal the plant additions reported in 1982, since this number has not had any retirements subtracted from it yet.

another $500 to be retired in the next oldest year with positive plant values, which is 1982. The plant in service in 1982 is reduced by that remaining $500 and moves from a value of $2,000 to $1,500.

This calculation would then be conducted in the next year (1991) using the 1991 reported retirement and additions data. The 1991 retirements would be subtracted from the 1982 remaining plant first, since that is the oldest year with a positive value. All subsequent years will build off the prior year in this fashion up through 2019 for the sample and up through 2027 for Hydro One.

An assumption in the calculation is that plant retirements eliminate the oldest available plant in service. Since we do not know the vintages of the gross plant in service at each utility or the vintages of the plant being retired in each year, this assumption is necessary to create a level playing field among the entire sample. It will tend to underestimate the capital age since not all retirements will be from the earliest available year. However, this calculation and assumption is consistent over a large span of time and between utilities and provides a view into how capital age of each industry has moved over time and how they benchmark against each other using the same assumption.

Capital Quantity Vintage and Utility Capital Age Calculation

Once we have estimated the vintages of the plant in service, an adjustment for inflation needs to be made to transform the costs into quantity estimates. This is because $10,000 spent in 2000 will purchase far fewer capital assets than $10,000 spent in 1950, for example. Since we are estimating the capital age of the assets, we will need to divide by an asset price index to transform the plant in service costs to a quantity estimate in each year.[90]

To make this transformation, we use the same asset price deflator that we use in the total cost benchmarking research. This asset price deflator is described in Appendix A, “Perpetual Inventory Method”, and is designated as “WKA” in that section. This WKA estimates the relative asset prices for each utility, in each year. We divide the plant in service cost estimates in each year t by this WKA in year t to adjust for inflation and transform the costs to a quantity estimate for each utility i.

$$XK_{t,i} = \frac{Plant\ Remaining_{t,i}}{WKA_{t,i}}$$

[90] A basic equation from economics is that cost divided by price equals quantity.

Using the example from the prior section and assuming that for this utility WKA equals "0.8" in 1979 and then increases by 0.1 in each subsequent year, the estimated capital quantity for the 1989 and 1990 calculations are illustrated below.

Table 16 Sample Capital Quantity Calculation

Year	Plant Vintages as a Result of 1989 Plant Calculation	WKA	Capital Quantity Vintages after 1989 Calculation	Plant Vintages as a Result of 1990 Plant Calculation	WKA	Capital Quantity Vintages after 1990 Calculation
1979	0	0.8	**0**	0	0.8	**0**
1980	0	0.9	**0**	0	0.9	**0**
1981	$500	1.0	**500**	0	1.0	**0**
1982	$2,000	1.1	**1,818**	$1,500	1.1	**1,364**
1983	$3,000	1.2	**2,500**	$3,000	1.2	**2,500**
1984	$4,000	1.3	**3,077**	$4,000	1.3	**3,077**
1985	$5,000	1.4	**3,571**	$5,000	1.4	**3,571**
1986	$6,000	1.5	**4,000**	$6,000	1.5	**4,000**
1987	$7,000	1.6	**4,375**	$7,000	1.6	**4,375**
1988	$8,000	1.7	**4,706**	$8,000	1.7	**4,706**
1989	$9,000	1.8	**5,000**	$9,000	1.8	**5,000**
1990				$10,000	1.9	**5,263**

The last step in the capital age calculation is to create a weighted average of the age of the capital quantities for each year of the calculation. The weighted average is calculated by taking the percentage of the capital quantity that remains in each year to the total capital quantity at the utility in that given year. We assumed that assets built in the year of the calculation were 0.5 years old and then added "1" for every year prior.

The 1989 calculation using our prior example is illustrated in the following table.

Table 17 Sample Utility Capital Age Calculation

Year	Capital Quantity Vintages after 1989 Calculation	% of Total Capital Quantity	Age in 1989	Age * % of Total
1979	0	0%	10.5	0.0000
1980	0	0%	9.5	0.0000
1981	500	1.7%	8.5	0.1445
1982	1,818	6.2%	7.5	0.4650
1983	2,500	8.5%	6.5	0.5525
1984	3,077	10.4%	5.5	0.5720
1985	3,571	12.1%	4.5	0.5445
1986	4,000	13.5%	3.5	0.4725
1987	4,375	14.8%	2.5	0.3700
1988	4,706	15.9%	1.5	0.2385
1989	5,000	16.9%	0.5	0.0845
Sum in 1989	**29,547**	**100.0%**		**3.44**

In the illustrative sample calculation, the average age of the assets is 3.44 years in 1989. The 1990 calculation would then be conducted on the capital quantities calculated in the prior table in the 1990 calculation. Naturally, this is just an illustrative example, utilities in the sample will have assets far older than what is presented in this example.

These calculations are conducted on each utility separately and are specific to transmission and distribution. A utility that is in both the transmission and distribution samples will have a separate capital age calculation, one for distribution and one for transmission assets.

Combining Utility Specific Capital Ages to Industry Aggregate

The capital ages for each utility then are aggregated to determine a transmission or distribution industry capital age estimate for each year. This aggregation is conducted by calculating the weighted average capital age based on the percentage of the utility's capital quantity in year t to the sum of the capital quantity of the sample in that same year. For each year, the industry capital age is calculated as:

$$Industry\ Capital\ Age_t = \frac{\sum_i Capital\ Age_{i,t} * Capital\ Quantity_{i,t}}{\sum_i Capital\ Quantity_{i,t}}$$

Hydro One Calculation

The Hydro One capital age calculations are conducted using the same methodology as the U.S. sample, with the exception that Hydro One does not have addition and retirement data going back to 1948. It does have addition and retirement data beginning in 2004. To address this, the Company provided us vintage schedules that provided the vintages by historical of gross plant in service in 2003. This gives us a starting point to estimate the available plant in service vintages and begin the calculation from. After 2003, we then follow the same calculations as the U.S. sample, where the additions enter in as plant in service for that year and retirements reduce the plant in service for the earliest year where there remains positive plant in service. The Hydro One capital age calculations continue through 2027. These are based on the proposed plant additions and retirements for the transmission and distribution operations of the Company.

There are a couple of comparability issues caused by the lack of addition and retirement data prior to 2004. The first is that using the 2003 schedule likely shows Hydro One to be older in 2003 than what the calculation would have shown if the historical data were available. This is because of our assumption that the retirements reduce the oldest plant in service. Retirements do not always correspond to the oldest plant in service. The discrepancy between Hydro One and the sample benchmark caused by this assumption will diminish as the examined year gets further from 2003 and the calculation is able to mimic the U.S. calculation and reduce the impacts of the 2003 assumption. By a year such as 2019, the calculation has had 16 years to reduce this discrepancy. However, we do caution comparing Hydro One's capital age to the industry capital age in the earlier years of the sample.[91]

The 2003 vintage plant data provided to Clearspring did not include years prior to 1950 and appears to have summed up the plant in service in five-year buckets for 1950, 1955, 1960, and 1965. Our assumption is that the year 1950 captured the plant in service from 1950 and prior. The 1955 bucket includes the years 1951 to 1955, and so on. Clearspring assumed this reported dispersal when doing the calculations and made no attempt to evenly spread the plant in service through the applicable years. This would have made Hydro One's capital age appear younger in 2003 than otherwise would be the case. This partially balances out the first comparability issue of needing to start the calculation in 2003 using plant in service vintage data from Hydro One. In the more recent years, such as by 2019, this inaccuracy will have been reduced, as the retirements from 2004 to 2019 would have reduced the plant in those years first, thus reducing and eventually eliminating the inaccuracy.

[91] This is the reason why we only show Hydro One's capital age values starting in 2018. This enabled the calculation 15 years to reduce the discrepancy.

Appendix C: OM&A and Capital Age Correlation Models

We display six models below that show inconsistent results between the change in the capital age variable and the correlation with OM&A. The first three models are for transmission: one with no lag between an increase in spending, a second one with a one-year lag between changes in capital spending and OM&A expenses, and the third with a five-year lag. We do the same for the next three models for distribution. Each model also contains a variable that adjusts for the output growth, since OM&A expenses would be expected to increase as output increases.[92] For the variable to be found to be statistically significant at a 90% confidence level, the absolute value of the T-Statistic needs to be higher than 1.645.

Table 18 Capital Costs Impact on OM&A Expenses: Transmission Model 1

Variable	Estimated Coefficient	T-Statistic
Constant	0.043	4.537
One-Year Change in Tx Output	0.477	0.997
One-Year Change in Tx Capital Age in Year t	-0.197	-1.141

N = 750, R-squared = .00329

Dependent Variable is One Year % Change in Transmission OM&A in Year t

The Transmission Model 1 in Table 18 shows that the one-year change in the transmission capital age that occurs in Year t has an inverse relationship with the percentage change in OM&A spending, but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is reduced, or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is increased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level, and we note the low explanatory power of the model indicated by the R-squared statistic.

[92] These models are conducted using the ordinary least squares (OLS) method of econometric estimation.

Table 19 Capital Costs Impact on OM&A Expenses: Transmission Model 2

Variable	Estimated Coefficient	T-Statistic
Constant	0.043	4.538
One-Year Change in Tx Output	0.538	1.125
One-Year Change in Tx Capital Age in Year t-1	-0.164	-0.939

N = 750, R-squared = .00273

Dependent Variable is One Year % Change in Transmission OM&A in Year t

The Transmission Model 2 provides a view when the capital age change is lagged by one year and shows that the one-year change in the transmission capital age that occurs in Year t-1 (one year lag) has an inverse relationship with the percentage change in OM&A spending, but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is reduced, or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is increased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level.

The model results in Transmission Model 2 are like those in Transmission Model 1; both indicate that OM&A spending actually increases as capital spending increases (since more capital spending will tend to decrease the capital age). Both models indicate this with a low level of statistical confidence and low explanatory power of OM&A changes provided by the model.

Table 20 Capital Costs Impact on OM&A Expenses: Transmission Model 3

Variable	Estimated Coefficient	T-Statistic
Constant	0.047	11.674
Five-Year Change in Tx Output	1.512	5.140
One-Year Change in Tx Capital Age in Year t-5	0.069	0.937

N = 750, R-squared = .0362

Dependent Variable is Five Year % Change in Transmission OM&A in Year t

The Transmission Model 3 provides a view when the capital age change is lagged by five years and the OM&A spending change is over the subsequent five year period. The coefficient estimate changes sign compared to Transmission Model 1 and Transmission Model 2 on the capital age variable, indicating that there is a positive relationship with the percentage change in OM&A spending, but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is increased, or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is decreased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level, and there remains a very low explanatory power of the model indicated by the R-squared statistic. We now turn to the distribution models.

Table 21 Capital Costs Impact on OM&A Expenses: Distribution Model 1

Variable	Estimated Coefficient	T-Statistic
Constant	0.022	4.037
One-Year Change in Customers	0.822	1.732
One-Year Change in Dx Capital Age in Year t	-0.043	-0.204

N = 1,035, R-squared = .00290

Dependent Variable is One Year % Change in Distribution OM&A in Year t

The Distribution Model 1 shows that the one-year change in the distribution capital age that occurs in Year t has an inverse relationship with the percentage change in OM&A spending but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is reduced, or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is increased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level, and we note the low explanatory power of the model indicated by the R-squared statistic.

Table 22 Capital Costs Impact on OM&A Expenses: Distribution Model 2

Variable	Estimated Coefficient	T-Statistic
Constant	0.023	4.060
One-Year Change in Customers	0.823	1.738
One-Year Change in Dx Capital Age in Year t-1	-0.092	-0.426

N = 1,035, R-squared = .00304

Dependent Variable is One Year % Change in Distribution OM&A in Year t

The Distribution Model 2 provides a view when the capital age change is lagged by one year and shows that the one-year change in the distribution capital age that occurs in Year t-1 (one year lag) has an inverse relationship with the percentage change in OM&A spending, but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is reduced, or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is increased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level.

The model results in Distribution Model 2 are like those of the Distribution Model 1, both indicating that OM&A spending actually increases as capital spending increases (since more capital spending will tend to decrease the capital age). Both models indicate this with a low level of statistical confidence and low explanatory power of OM&A changes provided by the model.

Table 23 Capital Costs Impact on OM&A Expenses: Distribution Model 3

Variable	Estimated Coefficient	T-Statistic
Constant	0.021	11.301
Five-Year Change in Customers	0.695	3.976
One-Year Change in Dx Capital Age in Year t-5	-0.058	-0.959

N = 1,035, R-squared = .01554

Dependent Variable is Five Year % Change in Distribution OM&A in Year t

The Dx Model 3 provides a view when the capital age change is lagged by five years and the OM&A spending change is over the subsequent five year period. Unlike the Tx Model 3, the coefficient estimate is the same sign compared to Dx Model 1 and Dx Model 2 on the capital age variable indicating that there is an inverse relationship with the percentage change in OM&A spending but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is decreased or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is increased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level and there remains low explanatory power of the model indicated by the R-squared statistic.

Appendix D: Summary Curriculum Vitae

STEVEN A. FENRICK

SUMMARY OF EXPERIENCE AND EXPERTISE

- I have directed project teams and engaged in research in the fields of performance based regulation, performance benchmarking, DSM, load research and forecasting, and survey design and implementation
- I have been a expert witness in a number of cases involving incentive regulation and other utility research topics.

PROFESSIONAL EXPERIENCE

Clearspring Energy Advisors, LLC (2019 to Present)

Principal Consultant

Responsible for providing consulting services and expert witness testimony to utilities and regulators in the areas of reliability and cost benchmarking, productivity studies and other empirical aspects of performance-based ratemaking and incentive regulation. Direct activities in the areas of demand-side management programs, peak time rebate programs, load forecasting, and market research.

Power System Engineering, Inc.– Madison, WI (2009 to 2018)

Director of Economics

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management including demand response and energy efficiency, ran peak time rebate programs, load research, load forecasting, end-use surveys, and market research.

Pacific Economics Group – Madison, WI (2001 - 2009)

Senior Economist

Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling. Managed and supervised PEG support staff in research and marketing efforts.

EDUCATION

University of Wisconsin - Madison, WI

Bachelor of Science, Economics (Mathematical Emphasis)

University of Wisconsin - Madison, WI

Master of Science, Agriculture and Applied Economics

Publications & Papers

- “Peak-Time Rebate Programs: A Success Story”, *TechSurveillance*, July 2014 (with David Williams and Chris Ivanov).
- “Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes and other Customer Characteristics:, *The Energy Journal*, January 2014. (With Lullit Getachew, Chris Ivanov, and Jeff Smith).
- “Evaluating the Cost of Reliability Improvement Programs”, *The Electricity Journal*, November 2013. (With Lullit Getachew)
- “Expected Useful Life of Energy Efficiency Improvements”, Cooperative Research Network, 2013 (with David Williams).
- “Cost and Reliability Comparisons of Underground and Overhead Power Lines”, *Utilities Policy*, March 2012. (With Lullit Getachew).
- “Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)
- “Enabling Technologies and Energy Savings: The Case of EnergyWise Smart Meter Pilot of Connexus Energy”, Utilities Policy, November 2012. (With Chris Ivanov, Lullit Getachew, and Bethany Vittetoe)
- “The Value of Improving Load Factors through Demand-Side Management Programs”, Cooperative Research Network, 2012 (with David Williams and Chris Ivanov).
- “Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities”, *Applied Economics Letters*, 2012, 19:14, 1373-1380.
- “Altreg Rate Designs Address Declining Average Gas Use”, *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).
- “Regulation of Gas Distributors with Declining Use per Customer”, *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).
- “Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects.” April 2011. *RE Magazine*.
- “Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities”. Master’s Thesis.
- “Demand Response: How Much Value is Really There?” *PSE whitepaper.*
- “How is My Utility Performing” *PSE whitepaper*.
- “Improving the Performance of Power Distributors by Statistical Performance Benchmarking” *PSE whitepaper*.
- “Peak Time Rebate Programs: Reducing Costs While Engaging Customers” *PSE whitepaper*.
- “Performance Based Regulation for Electric and Gas Distributors” *PSE whitepaper*.
- “Revenue Decoupling: Designing a Fair Revenue Adjustment Mechanism” *PSE whitepaper.*

Expert Witness Experience

- Case No. 2020-00299, Big Rivers Electric Corporation, Integrated Resource Plan.
- Docket EB-2019-0261, Hydro Ottawa, Custom Incentive Regulation Application.

- Docket EB-2019-0082, Hydro One Networks Transmission, TFP and Econometric Benchmarking research.
- Docket EB-2018-0165, Toronto Hydro Electric System Limited, Econometric Benchmarking research.
- Docket EB-2018-0218, Hydro One Transmission Sault St. Marie, TFP and Econometric Benchmarking research.
- Docket EB-2017-0049, Hydro One Distribution, TFP and Benchmarking research.
- Docket EB-2015-0004, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.
- Docket EB-2014-0116, Toronto Hydro, Custom Incentive Regulation Application.
- Docket EB-2010-0379, The Coalition of Large Distributors in Ontario regarding "Defining & Measuring Performance".
- Docket No. 6690-CE-198, Wisconsin Public Service Corporation, "Application for Certificate of Authority for System Modernization and Reliability Project".
- Expert Witness presentation to Connecticut Governors "Two Storm Panel", 2012.
- Docket No. EB-2012-0064, Toronto Hydro's Incremental Capital Module (ICM) request for added capital funding.
- Docket No. 09-0306, Central Illinois Light rate case filing.
- Docket No. 09-0307, Central Illinois Public Service Company rate case filing.
- Docket No. 09-0308, Illinois Power rate case filing.

Recent Conference Presentations

- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2019.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2018.
- Panel Moderator at WPUI conference on cost allocation and innovative rate designs at Madison WI. June 2018.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2017.
- Wisconsin Manager's Meeting, "Reliability Target Setting Using Econometric Benchmarking". November 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2016.
- Wisconsin Electric Cooperative Association (WECA) Conference, "An Introduction to Peak Time Rebates". September 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2015.
- EUCI conference chair, 2015. "Evaluating the Performance of Gas and Electric Distribution Utilities."

- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2014.
- Cooperative Exchange Conference, Williamsburg VA. "Smart Thermostat versus AC Direct Load Control Impacts". August 2014.
- EUCI conference chair in Chicago. "The Economics of Demand Response". February 2014.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2013.
- EUCI conference chair in Chicago. "Evaluating the Performance of Gas and Electric Distribution Utilities." August 2013.
- Presentation to the Ontario Energy Board, "Research and Recommendations on 4th Generation Incentive Regulation".
- Presentation to the Canadian Electricity Association's best practice working group. 2013
- Conference chair for EUCI conference in March 2013 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- Presentation to the board of directors of Great Lakes Energy on benchmarking results, December 2012.
- Presentation on making optimal infrastructure investments and the impact on rates, Electricity Distribution Association, Toronto, Ontario. November 2012.
- Conference chair for EUCI conference in August 2012 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Reliability Target Setting and Performance Evaluation".
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Making the Business Case for Reliability-Driven Investments".
- Conference chair for EUCI conference in 2012 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". St. Louis.
- Conference chair for EUCI conference in 2012 titled, "Demand Response: The Economic and Technology Considerations from Pilot to Deployment". St. Louis.
- 2012 Presentation in the Missouri PSC Smart Grid conference entitled, "Maximizing the Value of DSM Deployments". Jefferson City.
- 2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.
- 2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.
- Conference chair for EUCI conference in 2011 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". Denver.
- 2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

COMPONENTS OF CUSTOM IR FORMULA - TRANSMISSION

1.0 HYDRO ONE TRANSMISSION – RCI COMPONENTS

This exhibit describes the specific parameters of the Custom Revenue Cap Index (RCI) proposed for Hydro One Transmission. As described in Exhibit A-04-01, the RCI is expressed as follows:

$$RCI = I - X + C$$

Where:

- "I" is the Inflation Factor;
- "X" is the Productivity Factor; and
- "C" is Hydro One's Custom Capital Factor.

1.1 INFLATION FACTOR

For its Transmission business, Hydro One is proposing an Inflation Factor (I) based on the weighted sum of:

- 86% of the annual percentage change in Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- 14% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

The proposed industry-specific weighting of 14% labour and 86% non-labour is supported by the independent analysis conducted for Hydro One and approved by the OEB in both EB-2018-0218[1] and EB-2019-0082.[2] The weightings were also adopted by the OEB in its November 9, 2020 letter setting out inflation parameters for utilities.[3]

---

[1] Hydro One Sault Ste. Marie LP Application for electricity transmission revenue requirement beginning January 1, 2019 and related matters.
[2] EB-2019-0082, Decision and Order, pg. 25
[3] Available at https://www.oeb.ca/sites/default/files/OEB-ltr-2021-inflation-updates-20201109.pdf

In the November 9, 2020 letter, the OEB released the latest Inflation Factor of 2.0% for transmission, for use in applications for rates effective in 2021. Hydro One has used the 2021 Inflation Factor on a pro-forma basis in its RCI calculation for the years 2024 to 2027.

The Inflation Factor will be updated annually over the 2024-2027 period to reflect the OEB issued factors applicable to those years.

1.2 PRODUCTIVITY FACTOR

The Productivity Factor (X-factor) is equal to the sum of Hydro One's Custom Industry Total Factor Productivity (TFP) measure and Hydro One's Custom Productivity Stretch Factor.

Hydro One engaged an independent consultant, Clearspring Energy Advisors (Clearspring), to undertake a study of the TFP trend for the transmission industry and to undertake an econometric total cost benchmarking study of Hydro One's Transmission costs in order to recommend a Custom Productivity Stretch Factor. Clearspring also conducted a separate analysis which calculated the overall age of Hydro One's assets relative to those of the industry at large. The Clearspring study is provided in Exhibit A-04-01-01.

Based on the Clearspring study, the proposed X-factor of 0% for Hydro One Transmission reflects the sum of the Custom Industry TFP measure of 0% and a Custom Productivity Stretch Factor of 0%. Clearspring's study concluded that the transmission industry TFP is -1.66% from 2000 to 2019. Even though the industry TFP is negative, Clearspring proposed a Custom Industry TFP measure of 0% in light of and consistent with previous OEB decisions, including in EB-2010-0379. Clearspring noted that the adoption of an industry TFP measure of 0% would represent a significant implicit stretch factor for Hydro One. Hydro One has adopted Clearspring's proposal.

Clearspring recommended a Custom Productivity Stretch Factor of 0% for Transmission, based principally on the results of its total cost benchmarking study which shows Hydro One to be a very strong cost performer. In that study, Hydro One Transmission's projected total costs were found to average 34.5% below the benchmark costs throughout the Custom IR term. Hydro One ranked well in the top quartile in this regard. Clearspring's recommended stretch factor of 0% is supported by: (1) Hydro One's superior Transmission total cost performance score and ranking, (2) the Transmission capital age results, indicating Hydro One's capital age is older than the sample, (3) the stretch factor implicit in a 0% base productivity factor, (4) Hydro One's proposed incremental stretch factor on capital of 0.15%, as detailed below, and (5) the application of all stretch factors on a cumulative basis. Hydro One has adopted this recommendation.

Clearspring's stretch factor recommendation is also consistent with the approach under the OEB's 4th Generation IRM (4GIRM). As noted in the OEB's 4GIRM report, the OEB set "the lower-bound stretch factor value to zero to strengthen the efficiency incentives inherent in the rate-adjustment mechanism and in doing so reward the top performers."[4]

Consistent with the approach in previous applications, the X-factor used in the RCI will not be updated annually over the Custom IR term. In its total cost benchmarking study, Clearspring conducted a forward-looking analysis using Hydro One's forecast costs. This analysis concluded that Hydro One's projected total costs will remain significantly below benchmark expectations and Hydro One's internal TFP will remain above that of the industry over the Custom IR term. Further details can be found in Clearspring's report provided in Exhibit A-04-01-01.

1.3 CAPITAL FACTOR

The Custom Capital Factor (C-factor) is the percentage change in the Total Revenue Requirement (line 18 of Table 1 below) attributable to new capital investment that is not otherwise recovered from customers through the I – X adjustment. The C-factor is reduced by a supplemental stretch factor of 0.15% (the Supplemental Stretch). The C-factor includes depreciation, return on equity, interest and taxes attributable to new capital investment placed

[4] Report of the Board – Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (EB-2010-0379, Dec. 2013), p. 20

in-service each year of the Custom IR term. The C-factor will be updated annually to reflect any changes to inflation. The calculation of the C-factor is set out in Table 1.The Total Capital Related Revenue Requirement (line 6 of Table 1) each year is based on the annual rate base.

The final capital related revenue requirement metrics in lines 1 to 12 of Table 1 will be calculated by Hydro One in conjunction with the Draft Rate Order using OEB-approved values. Consistent with the OEB's decision in EB-2019-0082, working capital has been removed from the calculation of the C-factor as shown in lines 7 and 11 of Table 1. These metrics will not change over the Custom IR term.

The OM&A (line 13 of Table 1) for each year is determined based on the 2023 forecast included in the Application, increased by the Inflation Factor (I) and subject to the proposed X-factor, for a total increase of 2.0% per annum.

Table 1 - Summary of Revenue Requirement Components ($ Millions) for Hydro One Transmission

Line		Reference	2023	2024	2025	2026	2027
1	Rate Base	C-01-01	14,592.7	15,450.3	16,448.9	17,394.1	18,256.2
2	Return on Debt	F-01-02	339.5	359.5	382.7	404.7	424.8
3	Return on Equity	F-01-01	486.8	515.4	548.7	580.3	609.0
4	Depreciation (note 1)	E-08-01 D-01-01	528.2	557.6	593.8	625.1	647.3
5	Income Taxes	E-09-01	40.5	70.9	61.4	83.1	84.3
6	**Total Capital Related Revenue Requirement**		**1,395.1**	**1,503.4**	**1,586.7**	**1,693.2**	**1,765.4**
7	Less Working Capital Related Revenue Requirement		2.2	2.3	2.3	2.4	2.4
8	**Total Capital Related Revenue Requirement (excluding working capital)**		**1,392.9**	**1,501.1**	**1,584.4**	**1,690.7**	**1,763.0**
9	Less Productivity Factor on Capital (0.00%+0.15%)			(2.252)	(2.377)	(2.536)	(2.645)
10	Less Prior Year Productivity Factor on Capital				(2.252)	(4.628)	(7.164)
11	Less Removing Working Capital from Capital Factor			(0.1)	(0.0)	(0.1)	(0.0)
12	**Total Capital Related Revenue Requirement (excluding working capital and Productivity)**		**1,395.1**	**1,501.1**	**1,582.1**	**1,685.9**	**1,755.6**
13	OM&A (note 1)	E-02-01 D-01-01	428.1	436.7	445.4	454.3	463.4
14	**Total Revenue Requirement**		**1,823.2**	**1,937.8**	**2,027.5**	**2,140.3**	**2,219.0**
15	Increase in Capital Related Revenue Requirement			106.1	81.0	103.9	69.7
16	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			5.82%	4.18%	5.12%	3.26%
17	Less Capital Related Revenue Requirement in I-X			1.53%	1.55%	1.56%	1.58%
18	**Capital Factor**			**4.29%**	**2.63%**	**3.56%**	**1.68%**

**Note 1: The OM&A and Depreciation lines reflect the Proposed PCB Treatment as further explained in Section 4 of Exhibit D-01-01*

The 2023 Total Revenue Requirement of $1,823.2M (line 14 of Table 1) is determined based on a forward test year, cost of service approach and is the rebasing year for this Application.

In 2024, the Capital Related Revenue Requirement (line 6 of Table 1) increases to $1,503.4M from $1,395.1M in 2023. Hydro One will reduce the Capital Related Revenue Requirement excluding working capital (line 8 of Table 1) by the approved X-factor and the Supplemental Stretch of 0.15% (line 9 of Table 1). In 2025-2027 Hydro One will also reduce the Capital Related Revenue Requirement by the cumulative capital-related productivity reductions from prior years (line 10 of Table 1), and Hydro One has reduced the Capital Related Revenue Requirement to account for the impact of the X-Factor on working capital (line 11 of Table 1).[5] The change in Total Capital Related Revenue Requirement excluding working capital and Productivity (line 12 of Table 1) in 2024 versus 2023 is $106.1M (line 15 of Table 1). This difference is equal to 5.82% of the 2023 Total Revenue Requirement of $1,823.2M ($106.1M divided by $1,823.2M).

The 5.82% increase in Total Capital Related Revenue Requirement is the total increase in revenue requirement arising from the higher 2024 Capital Related Revenue Requirement (line 12 of Table 1). However, the 5.82% increase must be reduced by the increase in revenue requirement that results from the application of the Inflation and Productivity Factors (I - X) of the RCI. This is done by determining the percentage of the Total Capital Related Revenue Requirement excluding working capital and Productivity (line 12 of Table 1) that is already provided for by the Inflation and Productivity Factors. In 2024, this equals 1.53% ($1,395.1M x 2% / $1,823.2M). The net result of 4.29% (5.82% less 1.53%) is the 2024 Custom Capital Factor. As noted in Exhibit A-04-01, Hydro One has modified the application of its productivity factors so that they are applied on a cumulative basis. The cumulative application of the Supplemental Stretch results in a significant revenue requirement reduction for customers that grows each year beginning in 2024.

[5] This is consistent with the approach approved by the OEB in EB-2017-0049 and EB-2019-0082.

1.4 CUSTOM RCI SUMMARY

Table 2 below summarizes the Custom RCI by component that Hydro One is proposing to use to determine the total revenue requirement for rate-making purposes for 2024 to 2027.

Table 2 - Custom Revenue Cap Index (RCI) by Component (%) for Hydro One Transmission

Custom Revenue Cap Index by Component	2024	2025	2026	2027
Inflation Factor (I)	2.00	2.00	2.00	2.00
Productivity Factor (X)	0.00	0.00	0.00	0.00
Capital Factor (C) *	4.29	2.63	3.56	1.68
Custom Revenue Cap Index Total	6.29	4.63	5.56	3.68

** Includes a Supplemental Stretch of 0.15% on capital.*

The Inflation Factor in Table 2 will be updated annually, as described above in section 1.1. Hydro One proposes that the X-factor remain unchanged throughout the Custom IR term. The Total Capital Related Revenue Requirement in line 12 of Table 1 would remain unchanged in subsequent annual update applications, however the 2024 to 2027 C-factors would be updated for the applicable year, to reflect the OEB's annual inflation factor, in subsequent annual update applications. Table 3 below summarizes the Total Revenue Requirement that would result from the OEB's approval of Hydro One's Custom IR, as proposed.

Table 3 - Hydro One Transmission Revenue Requirement by Year

Year	Formula	Revenue Requirement ($millions)
2023	Cost of Service	$1,823.2
2024	2023 Revenue Requirement x 1.0629	$1,937.8
2025	2024 Revenue Requirement x 1.0463	$2,027.5
2026	2025 Revenue Requirement x 1.0556	$2,140.3
2027	2026 Revenue Requirement x 1.0368	$2,219.0

**Calculations assume that Inflation Factor remains at 2% through term.*

2.0 PROPOSED FRAMEWORK FOR ANNUAL UPDATE APPLICATIONS

Hydro One expects to file annual update applications from 2024-2027. These applications are expected to be filed in August.

These applications would calculate the revenue requirement for Hydro One Transmission using the RCI to reflect the most up to date Inflation Factor. Hydro One Transmission will also provide revised Uniform Transmission Rate calculations that reflect the revised revenue requirement and OEB-approved billing determinants for the applicable year. In the event that deferral and variance account balances accumulated in subsequent years are material, Hydro One may also seek to dispose of any balances in its annual update applications.

COMPONENTS OF CUSTOM IR FORMULA - DISTRIBUTION

1.0 INTRODUCTION

This exhibit describes the components of the Custom Revenue Cap Index (RCI) proposed for Hydro One Distribution. As described in Exhibit A-04-01, the RCI is expressed as follows:

$$RCI = I - X + C$$

Where:

- "I" is the Inflation Factor;
- "X" is the Productivity Factor; and
- "C" is Hydro One's Custom Capital Factor.

1.1 INFLATION FACTOR

In its December 2013 Report, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" (EB-2010-0379), the OEB established a methodology for determining the annual Inflation Factor (I) to be used in incentive-based rate adjustment mechanisms for electricity distributors.

The Inflation Factor is based on the weighted sum of:

- 70% of the annual percentage change in Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- 30% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

Consistent with its prior Custom IR application, Hydro One proposes to use the same Inflation Factor in its RCI.

On November 9, 2020,[1] the OEB released the latest Inflation Factor of 2.2% for distribution, for use in applications for rates effective in 2021. Hydro One has used the 2021 Inflation Factor on a pro-forma basis in its RCI calculation for the years 2024 to 2027.

The Inflation Factor will be updated annually over the 2024-2027 period to reflect the applicable factors in those years, consistent with current OEB practice.

1.2 PRODUCTIVITY FACTOR

The Productivity Factor (X-factor) is equal to the sum of the OEB's industry Total Factor Productivity (TFP) measure for distributors and Hydro One's Custom Productivity Stretch Factor. Based on the recommendations of its independent consultant, Clearspring Energy Advsiors (Clearspring), Hydro One is proposing an X-factor of 0.3% for Hydro One Distribution. The Clearspring study is provided in Exhibit A-04-01-01.

Clearspring undertook an econometric total cost benchmarking study of Hydro One's Distribution costs in order to recommend a Custom Productivity Stretch Factor. The study found Hydro One Distribution's costs to average 7.0% above the benchmark costs over the Custom IR term, and Clearspring accordingly recommended a stretch factor of 0.3%.

Clearspring also recommended an industry TFP measure of 0% based on the results of the latest Ontario TFP study conducted in Hydro One's last Distribution application (EB-2017-0049) and on the 4GIRM results, both of which showed negative industry TFP trends. The recommendation of 0%, which Hydro One has adopted, is consistent with previous OEB decisions.

The above components combine to form the proposed X-factor of 0.3%.

---

[1] Available at https://www.oeb.ca/sites/default/files/OEB-ltr-2021-inflation-updates-20201109.pdf

As detailed in section 1.3 below, Hydro One has modified the application of the X-factor such that it will be applied in a cumulative manner to both OM&A and capital.

Consistent with the approach in previous applications, the X-factor in the RCI will not be updated annually over the Custom IR term. In its total cost benchmarking study, Clearspring conducted a forward-looking analysis using Hydro One's forecast costs. This analysis concluded that Hydro One's projected cost performance over the Custom IR term would indicate a 0.3% stretch factor, based on established OEB precedent. Further details can be found in Clearspring's report provided in Exhibit A-04-01-01.

1.3 CAPITAL FACTOR

The Custom Capital Factor (C-factor) is the percentage change in the Total Revenue Requirement (line 18 of Table 1 below) attributable to new capital investment that is not otherwise recovered from customers through the I – X adjustment. The C-factor is reduced by a supplemental stretch factor of 0.15% (the Supplemental Stretch). The C-factor includes depreciation, return on equity, interest and taxes attributable to new capital investment placed in-service each year of the Custom IR term. The C-factor will be updated annually to reflect any changes to inflation. The calculation of the C-factor is set out in Table 1.

The Total Capital Related Revenue Requirement (line 6 of Table 1) each year is based on the annual rate base.

The final capital related revenue requirement metrics in lines 1 to 12 of Table 1 will be calculated by Hydro One in conjunction with the Draft Rate Order using OEB-approved values. Consistent with the OEB's decision in EB-2017-0049, working capital has been removed from the calculation of the C-factor as shown in lines 7 and 11 of Table 1. These metrics will not change over the Custom IR term.

The OM&A (line 13 of Table 1) for each year is determined based on the 2023 forecast included in the Application increased by the Inflation Factor (I) and subject to the proposed X-factor, for a total increase of 1.9% (2.2% - 0.3%) per annum.

Table 1 - Summary of Revenue Requirement Components ($ Million) for Hydro One Distribution

Line		Reference	2023	2024	2025	2026	2027
1	Rate Base	C-01-01	9,372.0	9,962.9	10,641.2	11,301.8	11,880.5
2	Return on Debt	F-01-02	219.4	233.3	249.2	264.6	278.2
3	Return on Equity	F-01-01	312.7	332.4	355.0	377.0	396.3
4	Depreciation (note 1)	E-08-01 D-01-01	460.1	481.3	522.0	557.3	592.3
5	Income Taxes	E-09-01	37.2	54.6	42.4	59.2	68.7
6	**Total Capital Related Revenue Requirement**		**1,029.4**	**1,101.5**	**1,168.6**	**1,258.1**	**1,335.5**
7	Less Working Capital Related Revenue Requirement		17.2	17.4	17.5	17.8	18.0
8	**Total Capital Related Revenue Requirement (excluding working capital)**		**1,012.2**	**1,084.1**	**1,151.0**	**1,240.3**	**1,317.5**
9	Less Productivity Factor on Capital (0.30%+0.15%)			(4.879)	(5.180)	(5.582)	(5.929)
10	Less Prior Year Productivity Factor on Capital				(4.879)	(10.058)	(15.640)
11	Less Removing Working Capital from Capital Factor			0.2	0.4	0.6	0.8
12	**Total Capital Related Revenue Requirement (excluding working capital and Productivity)**		**1,029.4**	**1,096.8**	**1,158.9**	**1,243.1**	**1,314.8**
13	OM&A (note 1)	E-03-01 D-01-01	603.0	614.5	626.1	638.0	650.2
14	**Total Revenue Requirement**		**1,632.4**	**1,711.3**	**1,785.1**	**1,881.1**	**1,965.0**
15	Increase in Capital Related Revenue Requirement			67.5	62.1	84.2	71.7
16	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			4.13%	3.63%	4.71%	3.81%
17	Less Capital Related Revenue Requirement in I-X			1.20%	1.22%	1.23%	1.26%
18	**Capital Factor**			**2.93%**	**2.41%**	**3.48%**	**2.56%**

**Note 1: The OM&A and Depreciation lines reflect the Proposed PCB Treatment as further explained in Section 4 of Exhibit D-01-01*

The 2023 Total Revenue Requirement of $1,632.4M (line 14 of Table 1) is determined based on a forward test year, cost of service approach and is the rebasing year for this Application.

In 2024, the Capital Related Revenue Requirement (line 6 of Table 1) increases to $1,101.5M from $1,029.4M in 2023. Hydro One will reduce the Capital Related Revenue Requirement excluding working capital (line 8 of Table 1) by the approved X-factor of 0.3% and the Supplemental Stretch of 0.15% (line 9 of Table 1). In the years 2025-2027, Hydro One will also reduce the Capital Related Revenue Requirement by the cumulative capital-related productivity reductions from prior years (line 10 of Table 1). Hydro One has reduced the Capital Related Revenue Requirement to account for the impact of the X-factor on working capital (line 11 of Table 1).[2] The change in Total Capital Related Revenue Requirement excluding working capital and Productivity (line 12 of Table 1) in 2024 versus 2023 is $67.5M (line 15 of Table 1). This difference is equal to 4.13% of the 2023 Total Revenue Requirement of $1,632.4M ($67.5M divided by $1,632.4M).

The 4.13% increase in Total Capital Related Revenue Requirement is the total increase in revenue requirement arising from the higher 2024 Capital Related Revenue Requirement (line 12 of Table 1). However, the 4.13% increase must be reduced by the increase in revenue requirement that results from the application of the Inflation and Productivity Factors (I - X) of the RCI. This is done by determining the percentage of the Total Capital Related Revenue Requirement excluding working capital and Productivity (line 12 of Table 1) that is already provided for by the Inflation and Productivity Factors. In 2024, this equals 1.20% ($1,029.4M x 1.9% / $1,632.4M). The net result of 2.93% (4.13% less 1.20%) is the 2024 Custom C-factor. As noted in Exhibit A-04-01, Hydro One has modified the application of its productivity factors so that they are applied on a cumulative basis. The cumulative application of the X-factor and Supplemental Stretch results in a significant revenue requirement reduction for customers that grows each year beginning in 2024.

[2] This is consistent with the approach approved by the OEB in EB-2017-0049 and EB-2019-0082.

1.4 CUSTOM RCI SUMMARY

Table 2 below summarizes the Custom RCI by component that Hydro One is proposing to use to determine the total revenue requirement for rate-making purposes for 2024 to 2027.

Table 2 - Custom Revenue Cap Index (RCI) by Component (%) for Hydro One Distribution

	2024	**2025**	**2026**	**2027**
Inflation Factor (I)	2.20	2.20	2.20	2.20
Productivity Factor (X)	-0.30	-0.30	-0.30	-0.30
Capital Factor (C) *	2.93	2.41	3.48	2.56
Custom Revenue Cap Index Total	**4.83**	**4.31**	**5.38**	**4.46**

** Includes Supplemental Stretch of 0.15% on capital.*

The Inflation Factor in Table 2 will be updated annually, as described in section 1.1 above. Hydro One proposes that the X-factor in Table 2 will remain unchanged throughout the Custom IR term. The Total Capital Related Revenue Requirement in line 12 of Table 1 above would remain unchanged in subsequent annual update applications, however the 2024 to 2027 C-factors would be updated, for the applicable year, to reflect the OEB's annual inflation factor in subsequent annual update applications.

Table 3 below summarizes the Total Revenue Requirement that would result from the OEB's approval of Hydro One's Custom IR, as proposed.

Table 3 - Hydro One Distribution Revenue Requirement by Year

Year	Formula	Revenue Requirement ($M)
2023	Cost of Service	$1,632.4
2024	2023 Revenue Requirement x 1.0483	$1,711.3
2025	2024 Revenue Requirement x 1.0431	$1,785.1
2026	2025 Revenue Requirement x 1.0538	$1,881.1
2027	2026 Revenue Requirement x 1.0446	$1,965.0

2.0 PROPOSED FRAMEWORK FOR ANNUAL UPDATE APPLICATIONS

Hydro One expects to file annual update applications from 2024-2027. These applications are expected to be filed in August.

These applications would calculate the revenue requirement for Hydro One Distribution using the RCI to reflect the most up to date Inflation Factor. Hydro One Distribution will also dispose of Group 1 deferral accounts if appropriate and update Retail Transmission Service Rates.