Report to the Ontario Energy Board

Activities and Program Benchmarking: 2021-2022 Results

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Rebecca Kavan

Dave Hovde

PACIFIC ECONOMICS GROUP RESEARCH LLC

44 East Mifflin St., Suite 601
Madison, Wisconsin USA 53703
608.257.1522   608.257.1540 Fax

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1. Introduction and Summary

1.1. Introduction

In 2018, Ontario Energy Board ("OEB") staff began a project to benchmark granular costs utilities incur at the activity level (e.g., reported right of way expenses) or program level (e.g., tree-trimming costs). This came to be called the activities and programs benchmarking ("APB") project. The project has focused on granular operation and maintenance ("O&M") expenses and capital expenditures ("capex") of power distributors. Pacific Economics Group Research LLC ("PEG") was chosen as project consultant.

PEG prepared a concept paper that discussed the challenges of granular cost benchmarking and considered alternative benchmarking methods. Several working group sessions were conducted to draw input from stakeholders and inform them of the state of the initiative. OEB staff prepared a discussion paper that identified 19 activities that were shortlisted to 10 activities for benchmarking. These categories included capex as well as O&M expenses. They consist of the following cost areas

1. billing O&M;
2. meter O&M;
3. vegetation management O&M;
4. lines O&M;
5. distribution station equipment O&M;
6. poles, towers, and fixtures maintenance;
7. distribution station equipment capex;
8. pole, towers, and fixtures capex;
9. line transformer capex;
10. meter capex.

PEG prepared a report presenting benchmarking results for these 10 cost areas. The final version of this report was issued in May of 2021. A meeting was held on December 9, 2021 to gather input from stakeholders, at which OEB Staff presented their thoughts on APB and proposed changes to the work. A report to update the work to include 2020 data was published in April 2022. This data request and other APB documents can be found on the OEB website. Some data were collected from distributors by way of a small request for data not already provided to the OEB. This report updates the benchmarking results for the 10 cost areas for 2021 and 2022 data and implements new methods and improved data. These updates tended to improve the accuracy of the models. Section 2 describes the purpose of econometric benchmarking and the goals associated with calculating cost scores. Section 3 discusses the econometric models and results. Section 4 contains the model tables and the cost scores for each distributor. Section 5 provides some commentary to aid interpretation of the results and possible applications.

2. Econometric Methods and Goals

2.1 Overview of Econometrics

Evaluating Utility Cost Performance: Why Econometric Benchmarking?

When evaluating cost performance of a utility (or any other business), it is generally unproductive to simply compare the total "raw" cost for two companies. For example, there is not much insight to glean from observing that Alectra Utilities Corporation spent an average of $8,409,579 on Station Operation and Maintenance ("O&M") from 2020-2022, while Westario Power Inc. spent $266,470 on the same accounts over the same time period. While we might know that Alectra is much larger and that the size of the operations must contribute greatly to the large difference in raw cost levels, we don't have specific useful information about the relationship between size and cost.

Unit Cost

To adjust for size we can divide raw cost by the number of units the company produced. Then we can compare the two distributors' *cost per unit* (commonly known as "average cost" or "unit cost"). This is the simplest meaningful approach to cost comparison, and it has the benefit of being widely used and easily understood.

For a goods-producing company, the unit cost is calculated by dividing the total cost incurred by the company by the total number of goods produced during the same time period.

$$\frac{Total\ Cost}{Number\ Items\ Produced} = Company\ \boldsymbol{Unit\ Cost}$$

We can use the resulting unit cost information to compare the amount each company spends, on average, to produce each item (unit). For service-providing industries like electric distribution, we can choose a logical measure of scale such as the number of customers served for the denominator. Once we've calculated unit cost, we might infer that the company with the lower unit cost for the same product is more efficient. If the larger companies tend to have a lower unit cost, we have observed evidence of scale economies available within the industry.

While unit cost may be a helpful starting point, it remains a relatively blunt measure of the company's cost efficiency. What if we discover that the larger company has a higher unit cost? Or what if similarly sized companies have very different unit costs? We know that economies of scale are not linear with company size (i.e. it is *certainly* not always true that the bigger the company, the more efficient its cost of production). We need other tools to make further inferences.

The bluntness of unit cost is particularly concerning in regulated industries like electric distribution. For example, even after adjusting for scale we would expect that costs would be higher in Toronto than in other areas of Ontario. Input price conditions such as local differences in wage rates can help explain the remaining differences in cost levels. Prices for other non-wage inputs may vary dramatically depending on the location of the service territory. Distributors do not have their choice of service territory or the number of customers they serve. Terrain, climate, and customer density are also outside of the distributors' control. These types of issues, referred to as "business conditions", may have significant effects on a distributor's necessarily incurred costs, but they do not result from the company's business choices. Our goal is to evaluate cost performance based on efficiency and productivity in the areas which the company does have some control and decision-making power.

To be able to include this additional information to make *valid* cost comparisons, we can't just keep dividing cost by more and more conditions. We need to use a statistical technique called econometric benchmarking. While econometric statistical methods are very well-established, they are not as easily understood as unit cost and they do require additional tools and training to be able to develop and implement correctly. Thus, they are rarer to see in regulatory environments, though a number of jurisdictions around the world have utilized econometric benchmarking for many years now. Econometric models have major benefits as a method of cost performance comparison, but they have limitations to consider as well.

The benefits include the ability to account for multiple scale variables (see Table 2 below) and numerous business conditions using data from the entire industry, and to obtain specific information about the magnitude and statistical significance of the effects of each variable. Challenges include data availability, data accuracy, and collection time and cost. The models themselves may also be constrained in the number of variables they can statistically support due to the size of the sample (total number of companies and years). Public and industry interpretation and understanding of the models and results is also more challenging to facilitate than it is for unit cost comparisons.

Table 1

Variable Detail for Models with One Scale Variable

Single Scale Variable Models						
Model	**Vegetation Management O&M**	**Pole Maintenance**	**PTF Capex**	**Billing**	**Station O&M**	**Station Capex**
Scale Variable	Number of Poles	Number of Poles	Number of Poles	Number of Customers	Number of Stations	Number of Station Transformers
Expected Scale Economies?	No	Yes	N/A	Yes	No	N/A
Average Increase in Cost Per 1% Increase in Scale Variable*	1.66%	0.82%	1.79%	0.91%	1.11%	0.92%
Comments	Vegetation management does not seem to lend itself to efficiencies simply by increasing the scale of operations. Perhaps new and replacement poles require additional vegetation management to facilitate installation.	It is logical that increasing the number of poles, new or replacement, results in a fewer poles needing maintenance expenditures that year.	Scale economies do not directly apply to capex models.	Billing methods are designed to create efficiencies for repeated tasks, as well as handle increases and decreases in customer numbers.	The data suggest fewer opportunities for cost savings with operating and maintaining an increased number of stations.	Scale economies do not directly apply to capex models.

***For a distributor of sample mean scale. The amount of economies available will differ for companies larger or smaller than average.**

Table 2

Variable Detail for Models with Two Scale Variables

Multiple Scale Variable Models												
Model	**Meter O&M**			**Lines O&M**			**Line Transformer Capex**			**Meter Capex**		
Scale Variable	Number of Poles	Number of Customers	**Total Effect of Scale Variables**	Number of Poles	Number of Customers	**Total Effect of Scale Variables**	Number of Customers	km of Distribution Line	**Total Effect of Scale Variables**	Number of Customers	km of Distribution Line	**Total Effect of Scale Variables**
Expected Scale Economies?	**Yes**			**No**			**N/A**			**N/A**		
Average Increase in Cost Per 1% Increase in Scale Variable*	0.44%	0.44%	**0.88%**	0.34%	0.70%	**1.04%**	0.79%	0.24%	**1.03%**	0.61%	0.39%	**1.00%**
Comments	Using two scale variables implicitly accounts for interplay between those variables. Increasing customers without increasing the number of poles is expected to result in only a 0.44% increase in metering cost for every 1% increase in customer numbers.			As with the Meter O&M model, customer density effects are implicity in this model, such that changes in both scale and density are captured by the two scale variables. The increased cost effect we find here is quite small, possibly because increased pole numbers and customer growth are associated with newer equipment requiring less maintenance.			Scale economies do not directly apply to capex models.			Scale economies do not directly apply to capex models.		

***For a distributor of sample mean scale. The amount of economies available will differ for companies larger or smaller than average.**

2.2 Review of Variables & Econometric Model Construction

Earlier PEG Reports discussed the methodology in detail. The following section touches on some of these issues.

Each company's data for each year is a single observation in the model. To make valid statistical comparisons, there must be enough observations to support reliable model coefficients and standard error calculations. The number of observations is the basis for the model "degrees of freedom". Each variable included in the model reduces the degrees of freedom available for the calculations of the variable standard errors. If there are too few observations, the model will not have enough underlying data to determine whether the coefficients are accurate. Further complicating things, the standard degrees of freedom calculation requires that each observation is independent. Since these sets of observations consist of multiple observations from each company, they are not independent. PEG uses a panel model specification and several standard error adjustments to appropriately account for the non-independence of the repeated company observations.

To begin the process, PEG divides each company's raw cost by the applicable input prices. We then use the resulting *real cost* as the left-hand-side variable in each model. This conserves degrees of freedom, allowing for more flexibility in the number of variables used. Parsimony in variable selection is a virtue in econometric modeling.

For the variable selection process, PEG developed and tested variables with strong theoretical foundation which have been established in other electric utility cost econometric modeling exercises. A challenge of statistical modeling is that just because a variable is an important contributor to cost does not mean it will be statistically significant in the model. If the values of the variable are too similar to other variables, or if there is not enough variability within the data, it will not be statistically significant in the model regardless of its real-life importance. Adding to the challenge of variable identification, the more granular the model, the less precise the model tends to be as a function of the amount of data involved. Below, Table 3 lists each of the business condition variables used across the ten models.

Table 3

Business Condition Variables

Econometric Model Variable Details		
Business Condition Variable	**Definition**	**Theoretical Basis**
ykmoh	Number of km of overhead distribution line	Generally, overhead line is expected to incur higher O&M costs over time and underground line lower O&M costs; the reverse is expected for capital expenditures.
vegDE	Estimated percent of service territory with 60% or greater vegetation coverage	We expect distributors with higher overall vegetation challenges to incur higher costs maintaining the affected lines,
pctmscdx	Account 5085, Miscellaneous Distribution Expense, as a percentage of Total Distribution O&M Expense	Differences in accounting practices present challenges for cost comparision exercises. If distributors with lower costs in the accounts being evaluated are placing many of those expenses in Supervision or Miscellaneous accounts, their cost performance will appear better than it may actually be. Including these variables to adjust for this practice where appropriate facilitates more equal cost comparison without requiring costly and time-consuming retroactive adjustments to accounting practices.
pctsupdx	Accounts 5005, 5105, and 5405 as a percentage of Total Distribution O&M Expense	
pctmscbill	Account 5340, Miscellaneous Customer Accounts Billing and Collections Expense, as a percentage of Total Billing O&M Expense	
pctsupbill	Account 5305, Billing and Collections Supervision, as a percentage of Total Billing O&M Expense	
penload	Yes/no for whether pensions are allocated to the O&M accounts	This accounting practice variable adjusts for differences in how distributors treat pension costs.
pctwood	Percent of total distribution poles which are wood	We might expect that wood poles would have a higher maintenance cost. This is not the case in this model; it could be that steel and composite poles tend to be larger and higher, resulting in higher overall maintenance costs.
oldpol50	Percent of total distribution poles older than 50 years	We expect distributors with a higher percentage of very old wood poles to have increased maintenance costs.
LTovr30	Percent of total line transformers over 30 years old	We expect distributors with a higher percentage of very old line transformers to have increased maintenance costs.
MVA	Total MVA across all stations	This variable is used in conjunction with the number of stations to create a station capacity variable. We expect more operation and maintenance costs for stations with higher voltages and potentially more complex operations.
statyes	Affirmed station outsourcing	We expect outsourcing of station O&M to result in lower costs.
nlinetrf	Total number of line transformers	We expect a higher number of line transformers to be correlated with higher station capex, whether new or replacement.
ynadd3	3-Year Average of Customer Growth in Last 3 Years	Used in capex models, this variable accounts for the effects of adding new customers. We expect higher necessary capital costs for companies adding new customers.

2.3 Econometric Model Interpretation

The phrase "predicted cost", while accurate, sometimes causes parties to think it is the cost level company should have actually achieved. Because no model is perfect, some clarification is useful. The predicted cost is the company's cost *after* accounting for regional input prices and the industry-average effect of each variable applied to the company's specific values for those variables. While distributor productivity and efficiencies are part of the difference between actual and predicted cost, any controllable or non-controllable cost driver that is not reflected (explicitly or implicitly) in the model variables will contribute to the difference as well. Rather than being directly compared to all other distributors, each distributor is compared versus the average cost[1] associated with a single hypothetical distributor that faces the exact same circumstances[2]. The predicted cost is essentially the cost a hypothetical distributor with the exact same characteristics as the actual distributor would be expected to incur if they spent exactly the statistically-calculated industry average for each of the model variables. This hypothetical standard is used to judge cost performance.

We use econometric modeling to facilitate better comparisons by going beyond unit cost to adjust costs for scale and some relevant business conditions. The goal of these exercises is to draw closer to a more objective, apples-to-apples comparison while keeping the time and cost demands on distributors low. The cost scores can be thought of as a data-based starting point; the models clearly identify the factors which have been accounted for so that time and effort can be spent on more productive examinations. If a distributor is an average or better cost performer, they are not spending significantly more than the amount we'd expect if they spent the industry average on their own scale and business condition inputs. Detailed cost investigation is not likely to be a good use of resources. Although, if a company is a consistently good performer, it could be worthwhile to investigate whether any of their methods can be useful to other distributors. If a company is worse than average, it may be worth examining whether the distributor faced additional or unique cost

[1] As implied in the preceding paragraphs, this is far more complicated than just taking the industry average cost for each variable. The coefficients (average effects) are calculated using the average effects and variance of the other variables so that the model works as a whole without double-counting or distorting effects.
[2] Additional discussion of the econometric methods can be found in earlier reports by PEG.

challenges out of their control. The distributor with higher costs may also benefit from insights from other distributors who have found cost savings for that activity or program.

3. Summary of Models

The econometric models for each of the cost areas have been updated to include 2021 and 2022 data. Table 4 below gives a summary of model performance for each of the 10 models. A brief discussion of each of the ten models follows. Tables containing the parameter estimates and benchmarking scores for all ten models are provided after the discussion in Tables 6-25.

Table 4

High-Level Model Summary

Econometric Model Summary			
Cost Area	**R^2**	**Percent of Distributors within 50% of average**	**Trend (expressed as percent cost increase or decrease expected per year)**
O&M Models			
Vegetation Management	0.866	50%	-0.70%
Billing	0.908	89%	-1.00%
Pole	0.576	42%	-2.30%
Meter	0.847	57%	-3.20%
Line	0.886	70%	-0.70%
Station	0.863	51%	-1.50%
Capex Models			
Station	0.506	14%	0.04%
Poles, Towers, and Fixtures	0.880	61%	5.00%
Line Transformer	0.889	65%	2.20%
Meter	0.788	59%	-3.60%

3.1 O&M Models

Billing O&M

Our econometric work resulted in the model for billing O&M shown in Table 5. The model identified the number of customers as the appropriate scale variable. For a distributor of average scale, a 1% increase in the number of customers results in a 0.91% increase in predicted cost. This suggests that a distributor of average scale should expect some scale economies from increasing its scale of operations, because cost increases less than the relative size increase.

The econometric work can account for the average effects of other relevant business conditions such as customer density, accounting practices such as the percentage distribution cost recorded as miscellaneous or supervision and the impact of pension accounting, and the overall industry trend in cost over time. The pension variable is intended to adjust for the average impact of differing accounting treatment of pensions and other benefits. It identifies cases in which the distributor includes more than just salaries and wages in the detailed operating accounts as opposed to consolidating the cost in the Administrative & General accounts. It is expected to have a positive relationship with cost. Both allocation variables were included to adjust for the impact of suspected accounting issues with the itemization of expenses. One version is the ratio of supervision and engineering expense to total O&M. The second is the ratio of miscellaneous O&M to total O&M. To the extent that a distributor reported higher than average amounts in these broad categories, one may expect lower values in the billing account due to a lack of itemization of expenses. Both have negative signs and are statistically significant which suggests that some distributors may be putting less effort into itemizing O&M expenses than others. Including these variables in the model facilitates getting closer to an apples-to-apples comparison of distributor cost. The very small negative value of the trend variable parameter suggests that cost declines for reasons other than those measured by the business condition variables. These reasons include productivity growth.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 6 below. The percentage of distributors with a cost performance within 50% was 89%, which was improved from the previous work. There are several possible reasons to explain why some results seem extreme. The first is that there is an unknown or unmeasurable business condition that affects billing O&M which is not included in the current model. The second is that there is another accounting issue not addressed by the supervision, miscellaneous, and pension variables which resulted in significantly more or less cost being recorded in the billing account. A third possible explanation is that the distributor is significantly better or worse at performing the billing function relative to other distributors. Overall, the billing O&M econometric model was improved by the inclusion of 2021-2022 data.

Meter O&M

Our econometric work resulted in the model for Meter O&M cost shown in Table 7. The model identified the number of poles and the number of customers as relevant scale variables. The number of poles is a proxy for the geographical dispersion of meters. The results suggest that the long-run impact of customers is similar to that of poles. For a distributor of average scale, a 1% increase in the number of customers results in an increase in predicted cost of 0.44% and a 1% increase in number of poles also results in an increase of 0.44%. A 1% increase in overall scale (i.e., 1% increase in both poles and customers) results in an expected cost increase of 0.88%. This suggests that a distributor of average scale should expect some cost savings as a result of increasing its scale of operations because on average, size increases more than cost. The inclusion of 2021-2022 data essentially equalized the weights, with relatively more weight being placed on customers (+10 %) and a little less on poles (-10%), but ultimately a nearly identical overall scale estimate.

The econometric work was able to account for other relevant business conditions such as the percentage distribution cost recorded as miscellaneous, the impact of pension accounting, and the unexplained trend in cost over time. As in the other models, there was a negative relationship between the cost allocation variable and meter O&M cost, which suggests that distributors recording more cost in the miscellaneous account will tend to have less cost recorded in the accounts we are benchmarking. The pension variable once again had a positive relationship with cost. The negative value on the trend variable suggests that cost should decline by 3.2% per year for reasons other than measured by the business condition variables. The impact of the scale variables is discussed above.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 8. The explanatory power of the model as measured by R-squared is 0.847 and slightly improved from the previous work. The percentage of distributors with a cost performance within 50% of predicted cost was 57%.

Vegetation Management

Our econometric work resulted in the model for vegetation management cost shown in Table 9. The model identified the number of poles as the relevant scale variable. For a distributor of average scale, a 1% increase in the number of poles results in an increase in predicted cost of 1.07%. This suggests that a distributor of average scale should not expect cost savings from increasing its scale of operations because size increases less than cost. The latest results show an increase in the estimated cost effect relative to earlier models.

The econometric work was able to account for other relevant business conditions such as overhead line km per pole, whether the percentage of the system with vegetation challenges exceeded 60%[3], the percentage distribution cost recorded as supervision, the impact of pension accounting, and the overall trend in cost over time.

The model found a negative relationship between the cost allocation variable and cost which suggests that distributors that have more cost recorded in supervision and engineering will tend to have less cost recorded in the accounts we are benchmarking. The pension variable has a positive relationship with cost. The negative value on the trend variable suggests that cost should decline by 0.7% per year for reasons other than those measured by the model's business condition variables. The percentage of distributors with results within 50% of that predicted was 50% and similar to past results. The impact of the scale variables is discussed above and the company-by-company benchmark results are shown in Table 10.

Lines O&M

The econometric work resulted in the model for lines O&M cost shown in Table 11. The explanatory power of the model as measured by R-squared was 0.89 which was very slightly improved

[3] The vegetation management model contains a variable vegDE that was assembled from the survey responses from distributors that identifies those with the highest two categories of vegetation challenge. The statistical significance of this variable has declined since it was first used with data that ended in 2019. The lack of correlation with the more recent data could be indicative that conditions have changed for enough distributors such that it does not have the explanatory power it had in the past. PEG attempted an alternative form of the variable that isolated the distributors with the highest indicated level of vegetation challenge but this variable was not any more significant than the current version. Intuitively, the vegetation management cost should be proportional to the amount of vegetation that needs to be managed. The survey attempted to gather this information in a manner that was easy for distributors to provide a response. PEG recommends that an better measure of vegetation be considered in the future to improve this variable and the accuracy of the model. The input of distributors will be very helpful in determining a way to report this information that is both more accurate and minimizes reporting burden.

from earlier work. The percentage of distributors with cost performance within 50% was 70% which is improved compared to the earlier work. The improvement in explanatory power is supported by the availability of much more relevant and intuitive scale variables.

The econometric work was able to account for other relevant business conditions such as accounting practice differences which were also included in the model. The impact of pension accounting and the propensity for distributors to not itemize but rather record expenses as supervision or miscellaneous were also considered. The variables measuring the proportion of total distribution O&M recorded as supervision or miscellaneous respectively each had negative signs. This means that the more distributors tended to record expenses in these general categories, the less cost was observed in the more itemized account being benchmarked. The negative value on the trend variable suggests that cost should decrease by 0.7% per year for reasons other than measured by the business condition variables. This model included a variable for the percentage of line transformers more than 30 years old, which was associated with higher O&M costs. The impact of the scale variables is discussed above.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 12.

Distribution Station Equipment O&M

The econometric work resulted in the model for distribution station O&M cost shown in Table 13. The model identified the number of substations as the most important scale variable. For a distributor of average scale, a 1% increase in the number of substations results in an increase in predicted cost of 1.11%. This suggests that a distributor of average scale should expect no additional scale economies from increasing the scale its substation operations.

The econometric work accounts for other relevant business conditions such as average station capacity (in MVA), whether company outsourced station maintenance, the percentage of distribution cost reported as miscellaneous, the impact of pension accounting, and the unexplained trend in cost over time. The model found a negative relationship between the cost allocation variable and cost which suggests that distributors that have more cost recorded in miscellaneous will tend to have less cost reported as substation O&M. The pension variable once again had a positive relationship with reported substation cost. The trend variable parameter indicates that cost should decrease by 1.5% each year for reasons other than measured by the business condition variables.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 14. There are a fair number of distributors with actual cost that differs from that predicted by the model by more than 50%, with 48.8% falling outside of that. The explanatory power of the model as measured by R-squared was 0.863, higher than the result for the 2020 model.

Maintenance of Poles, Towers and Fixtures

PEG has refined the maintenance cost model for Poles Towers and Fixtures. With the addition of data for the years 2020-2022, the accuracy of the model prediction for type of pole (wood, steel, etc.) has become much less significant. The model has been simplified to only estimate the impact of wood vs. other poles and not attempt to separately isolate the effect of steel. The result has been a statistically significant negative relationship between maintenance cost and the prevalence of wooden poles. The anticipated relationship of construction material and maintenance is not clear. PEG thought that the expected fewer number of fixtures and lower height of wood poles relative to steel towers would suggest that wood might be easier to maintain. It is also possible that wood poles might require more frequent repair than steel structures suggesting a positive relationship. The data suggests that on balance the factors that tend to lower cost are stronger than those that raise cost. PEG welcomes comments from the distributors regarding the expected relationship between type of construction and maintenance cost.

Our new econometric work resulted in the model for poles, towers and fixtures maintenance (“Poles Maintenance”) shown in Table 15. The model identified the number of poles as the most relevant scale variable. For a distributor of average scale, a 1% increase in the number of poles results in an increase in predicted maintenance cost of 0.82%. This suggests that a distributor of average scale should expect some cost savings as a result of increasing its scale of operations because size increases more than cost. The 0.58 R-squared statistic is much lower than that for billing and the lowest by far of all of the new O&M cost models that we developed. However, it is improved from the 2020 model due to the inclusion of the 2021-2022 data.

The econometric work was able to account for some other relevant business conditions including the percentage of poles over 50 years old, the percent of poles made of wood, the impact of pension accounting, and the unexplained trend in cost over time. The pension variable also has a positive relationship with cost. The negative value of the trend variable suggests that cost should decline by 2.3% per year for reasons other than measured by the business condition variables. The impact of the scale variables is discussed above. The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 16 below. The number of distributors with actual cost that differs from that predicted by the model by less than 50% was 42.3% which was an improvement from the previous model.

3.2 Capital Expenditure Model Updates

Previous versions of APB reports have discussed accuracy as one criterion for the quality and reliability of an econometric model. The capex models have previously not been as good as the O&M models when examining the dispersion of results and goodness of fit statistics such as R-squared. In an effort to improve the accuracy and usefulness of the capex models, PEG made a change to the estimation methodology for these models. Previously the models attempted to predict each individual year of capital expenditures and then average the year-by-year performance over three years. The volatility of investment made this a difficult modeling challenge. The use of a three-year average was intended to smooth the performance evaluation as is done in the Total Cost Benchmarking work and the APB O&M models. PEG sought to improve the estimation, keeping the character of the models similar to the previous report without requiring new data from distributors.

The new method is to model an average of three years of capital expenditures instead of a single year. For example, the old method would attempt to individually estimate capex for 2020, 2021, and 2022 and then average the resulting cost performance of those three years. The new method sets up the model to predict the average capex for 2020-2022 and then report a single performance measure. This method has led to an overall increase in accuracy as measured by R-squared at the cost of not distinguishing individual years of performance. Since performance was being averaged anyways, this does not seem like a significant change.

This method also solves a known deficiency of all the capex models. Distributors can occasionally report zero capex for a particular year. For station equipment this is very common. The econometric method has a limitation in that it cannot model observations with zero capex and these observations had to be excluded. The previous results therefore did not account for cases in which distributors had zero capex (i.e. very good cost performance) and were only being benchmarked when investments were being made. With the new method, these zero observations will be averaged into cost and the distributor will be given credit for not having capex in a given year. The results tended to show a little more dispersion in performance than earlier which is possibly due to the inclusion of the zero value observations into the analysis.

3.3 Capital Expenditure Model Details

Capital Expenditures: Distribution Station Equipment

The econometric work resulted in the model for distribution station equipment capex ("station capex") shown in Table 17. The model identified the number of station transformers as the potentially relevant scale variable. The number of line transformers was included as a business condition. It serves to estimate the cost effects of the voltage and number of customers served by the stations. The explanatory power of the model as measured by R-squared was 0.51. The percentage of distributors with cost performance less than 50% was 13%. Both were similar to the results obtained previously.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 18. There are a fair number of distributors with actual cost differing from that predicted by the model by more than 50%. There are several possible reasons to explain the dispersion of results. The first is that there is an unknown or unmeasurable business condition that affects distribution station capex that is not included in the current model. The second is that there is an accounting issue that has resulted in significantly more or less cost being recorded in this account. A third possible explanation is that the distributor is significantly better or worse at performing this function relative to other distributors.

Capital Expenditures: Poles, Towers, and Fixtures

The econometric work resulted in the model for poles, towers, and fixtures capital expenditures ("poles capex")[4] shown in Table 19. The model identified the number of poles as the relevant scale variable. In the context of capital investment, the interpretation of scale is a little different than for O&M. For O&M an above-average number of poles should imply that cost will be higher than average, assuming an average level of O&M per pole. For capital expenditures, the source of demand for poles can come from several sources which include system replacement as well as system augmentation.

[4] The data used for capital expenditure is plant additions from the capital continuity schedules provided by distributors. It is technically a little different from capital expenditures because of timing. The capital expenditure comes first when the asset is being constructed and is later recognized as plant in service when completed.

Assuming a certain percentage of system assets reach the end of their useful life and need to be replaced each year, a scale measure such as number of customers or km of line measures the need for pole replacement because customers and km should be correlated with poles. A larger number of poles will need to be replaced on larger systems than on smaller systems. The same is true for system augmentation. To the extent that a system gets larger or needs to be reinforced by a certain percentage, a larger than average scale variable will imply more investment.

The econometric work was able to account for other relevant business conditions such as the km of line per pole, the age of poles, customer growth and the overall trend in cost over time. The model found a positive relationship between each of these variables and cost. Higher values of km per customer may be correlated with more structures made of steel instead of wood. Higher values of the percent of poles over 50 years old will imply a greater probability that poles will need to be replaced. Higher customer growth is correlated with an expansion of the area served which increases the number of poles needed. The positive value on the trend variable suggests that poles, towers, and fixtures capex should increase by 5.0% per year for reasons not measured by the included business condition variables.

The econometric model produced cost predictions for an average of the last three years for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 20. As can be seen that there are a fair number of distributors with actual cost that differs from that predicted by the model by more than 50%. The percentage of distributors with cost performance less than 50% was 61% vs. 68% earlier. The explanatory power of the model as measured by R-squared was 0.880. This is an improvement over the previous value of 0.831.

Capital Expenditures: Line Transformers

The econometric work resulted in the model for line transformer capital expenditures ("transformer capex") shown in Table 21. The research identified the number of customers and km of line as the potentially relevant scale variables. For a distributor of average scale, a 1% increase in the number of customers increases predicted capex by 0.79% whereas a 1% increase in km of line increases predicted capex by 0.24%.

The econometric work was able to account for other relevant business conditions such as customer growth. The trend variable suggests that capex should increase by 2.2% per year for reasons other than the changes in the model's business condition variables.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 22. As can be seen there are a fair number of distributors with actual cost that differs from that predicted by the model by more than 50%. The percentage of distributors with cost performance within 50% of predicted was 65% vs. 75% earlier. The explanatory power of the model as measured by R-squared was 0.889. This is an improvement over the previous value of 0.856.

Capital Expenditures: Meters

The econometric work resulted in the model for meter capital expenditures ("meter capex") shown in Table 23. The model identified the number of customers and km of line as the relevant scale variables. The relationship between the number of customers and number of installed meters should be close. The km of line serves as a measure of service territory size and provides a more accurate statistical cost relationship than service territory area. The model indicates that, for a distributor of average scale, a 1% increase in the number of customers results in an increase in predicted meter capex of 0.61% whereas a 1% increase in the km of line results in an increase in predicted capex of 0.39%.

The econometric work was able to account for other relevant business conditions. A positive relationship was found between customer growth and cost. Higher customer growth implies system expansion which increases the number of meters required. The -0.036 value of the trend variable parameter suggests that capex should fall by 3.6% annually for reasons other than changes in the values of the model's business condition variables.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 24. As can be seen there are a fair number of distributors with actual cost that differs from that predicted by the model by more than 50%. The explanatory power of the model as measured by R-squared was 0.788. This is an improvement over the previous value of 0.659. The percentage of distributors with cost performance less than 50% was 59% vs 54% earlier.

4. Econometric Models and Benchmarking Results

Table 5

Econometric Model of Billing O&M

VARIABLE KEY

Scale Variables:

yn = Number of customers

Business Conditions:

custperkm = Customers per km of line
penload = Pensions allocated to O&M
pctmscbill = Percentage of O&M that is miscellaneous
pctsupbill = Percentage of O&M that is supervision
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn	0.905	40.020	0.000
I(yn * yn/2)	0.146	12.116	0.000
custperkm	0.082	3.471	0.001
penload	0.347	8.008	0.000
pctmscbill	-0.048	-6.840	0.000
pctsupbill	-0.035	-4.218	0.000
trend	-0.010	-3.494	0.001
Constant*	2.697	42.197	0.000
System Rbar-Squared	0.908		
Sample Period	2012-2022		
Number of Observations	593		

Table 6

Cost Performance Results: Billing O&M

Distributor	Average Actual Cost	Average Predicted Cost	Average Actual Less Predicted 2020-2022
Alectra Utilities Corporation	$ 30,239,492	$ 36,348,348	-18.4%
Algoma Power Inc.	$ 207,138	$ 297,491	-36.2%
Atikokan Hydro Inc.	$ 143,196	$ 191,179	-28.9%
Bluewater Power Distribution Corporation	$ 1,003,029	$ 903,052	10.5%
Burlington Hydro Inc.	$ 1,137,396	$ 1,392,000	-20.2%
Canadian Niagara Power Inc.	$ 378,110	$ 610,443	-47.9%
Centre Wellington Hydro Ltd.	$ 310,168	$ 316,118	-1.9%
Chapleau Public Utilities Corporation	$ 76,270	$ 118,781	-44.3%
Cooperative Hydro Embrun Inc.	$ 204,822	$ 143,186	35.8%
E.L.K. Energy Inc.	$ 276,472	$ 351,114	-23.9%
Elexicon Energy Inc.	$ 5,468,013	$ 3,343,156	49.2%
Enova Power Corp.	$ 3,965,982	$ 2,917,577	30.7%
Entegrus Powerlines Inc.	$ 1,312,840	$ 1,193,862	9.5%
ENWIN Utilities Ltd.	$ 1,559,519	$ 2,103,026	-29.9%
EPCOR Electricity Distribution Ontario Inc.	$ 547,358	$ 547,358	0.0%
ERTH Power Corporation	$ 1,078,508	$ 657,427	49.5%
Essex Powerlines Corporation	$ 859,396	$ 756,142	12.8%
Festival Hydro Inc.	$ 635,585	$ 577,984	9.5%
Fort Frances Power Corporation	$ 168,244	$ 259,931	-43.5%
GrandBridge Energy Inc.	$ 2,730,869	$ 1,699,986	47.4%
Greater Sudbury Hydro Inc.	$ 1,067,142	$ 1,034,568	3.1%
Grimsby Power Incorporated	$ 421,516	$ 422,782	-0.3%
Halton Hills Hydro Inc.	$ 428,229	$ 677,668	-45.9%
Hearst Power Distribution Company Limited	$ 229,257	$ 175,712	26.6%
Hydro 2000 Inc.	$ 167,304	$ 111,254	40.8%
Hydro Hawkesbury Inc.	$ 260,084	$ 220,524	16.5%
Hydro One Networks Inc.	$ 43,846,158	$ 29,627,030	39.2%

Table 6 (continued)

Cost Performance Results: Billing O&M

Hydro Ottawa Limited	$	7,695,160	$	8,833,856	-13.8%
Innpower Corporation	$	415,903	$	342,904	19.3%
Kingston Hydro Corporation	$	378,182	$	944,236	-91.5%
Lakefront Utilities Inc.	$	226,908	$	336,818	-39.5%
Lakeland Power Distribution Ltd.	$	487,691	$	369,696	27.7%
London Hydro Inc.	$	1,823,368	$	3,531,368	-66.1%
Milton Hydro Distribution Inc.	$	1,178,740	$	1,082,687	8.5%
Newmarket-Tay Power Distribution Ltd.	$	1,065,042	$	1,150,291	-7.7%
Niagara Peninsula Energy Inc.	$	2,892,007	$	1,101,806	96.5%
Niagara-on-the-Lake Hydro Inc.	$	385,093	$	404,837	-5.0%
North Bay Hydro Distribution Limited	$	708,150	$	726,803	-2.6%
Northern Ontario Wires Inc.	$	251,071	$	239,065	4.9%
Oakville Hydro Electricity Distribution Inc.	$	1,360,891	$	1,750,917	-25.2%
Orangeville Hydro Limited	$	422,883	$	461,321	-8.7%
Oshawa PUC Networks Inc.	$	1,229,802	$	1,748,665	-35.2%
Ottawa River Power Corporation	$	545,756	$	448,618	19.6%
PUC Distribution Inc.	$	393,837	$	891,528	-81.7%
Renfrew Hydro Inc.	$	337,484	$	288,449	15.7%
Rideau St. Lawrence Distribution Inc.	$	376,280	$	325,816	14.4%
Sioux Lookout Hydro Inc.	$	195,768	$	183,632	6.4%
Synergy North Corporation	$	1,507,302	$	1,456,915	3.4%
Tillsonburg Hydro Inc.	$	438,502	$	284,965	43.1%
Toronto Hydro-Electric System Limited	$	22,681,606	$	22,165,882	2.3%
Wasaga Distribution Inc.	$	487,122	$	509,543	-4.5%
Welland Hydro-Electric System Corp.	$	961,927	$	773,510	21.8%
Wellington North Power Inc.	$	110,364	$	189,386	-54.0%
Westario Power Inc.	$	382,695	$	696,618	-59.9%
Average	**$**	**2,734,475**	**$**	**2,559,960**	**-3.2%**
Median	**$**	**487,406**	**$**	**633,935**	**1.2%**

Table 7

Econometric Model of Meter O&M

VARIABLE KEY

Scale Variables:

yn = Number of customers
npoles= Number of poles

Business Conditions:

pctmscdx = Percent of distribution O&M that is miscellaneous
penload = Pensions allocated to O&M
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn	0.436	15.232	0.000
I(yn * yn/2)	-0.071	10.332	0.000
npoles	0.441	-4.833	0.000
pctmscdx	-0.046	11.330	0.004
penload	0.504	-2.913	0.001
trend	-0.032	3.412	0.000
Constant*	2.631	-6.997	0.000
System Rbar-Squared	0.847		
Sample Period	2012-2022		
Number of Observations	591		

Table 8

Cost Performance Results: Meter O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2020-2022
Alectra Utilities Corporation	$ 3,980,211	$ 6,432,317	-48.0%
Algoma Power Inc.	$ 894,382	$ 448,600	69.0%
Atikokan Hydro Inc.	$ 82,582	$ 36,627	81.3%
Bluewater Power Distribution Corporation	$ 807,088	$ 737,623	9.0%
Burlington Hydro Inc.	$ 861,738	$ 1,177,267	-31.2%
Canadian Niagara Power Inc.	$ 831,730	$ 842,613	-1.3%
Centre Wellington Hydro Ltd.	$ 196,806	$ 108,768	59.3%
Chapleau Public Utilities Corporation	$ 31,503	$ 12,643	91.3%
Cooperative Hydro Embrun Inc.	$ 4,132	$ 30,805	-200.9%
E.L.K. Energy Inc.	$ 240,672	$ 119,514	70.0%
Elexicon Energy Inc.	$ 1,416,150	$ 2,764,727	-66.9%
Enova Power Corp.	$ 2,946,753	$ 2,278,925	25.7%
Entegrus Powerlines Inc.	$ 432,222	$ 1,160,886	-98.8%
ENWIN Utilities Ltd.	$ 1,378,101	$ 1,428,616	-3.6%
EPCOR Electricity Distribution Ontario Inc.	$ 437,799	$ 310,369	34.4%
ERTH Power Corporation	$ 546,538	$ 449,261	19.6%
Essex Powerlines Corporation	$ 252,374	$ 488,779	-66.1%
Festival Hydro Inc.	$ 609,113	$ 366,136	50.9%
Fort Frances Power Corporation	$ 93,939	$ 76,527	20.5%
GrandBridge Energy Inc.	$ 2,130,369	$ 1,680,843	23.7%
Greater Sudbury Hydro Inc.	$ 779,860	$ 654,659	17.5%
Grimsby Power Incorporated	$ 313,492	$ 227,414	32.1%
Halton Hills Hydro Inc.	$ 88,437	$ 551,859	-183.1%
Hearst Power Distribution Company Limited	$ 33,949	$ 59,613	-56.3%
Hydro 2000 Inc.	$ 4,357	$ 21,410	-159.2%
Hydro Hawkesbury Inc.	$ 51,744	$ 54,072	-4.4%
Hydro One Networks Inc.	$ 28,381,007	$ 13,036,070	77.8%

Table 8 (continued)

Cost Performance Results: Meter O&M

Hydro Ottawa Limited	$	2,092,116	$	3,695,722	-56.9%
Innpower Corporation	$	401,706	$	478,530	-17.5%
Kingston Hydro Corporation	$	705,936	$	405,258	55.5%
Lakefront Utilities Inc.	$	281,041	$	99,038	104.3%
Lakeland Power Distribution Ltd.	$	182,107	$	299,045	-49.6%
London Hydro Inc.	$	3,349,531	$	1,593,321	74.3%
Milton Hydro Distribution Inc.	$	719,460	$	599,143	18.3%
Newmarket-Tay Power Distribution Ltd.	$	889,654	$	597,547	39.8%
Niagara Peninsula Energy Inc.	$	1,178,827	$	1,191,866	-1.1%
Niagara-on-the-Lake Hydro Inc.	$	192,286	$	222,958	-14.8%
North Bay Hydro Distribution Limited	$	618,585	$	551,937	11.4%
Northern Ontario Wires Inc.	$	283,187	$	114,218	90.8%
Oakville Hydro Electricity Distribution Inc.	$	1,389,622	$	846,227	49.6%
Orangeville Hydro Limited	$	240,032	$	157,397	42.2%
Oshawa PUC Networks Inc.	$	759,902	$	1,041,262	-31.5%
Ottawa River Power Corporation	$	165,865	$	293,880	-57.2%
PUC Distribution Inc.	$	686,444	$	789,599	-14.0%
Renfrew Hydro Inc.	$	63,817	$	94,257	-39.0%
Rideau St. Lawrence Distribution Inc.	$	80,794	$	124,574	-43.3%
Sioux Lookout Hydro Inc.	$	72,329	$	85,817	-17.1%
Synergy North Corporation	$	450,278	$	1,270,117	-103.7%
Tillsonburg Hydro Inc.	$	85,446	$	109,605	-24.9%
Toronto Hydro-Electric System Limited	$	5,055,013	$	9,577,154	-63.9%
Wasaga Distribution Inc.	$	182,504	$	294,645	-47.9%
Welland Hydro-Electric System Corp.	$	379,055	$	508,102	-29.3%
Wellington North Power Inc.	$	137,971	$	71,382	65.9%
Westario Power Inc.	$	464,429	$	493,641	-6.1%
Average	**$**	**1,276,574**	**$**	**1,132,652**	**-5.6%**
Median	**$**	**435,011**	**$**	**463,896**	**-2.5%**

Table 9

Econometric Model of Vegetation Management O&M

VARIABLE KEY

Scale Variables:

npoles = Number of poles

Business Conditions:

ykmohpernpol = Overhead line km per pole
vegDE = 60% or more vegetation
pctsupdx = Percent of distribution O&M that is supervision
penload = Pensions allocated to O&M
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
npoles	1.066	14.517	0.000
npoles*npoles	0.035	41.490	0.036
ykmohpernpol	0.119	2.100	0.014
vegDE	0.052	2.477	0.109
pctsupdx	-0.144	1.604	0.000
penload	0.676	-5.533	0.000
trend	-0.007	5.938	0.148
Constant*	2.116	-1.448	0.000
System Rbar-Squared	0.866		
Sample Period	2012-2022		
Number of Observations	567		

Table 10

Cost Performance Results: Vegetation Management O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2020-2022
Alectra Utilities Corporation	$ 4,956,529	$ 5,816,540	-16.0%
Algoma Power Inc.	$ 3,752,009	$ 1,053,683	127.0%
Atikokan Hydro Inc.	$ 39,228	$ 62,141	-46.0%
Bluewater Power Distribution Corporation	$ 261,795	$ 517,787	-68.2%
Burlington Hydro Inc.	$ 677,671	$ 562,652	18.6%
Canadian Niagara Power Inc.	$ 554,118	$ 919,085	-50.6%
Centre Wellington Hydro Ltd.	$ 59,332	$ 56,948	4.1%
Chapleau Public Utilities Corporation	$ 2,793	$ 9,100	-118.1%
Cooperative Hydro Embrun Inc.	$ 6,765	$ 8,296	-20.4%
E.L.K. Energy Inc.	$ 151,144	$ 58,571	94.8%
Elexicon Energy Inc.	$ 1,176,848	$ 1,417,422	-18.6%
Enova Power Corp.	$ 1,357,307	$ 1,353,241	0.3%
Entegrus Powerlines Inc.	$ 257,887	$ 715,172	-102.0%
ENWIN Utilities Ltd.	$ 1,094,350	$ 603,603	59.5%
EPCOR Electricity Distribution Ontario Inc.	$ 163,459	$ 155,955	4.7%
ERTH Power Corporation	$ 160,979	$ 286,940	-57.8%
Essex Powerlines Corporation	$ 424,651	$ 235,160	59.1%
Festival Hydro Inc.	$ 179,721	$ 184,455	-2.6%
Fort Frances Power Corporation	$ 55,882	$ 45,162	21.3%
GrandBridge Energy Inc.	$ 1,011,123	$ 959,888	5.2%
Greater Sudbury Hydro Inc.	$ 590,863	$ 337,844	55.9%
Grimsby Power Incorporated	$ 86,077	$ 134,726	-44.8%
Halton Hills Hydro Inc.	$ 231,202	$ 337,407	-37.8%
Hearst Power Distribution Company Limited	$ 9,628	$ 56,640	-177.2%
Hydro 2000 Inc.	$ 5,225	$ 12,055	-83.6%
Hydro Hawkesbury Inc.	$ 95,669	$ 16,492	175.8%
Hydro One Networks Inc.	$ 138,389,624	$ 39,887,902	124.4%

Table 10 (continued)

Cost Performance Results: Vegetation Management O&M

Hydro Ottawa Limited	$	4,662,355	$	2,109,647	79.3%
Innpower Corporation	$	360,500	$	396,427	-9.5%
Kingston Hydro Corporation	$	369,943	$	177,390	73.5%
Lakefront Utilities Inc.	$	47,673	$	66,246	-32.9%
Lakeland Power Distribution Ltd.	$	190,693	$	176,738	7.6%
London Hydro Inc.	$	1,219,370	$	762,871	46.9%
Milton Hydro Distribution Inc.	$	348,504	$	463,891	-28.6%
Newmarket-Tay Power Distribution Ltd.	$	193,958	$	282,208	-37.5%
Niagara Peninsula Energy Inc.	$	391,814	$	908,492	-84.1%
Niagara-on-the-Lake Hydro Inc.	$	58,854	$	182,373	-113.1%
North Bay Hydro Distribution Limited	$	744,006	$	341,398	77.9%
Northern Ontario Wires Inc.	$	142,550	$	84,664	52.1%
Oakville Hydro Electricity Distribution Inc.	$	498,223	$	194,425	94.1%
Orangeville Hydro Limited	$	149,005	$	33,414	149.5%
Oshawa PUC Networks Inc.	$	100,902	$	264,847	-96.5%
Ottawa River Power Corporation	$	161,814	$	182,263	-11.9%
PUC Distribution Inc.	$	698,939	$	574,536	19.6%
Renfrew Hydro Inc.	$	74,759	$	62,257	18.3%
Rideau St. Lawrence Distribution Inc.	$	41,989	$	69,994	-51.1%
Sioux Lookout Hydro Inc.	$	62,259	$	151,005	-88.6%
Synergy North Corporation	$	1,406,348	$	708,218	68.6%
Tillsonburg Hydro Inc.	$	51,184	$	71,623	-33.6%
Toronto Hydro-Electric System Limited	$	2,914,531	$	7,335,378	-92.3%
Wasaga Distribution Inc.	$	147,401	$	159,837	-8.1%
Welland Hydro-Electric System Corp.	$	218,060	$	279,435	-24.8%
Wellington North Power Inc.	$	67,183	$	46,359	37.1%
Westario Power Inc.	$	324,550	$	369,607	-13.0%
Average	**$**	**3,174,060**	**$**	**1,338,156**	**-1.7%**
Median	**$**	**206,009**	**$**	**250,004**	**-8.8%**

Table 11

Econometric Model of Lines O&M

VARIABLE KEY

Scale Variables:

yn = Number of customers
npoles = Number of poles

Business Conditions:

LTovr30 = % line transformers over 30 years old
pctmscdx = % distribution O&M miscellaneous
pctsupdx = % distribution O&M supervision
penload = Pensions allocated to O&M
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn	0.701	13.805	0.000
I(yn * yn/2)	0.099	3.461	0.001
npoles	0.343	6.131	0.000
npoles*npoles	-0.116	-4.327	0.000
LTovr30	0.090	2.804	0.005
pctmscdx	-0.176	-10.625	0.000
pctsupdx	-0.126	-6.078	0.000
penload	0.354	2.489	0.013
trend	0.007	1.472	0.142
Constant*	3.651	21.651	0.000
System Rbar-Squared	0.886		
Sample Period	2012-2022		
Number of Observations	594		

Table 12

Cost Performance Results: Lines O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2020-2022
Alectra Utilities Corporation	$ 54,394,886	$ 58,106,071	-6.6%
Algoma Power Inc.	$ 1,651,344	$ 1,525,908	7.9%
Atikokan Hydro Inc.	$ 408,367	$ 103,458	137.3%
Bluewater Power Distribution Corporation	$ 1,873,518	$ 1,643,483	13.1%
Burlington Hydro Inc.	$ 4,984,247	$ 3,384,758	38.7%
Canadian Niagara Power Inc.	$ 1,675,153	$ 2,050,132	-20.2%
Centre Wellington Hydro Ltd.	$ 305,170	$ 185,280	49.9%
Chapleau Public Utilities Corporation	$ 201,214	$ 28,944	193.9%
Cooperative Hydro Embrun Inc.	$ 19,220	$ 46,944	-89.3%
E.L.K. Energy Inc.	$ 630,429	$ 306,863	72.0%
Elexicon Energy Inc.	$ 4,860,264	$ 7,185,699	-39.1%
Enova Power Corp.	$ 7,606,236	$ 6,572,988	14.6%
Entegrus Powerlines Inc.	$ 2,018,416	$ 2,633,499	-26.6%
ENWIN Utilities Ltd.	$ 4,376,128	$ 3,483,942	22.8%
EPCOR Electricity Distribution Ontario Inc.	$ 903,849	$ 588,550	42.9%
ERTH Power Corporation	$ 976,354	$ 741,611	27.5%
Essex Powerlines Corporation	$ 988,264	$ 1,164,387	-16.4%
Festival Hydro Inc.	$ 1,503,351	$ 825,882	59.9%
Fort Frances Power Corporation	$ 97,735	$ 146,681	-40.6%
GrandBridge Energy Inc.	$ 5,488,504	$ 4,882,492	11.7%
Greater Sudbury Hydro Inc.	$ 1,665,565	$ 1,399,569	17.4%
Grimsby Power Incorporated	$ 424,718	$ 413,818	2.6%
Halton Hills Hydro Inc.	$ 706,513	$ 1,202,721	-53.2%
Hearst Power Distribution Company Limited	$ 225,754	$ 113,346	68.9%
Hydro 2000 Inc.	$ 18,236	$ 82,220	-150.6%
Hydro Hawkesbury Inc.	$ 105,072	$ 162,495	-43.6%
Hydro One Networks Inc.	$ 78,363,262	$ 11,193,746	194.6%

Table 12 (continued)

Cost Performance Results: Lines O&M

Hydro Ottawa Limited	$	7,333,947	$	9,909,698	-30.1%
Innpower Corporation	$	703,013	$	1,082,875	-43.2%
Kingston Hydro Corporation	$	1,031,477	$	929,593	10.4%
Lakefront Utilities Inc.	$	532,062	$	238,355	80.3%
Lakeland Power Distribution Ltd.	$	1,139,907	$	585,052	66.7%
London Hydro Inc.	$	6,278,351	$	4,586,455	31.4%
Milton Hydro Distribution Inc.	$	1,268,119	$	1,160,133	8.9%
Newmarket-Tay Power Distribution Ltd.	$	1,394,491	$	1,202,653	14.8%
Niagara Peninsula Energy Inc.	$	2,688,073	$	1,911,379	34.1%
Niagara-on-the-Lake Hydro Inc.	$	510,457	$	433,680	16.3%
North Bay Hydro Distribution Limited	$	1,475,417	$	1,617,596	-9.2%
Northern Ontario Wires Inc.	$	622,164	$	193,099	117.0%
Oakville Hydro Electricity Distribution Inc.	$	1,501,010	$	1,931,194	-25.2%
Orangeville Hydro Limited	$	215,490	$	209,121	3.0%
Oshawa PUC Networks Inc.	$	1,028,282	$	3,018,890	-107.7%
Ottawa River Power Corporation	$	329,374	$	525,417	-46.7%
PUC Distribution Inc.	$	2,344,022	$	1,849,413	23.7%
Renfrew Hydro Inc.	$	134,413	$	173,281	-25.4%
Rideau St. Lawrence Distribution Inc.	$	341,666	$	201,509	52.8%
Sioux Lookout Hydro Inc.	$	525,936	$	208,759	92.4%
Synergy North Corporation	$	3,393,574	$	3,049,213	10.7%
Tillsonburg Hydro Inc.	$	153,441	$	105,775	37.2%
Toronto Hydro-Electric System Limited	$	27,788,606	$	39,790,416	-35.9%
Wasaga Distribution Inc.	$	521,238	$	705,712	-30.3%
Welland Hydro-Electric System Corp.	$	1,904,563	$	1,149,414	50.5%
Wellington North Power Inc.	$	117,065	$	157,547	-29.7%
Westario Power Inc.	$	964,404	$	1,427,258	-39.2%
Average	**$**	**4,494,673**	**$**	**3,491,277**	**13.3%**
Median	**$**	**1,008,273**	**$**	**1,116,145**	**11.2%**

Table 13

Econometric Model of Station Maintenance O&M

VARIABLE KEY

Scale Variables:

nstation = Number of stations

Business Conditions:

mvaperstat = Station capacity
statyes = Affirmed outsourcing
pctmscdx = Percent of distribution O&M that is miscellaneous
penload = Pensions allocated to O&M
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
nstation	1.108	37.066	0.000
I(nstation * nstation/2)	0.080	2.774	0.006
mvaperstat	0.240	6.466	0.000
statyes	-0.249	-9.528	0.000
pctmscdx	-0.090	-4.543	0.000
penload	0.621	4.348	0.000
trend	-0.015	-2.287	0.023
Constant*	1.450	7.935	0.000
System Rbar-Squared	0.863		
Sample Period	2012-2022		
Number of Observations	489		

Table 14

Cost Performance Results: Station Maintenance O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2020-2022
Alectra Utilities Corporation	$ 8,409,579	$ 4,727,381	57.6%
Algoma Power Inc.	$ 86,942	$ 204,434	-85.5%
Atikokan Hydro Inc.	$ 18,699	$ 63,464	-122.2%
Bluewater Power Distribution Corporation	$ 128,769	$ 122,000	5.4%
Burlington Hydro Inc.	$ 1,147,684	$ 637,466	58.8%
Canadian Niagara Power Inc.	$ 165,841	$ 265,610	-47.1%
Centre Wellington Hydro Ltd.	$ 51,694	$ 41,485	22.0%
Chapleau Public Utilities Corporation	$ 3,495	$ 12,916	-130.7%
Cooperative Hydro Embrun Inc.	$ 14,474	$ 12,992	10.8%
Elexicon Energy Inc.	$ 714,242	$ 870,634	-19.8%
Enova Power Corp.	$ 319,679	$ 143,354	80.2%
Entegrus Powerlines Inc.	$ 293,070	$ 255,804	13.6%
EPCOR Electricity Distribution Ontario Inc.	$ 134,766	$ 109,787	20.5%
ERTH Power Corporation	$ 81,725	$ 64,351	23.9%
Greater Sudbury Hydro Inc.	$ 826,152	$ 412,724	69.4%
Halton Hills Hydro Inc.	$ 333,705	$ 184,059	59.5%
Hydro One Networks Inc.	$ 14,825,247	$ 80,909,529	-169.7%
Hydro Ottawa Limited	$ 1,748,931	$ 1,973,887	-12.1%
Innpower Corporation	$ 88,062	$ 88,150	-0.1%
Kingston Hydro Corporation	$ 258,051	$ 285,191	-10.0%
Lakefront Utilities Inc.	$ 67,817	$ 31,212	77.6%

Table 14 (continued)

Cost Performance Results: Station Maintenance O&M

Lakeland Power Distribution Ltd.	$	76,062	$	75,910	0.2%
London Hydro Inc.	$	1,197,521	$	498,702	87.6%
Milton Hydro Distribution Inc.	$	169,556	$	59,215	105.2%
Newmarket-Tay Power Distribution Ltd.	$	131,157	$	167,736	-24.6%
Niagara Peninsula Energy Inc.	$	36,404	$	156,284	-145.7%
North Bay Hydro Distribution Limited	$	152,957	$	310,802	-70.9%
Northern Ontario Wires Inc.	$	26,279	$	71,149	-99.6%
Oakville Hydro Electricity Distribution Inc.	$	216,886	$	189,307	13.6%
Orangeville Hydro Limited	$	44,337	$	24,725	58.4%
Oshawa PUC Networks Inc.	$	276,931	$	234,339	16.7%
Ottawa River Power Corporation	$	75,336	$	186,598	-90.7%
PUC Distribution Inc.	$	429,665	$	135,505	115.4%
Renfrew Hydro Inc.	$	53,492	$	68,891	-25.3%
Rideau St. Lawrence Distribution Inc.	$	74,269	$	139,031	-62.7%
Synergy North Corporation	$	289,162	$	198,143	37.8%
Toronto Hydro-Electric System Limited	$	8,092,233	$	5,446,127	39.6%
Wasaga Distribution Inc.	$	22,310	$	48,571	-77.8%
Welland Hydro-Electric System Corp.	$	187,013	$	188,704	-0.9%
Wellington North Power Inc.	$	49,524	$	37,318	28.3%
Westario Power Inc.	$	266,470	$	196,421	30.5%
Average	**$**	**958,794**	**$**	**2,173,164**	**6.6%**
Median	**$**	**130,698**	**$**	**174,175**	**3.1%**

Table 15

Econometric Model of Poles Maintenance O&M

VARIABLE KEY

Scale Variables:

npoles = Number of poles

Business Conditions:

pctwood = Percent of poles that are wood
oldpol50 = % poles over 50 years old
penload = Pensions allocated to O&M
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
npoles	0.820	11.787	0.000
npoles*npoles	0.053	1.417	0.157
pctwood	-0.796	-2.866	0.004
oldpol50	0.183	6.029	0.000
penload	-0.024	0.991	0.322
trend	-0.023	-2.505	0.013
Constant*	1.178	3.413	0.001
System Rbar-Squared	0.576		
Sample Period	2012-2022		
Number of Observations	550		

Table 16

Cost Performance Results: Poles Maintenance O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2020-2022
Algoma Power Inc.	$ 69,896	$ 90,470	-25.8%
Atikokan Hydro Inc.	$ 1,562	$ 9,403	-179.5%
Bluewater Power Distribution Corporation	$ 108,437	$ 2,028,741	-292.9%
Burlington Hydro Inc.	$ 499,482	$ 944,421	-63.7%
Canadian Niagara Power Inc.	$ 16,846	$ 15,121	10.8%
Centre Wellington Hydro Ltd.	$ 240,630	$ 117,010	72.1%
Chapleau Public Utilities Corporation	$ 6,328	$ 25,918	-141.0%
Cooperative Hydro Embrun Inc.	$ 42,581	$ 29,412	37.0%
E.L.K. Energy Inc.	$ 1,992,423	$ 623,973	116.1%
Elexicon Energy Inc.	$ 49,761	$ 115,035	-83.8%
Enova Power Corp.	$ 44,620	$ 17,623	92.9%
Entegrus Powerlines Inc.	$ 226,493	$ 162,343	33.3%
ENWIN Utilities Ltd.	$ 17,277	$ 1,852	223.3%
EPCOR Electricity Distribution Ontario Inc.	$ 46,849	$ 32,948	35.2%
ERTH Power Corporation	$ 84,481	$ 91,976	-8.5%
Essex Powerlines Corporation	$ 34,559	$ 17,915	65.7%
Festival Hydro Inc.	$ 9,818	$ 11,014	-11.5%
Fort Frances Power Corporation	$ 71,169	$ 97,618	-31.6%
GrandBridge Energy Inc.	$ 58,472	$ 46,925	22.0%
Greater Sudbury Hydro Inc.	$ 80,740	$ 92,041	-13.1%
Grimsby Power Incorporated	$ 17,081	$ 8,020	75.6%
Halton Hills Hydro Inc.	$ 5,845	$ 54,956	-224.1%
Hearst Power Distribution Company Limited	$ 428,298	$ 157,562	100.0%
Hydro 2000 Inc.	$ 80,039	$ 101,242	-23.5%
Hydro Hawkesbury Inc.	$ 174,650	$ 121,727	36.1%
Hydro One Networks Inc.	$ 145,099	$ 7,152	301.0%

Table 16 (continued)

Cost Performance Results: Poles Maintenance O&M

Hydro Ottawa Limited	$	32,529	$	13,398	88.7%
Innpower Corporation	$	65,930	$	54,413	19.2%
Kingston Hydro Corporation	$	581,562	$	423,146	31.8%
Lakeland Power Distribution Ltd.	$	128,811	$	74,466	54.8%
London Hydro Inc.	$	105,850	$	22,943	152.9%
Milton Hydro Distribution Inc.	$	14,211	$	5,114	102.2%
Newmarket-Tay Power Distribution Ltd.	$	9,985	$	12,233	-20.3%
Niagara Peninsula Energy Inc.	$	86,622	$	98,648	-13.0%
Niagara-on-the-Lake Hydro Inc.	$	8,372	$	9,078	-8.1%
North Bay Hydro Distribution Limited	$	84,524	$	69,619	19.4%
Northern Ontario Wires Inc.	$	90,537	$	196,520	-77.5%
Oakville Hydro Electricity Distribution Inc.	$	1,014,393	$	1,850,195	-60.1%
Orangeville Hydro Limited	$	2,680	$	37,070	-262.7%
Oshawa PUC Networks Inc.	$	20,924	$	11,011	64.2%
Ottawa River Power Corporation	$	53,729	$	83,175	-43.7%
PUC Distribution Inc.	$	77,119	$	570,979	-200.2%
Renfrew Hydro Inc.	$	119,096	$	868,644	-198.7%
Rideau St. Lawrence Distribution Inc.	$	50,364	$	24,368	72.6%
Sioux Lookout Hydro Inc.	$	2,401	$	1,020	85.6%
Synergy North Corporation	$	22,485	$	6,283	127.5%
Tillsonburg Hydro Inc.	$	131,514	$	246,192	-62.7%
Toronto Hydro-Electric System Limited	$	178,007	$	208,684	-15.9%
Wasaga Distribution Inc.	$	30,762	$	198,402	-186.4%
Welland Hydro-Electric System Corp.	$	22,839,681	$	19,895,616	13.8%
Wellington North Power Inc.	$	1,340,219	$	1,166,296	13.9%
Westario Power Inc.	$	1,579	$	816	66.0%
Average	**$**	**608,602**	**$**	**599,438**	**-2.2%**
Median	**$**	**67,913**	**$**	**72,043**	**13.9%**

Table 17

Econometric Model of Distribution Station Capex

VARIABLE KEY

Scale Variables:

nstattrf = Number of station transformers, rolling 3-year average

Business Conditions:

nlinetrf = Number of line transformers, rolling 3-year average

trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
nstattrf	0.920	5.599	0.000
I(nstattrf * nstattrf/2)	-0.073	-1.377	0.169
nlinetrf	0.373	2.614	0.009
trend	0.000	0.019	0.985
Constant*	9.272	48.238	0.000
System Rbar-Squared	0.506		
Sample Period	2012-2022		
Number of Observations	371		

Table 18

Cost Performance Results: Distribution Station Capex

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2020-2022
Alectra Utilities Corporation	$ 3,701,075	$ 12,436,346	-121.2%
Algoma Power Inc.	$ 1,237,196	$ 253,814	158.4%
Bluewater Power Distribution Corporation	$ 243,596	$ 242,138	0.6%
Burlington Hydro Inc.	$ 317,327	$ 709,055	-80.4%
Canadian Niagara Power Inc.	$ 2,028,607	$ 273,720	200.3%
Chapleau Public Utilities Corporation	$ 29,340	$ 3,947	200.6%
Elexicon Energy Inc.	$ 3,558,298	$ 1,842,793	65.8%
Enova Power Corp.	$ 280,670	$ 203,808	32.0%
Entegrus Powerlines Inc.	$ 126,104	$ 327,048	-95.3%
EPCOR Electricity Distribution Ontario Inc.	$ 48,882	$ 140,670	-105.7%
Festival Hydro Inc.	$ 76,321	$ 14,027	169.4%
Greater Sudbury Hydro Inc.	$ 1,294,126	$ 507,548	93.6%
Halton Hills Hydro Inc.	$ 448,273	$ 137,058	118.5%
Hydro One Networks Inc.	$ 27,220,905	$ 243,711,522	-219.2%
Hydro Ottawa Limited	$ 3,053,789	$ 3,851,193	-23.2%
Innpower Corporation	$ 1,908,221	$ 147,073	256.3%
Kingston Hydro Corporation	$ 1,123,562	$ 274,859	140.8%
Lakefront Utilities Inc.	$ 23,319	$ 51,897	-80.0%

Table 18 (continued)

Cost Performance Results: Distribution Station Capex

Lakeland Power Distribution Ltd.	$	34,389	$	108,067	-114.5%
London Hydro Inc.	$	239,762	$	1,178,087	-159.2%
Milton Hydro Distribution Inc.	$	15,744	$	111,884	-196.1%
Newmarket-Tay Power Distribution Ltd.	$	900,110	$	277,971	117.5%
Niagara Peninsula Energy Inc.	$	27,432	$	314,723	-244.0%
North Bay Hydro Distribution Limited	$	405,891	$	325,084	22.2%
Northern Ontario Wires Inc.	$	3,547	$	96,743	-330.6%
Oakville Hydro Electricity Distribution Inc.	$	728,638	$	323,493	81.2%
Orangeville Hydro Limited	$	1,465	$	27,103	-291.8%
Oshawa PUC Networks Inc.	$	441,344	$	246,614	58.2%
Ottawa River Power Corporation	$	321,557	$	105,444	111.5%
PUC Distribution Inc.	$	5,284,594	$	374,110	264.8%
Renfrew Hydro Inc.	$	26,580	$	29,200	-9.4%
Synergy North Corporation	$	5,300	$	349,895	-419.0%
Toronto Hydro-Electric System Limited	$	24,480,973	$	4,763,088	163.7%
Wasaga Distribution Inc.	$	1,113,960	$	42,211	327.3%
Welland Hydro-Electric System Corp.	$	378,404	$	146,344	95.0%
Westario Power Inc.	$	755,963	$	306,431	90.3%
Average	**$**	**2,274,591**	**$**	**7,618,195**	**7.7%**
Median	**$**	**392,147**	**$**	**263,767**	**45.1%**

Table 19

Econometric Model of Poles, Towers and Fixtures Capex

VARIABLE KEY

Scale Variables:

npoles = Number of poles, rolling 3-year average

Business Conditions:

ykmpernpol = km of line per pole, rolling 3-year average
oldpol50 = percentage of poles older than 50 years
ynadd3 = Customer growth over the last 3 years, 3-year average
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
npoles	1.079	101.361	0.000
I(npoles*npoles/2)	-0.048	-5.185	0.000
ykmpernpol	0.158	2.749	0.006
oldpol50	0.046	1.428	0.154
ynadd3	3.360	2.357	0.019
trend	0.050	7.385	0.000
Constant*	10.581	149.870	0.000
System Rbar-Squared	0.880		
Sample Period	2012-2022		
Number of Observations	486		

Table 20

Cost Performance Results: Poles, Towers and Fixtures Capex

Distributor		Average Actual		Average Predicted	Average Actual Less Predicted 2020-2022
Alectra Utilities Corporation	$	47,978,445	$	33,306,476	36.5%
Algoma Power Inc.	$	3,301,321	$	5,019,461	-41.9%
Atikokan Hydro Inc.	$	136,812	$	110,124	21.7%
Bluewater Power Distribution Corporation	$	2,713,836	$	2,158,391	22.9%
Burlington Hydro Inc.	$	2,144,569	$	2,367,747	-9.9%
Canadian Niagara Power Inc.	$	2,489,457	$	3,424,874	-31.9%
Centre Wellington Hydro Ltd.	$	298,752	$	194,535	42.9%
Chapleau Public Utilities Corporation	$	60,781	$	60,781	0.0%
Cooperative Hydro Embrun Inc.	$	26,914	$	23,328	14.3%
E.L.K. Energy Inc.	$	157,394	$	435,176	-101.7%
Elexicon Energy Inc.	$	9,850,688	$	6,414,373	42.9%
Enova Power Corp.	$	8,264,334	$	7,492,850	9.8%
Entegrus Powerlines Inc.	$	3,402,568	$	3,752,906	-9.8%
ENWIN Utilities Ltd.	$	2,562,187	$	3,510,861	-31.5%
EPCOR Electricity Distribution Ontario Inc.	$	1,766,614	$	664,357	97.8%
ERTH Power Corporation	$	912,691	$	1,394,649	-42.4%
Essex Powerlines Corporation	$	579,721	$	1,012,874	-55.8%
Festival Hydro Inc.	$	446,328	$	722,742	-48.2%
Fort Frances Power Corporation	$	62,916	$	155,057	-90.2%
GrandBridge Energy Inc.	$	3,813,895	$	5,236,488	-31.7%
Greater Sudbury Hydro Inc.	$	2,247,689	$	1,661,802	30.2%
Grimsby Power Incorporated	$	603,210	$	521,269	14.6%
Halton Hills Hydro Inc.	$	1,474,512	$	1,462,763	0.8%
Hearst Power Distribution Company Limited	$	145,056	$	221,655	-42.4%
Hydro 2000 Inc.	$	44,570	$	20,740	76.5%
Hydro Hawkesbury Inc.	$	39,679	$	114,184	-105.7%
Hydro One Networks Inc.	$	297,974,112	$	238,890,816	22.1%

Table 20 (continued)

Cost Performance Results: Poles, Towers and Fixtures Capex

Hydro Ottawa Limited	$	11,169,175	$	9,846,911	12.6%
Innpower Corporation	$	3,873,253	$	1,846,136	74.1%
Kingston Hydro Corporation	$	878,593	$	594,858	39.0%
Lakefront Utilities Inc.	$	597,742	$	341,777	55.9%
Lakeland Power Distribution Ltd.	$	1,501,687	$	753,210	69.0%
London Hydro Inc.	$	2,335,726	$	4,822,646	-72.5%
Milton Hydro Distribution Inc.	$	2,181,410	$	1,849,604	16.5%
Newmarket-Tay Power Distribution Ltd.	$	855,038	$	1,229,233	-36.3%
Niagara Peninsula Energy Inc.	$	3,664,218	$	4,980,921	-30.7%
Niagara-on-the-Lake Hydro Inc.	$	370,995	$	615,349	-50.6%
North Bay Hydro Distribution Limited	$	1,626,179	$	1,595,574	1.9%
Northern Ontario Wires Inc.	$	192,004	$	367,791	-65.0%
Oakville Hydro Electricity Distribution Inc.	$	3,116,018	$	1,362,820	82.7%
Orangeville Hydro Limited	$	235,445	$	168,929	33.2%
Oshawa PUC Networks Inc.	$	5,126,244	$	1,608,615	115.9%
Ottawa River Power Corporation	$	198,835	$	722,326	-129.0%
PUC Distribution Inc.	$	8,895,616	$	2,324,625	134.2%
Renfrew Hydro Inc.	$	361,709	$	140,448	94.6%
Rideau St. Lawrence Distribution Inc.	$	351,166	$	204,846	53.9%
Sioux Lookout Hydro Inc.	$	141,990	$	396,532	-102.7%
Synergy North Corporation	$	5,632,260	$	3,213,982	56.1%
Tillsonburg Hydro Inc.	$	198,954	$	336,324	-52.5%
Toronto Hydro-Electric System Limited	$	32,123,272	$	35,289,333	-9.4%
Wasaga Distribution Inc.	$	662,774	$	773,120	-15.4%
Welland Hydro-Electric System Corp.	$	947,033	$	1,240,580	-27.0%
Wellington North Power Inc.	$	169,958	$	220,424	-26.0%
Westario Power Inc.	$	1,531,473	$	1,439,405	6.2%
Average	**$**	**8,934,034**	**$**	**7,382,178**	**0.3%**
Median	**$**	**1,210,773**	**$**	**1,234,906**	**1.4%**

Table 21

Econometric Model of Line Transformers Capex

VARIABLE KEY

Scale Variables:

yn = Number of customers, rolling 3-year average
ykm = km of line, rolling 3-year average

Business Conditions:

ynadd3 = Customer growth over the last 3 years, 3-year average
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn	0.785	23.617	0.000
yn*yn	-0.138	-6.959	0.000
ykm	0.237	8.002	0.000
ynadd3	7.565	7.090	0.000
trend	0.022	4.093	0.000
Constant*	10.155	225.395	0.000
System Rbar-Squared	0.889		
Sample Period	2012-2022		
Number of Observations	486		

Table 22

Cost Performance Results: Line Transformers Capex

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2020-2022
Alectra Utilities Corporation	$ 54,762,385	$ 34,570,598	46.0%
Algoma Power Inc.	$ 758,749	$ 494,067	42.9%
Atikokan Hydro Inc.	$ 7,427	$ 18,600	-91.8%
Bluewater Power Distribution Corporation	$ 1,396,388	$ 1,058,538	27.7%
Burlington Hydro Inc.	$ 1,209,882	$ 2,124,471	-56.3%
Canadian Niagara Power Inc.	$ 1,429,821	$ 1,087,138	27.4%
Centre Wellington Hydro Ltd.	$ 49,138	$ 164,289	-120.7%
Chapleau Public Utilities Corporation	$ 4,838	$ 12,916	-98.2%
Cooperative Hydro Embrun Inc.	$ 131,713	$ 30,896	145.0%
E.L.K. Energy Inc.	$ 390,720	$ 285,429	31.4%
Elexicon Energy Inc.	$ 7,293,972	$ 6,037,851	18.9%
Enova Power Corp.	$ 7,099,196	$ 5,312,070	29.0%
Entegrus Powerlines Inc.	$ 1,685,198	$ 2,658,822	-45.6%
ENWIN Utilities Ltd.	$ 2,022,452	$ 3,626,655	-58.4%
EPCOR Electricity Distribution Ontario Inc.	$ 372,860	$ 578,943	-44.0%
ERTH Power Corporation	$ 802,137	$ 685,590	15.7%
Essex Powerlines Corporation	$ 1,019,272	$ 1,124,219	-9.8%
Festival Hydro Inc.	$ 362,385	$ 563,804	-44.2%
Fort Frances Power Corporation	$ 52,122	$ 48,647	6.9%
GrandBridge Energy Inc.	$ 4,406,326	$ 3,687,841	17.8%
Greater Sudbury Hydro Inc.	$ 1,455,792	$ 1,323,858	9.5%
Grimsby Power Incorporated	$ 194,155	$ 349,554	-58.8%
Halton Hills Hydro Inc.	$ 648,286	$ 783,939	-19.0%
Hearst Power Distribution Company Limited	$ 20,009	$ 38,138	-64.5%
Hydro 2000 Inc.	$ 62,643	$ 7,850	207.7%
Hydro Hawkesbury Inc.	$ 42,320	$ 83,618	-68.1%
Hydro One Networks Inc.	$ 7,324,297	$ 42,657,247	-176.2%

Table 22 (continued)

Cost Performance Results: Line Transformers Capex

Hydro Ottawa Limited	$	10,585,821	$	11,995,306	-12.5%
Innpower Corporation	$	1,233,574	$	992,941	21.7%
Kingston Hydro Corporation	$	286,595	$	667,855	-84.6%
Lakefront Utilities Inc.	$	288,623	$	243,257	17.1%
Lakeland Power Distribution Ltd.	$	549,113	$	386,567	35.1%
London Hydro Inc.	$	5,284,542	$	5,289,829	-0.1%
Milton Hydro Distribution Inc.	$	1,951,235	$	2,006,641	-2.8%
Newmarket-Tay Power Distribution Ltd.	$	887,105	$	1,392,649	-45.1%
Niagara Peninsula Energy Inc.	$	2,373,647	$	2,615,427	-9.7%
Niagara-on-the-Lake Hydro Inc.	$	332,197	$	238,585	33.1%
North Bay Hydro Distribution Limited	$	710,178	$	730,344	-2.8%
Northern Ontario Wires Inc.	$	57,725	$	128,598	-80.1%
Oakville Hydro Electricity Distribution Inc.	$	1,984,726	$	2,777,305	-33.6%
Orangeville Hydro Limited	$	455,220	$	267,410	53.2%
Oshawa PUC Networks Inc.	$	1,991,924	$	1,764,912	12.1%
Ottawa River Power Corporation	$	326,755	$	317,732	2.8%
PUC Distribution Inc.	$	6,010,446	$	876,778	192.5%
Renfrew Hydro Inc.	$	17,338	$	64,320	-131.1%
Rideau St. Lawrence Distribution Inc.	$	133,850	$	94,795	34.5%
Sioux Lookout Hydro Inc.	$	74,952	$	57,850	25.9%
Synergy North Corporation	$	1,875,808	$	1,634,014	13.8%
Tillsonburg Hydro Inc.	$	272,793	$	254,350	7.0%
Toronto Hydro-Electric System Limited	$	83,858,053	$	20,679,141	140.0%
Wasaga Distribution Inc.	$	502,676	$	407,054	21.1%
Welland Hydro-Electric System Corp.	$	747,228	$	793,434	-6.0%
Wellington North Power Inc.	$	197,492	$	77,610	93.4%
Westario Power Inc.	$	351,866	$	713,549	-70.7%
Average	**$**	**4,043,444**	**$**	**3,090,441**	**-2.0%**
Median	**$**	**679,232**	**$**	**699,569**	**4.9%**

Table 23

Econometric Model of Meter Capex

VARIABLE KEY

Scale Variables:

yn = Number of customers, rolling 3-year average

ykm = km of line, rolling 3-year average

Business Conditions:

ynadd3 = Customer growth over the last 3 years, 3-year average

trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn3a	0.612	7.843	0.000
I(yn3a * yn3a/2)	-0.076	-2.212	0.027
ykm3a	0.390	5.939	0.000
ynadd33a	1.676	0.771	0.441
trend	-0.036	-3.307	0.001
Constant*	9.606	104.279	0.000
System Rbar-Squared	0.788		
Sample Period	2012-2022		
Number of Observations	486		

Table 24

Cost Performance Results: Meter Capex

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2020-2022
Alectra Utilities Corporation	$ 10,393,751	$ 19,052,623	-60.6%
Algoma Power Inc.	$ 140,330	$ 237,935	-52.8%
Atikokan Hydro Inc.	$ 10,095	$ 9,787	3.1%
Bluewater Power Distribution Corporation	$ 278,269	$ 354,104	-24.1%
Burlington Hydro Inc.	$ 636,709	$ 639,900	-0.5%
Canadian Niagara Power Inc.	$ 268,513	$ 373,493	-33.0%
Centre Wellington Hydro Ltd.	$ 47,688	$ 55,295	-14.8%
Chapleau Public Utilities Corporation	$ 2,913	$ 8,561	-107.8%
Cooperative Hydro Embrun Inc.	$ 11,455	$ 11,839	-3.3%
E.L.K. Energy Inc.	$ 50,316	$ 90,408	-58.6%
Elexicon Energy Inc.	$ 1,122,027	$ 1,700,865	-41.6%
Enova Power Corp.	$ 1,206,048	$ 1,627,994	-30.0%
Entegrus Powerlines Inc.	$ 1,552,257	$ 789,552	67.6%
ENWIN Utilities Ltd.	$ 907,505	$ 1,188,799	-27.0%
EPCOR Electricity Distribution Ontario Inc.	$ 91,168	$ 170,495	-62.6%
ERTH Power Corporation	$ 312,164	$ 197,459	45.8%
Essex Powerlines Corporation	$ 243,860	$ 386,292	-46.0%
Festival Hydro Inc.	$ 253,702	$ 147,107	54.5%
Fort Frances Power Corporation	$ 44,911	$ 23,097	66.5%
GrandBridge Energy Inc.	$ 596,081	$ 1,022,879	-54.0%
Greater Sudbury Hydro Inc.	$ 225,096	$ 444,312	-68.0%
Grimsby Power Incorporated	$ 63,503	$ 152,792	-87.8%
Halton Hills Hydro Inc.	$ 360,306	$ 303,978	17.0%
Hearst Power Distribution Company Limited	$ 5,775	$ 20,035	-124.4%
Hydro 2000 Inc.	$ 4,187	$ 4,031	3.8%
Hydro Hawkesbury Inc.	$ 32,853	$ 32,526	1.0%
Hydro One Networks Inc.	$ 69,681,679	$ 10,073,794	193.4%

Table 24 (continued)

Cost Performance Results: Meter Capex

Hydro Ottawa Limited	$	3,804,390	$	3,222,494	16.6%
Innpower Corporation	$	253,213	$	320,612	-23.6%
Kingston Hydro Corporation	$	232,628	$	182,626	24.2%
Lakefront Utilities Inc.	$	92,129	$	81,304	12.5%
Lakeland Power Distribution Ltd.	$	148,100	$	124,947	17.0%
London Hydro Inc.	$	1,140,609	$	1,500,146	-27.4%
Milton Hydro Distribution Inc.	$	1,160,792	$	582,226	69.0%
Newmarket-Tay Power Distribution Ltd.	$	379,074	$	420,621	-10.4%
Niagara Peninsula Energy Inc.	$	1,019,678	$	802,107	24.0%
Niagara-on-the-Lake Hydro Inc.	$	106,540	$	88,281	18.8%
North Bay Hydro Distribution Limited	$	150,068	$	249,657	-50.9%
Northern Ontario Wires Inc.	$	26,897	$	64,523	-87.5%
Oakville Hydro Electricity Distribution Inc.	$	947,392	$	753,488	22.9%
Orangeville Hydro Limited	$	90,671	$	92,781	-2.3%
Oshawa PUC Networks Inc.	$	1,017,679	$	485,064	74.1%
Ottawa River Power Corporation	$	96,217	$	120,134	-22.2%
PUC Distribution Inc.	$	2,022,887	$	293,618	193.0%
Renfrew Hydro Inc.	$	40,690	$	25,764	45.7%
Rideau St. Lawrence Distribution Inc.	$	41,977	$	38,672	8.2%
Sioux Lookout Hydro Inc.	$	8,929	$	57,418	-186.1%
Synergy North Corporation	$	529,319	$	514,703	2.8%
Tillsonburg Hydro Inc.	$	80,403	$	61,317	27.1%
Toronto Hydro-Electric System Limited	$	17,780,144	$	6,488,831	100.8%
Wasaga Distribution Inc.	$	91,861	$	123,011	-29.2%
Welland Hydro-Electric System Corp.	$	95,294	$	220,516	-83.9%
Wellington North Power Inc.	$	110,750	$	34,545	116.5%
Westario Power Inc.	$	214,446	$	218,559	-1.9%
Average	**$**	**2,226,406**	**$**	**1,042,369**	**-3.6%**
Median	**$**	**219,771**	**$**	**219,538**	**-2.1%**

5. Interpretation of Results and Applications of APB

5.1. Noteworthy Limitations

The econometric models that have been developed have several potential applications. These tools also have limitations which the users of these results should consider. Although some of these models have significant explanatory power, no statistical model will be perfect and cannot replace sound judgement. In general, statistical models can be important tools the regulatory community can use in the discovery process to help determine just and reasonable rates. In addition to being a regulatory tool, the models can also be used as part of a process to discover best practices which leads to better productivity and cost efficiency.

Econometric cost models will have some limitations that should be noted. The first is that the measurement of input prices may differ from the actual experience of distributors. The O&M price indexes are taken from PEG's total cost benchmarking work for OEB staff and contain assignments of distributors to cities with available data. It also assumes that labor cost is a substantial 75% of OM&A cost. The capital expenditure models assume that all distributors face the same construction costs which assumes that crews doing such construction operate regionally and are not necessarily based near where the work is being done.

The econometric models contain variables that attempt to capture the average impact of accounting issues associated with the classification of expenses. To the extent that the actual impact of accounting differs, the impact on the results could be considered. Although the inclusion of estimated data provides a good basis for the estimation of an econometric model, some care should be exercised when interpreting particular results based on estimates.

A final factor that should be considered is that some relevant business conditions will not be measured in the models. Some are difficult or impossible to model. Additional analysis to quantify the cost impact should be considered to explain differences between actual and predicted cost that is currently interpreted as management performance. For example, some distributors were asked to physically move a significant amount of assets to allow for highway projects. This is a case in which there is a clearly relevant business condition beyond the control of management that has an impact on cost. A distributor facing questions related to benchmarking results in a rate case could undertake to provide an estimate of the incremental cost of this unmeasured business condition. It could be used to explain the cost performance results, thereby reducing the amount of any cost performance deficiency that is attributed to management performance.

5.2. Increasing the Effectiveness of Regulation

A major goal of APB is to provide tools to the regulatory community that will help focus a limited amount of attention and other resources to areas that appear to deserve additional inquiry. Results are useful for identifying chronically good and bad cost performance and notable declines in performance in test years that could indicate strategic behavior.

The benchmarking results presented in this report can assist this effort. Examining the results of the unit cost and econometric models for a particular cost area could act as a screening tool to help determine where to focus effort. PEG prefers to characterize this screening as identifying areas that are *not* worth spending much effort. Should APB suggest that a distributor has average or below-average cost in a certain area, this should provide some evidence that additional time spent examining this cost area would be unlikely to uncover a significant cost control problem by management. Unless there is relevant information not addressed by the model, it would be reasonable for a reviewer to ignore this area and presume that management is doing an acceptable job.

As for areas in which a distributor is performing significantly worse than predicted by the model, some care should be taken to put the result in context. There are many reasons why a distributor might perform poorly in a statistical model, and only one reason is poor management performance. Other reasons include:

- Differences in accounting arising from inconsistent application of the OEB's accounting guidance in the Accounting Procedures Handbook (APH)
- Measurable business conditions with significant cost impact not included in the econometric model
- Other random, exogenous events that are difficult or impossible to measure for all distributors

By attempting to account for many measurable reasons for differences in cost, it is hoped that the limited amount of regulatory attention can be focused on areas in which a distributor has special circumstances.

5.3. Continuous Improvement in Existing and New APB Models

Just as the APB results presented here are a starting point for analysis and not an end in themselves, the models themselves can also be improved and additional cost areas considered. With a detailed benchmarking program such as APB, the areas that could be potentially benchmarked were too numerous. The near-term goal of APB was to make a set of relevant models available. Improvement in the data and methods used to generate these benchmarking results will continue over time. Input from distributors and other parties making use of these results is vital to making APB a useful resource for Ontario Regulation.