BENCHMARKING THE COSTS OF ONTARIO POWER DISTRIBUTORS

Pacific Economics Group, LLC

Economic and Litigation Consulting

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Executive Summary

The Ontario Energy Board has in recent years taken a growing interest in the benchmarking of jurisdictional power distributors. Last November, Board staff announced a consultation process on cost benchmarking for the next round of Electricity Distribution Rate ("EDR") applications. It released four years of Ontario distributor operating data and requested feedback from stakeholders on a new unit cost approach to benchmarking that it developed.

Staff have retained Pacific Economics Group to help it develop an operational benchmarking method for ratemaking. We have been asked to

- Review and appraise staff's unit cost benchmarking approach;
- Consider other approaches and recommend a best approach;
- Review precedents for the use of benchmarking in regulation; and
- Recommend reforms in the Board's data collection.

This is the report on our work.

Introduction to Statistical Benchmarking

Benchmarking is an approach to performance evaluation in which comparisons are made to benchmarks that represent external performance standards. Statistics can be used to calculate benchmarks and draw conclusions about operating efficiency from benchmark comparisons. The benchmarking of cost levels is undertaken voluntarily by many utilities and is used in ratemaking in several jurisdictions around the world.

A fundamental result of benchmarking science is that differences between the costs of utilities depend in large measure on differences in external business conditions. The cost performance of a company is thus a matter of the cost that it incurs given the business conditions that it faces. Benchmarks should accurately reflect these conditions.

Cost theory plays an essential role in rigorous cost benchmarking. Theory suggests that the costs incurred by utilities may differ due to differences in workloads, input prices, and miscellaneous other business conditions. Workloads can be multifaceted, and thus poorly measured by simple measures of output such as the number of customers served.

Theory also suggests that accurate benchmarking is more difficult the more micro are the cost categories considered.

Two methodologies are used extensively in North American regulation to benchmark costs: indexing and econometrics. Indexing commonly involves the calculation of unit costs that make an automatic adjustment for differences in utility workloads. Unit cost metrics can be as simple as cost per customer, but more sophisticated unit cost indexes are available that permit comparisons of several workload dimensions simultaneously. In either case, performance is measured by comparing the metric for a utility to the average for a peer group. The accuracy of the indexing approach to benchmarking hinges on the degree to which the cost pressures faced by the peer group resemble those faced by the subject utility.

Under the econometric approach to benchmarking, historical operating data are used to estimate the parameters of a model of the relationship between cost and various business conditions. The resultant econometric cost model, fitted with data on the business conditions faced by a utility, then generates a cost benchmark. Sensible statistical tests of efficiency hypotheses are available.

Special challenges are encountered in the benchmarking of capital cost. These include the need to control for differences in the depreciation practices and the system age of utilities. Methods designed to address these challenges require years of capital cost data.

Precedents for Cost Benchmarking in Ratemaking

The use of cost benchmarking in ratemaking varies greatly in the advanced industrial world. In the United States and Canada, benchmarking has been largely limited to occasional and voluntary submissions by utilities. Indexing and econometric methods have both been used.

In Western Europe, benchmarking has been used in several countries to adjust rate levels and/or the pace of automatic rate escalation. Regulators in several Australian states were unhappy with early statistical benchmarking experiments and have not continued. However, benchmarking recently played a role in the development of a ratemaking method for power distributors in New Zealand.

Where regulators have taken the initiative in statistical benchmarking studies they have generally favored more complex methods over simple unit cost metrics. The operation, maintenance, and adminstration ("OM&A") expenses of power distributors have been a common focus. Benchmarking is especially common where regulators have jurisdiction over numerous utilities. There is ample precedent, then, for the use of benchmarking in the regulation of the OM&A expenses of Ontario's numerous power distributors.

Application: Power Distribution

Econometric research has identified numerous business conditions that drive power distributor cost. These include input prices, operating scale, system undergrounding, customer density, forestation, and the contiguity of the service territory. These business conditions can vary between utilities and an attempt should be made to recognize their impact in a responsible benchmarking study.

Ontario Data

The Board has established itself in recent years as a leader in the gathering of data that are useful in power distribution cost benchmarking. Despite the progress made, the data have flaws that limit their usefulness in benchmarking. Improvements in the data gathering and collection process can lead to better benchmarking and an expanded role for benchmarking in regulation. The following reforms are especially worthwhile:

- better guidelines for, and public reporting of, the share of salaries and wages in net OM&A expenses;
- greater consistency in the assignment of labour costs to the major categories of distributor activities;
- better guidelines for, and monitoring of, the itemized volume and peak load data;
- collection of data on aggregate deliveries to other power distributors; and
- standardized, publicly available data on plant additions.

Benchmarking Ontario Power Distributors

We developed several defensible econometric cost models for total OM&A expenses using Ontario data for the 2002-2005 period. All of the business condition variables in the models have statistically significant and sensibly signed parameter estimates. The explanatory power of the models is high. The results suggest that there are at least three scale-related drivers of distributor cost --- delivery volume, the number of customers served, and system extensiveness--- as well as miscellaneous other drivers that include undergrounding and forestation. The models also suggest that there are appreciable economies of scale in Ontario power distribution after controlling for other business conditions. These economies give larger utilities a material unit cost advantage over smaller utilities after controlling for differences in other business conditions. Econometric research can shed more light on cost drivers as new data become available for model estimation.

We calculated unit cost and productivity indexes for the sampled distributors using multi-dimensional output quantity treatments. These treatments take a weighted average of comparisons of delivery volumes, system extensiveness, and the number of customers served. The weights for these output dimensions (24 %, 15%, and 61% respectively) are based on our econometric estimates of their cost impact. We have used the econometric models, additionally, to directly benchmark the costs of the distributors.

Two distributors were excluded from the benchmarking exercises due to data problems: Oshawa and Hydro One Networks ("Hydro One"). Both can potentially be benchmarked with data reforms and additional years of data. Direct econometric modeling is preferable to indexing for Hydro One if Ontario data are used due to a lack of suitable peers. An alternative would be index-based benchmarking using data from utilities outside the province.

Board staff have developed an approach to the benchmarking of power distributor cost that features simple unit cost metrics (*e.g.* cost per customer). The peer groups do a good job of sorting utilities based on differences in the operating scale, input prices, and forestation that they face. However, utilities in some groups have widely varying degrees of customer density. This approach should be upgraded if it is to be used in ratemaking. Two steps are especially essential:

1. Focus on the cost of total OM&A expenses for the next round of rate cases.
2. Instead of simple unit cost metrics, use unit cost indexes with multidimensional output quantity treatments such as those that we have developed from our econometric work. The Board should also consider replacing or supplementing indexing with direct econometric cost benchmarking. All of these steps can be implemented now in time for use in the upcoming EDR applications.

In choosing between the benchmarking methods that have been developed for its consideration, the Board must balance the criteria of benchmarking accuracy and the complexity of methods. The direct econometric approach to benchmarking is more complex than cost indexing but has a number of advantages that include greater accuracy and the availability of sensible statistical tests of efficiency hypotheses. Regulators in several countries have concluded that the advantages of sophistication generally outweigh the advantages of simplicity when benchmarking is used in ratemaking.

Provided that staff moves, at a minimum, to upgrade its unit cost approach in the manner recommended, and/or adopts the direct econometric benchmarking approach we believe that benchmarking can and should play a role in the upcoming EDR applications for Ontario power distributors. Bridge year and test year costs should be benchmarked since these are the costs that future rates will most closely reflect.

None of the methods developed are good enough yet to provide the basis for mechanistic adjustments to initial rates and rate adjustment mechanisms. We are particularly concerned about the inability of current methods to control for differences between distributors in customer mix, capital usage, system age, and deliveries to other distributors. There are noteworthy deficiencies in the data available for benchmarking. In view of these constraints, we believe that benchmarking should be limited to the identification of companies that --- thanks to favorable scores --- merit expedited processing of rate applications and those that --- due to poor scores --- should be scheduled for especially thorough prudence reviews.

That said, it should be noted that the quality of benchmarking results can be materially improved in time for the 2008 EDR applications by updating the benchmarking study to include 2006 data and by improving the quality of data where possible. Based on our experience, we believe that the addition of even one year of additional data should permit material improvements in the accuracy of performance rankings for utilities involved in the 2008 EDR applications. The Board should, additionally, consider using 2007 and 2008 data as they become available to improve benchmarking results for the later EDR tranches.

With more and better data, benchmarking may reach a level of accuracy that will permit it to play a larger role in the regulation of Ontario power distributors. Regulators may still undertake more traditional prudence reviews but can rely in part on benchmarking results to set initial rates and the escalation terms of rate adjustment mechanisms. In that eventuality, statistical tests of efficiency hypotheses can help to ensure the reasonableness of regulatory outcomes. We also encourage the Board to consider awards for superior performance in addition to penalties for inferior performance.

1. Introduction

Statistical benchmarking has in recent years become an accepted tool in the assessment of utility performance. Managers look to benchmarking studies for indications of how efficient their companies are. Benchmarking also plays a role in utility regulation in several jurisdictions around the world. Such studies have, for example, been used to inform decisions concerning the initial rates and the rate adjustment mechanisms of multi-year regulatory plans.

Benchmarking of the operating performance of utilities is facilitated by the extensive data that utilities report to regulators. Accurate performance appraisals are nonetheless challenging. For example, there are important differences between companies in the services provided, the prices of inputs used in service provision, and in other business conditions that influence their cost. The sample of quality, standardized data available for benchmarking is sometimes small and data on key variables needed for benchmarking are sometimes unavailable.

The Ontario Energy Board has in recent years taken a growing interest in the benchmarking of jurisdictional power distributors. Cost benchmarking was used as a screening tool in the 2006 EDR applications. The Board announced in 2006 that it would continue its work on methods and techniques for distributor cost comparisons. In November, Board staff announced a cost comparison consultation process. It released data on Ontario utility operations for four recent years, and requested feedback from stakeholders on a new approach to benchmarking that involved particular cost centres, cost drivers, and peer groups.

Pacific Economics Group ("PEG") is a leading practitioner of energy utility benchmarking and has advised dozens of clients on benchmarking issues. We have more than forty man-years of experience in the field of utility performance measurement and pioneered the use of scientific benchmarking in U.S. regulation. We have benchmarked electric utility generation, transmission, distribution, customer, and administrative and general services, bundled power service, and gas distribution.

Staff has retained PEG to help it develop an operational benchmarking method for the next round of rebasing proceedings. We have been asked, specifically, to

- Review and appraise staff's benchmarking ideas;
- Recommend a specific approach to benchmarking;
- Review salient precedents for the use of benchmarking in regulation; and
- Identify needed reforms in the Board's data collection process.

This is the preliminary report on our work.

Here is the plan for the paper. An introduction to statistical benchmarking is provided in Section 2, which includes discussions of benchmarking methods. Section 3 provides a brief summary of precedents for benchmarking in energy utility regulation. There follows in Section 4 a discussion of the challenges encountered in benchmarking the costs of electric power distributors. In Section 5 we turn to a review of the data and staff's proposed methodology and report on our empirical research. The paper concludes with suggestions for improvements in staff's benchmarking program. More technical details of the research are discussed in the Appendix.

2. An Introduction to Benchmarking

In this section, we consider some important benchmarking concepts. The benchmarking methods most widely used in regulation are introduced and explained. The section concludes with a discussion of the special challenges of benchmarking capital costs.

2.1 What is Benchmarking?

The word benchmark comes from the field of surveying. The *Oxford English Dictionary* defines a benchmark as

> A surveyors mark, cut in some durable material, as a rock, wall, gate pillar, face of a building, etc. to indicate the starting, closing, ending or any suitable intermediate point in a line of levels for the determination of altitudes over the face of a country.

The term has subsequently been used more generally to indicate something that embodies a performance standard and can be used as a point of comparison in performance appraisals.

A quantitative benchmarking exercise commonly involves one or more gauges of activity. These are called, variously, comparators and performance indicators. The values of the indicators achieved by an entity under scrutiny are compared to benchmark values that reflect performance standards. Given information on the cost of a utility and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values.

$$\text{Cost Performance} = \text{Cost}^{\text{Actual}}/\text{Cost}^{\text{Benchmark}}$$

Benchmarks are often developed using data on the operations of agents that are involved in the activity under study. Statistical methods are useful in both the calculation of benchmarks and in the comparison process. An approach to benchmarking that prominently features statistical methods is called statistical benchmarking.

Various performance standards can be used in statistical benchmarking. These standards often reflect statistical concepts. For example, one sensible standard is the average performance of the utilities in the sample. Alternative standards include the apparent best or frontier performance in the sample and the performance that would define the margin of the top quartile of performers.

2.2 External Business Conditions

For costs and many other kinds of performance variables, it is widely recognized that differences in the values of the variables that companies achieve depend partly on differences in operating efficiency and partly on differences in external business conditions. In cost research, these conditions are sometimes called cost drivers. An external business condition is a condition of the operating environment that a firm cannot control. In the electric utility industry examples include the number of customers served and the market prices of labour, capital equipment, and other production inputs. Billing and collection expenses will, for example, vary with the number of customers served.

The cost performance of a company depends on the cost that it achieves given the external business conditions that it faces. Benchmarks must therefore reflect external business conditions if they are to reflect a chosen performance standard faithfully. This helps to explain why the identification of relevant business conditions and consideration of their impact on performance variables are important tasks in a responsible benchmarking study.

2.3 Contributions from Cost Theory

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. We begin by positing that the actual cost incurred by a company is the product of the *minimum achievable* cost and an efficiency factor.[1] The goal of cost benchmarking is then to accurately estimate the efficiency factor.

Consider next that, under certain reasonable assumptions, cost functions exist that relate the minimum cost of an enterprise to external business conditions in its service territory. Two kinds of cost functions yielded by this theory are useful in benchmarking. One is the *total* cost function in which the minimum total cost of an enterprise is a function of the prices of production inputs, output quantities, and variables representing

[1] Minimum achievable cost is a hypothetical notion and cannot be precisely calculated for specific utilities.

miscellaneous other business conditions. The latter group of variables is sometimes conveniently called “Z” variables.

The theory allows for the existence of *multiple* output variables. This is important because it is often impossible to accurately measure the workload of a utility using only one output variable. The cost of power transmission, for instance, depends as much or more on peak demand as it does on the volume delivered. It is also noteworthy that the theory allows for the possibility that numerous business conditions other than input prices and output quantities can affect the minimum cost of service.

Regulators considering the appropriate revenue requirement of a company often have special interest in certain subsets of the total cost of service. Examples include OM&A expenses (sometimes called “opex”) and even more “micro” categories such as distribution labour expenses. The interest in these expenses is due in part to the fact that they are subject to greater control by utilities in the short run than are capital costs.

When the focus of benchmarking is a subset of total cost, *restricted* cost functions are useful for identifying the full range of relevant cost drivers. In such functions the minimum cost of a group of inputs depends on the general run of prices of those inputs and on output quantities and other business conditions. It depends, additionally, on the amounts of *other inputs* that the company uses. The existence of the other input variables in restricted cost functions means that a fair appraisal of the efficiency with which a utility uses a certain class of inputs must consider the amounts of *other* inputs it uses.

This result is important for several reasons. One is that there are inconsistencies in the manner in which utilities classify costs. Utilities may, for example, differ in the way that they categorize certain expenditures between administrative and direct operating expenses.

Another reason that the result matters is that opportunities exist for the substitution of certain inputs in the production process. Suppose, for example, that the focus of inquiry is OM&A expenses. It is then germane that the minimum level of expenses depends on the *capital* inputs that the company uses. A firm may, for example, have unusually high opex because its facilities are in an advanced stage of depreciation so that it is using comparatively little capital. Suppose, alternatively, that the focus of benchmarking is the efficient use of labour. Economic theory suggests that the minimum amount of labour that a company uses depends on its use of other, non-labour OM&A inputs as well as the amount of capital it uses. A utility may have an unusually small labour force not because it is especially efficient in its use of labour but because it has relatively new facilities and/or outsources a lot of its OM&A activities. By the same token, a company with high labour costs might do very little outsourcing.

One complication that benchmarkers encounter in trying to control for the usage of capital inputs is the measurement of that usage. As a practical matter, it isn't always possible to measure capital quantities accurately. However, variables can sometimes be computed that represent important characteristics of the capital stock that influence OM&A expenses. For example, one might employ an indicator of the age of a system such as the number of customers added in the last ten years.

2.4 Benchmarking Methods

In this section we discuss at some length the two approaches to benchmarking that are widely used in North America: econometric modeling and indexing. The econometric approach is discussed first to establish a context for the appraisal of the index approach.

2.4.1 Econometric Modeling

Basic Assumptions

Relationships between the costs of utilities and the business conditions that they face can be estimated using econometric methods. In such an exercise, a specific mathematical form must be chosen for the cost function. The impact of business conditions on cost depends on the form chosen and on the values of model parameters.[2] The various alternative forms include the linear, the double log, and the translog. These

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[2] Here is a simple example of a cost function for power distribution that conforms to cost theory:

$$C_{h,t} = a_0 + a_1 \cdot YN_{h,t} + a_2 \cdot W_{h,t} \qquad [1]$$

Here for any firm h in year t, the variable $YN_{h,t}$ is the number of customers that the company serves. It quantifies one dimension of the work that it performs. The variable $W_{h,t}$ is a measure of the general run of wages in the service territory. The wage rate and number of customers are the measured business conditions in this cost function. The terms a_0, a_1, and a_2 are model parameters. The function in relationship [1] has a linear form.

forms vary in the flexibility with which they capture relationships between costs and cost drivers. Flexible functional forms are generally preferable. Suppose, for example, that economies of scale are exhausted at a certain level of output. We would then desire a functional form that permits the elasticity of cost with respect to output to increase with the level of output.

A branch of statistics called econometrics has developed procedures for estimating the parameters of economic models using historical data.[3] For example, cost model parameters can be estimated econometrically using historical data on the costs incurred by a group of utilities and the business conditions they faced.[4] The sample used in model estimation can be a time series consisting of data over several years for a single firm, a cross section consisting of one observation for each of several firms, or a panel data set that pools time series data for several companies.

Econometric research involves certain critical assumptions. The most important assumption, perhaps, is that the values of some economic variables (called dependent or left-hand side variables) are functions of certain other variables (called explanatory or right hand side variables) and error terms. In an econometric cost model, cost is the dependent variable and the cost drivers are the explanatory variables. The explanatory variables are generally assumed to be independent in the sense that their values are not influenced by the values of dependent variables.[5]

The error term in an econometric cost model is the difference between actual cost and the cost that is predicted by the model. It reflects imperfections in the development of the model. The imperfections may include any or all of the following: the mismeasurement of cost and the external business conditions, the exclusion from the model of relevant business conditions, and the failure of the model to capture the true form of the functional relationship. Error terms are a formal acknowledgement of the fact that the cost model is unlikely to provide a full explanation of the variation in the costs of sampled utilities.

[3] The act of estimating model parameters is sometimes called regression.

[4] A positive estimate for parameter a_1 in equation [1], for instance, would reflect the fact that the costs reported by sampled companies tended to be higher the greater were the number of customers that they served.

[5] In the simple cost model described in equation [1], for instance, we would assume that the number of customers that a utility serves and the price that it faces for labour are not influenced by its cost.

It is customary to assume that error terms are random variables with probability distributions that are determined by additional coefficients, such as mean and variance. This stochastic specification is useful in selecting business conditions for cost models. Specifically, tests can be constructed for the hypothesis that the parameter for each business condition variable equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected. Statistical significance is a sensible criterion for the inclusion of variables in cost models. Statistical theory reveals the parameters are more likely to be significant when the econometric work is based on a large and varied sample.

Estimation Procedures

A variety of estimation procedures are used in econometric research. The appropriateness of each procedure depends on the assumptions that are made about the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in over the counter econometric software. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic in the sense that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

Estimation procedures that address *several* of the error term issues that are routinely encountered in utility benchmarking are not readily available in commercial econometric software packages such as Gauss and Stata. They require, instead, the development of customized estimation programs. While the cost of developing sophisticated estimation procedures that are tailored for benchmarking applications is sizable, the incremental cost of applying them to different utilities is typically small once they have been developed.

Multiple Equation Cost Models

Economic cost benchmarking is sometimes undertaken with multiple equation cost models. For example, OM&A expenses might be benchmarked with a model that consists of an OM&A cost function and *cost share* equations for labour, and other OM&A inputs. The share equation for labour expenses, for instance, might address the share of the total expenses that is attributable to labour.

A rigorous multiple equation approach to cost modeling that includes share equations is generally preferable to the single equation approach. The chief advantage results from the fact that economic theory suggests that the parameters of the cost function and share equations are linked. More data can thus be used in the estimation of cost model parameters. This increases the prospects for developing a cost benchmarking model that accurately reflects the effects of external business conditions. The chief downside of multiple equation models is their greater complexity.

Cost Predictions and Performance Appraisals

A cost model fitted with econometric parameter estimates may be called an econometric cost model. We can use such a model to predict a company's cost given local values for the business condition variables. These predictions are econometric benchmarks. They can be made for historical years or a hypothetical test year.[6]

Cost performance in measured by comparing a company's cost in year *t* to the cost projected for that year by the econometric model. Suppose, by way of example, that a utility incurred $12,000,000 of OM&A expenses in 2005 and the model projected a cost of $10,000,000 for that year. Taking the ratio of these numbers we find that

$$\textit{actual cost}_t \,/\, \textit{projected cost}_t = 12{,}000{,}000 / 10{,}000{,}000 = 1.2$$

The percentage difference between the actual and projected cost is

$$(\textit{actual cost}_t - \textit{projected cost}_{t\text{-}1}) \,/\, \textit{projected}\cos t = \frac{12{,}000{,}000 - 10{,}000{,}000}{10{,}000{,}000} = .20$$

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[6] Suppose, for example, that we wish to benchmark the cost of hypothetical power distributor called Northern Electric. Returning to our example, we might predict the cost of Northern in period *t* using the following model.

$$\hat{C}_{Northern,t} = \hat{a}_0 + \hat{a}_1 \cdot YN_{Northern,t} + \hat{a}_2 \cdot W_{Northern,t}\,.$$

Here $\hat{C}_{Northern,t}$ denotes the predicted cost of the Company, $YN_{Northern,t}$ is the number of customers it serves, and $W_{Northern,t}$ measures its wage rate. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula such as

$$Performance = \left(C_{Northern,t} \big/ \hat{C}_{Northern,t} \right).$$

Performance Standards

The estimation procedure influences the performance standard that is embodied in the model predictions. Suppose, for example, that we choose a GLS procedure. It can then be shown that since these procedures do not explicitly account for the fact that the error terms are asymmetrically distributed, the predictions generated by the resultant cost model embody a *sample average* efficiency standard.[7] SFA procedures, on the other hand, generate benchmarks that reflect a frontier standard of operating efficiency.

The notion of minimum cost considered in SFA and other econometric research methods is of a *short run* character. Firms can, in the short run, incur a cost that is considerably below the cost that is sustainable in the long run. Example from the business of power distribution is the deferral of tree trimming and replacement capital spending. In the long run, utilities that defer maintenance will experience service quality deterioration. A benchmarking model of OM&A expenses that is estimated using a frontier estimation procedure such as SFA might then effectively compare the opex efficiency of a subject utility to that of utilities that have deferred maintenance expenditures.

Capital cost provides another example of the short run/long run issue. Plant investments in the electric utility industry are commonly useful for 30-50 years. The value of an investment in plant is commonly treated as depreciating over the service life. The growth patterns of utilities vary. In comparing two power distributors that serve 100,000 customers we might find, for example, that one of the companies had added 40,000 customers in the last ten years, whereas the other had added only 10,000. It is quite possible for this reason alone that utilities serving the same level of output have different levels of capital cost. A benchmarking model of capital cost that is estimated using SFA might then effectively compare the capital cost efficiency of any subject utility to the capital cost efficiency of utilities with highly depreciated rate bases.

Another problem with the use of a frontier performance standard is that it is unusually sensitive to irregularities in the data. As we discuss further in Section 3 below, such irregularities are frequently encountered in statistical benchmarking work.

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[7] See Appendix section A.1 for further discussion.

Efficiency comparisons using frontier cost performance standards are much more sensitive to data irregularities than are efficiency comparisons using a sample average performance standard.

Accuracy of Benchmarking Results

A cost prediction like that generated in the manner just described is our best *single* guess of the Company's cost given the business conditions it faces. This is an example of a point prediction. Such predictions are likely to differ from the true benchmark, which accurately embodies the desired standard and controls for the impact of external business conditions.

One potential source of inaccuracy is the values of the parameter estimates that measure the impact of external business conditions on cost. Another is the ability of the explanatory variables to accurately measure business conditions. A third is the extent to which the model captures the form of the relationship between business conditions and costs. Still another is a failure of the model to include all relevant business conditions.

Statistical theory provides useful guidance regarding the extent of inaccuracy. One important result is that an econometric cost model can yield *biased* predictions of the true benchmark if relevant business condition variables are excluded from the model. A model used to benchmark the opex of a rural power distributor might, for example, yield a value for the benchmark that is below its true value (and is thus excessively challenging) if it failed to include variables that properly represent the extensiveness of a distribution system and the magnitude of rural cost management challenges such as forestation. It is therefore desirable to include in an econometric benchmarking model all business conditions which are believed to be relevant, for which data are available at reasonable cost, and which have plausible and statistically significant parameter estimates. Even when an econometric benchmarking model is unbiased it can be imprecise, yielding values that are sometimes too high and on other occasions too low.

Statistical theory provides the foundation for the construction of confidence intervals that represent the full range of possible cost model predictions that are consistent with the data at a given level of confidence. These are readily constructed from the statistical results of an econometric run. A confidence interval is wider the greater is the uncertainty about the true benchmark level. In general, it can be shown that confidence intervals are wider to the extent that:

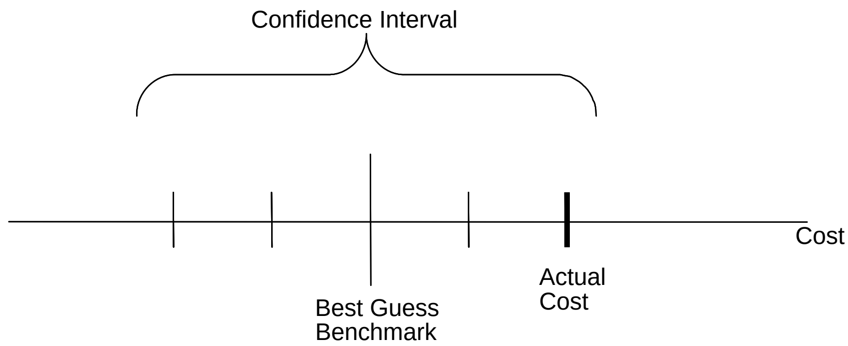
- the model is not successful in explaining the variation in cost in the historical data used in its development;
- the size of the sample is small;
- the number of cost driver variables included in the model is large;
- the business conditions of sample companies are not varied; and
- the business conditions of the subject utility are dissimilar to those of the typical firm in the sample.

These results suggest that econometric benchmarking will in general be more accurate to the extent that it is based on a large sample of good operating data. When the sample is small, it will be difficult to identify all of the relevant cost drivers and the appropriate functional form. It follows that it will generally be preferable to use panel data instead of a single cross section of data when these are available.

Notice also that the precision of an econometric benchmarking exercise is actually *enhanced* by using data from companies with diverse operating conditions. For example, we will obtain a better estimate of the impact of line length on cost if we include in the sample companies that, like Toronto Hydro Electric System (THES), have *high* customer density as well as data for companies that, like Sioux Lookout, have low customer density.

Testing Efficiency Hypotheses

Confidence intervals developed from econometric results do much more than provide indications of the accuracy of a benchmarking exercise. In particular, they permit us to test hypotheses regarding cost efficiency. Suppose, for example, that we use a sample average cost standard and compute the confidence interval that corresponds to the 90% confidence level. It is then possible to test the hypothesis that the company is an average cost performer. If the company's actual cost exceeds the benchmark generated by the model but nonetheless lies within the confidence interval (as in the figure below), this hypothesis cannot be rejected. In other words, the company is not a *significantly* inferior cost performer. Suppose, alternatively, that the company's cost is below the cost predicted by the model by enough to be outside the confidence interval. We may then conclude that it is a *significantly superior* cost performer.



An important advantage of efficiency hypothesis tests based on econometric research is that they take into account the accuracy of the benchmarking exercise. As we have just discussed, there is uncertainty involved in the prediction of benchmarks. These uncertainties are reflected in the confidence interval that surrounds the point estimate (best single guess) of the benchmark value. The confidence interval will be greater the greater is the uncertainty regarding the true benchmark value. If uncertainty is great, our ability to draw conclusions about operating efficiency is hampered.

2.4.2 Index-Based Approaches to Benchmarking

The index-based approach to benchmarking is commonly employed by utilities in internal reviews of operating performance. Benchmarking indexes are also used in the regulatory arena. We begin our discussion with a review of index basics and then consider unit cost and productivity indexes in turn.

Index Basics

An index is defined in one respected dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)".[8] In benchmarking, indexing involves the calculation of ratios of the values of performance variables for a subject utility to

[8] *Webster's Third New International Dictionary of the English Language Unabridged,* Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

corresponding values of the variables among a sample of utilities. The group of companies represented in the sample is called, variously, a cohort or a peer group.[9]

These concepts are usefully illustrated by the process through which decisions are made to elect athletes to Toronto's Hockey Hall of Fame. Statistical benchmarking undoubtedly plays a major (albeit informal) role in player selection. Goalies, for example, are evaluated using multiple performance variables that include the goals-against average. The values achieved by Hall of Fame members like Ken Dryden of the Montreal Canadians are useful benchmarks. These values reflect a Hall of Fame performance standard.

Economic indexes can be designed to summarize the results of multiple comparisons. Such summaries commonly involve the calculation of weighted averages of the comparisons. Consumer price indexes are familiar examples. These summarize the inflation (year to year comparisons) in the prices of hundreds of goods and services.

To better appreciate the advantages of complex indexes in benchmarking, recall from our discussion in Section 2 that economic theory allows for cost to depend on multiple output quantity variables and that multiple variables are often needed to accurately measure the workload of utilities. We might, then, wish to construct an output quantity index that is a weighted average of comparisons for several output measures. Suppose, by way of example, that we are benchmarking the power supply cost of a utility with a low load factor. It would be desirable in this case to consider its peak demand as well as its sales volume. If we separately calculate the company's cost per megawatt hour and per megawatt we would likely come up with two very different assessments. A final reckoning of performance then requires a sensible weighting of the assessments.

In a cost benchmarking application, it makes sense for the weights of an output quantity index to reflect the relative importance of the output measures as cost drivers. Econometric research is useful in this regard. We can, for example, use as the weight for

[9] The term cohort comes from the Latin word for one of the ten divisions of a Roman legion.

each measure its share in the sum of the econometric estimates of the output-related cost elasticities.[10]

Summary input price and quantity indexes can also be computed. We might, for example, compare the quantities of OM&A inputs used by a subject utility to those of a cohort using an index that involves weighted averages of the amounts of labour and non-labour OM&A inputs used. In the construction of input quantity indexes it is customary to use the corresponding cost shares to calculate weights. It can be shown that this approach to weighting best reflects the impact of input quantities on cost.

Unit Cost Indexes

Unit cost indexes are used to make unit cost comparisons. A simple example is the ratio of a company's cost per customer to the average cost per customer of a peer group. This can be stated, alternatively, as the ratio of a cost comparison to a comparison of the number of customers served.[11] In more sophisticated unit cost indexes, the workload comparison is a weighted average of several workload measures.

Unit cost indexes are, effectively, cost comparisons with a built in (but crude) control for differences between companies in one of the most important cost drivers: operating scale. The control is crude insofar as there are economies of scale in the business that permit larger companies to operate at a lower unit cost than smaller companies. This control nonetheless permits us to use data for utilities that have only broadly similar operating scales in evaluating cost performance. Unit cost is also of interest because it is the long run source of differences in the prices that utilities charge.

Despite these advantages, unit cost comparisons do not control for all of the cost drivers that are known to vary between utilities. Our discussion in Section 2 revealed that cost depends on input prices and miscellaneous other business conditions in addition

[10] The elasticity of cost with respect to a certain business condition variable is the percentage change in cost that results from a one percent change in the value of the variable.

[11] Here is an example of a unit cost index for our hypothetical subject utility.

$$\frac{\left(\dfrac{Cost_{Northern}}{Customer_{Northern}}\right)}{\left(\dfrac{Cost_{Mean}}{Customers_{Mean}}\right)} = \frac{\left(\dfrac{Cost_{Northern}}{Cost_{Mean}}\right)}{\left(\dfrac{Customers_{Northern}}{Customers_{Mean}}\right)}$$

to operating scale. The accuracy of unit cost benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these excluded business conditions are similar on balance to those facing the subject utility. The appropriateness of the peer group is extremely important to the accuracy of a benchmarking effort that uses unit cost indexes. The ability to assemble a satisfactory peer group can be limited when the number of candidate peers with comparable data is small.

Excluded business conditions are even more problematic when the focus of unit cost indexing is a narrow cost category. In that event, we have seen that a good benchmark should take account of the amounts of other kinds of inputs that a company uses. Suppose, for example, that we compare the labour costs per customer of two utilities that have a markedly different reliance on outsourced services. In that event, the comparison is apt to be unfavourable to the company that doesn't do much outsourcing. It follows that in comparing unit labour costs, attention should be paid to differences in the extent to which candidate peers rely on outsourcing. This discussion suggests that, absent appropriate peer group controls, unit cost benchmarking will tend to be more accurate to the extent that the scope of costs under consideration is comprehensive. It will, for example, be easier to accurately benchmark *OM&A* expenses using unit cost indexes than it will be to accurately benchmark *labour* expenses.

Productivity Indexes

A productivity index is the ratio of an output quantity index to an input quantity index. It is used to make productivity comparisons. Many readers will think of productivity indexes as measures of *trends* in operating efficiency over time. However, they can also be designed to compare the efficiency *levels* of utilities at a point in time.

A simple example of a productivity index is the ratio of customers served per employee to the mean value of same for a peer group. This can be stated, alternatively, as the ratio of a customer comparison to an employee comparison. [12] In more

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[12] Returning to our example, this can be expressed formulaically as

$$\frac{\left(\dfrac{Customers_{Northern}}{Employees_{Northern}}\right)}{\left(\dfrac{Customers_{Mean}}{Employees_{Mean}}\right)} = \frac{\left(\dfrac{Customers_{Northern}}{Customer_{Mean}}\right)}{\left(\dfrac{Employees_{Northern}}{Employees_{Mean}}\right)}$$

sophisticated productivity indexes, the output comparison is a weighted average of several output measures.

A productivity comparison such as this can be shown to be the portion of a unit cost index comparison that is not due to differences in input prices. The unit cost of a utility will then compare more favourably to that of a peer group to the extent that its input prices are lower and its productivity is higher. This result helps to explain why productivity indexes are generally more accurate benchmarking tools than unit cost indexes. Productivity indexes are, effectively, comparisons of cost that provide some control for differences in *two* sets of business conditions that vary between utilities and are major cost drivers: the amount of work performed and the prices paid for inputs. These controls make it possible to use data from a more diverse set of companies in choosing a peer group. Peer companies need only have broadly similar operating scales and can, additionally, operate under different input price conditions.

Despite these advantages, productivity comparisons do not control for all of the important cost drivers that vary between utilities. For example, a comparison of the productivity of the power generation businesses of two utilities could control for differences in their operating scale and generation fuel prices. However, it would not control for differences in their access to sites that are suitable for low cost hydroelectric generation. It follows that the selection of a peer group is still important to the accuracy of a benchmarking study that is based on productivity indexes.

As we discussed above for unit cost indexes, excluded business conditions are apt to be a bigger complication to the extent that the focus of productivity indexing is a narrow input category. When the focus is narrow, we have seen that a good benchmark should take account of the amounts of other kinds of inputs that a company uses. Suppose, for example, that we compare the customers per employee of two utilities that have a markedly different reliance on outsourced services. In that event, the comparison is apt to be unfair to the company that doesn't do much outsourcing.[13]

This problem can be finessed by considering a broader range of inputs in the productivity index. An index that compares productivity in the use of more than one

[13] It follows that in comparing labour productivity, attention should be paid to differences in the extent to which candidate peers rely on outsourcing.

input is called a multifactor productivity ("MFP") index. An MFP index that covers all inputs used by an enterprise is called a total factor productivity ("TFP") index.

Our discussion suggests that more comprehensive productivity indexes will generally yield more accurate benchmarking results. Consider, for example, the company that uses a lot of in-house labour and outsources very few tasks. Such a company is likely to have low labour productivity but will have high productivity in the use of other OM&A input. An MFP index covering all OM&A inputs can assess how things balance out.

Performance Standards

The cost performance indexes that we have discussed so far in this section embody a sample average standard of performance. Alternative standards can also be implemented. We can, for example, make calculations for each utility in the sample and then assess the apparent productivity shortfall between a subject utility and the utility with the best productivity ranking.

Frontier performance comparisons using indexes are, however, fraught with many of the same limitations as we discussed in the context of econometric modeling. The utilities with the best apparent productivity performance may, for instance, have achieved that status due to deferred maintenance. They may also have risen to the top of the rankings due to data irregularities.

Statistical Tests of Efficiency Hypotheses

Statistical tests are generally not employed in index-based benchmarking but can be developed for regulatory applications. To better appreciate the possibilities, suppose that we are benchmarking the unit cost performance of a company using a cost per customer measure. The unit costs of the companies in the peer group may vary considerably due to either or both of variations between companies in the many excluded business conditions and the year-to-year volatility of the data for each company. We can then treat the data for the peer group as a sample drawn from a probability distribution that has an unknown mean and variance. The mean cost per customer is then an estimate and our best guess of the true mean of the population. A confidence interval can be constructed around the sample mean unit cost. A utility may be deemed to have an anomalous cost performance if its unit cost exceeds the upper bound of the confidence interval. The confidence interval will generally be wider --- making conclusions about efficiency more difficult to draw --- the larger and more varied are the data for the peer group.

2.4.3 Index-Econometric Hybrids

Hybrid benchmarking approaches that employ elements of the econometric and indexing approaches are also possible. An example is the “comparators and cohorts” approach to benchmarking that the OEB used to assess the operating efficiency of distributors in the 2006 EDR process. The methodology involves several steps.

1. A number of cost performance indicators were chosen.
2. For each such indicator, cost models were developed in which the variable (*e.g.* distribution OM&A expenses) was a function of certain business condition variables (*e.g.* the number of customers served). The parameters of the model were estimated econometrically using data on the costs incurred by Ontario distributors and the business conditions that they faced.
3. The parameter estimates obtained from the econometric work were employed in a statistical clustering analysis. This analysis identified, for each cost performance variable, cohorts of distributors with relatively similar values for the measured business conditions.
4. “Comparative diagnostic” variables of more micro character were calculated for each of the companies in each cohort.
5. The cost comparisons, together with the comparative diagnostics, are now being used by Board staff to identify distributors with anomalously high costs.

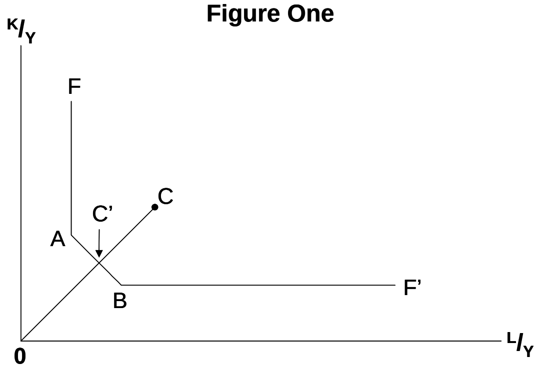
2.4.4 Data Envelopment Analysis

Data Envelopment Analysis (“DEA”) uses linear programming techniques to “envelope” data on sample firms that relate outputs to inputs. It is therefore essentially a technique for identifying what are known in economics as isoquant or isocost curves. Efficiency is measured as the distance from the best attainable curve.

In a basic input-oriented DEA model, the relative efficiency of a firm is determined by assigning weights to firm inputs and outputs such that the ratio of aggregated outputs to aggregated inputs is maximized. This linear programming problem is subject to the constraint that the efficiency score cannot exceed a value of one for a firm using the same set of weights. The result of this process will be an efficiency measure for each firm that takes a value between zero and 100%. A perfect efficiency score would be 100%. A more typical score might be 80%.

These scores are relative to "peers" identified through the analysis and which set the efficiency "frontier." The DEA efficiency score has the intuitive interpretation that, relative to the peers, it measures the amount by which a firm can radially contract all of its inputs while still producing the same level of output. This can perhaps be clarified through a visual example. In Figure 1, there are two inputs, capital (K) and labour (L). The X axis in this figure is labour per unit of output (L/Y) while the Y axis is capital per unit of output (K/Y).

Figure One



In this example, the points A, B and C refer to specific firms that are identified as peers. It can be seen that firms A and B are using fewer capital and labour inputs per unit of output than firm C. The DEA technique would construct a piece-wise linear frontier through points A and B, which is identified by the line FABF'. This line is the production frontier. The efficiency of firm C is measured relative to this frontier, and the efficiency measure is equal to OC'/OC. Suppose this value turns out to be 0.6. This implies that firm C is 40% below the production frontier, and it can reach the frontier by reducing both its capital and labour inputs by 40%. Under input-oriented DEA, the firm's measured inefficiency is therefore equal to the entire difference between its position and the constructed efficiency frontier.

The basic input-oriented DEA model can be expanded in various ways. Technically, this occurs by modifying the linear programming problem to relax various assumptions. These more sophisticated DEA models can break down the sources of efficiency into various components. As one example, the model above assumes *constant* returns to scale in the relationship between inputs and outputs. This assumption can be relaxed to allow for *variable* returns to scale. Under variable returns to scale, returns to scale can differ at different levels of output. A firm of average size would typically realize greater scale economies than one of small size. A DEA model with variable returns to scale permits the efficiency measure described above to be decomposed into scale efficiency and "pure" technical efficiency.

Another enhancement possible in a DEA analysis is to incorporate data on input prices into the analysis. It is then possible to consider a company's *allocative* efficiency (its success in choosing the right input mix given current input prices) as well as its technical efficiency. The sum of allocative efficiency and operating efficiency is a more complete measure of operating efficiency than technical efficiency alone.

To compute allocative efficiency, we proceed in two steps. First we calculate technical efficiency as described above. Then we use the output maximizing input variables, "the optimal inputs," that result from the first step for each cross section and multiply these with the input price data to be used in a second round of linear programs. In particular, in the second stage we envelop the data once again using price weighted optimal inputs and the original outputs. The resulting set of price weighted optimal inputs, which are really the minimum cost for each cross section, are then compared to actual cost to determine allocative efficiency. In particular, the ratio of the minimum to the actual form allocative efficiency. Total cost efficiency is then the product of technical efficiency and allocative efficiency.

DEA can also be modified to include second-stage regressions that regress DEA efficiency scores on other business condition variables. The results of these regressions can then be used to adjust the efficiency scores resulting from the DEA analysis. The primary reason for undertaking such regressions rather than including all relevant business condition variables in the linear programming problem is that increasing the number of inputs in DEA analysis tends to reduce the number of peers that are identified for any firm.   Having fewer peer firms can artificially inflate the efficiency measure. Indeed, in the limit, if enough inputs are introduced in the analysis, no firm may be identified as a peer for any other firm. The DEA measure therefore becomes one for all firms by default, which is usually an unrealistic result

2.5 Capital Cost

Capital inputs play important roles in utility operations. They are especially important in network businesses like power transmission and distribution. In these businesses, capital typically accounts for half or more of total cost. It follows that, in the long run, the success utilities have at holding down their costs depends greatly on their management of capital costs.

The cost of capital ownership has several components. One is the opportunity cost of having funds tied up in ownership. To the extent that the company borrows money, this is the interest that it must pay. To the extent that it secures financing in equity markets, this is the return on equity. Another important component of capital cost is depreciation. A third component of capital cost is taxes. The relevant taxes include income and property taxes and certain implicit taxes such as franchise fees.

The computation of depreciation and opportunity cost requires a valuation of utility plant. Two basic approaches to valuation can be used. One is book (historical cost) valuation. The other is current (replacement cost) valuation. Regulators must choose a method for calculating capital cost to establish revenue requirements. North American regulators commonly use book valuations of plant.[14]

Accurate benchmarking of the cost of any input generally requires a measure of the local input price. Accurate benchmarking of the cost of plant ownership requires, specifically, an estimate of the price of holding a unit of capital. These prices are sometimes called capital *service* (or rental) prices since prices for the rental of a unit of capital in competitive rental markets (*e.g.* those for real estate or automobiles) tend in theory to reflect the cost of owning a unit of capital. It can be shown that capital service prices reflect the cost of funds, depreciation and tax rates, and the cost of buying or building a unit of plant.

[14] Replacement valuations are used by regulators in some other countries, including Australia.

The benchmarking of capital cost involves special challenges. One is inconsistencies in the manner in which capital cost is reported. Companies differ most notably, perhaps, in the way that they calculate depreciation. Another problem is that the book valuation of plant used in regulatory accounts makes the reported net value of plant especially sensitive to the historical pattern of capital investment. Two utilities could thus own the same amount of plant, but one could have a lower net plant value because its plant is of older vintage.

A means of computing capital cost has been developed by scholars to help finesse these problems. This method is commonly employed in rigorous research on capital cost. The basic idea is to recompute the cost of capital using a standardized treatment of depreciation and historical data on net plant value in a certain benchmark year and on plant additions in subsequent years. The methodology involves the calculation of a capital quantity index using a perpetual inventory equation. The intent is to base capital cost calculation as much as possible on the plant *additions* data, which are less idiosyncratic.

The accuracy of this general approach to capital cost measurement is increased to the extent that the benchmark year is far in the past. In the electric power research of PEG that uses U.S. data, for instance, we use *1964* as the benchmark year. Computing past values of capital quantity indexes is complicated by past mergers and acquisitions involving sampled firms.

When this methodology is employed, data on capital cost and the amount of capital that utilities use is still sensitive to their patterns of plant additions over the years. For example, two utilities with the same operating scale and level of capital cost efficiency can still have different capital costs (and quantities) if one system has an average asset age of 20 years while the other has an average asset age of 30 years. This problem is just beginning to receive the attention that it deserves from benchmarking experts.

3. Precedents for Benchmarking In Regulation

The Board's decision on a strategy for benchmarking should be informed by knowledge of precedents for its use in regulation around the world. In this section we summarize salient precedents for benchmarking in the advanced industrial world. North America, Europe, and Australia and New Zealand are considered in turn.

3.1 North America

Statistical benchmarking has not to date been extensively used in North American regulation. Most benchmarking evidence that is filed comes voluntarily from utilities. PEG has filed testimony of this kind in many proceedings. Benchmarking results have rarely had a material impact on rates.

The lack of interest in benchmarking is, in our view, due chiefly to two considerations. Most regulation occurs at the state level, and most states regulate only a few utilities. Benchmarking is also discouraged by the extensive investment that has been made over the years in the cost of service approach to regulation.

Most studies that have been offered in North American proceedings use either indexing or econometric methods. In the United States, the development of sophisticated econometric cost models has been favored by the large amount of standardized, quality data that has been gathered over the years on FERC Form 1 and other federal government forms. Statistical costs of efficiency hypotheses have been performed in several of the studies prepared by PEG.

The index and econometric approaches to benchmarking have both been used in Ontario proceedings. For example, the indexing approach was used in 2006 testimony by Hydro One Networks on its power transmission cost. PEG used both indexing and econometric methods in 2004 and 2005 testimony on the OM&A expenses of Enbridge Gas Distribution. Statistical tests of efficiency hypotheses were featured in this evidence.

3.2 Western Europe

Benchmarking has played a much more important role in regulation overseas than in North America. Most notable has been its use in Britain, Germany, the Netherlands, Norway, and other European countries. Power distribution cost has been the most common benchmarking focus.

The greater use of benchmarking in Europe reflects in part the fact that there is not a well-established heritage of cost of service regulation. This is due in part to the fact that regulators in many countries have jurisdiction over numerous distributors.   The number of distributors in Norway, for instance, is comparable to that in Ontario, and the number of distributors in Germany is much greater. Benchmarking thus makes possible significant economies in the regulatory process, and can make use of samples of fairly standardized data.

European regulators tend to favour a frontier benchmarking standard. Britain's energy regulator recently moved from a frontier to a top quartile standard. Companies in the top quartile were given revenue requirements in excess of their costs. Benchmarking has been used to adjust the initial rates and the pace of rate escalation in multi-year rate plans. In some countries, rate escalation mechanisms have been calibrated to move rates toward the estimated performance frontier over time.

As for benchmarking methods, the DEA approach to benchmarking has been favored in continental Europe. This is due in part to a comparative paucity of good operating data that might be used to develop good econometric cost models. It also reflects a preference for the DEA approach by European economists.

Regulators in Britain have favored econometric benchmarking models. These models are quite crude, however, because they are based on samples that are remarkably small by North American standards. British regulators have not seen fit to accumulate and use years of standardized data.

No regulator in Europe has, to our knowledge, employed statistical tests of efficiency hypotheses in ratemaking. This is due in part to the fact that regulators have not generally favored direct econometric benchmarking. Statistical tests can be constructed using DEA but their use appears to be quite rare.

Benchmarking is often used mechanistically in the ratemaking process. In the Netherlands, for example, the cost performance of power distributors was appraised using DEA and a frontier performance standard. Rate escalation mechanisms were calibrated to move the rates for all utilities to a level commensurate with frontier cost performance over a multiyear period. Distributor rates will, prospectively, be escalated by a common formula that reflects the TFP trend of the industry.

3.3 Australia and New Zealand

The situation is more mixed in the ANZ countries. Regulators in New South Wales, Queensland, and Victoria have all initiated statistical cost benchmarking studies. Indexing, econometrics (based on models developed from U.S. data), and DEA have all been used, as have both frontier and industry average performance standards. Methodological controversies erupted in proceedings in New South Wales and Victoria states, and the studies in these proceedings seem to have carried little weight in final ratemaking decisions. Regulators have generally been dissatisfied with the outcome of benchmarking experiments and have not featured statistical benchmarking in subsequent proceedings.

In New Zealand, benchmarking evidence was recently used to design a mechanism for escalating certain price "thresholds" for power distributors. Distributors deemed to have inferior cost performance were granted less escalation. An industry average performance standard was employed in the benchmarking work, as well as total factor productivity indexes. The productivity indexes featured multidimensional output quantity indexes that summarized comparisons concerning customer numbers, the delivery volume, and a system line capacity measure, expressed in MVA-km.

A usage of benchmarking in regulation that is intermediate between that of North America and Europe can be explained by underlying conditions. Since ANZ countries do not have a long history of cost of service regulation of electric utilities, regulators were understandably intrigued with the benchmarking option. However, only New Zealand has to date confronted a situation in which a single regulator has jurisdiction over more than a dozen distributors.

3.4 Conclusions

Our review of benchmarking in the energy utility regulation of advanced industrial countries suggests that its use is more likely where regulators have limited experience with the prudence reviews that typify traditional cost of service regulation

(COPSR) and have responsibility over numerous utilities. For example, regulators in Britain, Germany, New Zealand, Norway and the Netherlands have limited experience with COSR and jurisdiction over more than ten utilities. In contrast, regulators in Australia, Canada, and the United States typically have jurisdiction over five or fewer utilities in each energy industry. Most North American regulators, additionally, have extensive COSR experience. In applying these lessons to Ontario, it is plain that the Board has extensive COSR experience but has jurisdiction over roughly 100 distributors. This situation gives it an understandable interest in taking a different path from most of its North American brethren.

4. Application: Power Distribution

The challenge of accurate benchmarking is better appreciated by considering its application to a specific sector of the electric power industry. In this section we take an in-depth look at power distribution. We consider in turn the challenges encountered in benchmarking the costs of local delivery and customer care services.

4.1 Benchmarking Local Delivery

4.1.1 The Local Delivery Business

The typical distributor receives power in bulk from points on a high-voltage transmission grid and delivers it to consumers. Receipt commonly occurs at substations, where voltage is reduced from transmission to distribution levels. Power is in most cases delivered to end users at the voltage at which it is consumed.[15]

Continuous use of electric power is essential to the functioning of modern homes and businesses. Power storage and self-delivery are, additionally, generally not cost competitive with power produced in bulk and delivered by utilities. It follows from these circumstances that customers want local delivery capability to be continuous. The technology for providing continuous service requires a network in the sense of a system that is physically connected to end user premises.

Power flows to the customer through wire conductors. Other capital inputs used in local delivery include poles, conduits, station equipment, meters, vehicles, storage yards, office buildings, and information technology ("IT") inputs such as computer hardware and software. Distributors commonly operate and maintain such facilities and are also frequently involved in the construction of distribution plant. These activities require labour, materials, and services. Local delivery also typically requires a certain amount of power in the form of line losses. Opportunities are available to outsource many OM&A and construction activities. Distributors vary greatly in the extent of their outsourcing.

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[15] However, some large volume customers perform their own voltage stepdowns. At the extreme, they may take delivery of power from the grid and bypass the distribution system entirely.

Local Delivery Cost

The total cost of local delivery service comprises OM&A expenses and the costs of plant ownership. At current input prices, capital inputs typically account for between 45 and 60 percent of the total cost of local power delivery and constitute the single most important input group. The exact cost share of capital depends on the age of a system and the manner in which plant is valued. The relative shares of labour and other OM&A inputs vary greatly. Prices for labour, capital, and other inputs are important drivers of power distribution cost.

Certain expenditures by distributors have a periodic character. As one example, overhead line maintenance activities such as tree trimming do not have to be undertaken at the same level each year. As another, distributor makes capital investments in response to expected output growth. These investments, once made, may not require replacement for 30-50 years. The amount and cost of capital in a particular year therefore depend greatly on the historic pattern of output growth. For example, a distributor serving a region that grew much more rapidly in the 1960s than in recent years may today have a highly depreciated system and an unusually large need to make replacement investments.

Distribution Outputs

Cost theory suggests that the operating scale of a utility is an important cost driver. The outputs of a power distributor may be narrowly defined as measures of its operating scale that also serve as billing determinants. Three such measures are salient: the delivery volume, the peak load, and the number of customers served.

Services Provided

Distributors vary in the package of local delivery services they provide. These differences can have a sizable impact on the cost of service. Here are some prominent examples.

- One of the most important differences between distributor service packages concerns the involvement in transformation of voltage from the transmission to the distribution level. Where transmission and distribution services are provided by separate companies, policymakers often decide which kind of company provides this service. Where transmission and distribution services are provided by the same company, as is commonly the case in North America, the issue is how these services are *categorized*.

- Many power systems have lines with voltages that are intermediate between the extra high voltage lines used for long distance transmission and the low voltage lines used to deliver power locally. These lines are sometimes counted as transmission and sometimes as distribution facilities.

Other Network Characteristics

Power distribution networks vary in a number of other respects that affect their cost.

- Systems vary widely in customer density. Density is highest in urban areas and is lowest in sparsely populated rural areas. All else equal, distribution cost is typically higher the lower is customer density. In cost research, system extensiveness is commonly measured by the number of line miles. This cost driver is sometimes treated as an output variable in benchmarking work due to its importance and its relevance to operating scale.
- There is marked diversity in the extent of distribution system undergrounding. Undergrounding generally raises the *total* cost of local delivery service but can lower local delivery OM&A expenses due to the reduced need for line maintenance. Undergrounding is most common in the central cities of major urban areas such as Toronto. Its prevalence in smaller towns depends greatly on public policy and local growth patterns.
- The shape of distribution systems must conform to special features of the landscape. For example, distribution lines will typically go around sizable hills as well as lakes and other large water bodies. Distribution cost can be raised by such complications.
- The reliability of distribution services provided by utilities varies widely. Better reliability generally comes at a higher cost. The cost impact of

quality is thus a valid issue in distribution benchmarking. There are special challenges in the estimation of the cost impact of quality. Despite its importance, empirical research on this topic is not well advanced.

Other Cost Drivers

Cost research by PEG and others using U.S. data has identified a range of additional business conditions that are drivers of local delivery costs.

- Distribution OM&A expenses are generally *lower* the younger is the system. *Capital* cost is typically *higher* in a young system. The net effect of system age then depends on the relative magnitudes of OM&A and capital cost effects. Our research to date has suggested that the *total* cost of power distribution is on balance *lower* in a younger power distribution system.
- Distribution cost is typically higher the greater is the degree of forestation in a service territory. An obvious reason is the greater need for tree-trimming and other maintenance expenses. Another is the greater difficulty in creating and accessing power line corridors.
- The rockiness of soil affects the cost of distribution pole installation.

4.1.2 Data Problems

Reporting Inconsistencies

Research has identified numerous inconsistencies in the manner in which distributors report operating data. These problems tend to be especially marked where utilities have some discretion in cost reporting due to lax reporting guidelines and/or the inherent arbitrariness of cost allocations. One area of reporting inconsistency is the capitalization of OM&A expenses. An example of OM&A expenses that are capitalized by most utilities is those for plant construction labour. Areas where practices are more varied include work on software.

Another area where reporting inconsistencies tend to develop is the categorization of OM&A expenses. One issue is the breakdown between direct expenses and administrative and general ("A&G") expenses. The latter category of expenses, sometimes called corporate service expenses, is those that cannot be directly attributed to specific lines of business. Inconsistencies are also encountered in the allocation of direct expenses. An example from the United States is the grey area between billings and collections and customer service and information expenses.

Missing Data

Benchmarking is also complicated by the unavailability of important data. One major problem is the unavailability of good capital data. Adequate data for the calculation of standardized capital costs and quantities are not available for Canada or most other countries of the world. The United States is a prominent exception to this rule since detailed capital cost data have been reported there by major investor-owned utilities for decades.

4.2 Benchmarking Customer Services

4.2.1 The Customer Care Business

The customer care unit of a distributor is responsible for revenue cycle and other customer contact responsibilities. Revenue cycle services include meter reading, billing, collection, and payment processing. Other customer contact responsibilities of distributors include the handling of calls and other contacts, arrangements to start and end services, and demand-side management.

The provision of customer care services requires capital, labour, and other operating inputs. Technological change has been rapid in the business in recent years. For example, software systems are now extensively used to manage customer information and prepare bills. With the advent of the internet, the technology exists for customers to access account information, pay bills, and change service requests electronically. Automated meter reading makes possible more sophisticated rate structures such as hourly pricing. Because of these changes, customer care technology has become more capital intensive and software has become an important class of capital inputs. This also means that the cost of customer services is more prone than in the past to occasional "bumps" when major new automated systems are introduced.

The cost effectiveness of software is generally greater the larger is the scale of a distributor's operations. That is because the chief cost in the use of an information system is its initial purchase and/or development. The cost incurred to serve an additional customer once a system is up and running is relatively modest. Major changes in the package of customer care services, such as those occasioned by the introduction of retail competition, can involve sizable short run cost growth due to investments in new systems.

There are many opportunities today to outsource calling centers and other customer care tasks. Customer service specialists can achieve scale economies by serving multiple utilities. Some utilities in the U.S. and Canada have outsourced the major portion of their customer service activities.

Customer Service Cost Drivers

The outputs of a customer service business can be narrowly defined as measures of its operating scale that also serve as billing determinants. One such measure is salient: the number of customers served. Our research on customer service expenses over the years has revealed some additional drivers of customer service cost. These include the following.

- The cost of local delivery services was noted above to be influenced by customer density. Customer density is likely to have an impact on the cost of customer service as well. One reason is that meter reading is a customer service. System extensiveness can once again be measured by the length of distribution lines.
- Customer service cost is quite sensitive to the scale of demand-side management activities. These activities, which can include the development of initiatives, equipment merchandizing, and extensive communications, can be quite expensive,
- Customer service cost will generally be raised by the transition to retail competition. The experience of Ontario is illustrative in this respect. Retail competition led to more complex customer bills and more frequent rate changes. Relationships had to be established with independent power

suppliers that included an extensive exchange of information. Distributors were required to have the capability to perform transactions with these suppliers electronically. The many changes in customer service responsibilities prompted larger distributors to make substantial and costly upgrades to their information systems.

- Cost is generally higher the greater is the number of languages spoken in the service territory. The service territories of several Canadian utilities have a mix of English and French-speaking customers that necessitates bilingual services.
- Cost is generally higher in areas that involve high customer migration or turnover. An example of the former might be rapidly growing areas such as Calgary or Alberta's tar sands region. An example of the latter might be a college town such as Guelph, Ontario.
- The quality of customer service matters to customers and some quality measures are used in service quality incentive plans. Important measures of customer service quality include billing accuracy, call response time, and the time required to resolve customer queries. The handling of sophisticated rate offerings such as real time pricing should be viewed as a premium quality service. Higher quality services are, in general, more costly.[16] Service quality expectations are generally highest in urban areas.

4.2.2 Data Problems and International Benchmarking Challenges

The data categorization problems discussed above for local power delivery apply with equal or greater force to customer services.

- Companies are inconsistent in their capitalization of OM&A expenses. A good example is the treatment of software maintenance expenses. Companies that outsource customer care tasks will report more of their IT costs as OM&A expenses.[17]

[16] This implies that requests for better service by regulators can involve material cost increases.
[17] Outsourcing companies will, furthermore, be less able to detail customer care expenses.

- Companies are inconsistent in their allocation of certain expenses between the customer care and A&G functions. For example, some companies assign most IT costs to A&G, whereas others allocate a sizeable share of the cost to customer care.

Missing data problems are, if anything, more severe for customer service benchmarking than for local delivery benchmarking. Data are not readily available in the public domain for important drivers of customer care cost such as service quality, language diversity, and customer turnover. Another salient problem is the poor quality of data on software costs. Data on the costs of intangible "plant" are not always reported with the same care as data on the costs of tangible plant. In the United States, the FERC Form 1 contains no itemized data on the cost of software plant whatsoever, much less a breakdown into software used for distribution and customer service. This is also a problem in local delivery cost research, as noted above, but is more of a problem for customer services because of the greater prominence of IT in customer service costs.

For all of these reasons, customer service costs have in our experience been more difficult to benchmark accurately than power delivery costs. Econometric research on customer service cost is much less advanced than in the power delivery sector. Benchmarking of detailed customer care cost items can be especially problematic due to the cost allocation inconsistencies we have discussed.

5. Ontario Data

We turn now to our empirical research on the benchmarking of Ontario power distributors. This section begins with an inventory of the data available. There follows an appraisal of the data and a suggested list of priority upgrades.

5.1 An Inventory of Available Data

Extensive data are available on the operations of Ontario power distributors which are potentially useful in benchmarking. The OEB is the primary source of such information. Stats Canada and various geographical surveys can provide useful supplements. The sample period for which OEB operating data were available at the time of our study was 2002-05. Data for 2006 have become available since the study's completion.

Cost data are gathered chiefly from the Trial Balance reports. These reports are filed annually by distributors as provided for under Section 2.1.7 of the Board's Electricity Reporting and Record Keeping Requirements ("RRRs"). The reported costs are expected to conform with Ontario's uniform system of accounts ("USoA"). They support the audited financial statements of the corporate entity that the Board regulates.

The available cost data include detailed itemizations of OM&A expenses. The itemizations include the cost of "labour with payroll burden" (presumably salaries and wages) for the following six distribution activities:

- transformer station equipment operation;
- distribution station equipment operation;
- overhead distribution lines and feeders operation;
- underground distribution lines and feeders operation;
- customer premises operation; and
- sentinel lights maintenance.

No comparable labour cost itemization exists for other distribution functions, or for any customer care or A&G functions.

There is, for each major activity group (*e.g.* billing and collection) a "supervision" category. There are, additionally, A&G expense categories for Executive Salaries and

Expenses, Management Salaries and Expenses, and General Administrative Salaries and Expenses. In all of these cases the USoA instructions speak of "expenses" in additional to payroll costs. Companies may vary considerably in their propensity to assign expenses other than salaries and wages to these categories.

The trial balances also include highly itemized data on gross plant value. The accumulated "amortization" (actually depreciation) on electric utility property plant and equipment is reported, as well as the accumulated amortization on intangible plant. Note also that these accumulations are not itemized with respect to plant function, nor to our knowledge are data reported (itemized or otherwise) on the corresponding plant additions.

A potentially important supplemental source of Ontario cost data is the Performance Based Regulation ("PBR") reports. These are prepared annually by distributors as provided for under Section 2.1.5 of the Board's RRRs. One item of interest in the reports is the breakout of the labour component for three categories of OM&A expenses:

- operation and maintenance (Distribution OM&A);
- billing and collection; and
- administration.[18]

Unfortunately, these costs are deemed confidential per section 1.7 of the RRR. The PBR data also include potentially useful figures on the total value of plant additions and retirements. The instructions do not require an itemization of these data by function.[19]

The PBR data also include information on output, revenue, and utility characteristics. Data on billed kWh, billed kW, total revenue, and the number of customers served are available for 5 customer classes:

- residential
- general service
- large use (>5,000 kW)

[18] We do not know whether administration as here described includes the cost of administration of transmission operations a distributor may have.
[19] We do not know whether these totals would include assets that the board considers to have a transmission purpose.

- street lighting
- sentinel lighting

PBR data include, as well, the total wholesale and retail kWh. The wholesale kWh evidently excludes deliveries that a utility may make to other (e.g. embedded) power distributors. Data are also available on the following characteristics of a distributor's network and service territory:

- urban, rural, and total areas of service territory;
- service area population;
- municipal population;
- number of seasonal occupancy customers;
- winter and summer maximum monthly and average peak loads;
- average load factor;
- overhead, underground, and total circuit kilometers of line;[20] and
- number of transmission, subtransmission, and distribution transformers.

5.2 Data Appraisal

Our appraisal of these data as a basis for distribution cost benchmarking identified a number of noteworthy strengths and weakness. In this section we discuss each in turn.

5.2.1 Data Strengths

The OEB has gone as far as any regulatory commission in the world in recent years to facilitate the development of data that are useful in benchmarking the operations of power distributors. The trial balance cost data are, like those gathered on FERC Form 1 in the United States, highly detailed and a USoA facilitates standardized reporting. The PBR data include useful detailed data on revenues and output, including data on peak loads that are unavailable for U.S. power distributors. The copious information on network and service territory characteristics also has no counterpart in U.S. government data collection. Last but not least, the large number of reporting distributors and the diverse character of their operating scale and other business conditions mean that a data

[20] The circuit kilometer data are also available broken down between 3 phase, 2 phase, and single phase.

set of considerable size and diversity has already accumulated and will continue to grow with each passing year. We have seen that a large and diverse set of data is highly desirable for statistical benchmarking. As we will discuss further below, the data set is already sufficient to develop fairly sophisticated econometric cost models.

5.2.2 Data Weaknesses

The formidable advantages of OEB data are offset by some noteworthy disadvantages that materially limit their usefulness. Good benchmarking work is possible only if these limitations are recognized and the data are used cautiously. The constructive contributions of benchmarking to Ontario regulation can grow if the data are improved.

One important problem with the OEB data is the questionable potential of available capital cost data. As we discussed in section 2.5, the calculation of standardized capital costs require years of consistent and detailed plant additions data. While the PBR data on plant additions may permit us to begin calculation of standardized capital costs, the accuracy of the calculations is hampered by the scant number of years for which the data are as yet available. Benchmarking results will be highly sensitive to our estimate of the replacement cost of capital in the benchmark year. It is possible to cobble together estimates of capital costs but these are not of a quality sufficient to make ratemaking decisions.

Another important problem is inconsistencies in the allocation of labour expenses between distributor activities. Staff observes in its November notice that distributors report most customer care labour expenses as administrative expenses. We have found that this problem extends as well to distribution labour expenses for many companies. A related problem is the poor quality of the publicly available data concerning the salary and wage ("S&W") component of net OM&A expenses. On the United States FERC Form 1 the salaries and wages corresponding to all net operations and maintenance activities are reported on an itemized basis for all major power distributor activity groups (distribution, customer accounts, customer service and information, and administration and general).

These limitations of the Ontario labour cost data make it impossible at present to benchmark labour costs with any accuracy. Moreover, uncertainty concerning the share of labour in OM&A expenses reduces the accuracy of OM&A multifactor productivity indexes and econometric models which require cost shares.

As for the revenue and output data, one major problem is the non-availability of data on power deliveries to other distributors. This is important in the businesses of several companies, most notably Hydro One. Absent supplemental data on these deliveries, the company's output will be understated and its cost cannot be accurately benchmarked.

Another problem is inconsistencies in the reporting of the detailed "billed" retail delivery volumes and peak demand. Some companies appear to have reported volumes only for service classes with volumetric rates and peak demand only for service classes with demand charges. Other companies appear to have reported total volumes and total peak. Absent standardization of these detailed output data it is difficult to control for differences between utilities in the relative magnitudes of services offered. It is desirable for benchmarking purposes to have a breakdown of total deliveries by service class, as well as a measure of peak demand. With such data in hand, we can control better for the cost impact of differences in the service mixes of utilities.

It also merits note that inconsistencies in reporting limit the usefulness of some of the data on service territory characteristics. In our view, inconsistencies are especially pervasive with respect to the following characteristics:

- rural vs. urban service area; and
- number of seasonal occupancy customers.

Hydro One, for example, reports that all of its service territory is rural when in fact many of its customers live in towns.

5.2.3 Conclusions

We believe that the OEB data are solid enough to provide the foundation for the continued use of benchmarking in Ontario power distributor regulation. However, they must be used cautiously if the just and reasonable standard is to be preserved. Most notably, we believe that it is best for now to confine benchmarking to total OM&A

expenses. The data are inadequate for accurate benchmarking of labour expenses, detailed OM&A (*e.g.* distribution) expenses, capital cost, or total cost.

Improvements in the data can make it possible to expand the role of benchmarking in Ontario regulation. Here is a suggested list of high-priority upgrades:

- Tighten data reporting rules and enforcement so as to encourage more consistent allocations of labour costs between distributor functions
- Make public the share of net OM&A expenses attributable to labour, ideally with itemization with respect to the major distributor functions.[21]
- Gather detailed plant addition data. At a minimum, the value of gross plant additions should be reported each year for the following asset categories:
    - Distribution Plant
    - General Plant - Software
    - General Plant - Other

The following more detailed data, which are similar to those gathered on the FERC Form 1, would also be useful.

- Distribution Plant - Land
- Distribution Plant - Structures
- Distribution Plant - Station Equipment
- Distribution Plant - Poles, Towers, & Fixtures
- Distribution Plant - Overhead Conductors and Devices
- Distribution Plant - Underground Conduit
- Distribution Plant - Underground Conductors and Devices
- Distribution Plant - Line Transformers
- Distribution Plant - Services
- Distribution Plant - Meters
- Distribution Plant - Customer Premises Equipment
- Distribution Plant - Street Lighting & Signal Systems
- General Plant - Structures
- General Plant - Software

[21] This can in principle can be done without revealing a company's labour cost per customer.

- General Plant - Other

- Tighten the rules and enforcement to ensure that accurate data are available on delivery volumes by service class, as well as data on the overall peak demand.
- Gather data on the volume of deliveries to other distributors[22]
- Tighten rules and enforcement concerning the reporting of network and service territory characteristics.
- Consider collection of some additional business condition variables. For example, data on the number of customers served in 1990 would permit an estimate of the share of customers added since that date, a useful measure of system age.

[22] This upgrade should be made immediately and retrospectively.

6. Empirical Research

We turn now to a discussion of our empirical research. We first address three subjects --- the sample, the definition of cost, and cost drivers --- that are relevant to both our econometric and our indexing research. We then discuss details of our research using each of these methods. There follows an appraisal of the benchmarking work that has been done by Board staff.

6.1 The Sample

The sample period for our empirical research, 2002-2005, is that for which the standardized data needed for benchmarking were available at the time of our study. We included in the sample data for all companies for which requisite data of good quality were available for at least two of the four years. The companies represented in the sample are identified in Table 1, together with the data on the number of customers served in a recent year. For some companies, the data needed for indexing were available but not the data for all of the additional business conditions needed for econometric research. These companies are indicated by an asterisk. Only one distributor – Oshawa PUC – was excluded from both exercises.[23]

A review of the table reveals that the number of companies in the sample is sizable. Since, additionally, there are several observations for each company and the business conditions faced by the companies are varied, the prospects are good that econometric research can help us identify cost drivers. Estimates of the cost impact of these business conditions are useful in peer group design and econometric cost models can also be used directly in benchmarking.

A noteworthy omission from the econometric sample is Hydro One. Its distribution business faces unusual challenges that include its large operating scale and sizable deliveries to other distributors. Data for its deliveries to other distributors have not been gathered. For these and other reasons, benchmarking results for Hydro One were highly unstable in econometric models. The ability to benchmark Hydro One econometrically should improve as additional years of data and better delivery data

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[23] This company did not report the requisite retail volume data.

Table 1

SAMPLED POWER DISTRIBUTORS FOR BENCHMARKING RESEARCH[1]

Company	Customers Served, 2005	Staff Grouping	Headquarters Location
Atikokan Hydro	1,765	Small Northern	W, near Quetico Provincial Park
Barrie Hydro Distribution	65,812	GTA Towns	SC, on Lake Simcoe
Bluewater Power Distribution	34,736	Southwestern Midsize Towns	SW on Detroit River
Brant County Power	9,149	Southwestern Small Towns	SW 40 km W Hamilton
Brantford Power	35,986	GTA Towns	SW, 30 km SW Hamilton
Burlington Hydro	59,537	GTA Towns	SW, near Hamilton
Cambridge and North Dumfries Hydro	47,346	GTA Towns	SW, 30 km NW Hamilton
Centre Wellington Hydro	6,086	GTA Towns	SW, 20 km NW Guelph
Chapleau Public Utilities	1,353	Small Northern	NC, 60 km E Lake Superior Provincial Park
Chatham-Kent Hydro	31,955	Southwestern Midsize Towns	SW, 20 km E Lake St. Clair
Clinton Power	1,633	Southwestern Small Towns	SW, 15 km E Lake Huron
COLLUS Power	14,124	Southwestern Small Towns	SW, on Georgian Bay
Cooperative Hydro Embrun	1,791	Small Eastern	SE 40 KM ESE of Ottawa
Dutton Hydro	586	Southwestern Small Towns	SW 10 km N Lake Erie
Eastern Ontario Power (CNP)	3,537	Eastern	SE on St. Lawrence
E.L.K. Energy	10,524 (2004)	Southwestern Midsize Towns	SW, 30 km SE Windsor
Enersource Hydro Mississauga	178,140	Large City Southern	SC Suburban Toronto
ENWIN Powerlines	84,254	Large City Southern	SW on Detroit River
Erie Thames Powerlines	13,570	Southwestern Midsize Towns	SW 15 km N Lake Erie
Espanola Regional Hydro Distribution	3,315	Small Northern	C 40 km N Little Current
Essex Powerlines	27,437	Southwestern Midsize Towns	SW 30 KM ESE Windsor
Festival Hydro	18,860	Southwestern Midsize Towns	SW 40 km ESE Kitchener
Fort Erie (CNP)	15,230	Southwestern Midsize Towns	Niagara Peninsula, near Buffalo
Fort Frances Power	4,040	Small Northern	W, adjacent to International Falls. MN
Grand Valley Energy	682	Southwestern Small Towns	SW, Between Barrie and Toronto
Great Lakes Power	11,457	Large Northern	C, on Sault St. Marie
Greater Sudbury Hydro	42,814	Large Northern	C, Sudbury
Grimsby Power	9,530	Southwestern Small Towns	SC, on Niagara Peninsula 20 km W Hamilton
Guelph Hydro Electric Systems	44,556	GTA Towns	SW, 50 km NW Hamilton
Haldimand County Hydro	20,462	Southwestern Midsize Towns	SW, 20 km SW Hamilton
Halton Hills Hydro	19,873	Southwestern Small Towns	SW, 60 km W Toronto
Hearst Power Distribution	2,780	Large Northern	NC, 300 km NNW Wawa
Horizon Utilities	230,327	Large City Southern	SW, 60 km SW Toronto
Hydro 2000	1,130	Small Eastern	SE 20 KM west of Hawkesbury (WL), 70 KM east of Ottawa (WK)
Hawksbury Hydro	5,248	Small Eastern	SE, on Ottawa River 60 KM ENE Ottawa
Hydro One Networks	1,151,989	Unclassified	SC, Toronto
Hydro One Brampton Networks	116,166	Large City Southern	SC, Suburban Toronto
Hydro Ottawa	278,581	Large City Southern	SE, Ottawa
Innisfil Hydro Distribution Systems	13,793	Southwestern Midsize Towns	SC, 12 KM south of Barrie
Kenora Hydro Electric	5,847	Large Northern	W, Kenora on Lake of the Woods
Kingston Electricity Distribution	26,265	Small Eastern	SE, on St. Lawrence River
Kitchener-Wilmot Hydro	79,487	GTA Towns	SW, 15 km SW Guelph
Lakefront Utilities	8,551	Eastern	SC, on Lake Ontario 100 km E Toronto
Lakeland Power Distribution	8,995	Small Northern	C, between Georgian Bay & Algonquin PP
London Hydro	138,046	Large City Southern	SW, London
Middlesex Power Distribution	6,829	Southwestern Midsize Towns	SW, 80 lm E Windsor
Midland Power Utility	6,516	Southwestern Small Towns	C, on Georgian Bay 50 km N Barrie
Milton Hydro Distribution	19,858	GTA Towns	SW, 35 km N Hamilton
Newbury Power	189	Southwestern Small Towns	SW, 49 km SW London
Newmarket Hydro	26,176	GTA Towns	SC, between Toronto & Lake Simcoe
Niagara Falls Hydro	33,683	GTA Towns	SC, Niagara Peninsula
Niagara-on-the-Lake Hydro	7,466	Southwestern Small Towns	SC, Niagara Peninsula 15 km N Niagara Falls
Norfolk Power Distribution	18,171	Southwestern Small Towns	SW, near Lake Erie
North Bay Hydro Distribution	23,405	Large Northern	C, on Lake Nipissing 160 km E Sudbury
Northern Ontario Wires	6,202	Large Northern	NE 105 NNE Timmins
Oakville Hydro Electricity Distribution	54,677	GTA Towns	SC, Suburban Toronto on Lake Ontario
Orangeville Hydro	9,927	Southwestern Small Towns	SW, 80 km NW Toronto
Orillia Power Distribution	12,374	Southwestern Midsize Towns	SC, on Lake Simcoe 35 km NE Barrie
Ottawa River Power	10,190	Small Northern	C, on Ottawa River near Algonquin PP
Parry Sound Power	3,265	Small Eastern	C, on Georgian Bay 130 km N Barrie
Peninsula West Utilities	14,988	Southwestern Small Towns	SW, Niagara Peninsula 38 km E Hamilton
Peterborough Distribution	33,531	Small Eastern	70 km ENE Toronto
Port Colborne	9,135	Southwestern Midsize Towns	SC, Niagara Peninsula on Lake Erie 60 km W Buffalo
Powerstream	219,788	Large Southern	SC, suburban Toronto
PUC Distribution	32,497	Large Northern	C, Sault St. Marie
Renfrew Hydro	4,116	Small Eastern	SE, 90 km W Ottawa
Rideau St. Lawrence Distribution	5,823	Small Eastern	SE, on St. Lawrence River 100 km SSE Ottawa
Sioux Lookout Hydro	2,760	Large Northern	W, 230 km ENE Kenora
St. Thomas Energy	15,243	Southwestern Midsize Towns	SW, 10 km N Lake Erie
Tay Hydro Electric Distribution	3,990	Southwestern Small Towns	SC, near Georgian Bay 50 KM north of Barrie
Terrace Bay Superior Wires	938	Large Northern	NC, on Lake Superior 215 km E Thunder Bay
Thunder Bay Hydro Electricity Distribution	49,558	Large Northern	W, on Thunder Bay
Tillsonburg Hydro	6,343	Southwestern Small Towns	SW, 62 km ESE London
Toronto Hydro-Electric System	676,678	Large City Southern	SC, at center of Golden Horshoes on Lake Ontario
Veridian Connections	106,730	Large City Southern	SC, on Lake Ontario between Toronto & Oshawa
Wasaga Distribution	10,545	Southwestern Midsize Towns	SC, on Georgian Bay 38 km NW Barrie
Waterloo North Hydro	48,041	GTA Towns	SW, adjacent to Kitchener 100 km WSW Toronto
Welland Hydro-Electric System	21,430	GTA Towns	SW, Niagara Peninsula 70 km W Buffalo
Wellington North Power	3,416	Southwestern Small Towns	SW, between Kitchener & Owen Sound
West Coast Huron Energy	3,773	Southwestern Small Towns	SW, on Lake Huron 129 km ENE Sarnia
West Nipissing Energy Services	3,101	Large Northern	C, on Lake Nipissing 38 km E North Bay
West Perth Power	2,653	Southwestern Small Towns	SW, 80 km N London
Westario Power	20,699	Southwestern Midsize Towns	SW, on Lake Huron 89 KM SW Owen Sound
Whitby Hydro Electric	36,235	GTA Towns	SC, on Lake Ontario between Ajaz and Oshawa
Woodstock Hydro Services	14,195	Southwestern Midsize Towns	SW, on Thames River 50 km ENE London

[1] Oshawa Hydro, which has not been benchmarked due to data problems, is a GTA utility that served 49,498 customers in 2005.

become available. The statistical tests of efficiency hypotheses that we have developed for econometric models have the advantage of being sensitive to the unusual character of its business conditions. Hydro One cannot be benchmarked accurately with unit cost metrics using Ontario data due to a lack of suitable peers. An alternative is to use indexes and data from outside the province.

6.2 Definition of Cost

In Section 4.1 we reported our conclusion that the cost centre that can presently be benchmarked with reasonable accuracy is total OM&A expenses. These expenses have been the focus of our empirical research for the Board. The source of our OM&A cost data is the trial balance reports. We have included all of the USoA categories of distribution, billing and collecting, community relations, sales, and administrative and general OM&A expenses save those that pertain to the following activities:

- street lighting, signal systems, and sentinel lights;
- bad debts;
- pensions and other benefits[24];
- water heating and other customer services on premises;
- franchise requirements; and
- energy conservation.

It is our understanding that the A&G expenses that Board staff have provided to us exclude expenses that have been allocated to power transmission services by Hydro One. It is difficult to control for this business condition in the benchmarking work since no other company in the sample has a comparable operating advantage.

6.3 Cost Drivers

In this section, we discuss important drivers of the cost of power distribution. These drivers should be considered in the design of peer groups when benchmarking is undertaken using unit cost or productivity indexes. The importance of drivers can be

[24] PEG generally excludes expenses for pensions and other benefits from its cost benchmarking studies. These expenses are volatile and reflect commitments to former employees.

assessed by including variables that quantify them in econometric cost models. The models can be used, additionally, to benchmark costs directly. The estimates of the corresponding parameters should be plausible with regard to sign (positive or negative) and magnitude (large or small).

6.3.1 Output Quantities

As noted above, economic theory suggests that quantities of work performed by utilities are cost drivers and should be included in our cost models as business condition variables. We considered three output variables in our econometric research: the number of retail customers, the total retail delivery volume, and the total circuit km of distribution line. Recall from Section 2 that circuit km is the best available proxy for the distances over which power is carried. Cost should be higher the higher are the values of all of these variables. We, accordingly, expect the parameter estimate for each output variable to have a positive sign.

6.3.2 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. We developed an input price index that summarizes differences over time and, between sampled distributors, at each point in time in the prices they pay for OM&A inputs. Cost should be higher the higher is the value of the index. We, accordingly, expect the econometric estimate of the parameter of this variable to have a positive sign.

The index is a weighted average of subindexes for labour and a miscellaneous category of inputs that includes materials and services. The weights assigned to these input classes in index construction (.35 and .65 respectively) reflect our knowledge of the corresponding cost shares for power distributor OM&A expenses in the States.

The labour price subindex used in this study was constructed by PEG using Stats Canada data. Data from the 2001 census were used to compute average employment income by level of educational attainment in various Ontario cities. The subindex reflects an (employment-cost weighted) average of local cost comparisons to provincial averages for each level of educational attainment. The averaging technique mitigates the aggregation bias that would result from using cost per employee as a labour price index.

Cost per employee in Toronto, for instance, exaggerates the pay premiums paid there because a larger share of the labour force is engaged in high-paying managerial and professional occupations. Values of the labour cost indexes for the years of the sample period were calculated by adjusting the 2001 levels for changes in an index of labour cost trends in the Ontario economy.

Results of our labour price index calculations appear in Table 2. It can be seen that the variation in input prices was considerable. Our use of external labour price comparisons rather than company data means that our benchmarking encompasses the salaries and wages paid per employee as well as the number of employees.

Prices for materials and services were assumed to be the same in a given year across Ontario. As a measure of inflation in these prices we use the Ontario gross domestic product implicit price index ("GDP-IPI") for final domestic demand. In our U.S. research, we have found that indexes like the GDP-IPI track the trend in the prices of materials and services used by utilities fairly well. Further details of our price index calculations are provided in the Appendix.

6.3.3 Other Business Conditions

Seven other business condition variables were found to be statistically significant cost drivers in one or more of the econometric cost models that we developed. One is the percentage of the reported gross value of distribution line plant that involves assets that are under ground. This variable is calculated from trial balance data. We use it to measure the extent of system undergrounding. Undergrounded plant typically involves higher capital costs and lower OM&A expenses. The extent of undergrounding varies greatly across Ontario's distribution systems. Generally speaking, undergrounding is greater in urban areas and where provincial and local governments encourage it. We expect OM&A expenses to be lower the greater is the value of this variable. The cost model parameter for this variable should therefore have a negative sign.

A second cost driver that we have identified is a binary variable that equals one if most or all of the company's service territory is located on the Canadian Shield. We

Table 2

Econometric Model of OM&A Expenses: Double Log Form

VARIABLE KEY

WL= Labour Price
N= Number Retail Customers
V= Retail Deliveries
M= Distribution Line Circuit Kilometers
F= % Forestation of Rural Service Territory
UN= Percent of Distribution Plant that is Underground
CS= Canadian Shield (binary)
NCT= Non-Contiguous Service Territory (binary)

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC
WL	0.794	4.835	**F**	0.014	2.992
N	0.643	20.738	**UN**	-0.059	-5.833
V	0.142	4.911	**CS**	0.015	3.522
M	0.140	8.871	**NCT**	0.004	1.650
Constant	15.788	2081.988			

Other Results

System Rbar-Squared	0.977
Sample Period	2002-2005
Number of Observations	324

developed this variable using a map from an authoritative text on Ontario's geography.[25] The Shield is a physiographic region characterized by shallow, rocky soils and numerous lakes. Since the land receives considerable precipitation but is unsuited for agriculture, rural areas of the Shield are typically forested. We expect OM&A expenses to be higher on the Shield. Accordingly, we expect this variable's parameter estimate to have a positive sign.

A third cost driver that we have identified is a measure of service territory forestation. Using an authoritative map, we first estimated the percentage of the rural area of each service territory (or the rural environs of an urban utility) that was forested. Using PBR data, we then multiplied this percentage by the share of the territory that is rural. This approach makes sense because forestation should have a greater impact on cost the more rural is the service territory. We expect cost to be higher the higher is the value of this variable. An estimate of its parameter should therefore be positively signed.

A fourth cost driver we have identified is the percentage of distribution revenue drawn from residential and commercial customers. This variable was calculated using PBR revenue data. Residential and commercial customers typically have more peaked loads than other customers. They also use a more extensive array of distributor services. For example, they almost always rely on the distributor to perform the voltage step down function whereas many large volume industrial customers own their own transformers. We expect the relationship between cost and this variable to be positive. An estimate of its parameter should therefore have a positive sign.

A fifth business condition variable that has been identified is a binary ("dummy") variable that indicates whether the service territory of a utility is highly non-contiguous.[26] This is based on a list of companies with highly non-contiguous service territories provided by Board staff. It is generally more costly to serve a territory with this attribute. We therefore expect a positive parameter estimate for this variable.

A sixth significant business condition variable identified is the ratio of gross plant value to a construction cost index. We used this as a measure of the quantity of capital

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[25] See L.J. Chapman and D.F. Putnam, *The Physiography of Southern Ontario* (Toronto: University of Toronto Press, 1996).
[26] A binary variable assumes a value that is either one or zero. In this case, the variable will have a value of one if a company has a highly non-contiguous service territory.

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employed. Capital often serves as a substitute for OM&A inputs, and companies vary in their propensity to capitalize OM&A expenses. OM&A expenses should thus be lower the higher is the capital quantity, and we expect the estimate of this variables' parameter to be negative.

A seventh significant business condition variable identified is the number of transmission and sub-transmission transformers that a company owns. These transformers involve extra voltage step down work. Companies vary greatly in the percentage of power that flows through transformers that they own. OM&A expenses should be higher the greater is the number of transformers owned. Accordingly we expect this variable's parameter estimate to have a positive sign.

6.4 Functional Forms and Estimation Procedures

We developed cost models using a variety of functional forms that included the double log and the translog. Regarding model structures, we developed both single and multiple equation models. For the single equation models that are featured in the report we used two estimation procedures: OLS and a custom, in-house GLS method that provides a correction for heteroskedasticity.

6.5 Model Estimation Results

Estimation results for the double log and translog single equation models cost are presented in Tables 2 and 3, respectively.[27] In the double log model, all parameters are elasticities of cost with respect to the business condition. In the translog model the prices and quantities receive the translog treatment. The parameters for the "first order" terms are the elasticities of the cost of the sample mean firm with respect to the basic variable. These are the terms that do not involve squared values of business condition variables or interactions between different variables. Estimates of elasticities are shaded in both tables for reader convenience.

The tables also report the values of the asymptotic *t* ratios that correspond to each parameter estimate. These were also generated by the estimation program. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value

[27] These results are obtained using the more sophisticated GLS estimation procedure.

Table 3

Econometric Model of OM&A Expenses: Translog Form

VARIABLE KEY

WL= Labour Price
N= Number Retail Customers
V= Retail Deliveries
M= Distribution Line Circuit Kilometers
UN= Percent of Distribution Plant that is Underground
CS= Canadian Shield (binary)

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC
WL	1.124	4.544	**M**	0.138	5.385
WLWL	4.294	0.522	MM	0.209	4.769
WLN	-3.727	-3.288			
WLV	5.356	5.707	**UN**	-0.034	-3.216
WLM	-2.423	-5.739			
			CS	0.024	5.186
N	0.576	14.465			
NN	-0.246	-0.957	Constant	15.805	1754.127
V	0.224	6.307			
VV	-0.208	-1.314			

Other Results

System Rbar-Squared	0.98
Sample Period	2002-2005
Number of Observations	324

equals zero is rejected. This statistical test requires the selection of a critical value for the asymptotic *t* ratio. In this study, we employed a critical value of 1.645, which is appropriate for a 90% confidence level given a large sample.

All included business conditions were required to have elasticity estimates that were plausible (*e.g.* sensibly signed) and significantly different from zero. All variables found to be statistically significant were included in the final model. Since, additionally, we consider for inclusion only variables that are predicted by theory or that seem relevant on the basis of our industry experience, the models are not "black boxes" that confound earnest appraisal.

Examining results first for the translog model it can be seen that the cost function parameter estimates are plausible in sign and magnitude. Cost was found to be higher the higher were input prices and output quantities. At the sample mean, a 1% increase in the number of customers served was estimated to raise OM&A expenses by about .58%. 1% hikes in the delivery volume and circuit km of distribution line were estimated to raise expenses by about .22% and .14% respectively.

At each level of operating scale, cost theory suggest that economies of scale are available from further output growth if the sum of the cost elasticities of the scale variables is less than one. Our research suggests that economies of scale are available over a wide range of output in Ontario. For example, at sample mean values of our three output variables, it can be seen that the sum of the elasticities is .938 (.576+.224+.138). Thus modest incremental scale economies are available at the average level of operating scale. This finding is consistent with our cost research over the years using U.S. power distribution data, which has found that incremental scale economies are not exhausted until a level of output has been reached that is somewhat above the Ontario mean.

Our research suggests that scale economies confer on the larger Ontario utilities a material unit cost advantage over smaller utilities. The potential of a company to realize scale economies should therefore be recognized in responsible benchmarking work. The research results can also be used to assess the potential OM&A cost savings from mergers. Better estimates of scale economies will be possible as additional years of data become available for use in the econometric sample.

The parameter estimates for the other business condition variables were also sensible. OM&A expenses were found to be lower the greater was the extent of system undergrounding and higher for distributors serving territories on the Canadian Shield.

The table also reports the adjusted R^2 statistic for the model. This measures the ability of the model to explain variation in the sampled cost of distributors. Its value was 0.98, suggesting that the explanatory power of the model was high.

Some results for the other econometric models that we estimated also merit mention. Note first that results for the simpler but less flexible double log model were sensible. It was possible, for example, to develop a model of high explanatory power that had three output variables and four additional business conditions. Recognition of the two additional business conditions---those pertaining to forestation and service territory congruity--- was facilitated by the simpler functional form, which economizes on the number of parameters to be estimated.

Based on these results, we feel that the double log model and the translog model are equally serviceable for benchmarking at this time. The double log model will tend to yield more accurate results for companies with heavily forested and/or highly contiguous service territories. The translog model will tend to yield more accurate results for extremely small or large companies and customers with unusual customer density due to its more sensitive treatment of the cost impact of output. The comparative advantage of the translog form, with its more numerous parameters, should improve in the future when more data are available for parameter estimation.

Sensible results were obtained, for both the translog and double log single equation models, using the simpler OLS estimation procedure. Parameter estimates were broadly similar but had lower statistical significance. OLS therefore hinders the recognition of additional business conditions and the development of more flexible functional forms.

Interesting results were obtained using multiple equation translog cost models. Sensible models were developed that had explanatory power similar to that of the single equation models. Additional cost drivers were recognized, including the number of subtransmission and transmission transformers, the forestation variable, the plant value variable, and the share of residential and general service customers in distribution revenue.

A disquieting feature of the multiple equation models was the greater prevalence of "extreme" performance appraisals, which we define as appraisals in which actual cost differed from predicted cost by more that 50%. On balance, we believe that the advantages of multiple equation models do not outweigh the downside of their greater complexity at this time. The benefit-cost balance should improve when more years of data are available to estimate model parameters and there is more reliable information available regarding the breakdown of cost by input group.

6.6 Econometric Benchmarking Results

Table 4 presents the results of our appraisals of the OM&A expenses of the sampled distributors using each of the two featured econometric cost models. For each company and for each model we report the ratio of the average cost incurred by the company during the years considered to the average of the model's cost projections over the same years. Results pertain to the average of the reported cost over the 2002-2005 period unless data for one or two of these years were unavailable or implausible.

Statistical tests were conducted for each distributor of the hypothesis that it was an average cost performer over the sample period. A 90% confidence level was utilized for these tests. The p-values reported in Table 5 indicate the results of the tests. For any distributor with a favorable appraisal and a p value between 0 and 0.10, the hypothesis of average performance can be rejected and we may conclude that the company was a *significantly superior* performer. Any distributor with an unfavorable appraisal and a p-value between 0 and 0.10 was, by analogous reasoning, a *significantly inferior* performer. Only 10 distributors were found to be significantly superior and 12 were significantly inferior in the translog model. The number of significantly superior and inferior utilities would be considerably higher using a lower (*e.g.* 75%) confidence level. The p values reflect, as they should, how out-of-the-ordinary are the business conditions faced by subject utilities.

Table 4

Effects of Cost Performance: Translog & Double Log Models

		Translog Model					Double Log Model				
	Years Benchmarked	Actual/Predicted [A]	Deviation Percentage [A-1]	P-Value	Excess Cost in $	Rank	Actual/Predicted [A]	Deviation Percentage [A-1]	P-Value	Excess Cost in $	Rank
Hydro 2000	2002-2005	0.686	-0.314	0.096	-74,601	1	0.647	-0.353	0.089	-88,784	1
Hydro One Brampton Networks	2002-2005	0.707	-0.293	0.001	-5,556,551	2	0.757	-0.243	0.012	-4,278,375	9
Hydro Hawkesbury	2002-2005	0.714	-0.286	0.007	-262,382	3	0.654	-0.346	0.000	-346,746	2
Newbury Power	2002-2005	0.717	-0.283	0.110	-16,382	4	0.835	-0.165	0.249	-8,156	16
Hearst Power	2002-2005	0.733	-0.267	0.011	-186,012	5	0.721	-0.279	0.005	-197,236	4
Kitchener-Wilmot Hydro	2002-2005	0.736	-0.264	0.001	-3,356,860	6	0.727	-0.273	0.001	-3,510,160	5
Tay Hydro Electric	2002-2005	0.767	-0.233	0.104	-392,542	7	0.703	-0.297	0.013	-307,747	3
Lakefront Utilities	2002-2004	0.767	-0.233	0.014	-221,328	8	0.819	-0.181	0.131	-286,424	14
Lakeland Power	2002-2005	0.773	-0.227	0.014	-565,560	9	0.820	-0.180	0.046	-422,585	15
Port Colborne (CNP)	2002-2005	0.775	-0.225	0.052	-416,948	10	0.751	-0.249	0.031	-475,272	8
Barrie Hydro	2002-2005	0.789	-0.211	0.054	-2,070,698	11	0.748	-0.252	0.031	-2,627,633	7
Grimsby Power	2002-2005	0.801	-0.199	0.045	-326,436	12	0.735	-0.265	0.006	-473,100	6
Cooperative Hydro Embrun	2002-2005	0.806	-0.194	0.026	-72,437	13	0.886	-0.114	0.167	-38,644	22
Cambridge & North Dumfries	2002-2005	0.811	-0.189	0.024	-1,649,361	14	0.842	-0.158	0.062	-1,331,706	17
Niagara-on-the-Lake Hydro	2002-2005	0.813	-0.187	0.028	-291,049	15	0.817	-0.183	0.042	-283,286	13
Chatham-Kent Hydro	2004-2005	0.818	-0.182	0.021	-1,045,214	16	0.807	-0.193	0.023	-1,131,966	12
Renfrew Hydro	2002-2005	0.827	-0.173	0.046	-150,659	17	0.775	-0.225	0.011	-208,202	11
Orangeville Hydro	2002-2005	0.849	-0.151	0.069	-294,264	18	0.905	-0.095	0.205	-171,832	25
E.L.K. Energy	2002-2005	0.874	-0.126	0.166	-242,263	19	0.937	-0.063	0.282	-114,357	30
Festival Hydro	2002-2005	0.875	-0.125	0.165	-423,298	20	0.878	-0.122	0.134	-409,824	20
Halton Hills Hydro	2002-2005	0.877	-0.123	0.107	-524,215	21	0.849	-0.151	0.093	-663,047	18
Wasaga Distribution	2002-2005	0.906	-0.094	0.158	-133,289	22	0.763	-0.237	0.025	-398,683	10
Fort Frances Power	2002-2005	0.907	-0.093	0.177	-93,677	23	0.863	-0.137	0.099	-144,073	19
Burlington Hydro	2002-2005	0.908	-0.092	0.171	-969,802	24	0.901	-0.099	0.170	-1,043,495	23
Hydro Ottawa	2002-2005	0.917	-0.083	0.096	-3,415,957	25	0.907	-0.093	0.093	-3,869,409	26
Guelph Hydro Electric Systems	2002-2005	0.931	-0.069	0.258	-554,396	26	0.977	-0.023	0.409	-175,301	40
Milton Hydro Distribution	2002-2005	0.934	-0.066	0.232	-85,131	27	0.944	-0.056	0.263	-212,953	31
Kenora Hydro Electric	2002-2005	0.934	-0.066	0.248	-250,934	28	0.950	-0.050	0.318	-63,302	33
St. Thomas Energy	2002-2005	0.940	-0.060	0.285	-159,655	29	0.965	-0.035	0.287	-93,043	35
Ottawa River Power	2002-2004	0.941	-0.059	0.298	-116,515	30	0.984	-0.016	0.358	-29,877	41
Peterborough Distribution	2002-2005	0.943	-0.057	0.280	-310,031	31	0.923	-0.077	0.233	-424,870	27
Oakville Hydro Electricity Distribution	2002-2005	0.947	-0.053	0.260	-511,115	32	0.993	-0.007	0.351	-73,990	42
Powerstream	2002-2005	0.954	-0.046	0.254	-1,610,386	33	0.974	-0.026	0.300	-847,161	37
West Perth Power	2002-2005	0.960	-0.040	0.061	-18,665	34	0.976	-0.024	0.080	-10,833	38
Waterloo North Hydro	2002-2005	0.966	-0.034	0.370	-291,019	35	0.967	-0.033	0.359	-282,562	36
Horizon Utilities	2002-2005	0.968	-0.032	0.252	-1,084,526	36	0.931	-0.069	0.235	-2,341,089	28
London Hydro	2002-2005	0.969	-0.031	0.383	-639,711	37	1.006	0.006	0.449	121,541	43
Espanola Regional Hydro Distribution	2003-2005	0.972	-0.028	0.197	-22,663	38	0.935	-0.065	0.129	-55,305	29
North Bay Hydro Distribution	2002-2005	0.974	-0.026	0.287	-118,142	39	0.905	-0.095	0.250	-485,664	24
Northern Ontario Wires	2002-2005	0.988	-0.012	0.370	-20,809	40	0.962	-0.038	0.314	-68,554	34
Haldimand County Hydro	2002-2005	0.990	-0.010	0.180	-50,003	41	1.169	0.169	0.084	718,639	67
Welland Hydro-Electric System	2002-2005	1.004	0.004	0.304	14,729	42	1.009	0.009	0.320	33,056	44
COLLUS Power	2002-2005	1.008	0.008	0.384	19,608	43	0.977	-0.023	0.404	-57,254	39
Innisfil Hydro Distribution Systems	2002-2005	1.022	0.022	0.163	53,493	44	0.884	-0.116	0.147	-321,759	21
Sioux Lookout Hydro	2002-2005	1.022	0.022	0.181	17,860	45	0.945	-0.055	0.182	-49,012	32
Woodstock Hydro Services	2002-2005	1.024	0.024	0.403	65,012	46	1.057	0.057	0.313	146,709	50
Clinton Power	2002-2005	1.025	0.025	0.364	8,369	47	1.161	0.161	0.146	48,855	65
PUC Distribution	2002-2005	1.034	0.034	0.188	196,030	48	1.023	0.023	0.250	141,529	45
West Nipissing Energy Services	2002-2005	1.041	0.041	0.311	28,231	49	1.051	0.051	0.311	35,115	49

Table 4, continued

	Years Benchmarked	Actual/Predicted [A]	Deviation from Sample Mean [A]-1	P-Value	Excess Cost in $	Rank	Actual/Predicted [A]	Deviation from Sample Mean [A]-1	P-Value	Excess Cost in $	Rank
Parry Sound Power	2002-2005	1.042	0.042	0.197	34,146	50	1.061	0.061	0.207	48,700	51
Middlesex Power Distribution	2002-2005	1.043	0.043	0.143	55,658	51	1.076	0.076	0.141	95,266	55
Rideau St. Lawrence Distribution	2002-2005	1.058	0.058	0.290	62,738	52	1.074	0.074	0.259	78,955	54
Grand Valley Energy	2002-2005	1.059	0.059	0.314	9,442	53	1.273	0.273	0.028	36,496	74
Norfolk Power Distribution	2002-2005	1.067	0.067	0.264	240,460	54	1.067	0.067	0.263	240,460	53
Brantford Power	2002-2005	1.076	0.076	0.246	433,404	55	1.102	0.102	0.212	569,121	59
Orillia Power Distribution	2002-2005	1.078	0.078	0.191	189,182	56	1.081	0.081	0.194	198,879	58
Bluewater Power Distribution	2002-2005	1.080	0.080	0.248	523,764	57	1.112	0.112	0.172	710,804	60
Greater Sudbury Hydro	2002-2005	1.083	0.083	0.242	243,158	58	1.063	0.063	0.295	483,001	52
Fort Erie (CNP)	2002-2005	1.083	0.083	0.146	627,525	59	1.050	0.050	0.199	149,442	48
Terrace Bay Superior Wires	2002-2005	1.084	0.084	0.195	21,600	60	1.046	0.046	0.240	12,481	47
Great Lakes Power	2002-2005	1.096	0.096	0.133	540,205	61	1.640	0.640	0.000	2,378,666	83
Newmarket Hydro	2002-2005	1.097	0.097	0.259	453,026	62	1.112	0.112	0.265	513,062	61
Dutton Hydro	2002-2005	1.099	0.099	0.282	13,588	63	1.314	0.314	0.094	36,182	76
Thunder Bay Hydro Electricity Distribution	2002-2005	1.116	0.116	0.139	1,071,135	64	1.076	0.076	0.260	723,913	56
Whitby Hydro Electric	2002, 2003, 2005	1.117	0.117	0.149	690,926	65	1.037	0.037	0.354	238,881	46
Kingston Electricity Distribution	2003-2005	1.137	0.137	0.113	584,554	66	1.134	0.134	0.120	575,912	63
Wellington North Power	2002-2005	1.138	0.138	0.109	102,360	67	1.079	0.079	0.253	61,896	57
Enersource Hydro Mississauga	2002-2004	1.143	0.143	0.116	4,460,773	68	1.200	0.200	0.055	5,918,723	71
Peninsula West Utilities	2002-2005	1.143	0.143	0.227	488,834	69	1.123	0.123	0.217	423,960	62
Centre Wellington Hydro	2002-2005	1.181	0.181	0.111	215,739	70	1.185	0.185	0.091	221,737	69
Westario Power	2002-2005	1.188	0.188	0.082	651,887	71	1.183	0.183	0.099	641,385	68
Eastern Ontario Power (CNP)	2002-2005	1.192	0.192	0.130	177,762	72	1.165	0.165	0.190	155,462	66
Niagara Falls Hydro	2002-2005	1.228	0.228	0.021	1,312,580	73	1.259	0.259	0.016	1,449,386	73
Toronto Hydro-Electric System	2002-2005	1.232	0.232	0.027	26,111,812	74	1.365	0.365	0.003	37,005,031	79
Essex Powerlines	2002-2005	1.259	0.259	0.024	1,138,847	75	1.224	0.224	0.053	1,013,796	72
Veridian Connections	2002-2005	1.280	0.280	0.038	4,341,254	76	1.190	0.190	0.151	3,167,842	70
ENWIN Powerlines	2002-2005	1.292	0.292	0.040	4,529,632	77	1.487	0.487	0.001	6,571,413	82
West Coast Huron Energy	2002-2005	1.301	0.301	0.013	264,103	78	1.405	0.405	0.006	328,077	80
Brant County Power	2002-2005	1.318	0.318	0.024	626,533	79	1.322	0.322	0.024	630,455	77
Tillsonburg Hydro	2002-2005	1.339	0.339	0.079	328,599	80	1.146	0.146	0.177	165,491	64
Chapleau Public Utilities	2002-2005	1.361	0.361	0.009	123,784	81	1.358	0.358	0.008	123,097	78
Midland Power Utility	2002-2005	1.430	0.430	0.018	481,871	82	1.302	0.302	0.026	370,681	75
Erie Thames Powerlines	2002-2005	1.435	0.435	0.002	1,128,102	83	1.428	0.428	0.007	1,115,095	81

The following companies were excluded due to mergers: Asphodel Norwood Distribution, Aurora Hydro Connections, Gravenhurst Hydro Electric, Guelph Hydro Electric Systems (without Wellington Electric Distribution), Hamilton Hydro, Lakefield Distribution, Peterborough Distribution (without Asphodel Norwood and Lakefield), Powerstream (without Aurora), Scugog Hydro Energy, St. Catherines Hydro Utility Services, Veridian Connections (without Gravenhurst Hydro Electric and Scugog), and Wellington Electric Distribution

These companies were excluded from the sample due to missing or inaccurate data: Oshawa, PUC Networks (no retail volumes reported), Hydro One Networks (no deliveries to other LDCs reported), and Atikokan Hydro (zero underground plant reported).

Benchmarking results for a few companies differ markedly between the two models. This is not surprising since one model controls for additional business conditions whereas the other has a flexible form that may better address the situation of companies with unusual mixes of customers and line km. For example, the translog model may do a better job of recognizing the special cost challenges faced by a company that, like Great Lakes Power, has extremely low customer density.

6.7 Indexing Results

Recall now from Section 2 that summary output quantity indexes can be constructed in which estimates of the elasticity of cost with respect to the measures of the individual workload dimensions serve as weights. We used the econometric estimates of the cost elasticities from the translog model to calculate output indexes that summarize comparisons of circuit km, retail deliveries, and the number of customers served. The elasticity-share weights for these comparisons were 15%, 24%, and 61%, respectively.

The resulting summary indexes were used to construct unit cost and productivity indexes. Results are presented in Table 5. The index numbers for individual companies are arranged by peer groups that are similar to those proposed by Board staff.[28]

We report the averages of the index values for the companies in each peer group. Differences between peer group averages are broadly consistent with our econometric research. We find, for example that the peer groups tend to have lower unit costs and higher productivity the larger are the typical companies. We would expect this given their greater opportunity to realize scale economies. Urban distributors also possess, as a group, lower unit costs and higher productivity. This is likely due to the greater opportunity to save on OM&A expenses that is afforded by extensive system undergrounding. The lowest scores on average are those for the firms serving the north country. This reflects the combined effects of forestation and extensive overheading in the region, as well as the generally small scale of operations.

The operating performance of each utility is best assessed using these indexes by taking the ratio of its average index value to the average for its peer group. That is

[28] The productivity index results are, in principle, a little more accurate than the unit cost results since they control for differences in input prices as well as operating scale.

because the peer groups provide important controls for business conditions that are not provided by the indexes themselves. To illustrate this point, consider that the average value of the productivity index of Sioux Lookout, which serves a small number of rural customers in western Ontario, was 15% below the full sample norm on average. This result does not control, however, for the special cost challenges that it faces. To assess its performance, we must take the ratio of its average productivity index value to that of the small northern LDC peer group, which is 17% below the norm for the full sample. We obtain the number 0.850/0.830=1.024%. The productivity of Sioux Lookout was thus slightly higher than the peer group standard. Given average OM&A expenses of around $831,000, this implies cost savings on the order of about $ 19,000 (.023x831,596).

6.8 Comparing Performance Rankings

In Table 6, we provide overall rankings for the companies that are based on the peer group comparisons. These rankings are comparable to those that result from the econometric models. Inspecting the results, it can be seen that the rankings from the indexing and econometric work suggests that they are broadly similar. For example, Hydro One Brampton has a high performance ranking using all of the methods.

The degree of similarity between rankings like these can be estimated statistically using Spearman rank correlation coefficients. A Spearman rank correlation coefficient provides the direction and extent of the relationship between two rank ordering variables. In the present application, it allows us to compute the degree of similarity with which two benchmarking methods rank the efficiency of a set of firms.

We calculated Spearman rank correlation coefficients for the following six pairs of benchmarking methods: the unit cost index and the productivity index; the unit cost index and (each of) the translog and the double log models; the productivity index and (each of) the translog and double log models; and the translog and double log models.

Table 7 provides these results. It can be seen that the rank correlation coefficients between the two indexing methods and between the two econometric models are each very high (0.99 and 0.94, respectively). They indicate that the ranks provided by benchmarking using the two indexing methods and the two econometric models are very

Table 5

Unit Cost and Productivity Indexes for Total OM&A Expenses [1, 2]

	Average OM&A Expenses	Unit Cost (Low Values suggest good cost management.)								Productivity (High values suggest good cost management.)							
		2002	2003	2004	2005	Average of Available Years	Average / Group Average [A]	Percentage Differences [A - 1]	Excess Cost Per Year	2002	2003	2004	2005	Average of Available Years	Average / Group Average [B]	Percentage Differences [B -1]	Excess Cost Per Year
Unclassified																	
Hydro One Networks	$322,140,448	1.182	1.169	1.113	1.307	1.193	N/A	N/A	**N/A**	0.846	0.866	0.925	0.804	0.860	N/A	N/A	**N/A**
Small Northern LDCs																	
Hearst Power Distribution	$512,184	0.776	0.701	0.857	0.883	0.804	0.634	-36.6%	**-$187,428**	1.242	1.393	1.158	1.147	1.235	1.488	48.8%	**-$249,691**
Lakeland Power Distribution	$1,931,900	0.853	0.973	0.899	0.939	0.916	0.722	-27.8%	**-$536,842**	1.136	1.009	1.111	1.084	1.085	1.307	30.7%	**-$593,093**
Ottawa River Power	$1,854,822	0.965	1.082	1.065	1.034	1.037	0.817	-18.3%	**-$338,669**	0.946	0.855	0.883	0.928	0.903	1.088	8.8%	**-$162,845**
Kenora Hydro Electric	$1,210,292	1.124	1.166	1.188	1.171	1.162	0.917	-8.3%	**-$101,003**	0.872	0.851	0.849	0.879	0.863	1.040	4.0%	**-$47,871**
Sioux Lookout Hydro	$831,596	1.109	0.924	1.297	1.399	1.182	0.932	-6.8%	**-$56,304**	0.865	1.051	0.762	0.721	0.850	1.023	2.3%	**-$19,369**
Espanola Regional Hydro Distribution	$802,114	1.384	1.143	1.070	1.116	1.178	0.929	-7.1%	**-$56,908**	0.696	0.854	0.928	0.907	0.846	1.019	1.9%	**-$15,542**
Northern Ontario Wires	$1,725,352	1.296	1.185	1.280	1.173	1.234	0.973	-2.7%	**-$46,983**	0.753	0.834	0.785	0.874	0.812	0.978	-2.2%	**$38,601**
Fort Frances Power	$911,479	1.209	1.169	1.222	1.303	1.226	0.967	-3.3%	**-$30,455**	0.793	0.831	0.809	0.773	0.802	0.966	-3.4%	**$31,405**
Terrace Bay Superior Wires	$278,342	1.690	1.486	1.382	1.681	1.560	1.230	23.0%	**$64,033**	0.567	0.654	0.715	0.600	0.634	0.764	-23.6%	**$65,819**
Chapleau Public Utilities	$467,979	1.763	1.811	1.619	1.930	1.781	1.404	40.4%	**$189,143**	0.547	0.539	0.613	0.525	0.556	0.669	-33.1%	**$154,689**
Atikokan Hydro	$738,959	1.511	2.581	1.732	1.659	1.870	1.475	47.5%	**$350,961**	0.635	0.377	0.571	0.608	0.547	0.659	-34.1%	**$251,745**
GROUP AVERAGE						*1.268*								*0.830*			
Large Northern LDCs																	
North Bay Hydro Distribution	$4,678,187	1.029	1.063	0.995	0.867	0.989	0.773	-22.7%	**-$1,062,606**	0.913	0.896	0.974	1.139	0.980	1.179	17.9%	**-$837,108**
PUC Distribution	$6,254,896	0.880	0.936	1.089	1.085	0.997	0.780	-22.0%	**-$1,378,448**	1.068	1.017	0.889	0.910	0.971	1.167	16.7%	**-$1,046,056**
Greater Sudbury Hydro	$8,171,498	1.006	0.995	0.980	1.099	1.020	0.797	-20.3%	**-$1,655,383**	0.958	0.981	1.013	0.921	0.968	1.164	16.4%	**-$1,341,231**
Thunder Bay Hydro Electricity Dist.	$10,287,890	1.055	1.094	1.055	1.023	1.057	0.826	-17.4%	**-$1,789,708**	0.909	0.888	0.937	0.985	0.930	1.118	11.8%	**-$1,214,525**
West Nipissing Energy Services	$720,306	1.359	1.250	1.413	1.365	1.347	1.053	5.3%	**$37,956**	0.692	0.762	0.686	0.724	0.716	0.861	-13.9%	**$100,341**
Great Lakes Power	$6,100,416	2.169	2.305	2.168	2.423	2.266	1.771	77.1%	**$4,705,664**	0.433	0.413	0.446	0.407	0.425	0.511	-48.9%	**$2,983,487**
GROUP AVERAGE						*1.279*								*0.832*			
Southwestern Small Town LDCs																	
Grimsby Power	$1,314,250	0.722	0.708	0.799	0.848	0.769	0.677	-32.3%	**-$424,760**	1.392	1.438	1.295	1.245	1.342	1.431	43.1%	**-$566,194**
Niagara-on-the-Lake Hydro	$1,267,288	0.838	0.757	0.851	0.792	0.810	0.712	-28.8%	**-$364,386**	1.145	1.284	1.162	1.274	1.216	1.296	29.6%	**-$375,201**
Halton Hills Hydro	$3,744,491	0.918	0.851	0.863	0.796	0.857	0.754	-24.6%	**-$920,482**	1.102	1.204	1.208	1.335	1.212	1.292	29.2%	**-$1,094,049**
Orangeville Hydro	$1,651,565	0.895	0.964	0.829	0.907	0.899	0.791	-20.9%	**-$345,247**	1.125	1.059	1.252	1.167	1.151	1.227	22.7%	**-$374,498**
Tay Hydro Electric Distribution	$736,780	0.777	0.873	0.972	1.115	0.934	0.822	-17.8%	**-$131,108**	1.283	1.157	1.056	0.939	1.108	1.181	18.1%	**-$133,653**
COLLUS Power	$2,463,634	0.903	0.859	0.919	0.907	0.897	0.790	-21.0%	**-$518,191**	1.049	1.117	1.063	1.097	1.082	1.153	15.3%	**-$376,245**
West Perth Power	$450,079	N/A	1.251	1.224	0.766	1.080	0.951	-4.9%	**-$22,133**	N/A	0.781	0.812	1.323	0.972	1.036	3.6%	**-$16,216**
Norfolk Power Distribution	$3,826,365	1.117	1.073	0.992	0.957	1.035	0.911	-8.9%	**-$341,897**	0.863	0.911	1.001	1.059	0.959	1.022	2.2%	**-$82,806**
Peninsula West Utilities	$3,895,811	1.018	1.019	1.200	1.257	1.124	0.989	-1.1%	**-$43,211**	0.987	0.998	0.862	0.839	0.922	0.982	-1.8%	**$68,705**
Newbury Power	$42,155	N/A	N/A	1.384	0.967	1.175	1.034	3.4%	**$1,446**	N/A	N/A	0.724	1.057	0.891	0.949	-5.1%	**$2,135**
Tillsonburg Hydro	$1,302,458	0.943	1.299	1.169	1.380	1.198	1.054	5.4%	**$70,474**	1.042	0.767	0.866	0.748	0.856	0.912	-8.8%	**$114,482**
Wellington North Power	$847,699	1.107	1.132	1.188	1.251	1.169	1.029	2.9%	**$24,612**	0.870	0.862	0.835	0.809	0.844	0.900	-10.0%	**$84,973**
Midland Power Utility	$1,598,480	1.270	1.254	1.205	1.089	1.204	1.060	6.0%	**$96,072**	0.741	0.761	0.805	0.908	0.804	0.857	-14.3%	**$228,960**
Clinton Power	$354,117	1.131	1.340	N/A	1.341	1.271	1.118	11.8%	**$41,878**	0.860	0.736	N/A	0.762	0.786	0.838	-16.2%	**$57,535**
Brant County Power	$2,603,177	1.120	1.342	1.489	1.301	1.313	1.156	15.6%	**$405,733**	0.861	0.728	0.667	0.779	0.759	0.809	-19.1%	**$498,502**
West Coast Huron Energy	$1,148,015	1.244	1.396	1.373	1.722	1.434	1.262	26.2%	**$300,593**	0.799	0.721	0.746	0.607	0.718	0.766	-23.4%	**$268,982**
Grand Valley Energy	$171,219	1.529	1.468	1.585	1.832	1.604	1.411	41.1%	**$70,456**	0.659	0.695	0.655	0.578	0.647	0.689	-31.1%	**$53,218**
Dutton Hydro	$155,646	1.311	1.436	2.335	1.638	1.680	1.478	47.8%	**$74,477**	0.742	0.686	0.429	0.624	0.620	0.661	-33.9%	**$52,739**
GROUP AVERAGE						*1.136*								*0.938*			

[1]The output index was calculated using the elasticity weights drawn from our translog econometric cost model. The weights were 61.4% for customers, 23.9% for retail volume, and 14.7% for circuit KM of line.

[2]Companies are ranked by the productivity indexes.

Table 5, continued

	Average OM&A Expenses	Unit Cost (Low Values suggest good cost management.)								Productivity (High values suggest good cost management.)							
		2002	2003	2004	2005	Average of Available Years	Average / Group Average [A]	Percentage Differences [A - 1]	Excess Cost Per Year	2002	2003	2004	2005	Average of Available Years	Average / Group Average [B]	Percentage Differences [B -1]	Excess Cost Per Year
Southwestern Midsize town LDCs																	
Chatham-Kent Hydro	$4,698,529	0.705	0.690	0.734	0.727	0.714	0.727	-27.3%	**-$1,281,658**	1.376	1.424	1.362	1.404	1.391	1.325	32.5%	**-$1,525,987**
Festival Hydro	$2,954,023	0.824	0.758	0.802	0.762	0.787	0.801	-19.9%	**-$587,022**	1.170	1.289	1.239	1.330	1.257	1.197	19.7%	**-$580,796**
Wasaga Distribution	$1,292,945	0.724	0.775	0.844	0.930	0.818	0.833	-16.7%	**-$215,311**	1.375	1.303	1.215	1.125	1.255	1.194	19.4%	**-$251,451**
Port Colborne (CNP)	$1,447,646	0.699	0.873	0.853	N/A	0.808	0.823	-17.7%	**-$255,948**	1.373	1.114	1.159	N/A	1.215	1.157	15.7%	**-$227,068**
Innisfil Hydro Distribution Systems	$2,465,220	0.861	0.884	0.975	0.977	0.924	0.941	-5.9%	**-$144,626**	1.157	1.141	1.053	1.071	1.106	1.053	5.3%	**-$129,486**
E.L.K. Energy	$1,679,279	0.935	1.029	0.879	N/A	0.948	0.965	-3.5%	**-$58,328**	1.098	1.011	1.204	N/A	1.104	1.051	5.1%	**-$86,078**
St. Thomas Energy	$2,549,829	0.813	0.868	0.941	1.009	0.908	0.924	-7.6%	**-$192,956**	1.196	1.135	1.065	1.013	1.102	1.050	5.0%	**-$126,308**
Bluewater Power Distribution	$7,072,941	0.944	1.001	0.925	0.942	0.953	0.971	-2.9%	**-$206,701**	1.044	0.998	1.098	1.100	1.060	1.009	0.9%	**-$65,046**
Woodstock Hydro Services	$2,746,297	0.919	0.943	1.021	1.034	0.979	0.997	-0.3%	**-$7,819**	1.069	1.056	0.992	0.999	1.029	0.980	-2.0%	**$56,113**
Orillia Power Distribution	$2,629,754	0.916	1.050	1.089	1.169	1.056	1.076	7.6%	**$198,599**	1.087	0.961	0.942	0.895	0.971	0.925	-7.5%	**$197,470**
Fort Erie (CNP)	$3,148,520	1.231	0.900	1.091	0.984	1.052	1.071	7.1%	**$223,379**	0.780	1.080	0.906	1.024	0.948	0.902	-9.8%	**$308,217**
Middlesex Power Distribution	$1,359,979	1.070	1.124	0.915	1.175	1.071	1.091	9.1%	**$123,509**	0.907	0.874	1.093	0.868	0.936	0.891	-10.9%	**$148,682**
Essex Powerlines	$5,561,232	1.141	1.025	1.133	1.247	1.137	1.158	15.8%	**$876,645**	0.900	1.015	0.934	0.865	0.928	0.884	-11.6%	**$645,797**
Haldimand County Hydro	$4,978,903	1.088	1.042	1.122	1.153	1.101	1.121	12.1%	**$604,083**	0.886	0.938	0.886	0.879	0.897	0.854	-14.6%	**$726,213**
Westario Power	$4,157,664	1.003	1.117	1.120	N/A	1.080	1.100	10.0%	**$416,244**	0.927	0.843	0.855	N/A	0.875	0.833	-16.7%	**$694,147**
Erie Thames Powerlines	$3,755,379	1.157	1.333	1.479	1.529	1.374	1.400	40.0%	**$1,500,691**	0.841	0.739	0.677	0.668	0.732	0.696	-30.4%	**$1,139,980**
GROUP AVERAGE						*0.982*								*1.050*			
Eastern LDCs																	
Hydro Hawkesbury	$656,384	0.596	0.630	0.570	0.687	0.621	0.636	-36.4%	**-$238,969**	1.566	1.500	1.684	1.426	1.544	1.443	44.3%	**-$290,935**
Hydro 2000	$170,263	0.578	0.678	0.659	1.230	0.786	0.805	-19.5%	**-$33,173**	1.614	1.394	1.459	0.797	1.316	1.230	23.0%	**-$39,171**
Lakefront Utilities	$1,307,426	0.711	0.678	0.808	0.971	0.792	0.811	-18.9%	**-$246,706**	1.358	1.443	1.232	1.045	1.270	1.186	18.6%	**-$243,810**
Peterborough Distribution	$5,103,207	0.835	0.781	0.814	0.831	0.815	0.835	-16.5%	**-$840,314**	1.132	1.226	1.196	1.195	1.187	1.109	10.9%	**-$557,701**
Cooperative Hydro Embrun	$302,333	0.993	1.079	0.974	1.151	1.049	1.075	7.5%	**$22,653**	1.023	0.954	1.074	0.927	0.995	0.929	-7.1%	**$21,318**
Renfrew Hydro	$719,735	0.967	0.947	0.949	0.906	0.942	0.965	-3.5%	**-$25,028**	0.944	0.977	0.992	1.059	0.993	0.928	-7.2%	**$51,852**
Kingston Electricity Distribution	$4,903,757	0.982	0.962	0.992	0.999	0.984	1.008	0.8%	**$37,745**	0.965	0.998	0.983	0.997	0.986	0.921	-7.9%	**$386,326**
Rideau St. Lawrence Distribution	$1,152,996	1.054	1.114	1.130	1.109	1.102	1.129	12.9%	**$148,327**	0.912	0.874	0.876	0.910	0.893	0.834	-16.6%	**$190,866**
Parry Sound Power	$856,835	1.037	1.138	1.302	1.365	1.210	1.240	24.0%	**$205,328**	0.945	0.873	0.775	0.755	0.837	0.782	-21.8%	**$186,491**
Eastern Ontario Power (CNP)	$1,100,647	N/A	1.632	1.216	1.534	1.461	1.496	49.6%	**$546,063**	N/A	0.588	0.803	0.649	0.680	0.635	-36.5%	**$401,229**
GROUP AVERAGE						*0.976*								*1.070*			
Large City Southern LDCs																	
Hydro One Brampton Networks	$13,370,715	0.629	0.609	0.544	0.587	0.592	0.704	-29.6%	**-$3,954,232**	1.618	1.694	1.930	1.823	1.766	1.368	36.8%	-$4,916,642
Hydro Ottawa	$37,805,068	0.852	0.698	0.634	0.625	0.702	0.834	-16.6%	**-$6,259,186**	1.193	1.475	1.652	1.709	1.507	1.167	16.7%	-$6,318,605
Powerstream	$33,730,504	0.644	0.733	0.780	0.818	0.744	0.884	-11.6%	**-$3,901,481**	1.581	1.408	1.345	1.308	1.411	1.092	9.2%	-$3,113,947
Horizon Utilities	$31,469,808	0.654	0.729	0.735	0.829	0.737	0.876	-12.4%	**-$3,905,639**	1.537	1.395	1.408	1.273	1.403	1.087	8.7%	-$2,724,183
London Hydro	$20,321,872	0.773	0.757	0.785	0.782	0.774	0.921	-7.9%	**-$1,613,649**	1.259	1.302	1.276	1.306	1.286	0.996	-0.4%	$91,428
Enersource Hydro Mississauga	$35,667,848	0.810	0.833	0.887	0.924	0.864	1.027	2.7%	**$955,497**	1.257	1.239	1.184	1.158	1.209	0.936	-6.4%	$2,270,048
Toronto Hydro-Electric System	$138,488,976	0.869	0.928	0.946	0.898	0.910	1.082	8.2%	**$11,377,729**	1.172	1.112	1.109	1.192	1.146	0.888	-11.2%	$15,556,149
Veridian Connections	$19,922,136	1.022	1.233	1.000	0.889	1.036	1.232	23.2%	**$4,618,033**	0.998	0.838	1.051	1.206	1.023	0.792	-20.8%	$4,135,764
ENWIN Powerlines	$20,080,970	1.265	1.239	1.228	1.112	1.211	1.440	44.0%	**$8,830,250**	0.812	0.840	0.861	0.970	0.871	0.674	-32.6%	$6,539,766
GROUP AVERAGE						*0.841*								*1.291*			
GTA towns LDCs																	
Kitchener-Wilmot Hydro	$9,351,437	0.594	0.610	0.608	0.619	0.608	0.699	-30.1%	**-$2,816,163**	1.673	1.653	1.685	1.688	1.674	1.383	38.3%	-$3,584,171
Barrie Hydro Distribution	$7,813,820	0.607	0.749	0.655	0.559	0.643	0.739	-26.1%	**-$2,040,601**	1.641	1.348	1.566	1.874	1.607	1.328	32.8%	-$2,559,109
Cambridge and North Dumfries Hydro	$7,104,172	0.711	0.698	0.760	0.706	0.719	0.826	-17.4%	**-$1,233,504**	1.398	1.443	1.348	1.481	1.417	1.171	17.1%	-$1,214,983
Burlington Hydro	$9,539,784	0.751	0.778	0.823	0.824	0.794	0.913	-8.7%	**-$828,373**	1.338	1.308	1.256	1.280	1.296	1.070	7.0%	-$671,762
Oakville Hydro Electricity Distribution	$9,223,560	0.784	0.880	0.827	0.798	0.822	0.945	-5.5%	**-$503,719**	1.291	1.165	1.261	1.331	1.262	1.042	4.2%	-$391,637
Guelph Hydro Electric Systems	$7,535,517	0.801	0.817	0.775	0.808	0.800	0.920	-8.0%	**-$600,090**	1.224	1.216	1.304	1.276	1.255	1.037	3.7%	-$277,380
Waterloo North Hydro	$8,171,374	0.863	0.846	0.848	0.801	0.839	0.965	-3.5%	**-$283,320**	1.152	1.190	1.208	1.305	1.214	1.003	0.3%	-$22,253
Milton Hydro Distribution	$3,572,770	0.958	0.889	0.849	0.870	0.891	1.025	2.5%	**$89,066**	1.049	1.145	1.219	1.213	1.156	0.955	-4.5%	$159,426
Whitby Hydro Electric	$6,584,501	0.949	1.025	0.918	0.950	0.960	1.104	10.4%	**$685,235**	1.076	1.009	1.145	1.129	1.090	0.900	-10.0%	$656,917
Welland Hydro-Electric System	$3,693,122	0.858	0.939	0.961	0.862	0.905	1.041	4.1%	**$150,503**	1.119	1.035	1.028	1.170	1.088	0.899	-10.1%	$373,639
Brantford Power	$6,180,431	0.841	0.923	1.001	0.982	0.937	1.078	7.8%	**$479,152**	1.146	1.058	0.992	1.031	1.057	0.873	-12.7%	$783,669
Newmarket Hydro	$5,165,882	0.916	1.327	0.926	0.866	1.009	1.160	16.0%	**$825,951**	1.100	0.769	1.121	1.223	1.053	0.870	-13.0%	$671,072
Niagara Falls Hydro	$7,093,752	1.026	1.035	1.048	1.106	1.054	1.212	21.2%	**$1,503,067**	0.935	0.939	0.944	0.911	0.932	0.770	-23.0%	$1,630,269
Centre Wellington Hydro	$1,420,028	1.295	1.214	1.151	1.114	1.194	1.373	37.3%	**$529,154**	0.758	0.818	0.878	0.925	0.845	0.698	-30.2%	$429,044
GROUP AVERAGE						*0.870*								*1.210*			

[1]The output index was calculated using the elasticity weights drawn from our translog econometric cost model. The weights were 61.4% for customers, 23.9% for retail volume, and 14.7% for circuit KM of line.
[2]Companies are ranked by the productivity indexes.
[3]Low values suggest good cost management
[4]High values suggest good cost management

Table 6

Performance Rankings Based on Peer Group Comparisons[1]

	Unit Cost Index (Low values suggest good cost management.)				Productivity Index (High values suggest good cost management.)			
	Average / Group Average [A]	Percentage Differences [A - 1]	Excess Cost Per Year	Efficiency Ranking	Average / Group Average [B]	Percentage Differences [B -1]	Excess Cost Per Year	Efficiency Ranking
Hearst Power Distribution	0.634	-36.6%	-$187,427.78	1	1.488	48.8%	-$249,690.71	1
Hydro Hawkesbury	0.636	-36.4%	-$238,968.93	2	1.443	44.3%	-$290,935.12	2
Grimsby Power	0.677	-32.3%	-$424,759.78	3	1.431	43.1%	-$566,193.56	3
Kitchener-Wilmot Hydro	0.699	-30.1%	-$2,816,163.17	4	1.383	38.3%	-$3,584,170.75	4
Hydro One Brampton Networks	0.704	-29.6%	-$3,954,232.42	5	1.368	36.8%	-$4,916,641.96	5
Barrie Hydro Distribution	0.739	-26.1%	-$2,040,600.56	9	1.328	32.8%	-$2,559,109.06	6
Chatham-Kent Hydro	0.727	-27.3%	-$1,281,658.43	8	1.325	32.5%	-$1,525,987.12	7
Lakeland Power Distribution	0.722	-27.8%	-$536,841.84	7	1.307	30.7%	-$593,093.35	8
Niagara-on-the-Lake Hydro	0.712	-28.8%	-$364,386.45	6	1.296	29.6%	-$375,200.81	9
Halton Hills Hydro	0.754	-24.6%	-$920,482.09	10	1.292	29.2%	-$1,094,048.97	10
Hydro 2000	0.805	-19.5%	-$33,172.55	17	1.230	23.0%	-$39,170.71	11
Orangeville Hydro	0.791	-20.9%	-$345,246.93	14	1.227	22.7%	-$374,498.32	12
Festival Hydro	0.801	-19.9%	-$587,021.55	16	1.197	19.7%	-$580,795.87	13
Wasaga Distribution	0.833	-16.7%	-$215,310.51	24	1.194	19.4%	-$251,450.92	14
Lakefront Utilities	0.811	-18.9%	-$246,705.88	18	1.186	18.6%	-$243,810.25	15
Tay Hydro Electric Distribution	0.822	-17.8%	-$131,107.98	20	1.181	18.1%	-$133,653.10	16
North Bay Hydro Distribution	0.773	-22.7%	-$1,062,606.25	11	1.179	17.9%	-$837,108.39	17
Cambridge and North Dumfries Hydro	0.826	-17.4%	-$1,233,503.80	23	1.171	17.1%	-$1,214,982.75	18
PUC Distribution	0.780	-22.0%	-$1,378,447.97	12	1.167	16.7%	-$1,046,055.52	19
Hydro Ottawa	0.834	-16.6%	-$6,259,185.68	25	1.167	16.7%	-$6,318,604.52	20
Greater Sudbury Hydro	0.797	-20.3%	-$1,655,382.72	15	1.164	16.4%	-$1,341,231.36	21
Port Colborne (CNP)	0.823	-17.7%	-$255,948.15	21	1.157	15.7%	-$227,068.03	22
COLLUS Power	0.790	-21.0%	-$518,191.07	13	1.153	15.3%	-$376,244.90	23
Thunder Bay Hydro Electricity Dist.	0.826	-17.4%	-$1,789,708.16	22	1.118	11.8%	-$1,214,524.53	24
Peterborough Distribution	0.835	-16.5%	-$840,314.47	26	1.109	10.9%	-$557,701.48	25
Powerstream	0.884	-11.6%	-$3,901,480.72	28	1.092	9.2%	-$3,113,946.64	26
Ottawa River Power	0.817	-18.3%	-$338,668.70	19	1.088	8.8%	-$162,844.95	27
Horizon Utilities	0.876	-12.4%	-$3,905,638.98	27	1.087	8.7%	-$2,724,182.93	28
Burlington Hydro	0.913	-8.7%	-$828,373.10	30	1.070	7.0%	-$671,762.33	29
Innisfil Hydro Distribution Systems	0.941	-5.9%	-$144,625.98	37	1.053	5.3%	-$129,486.20	30
E.L.K. Energy	0.965	-3.5%	-$58,327.69	41	1.051	5.1%	-$86,078.13	31
St. Thomas Energy	0.924	-7.6%	-$192,956.13	34	1.050	5.0%	-$126,307.61	32
Oakville Hydro Electricity Distribution	0.945	-5.5%	-$503,719.28	38	1.042	4.2%	-$391,636.70	33
Kenora Hydro Electric	0.917	-8.3%	-$101,003.21	31	1.040	4.0%	-$47,870.84	34
Guelph Hydro Electric Systems	0.920	-8.0%	-$600,090.18	32	1.037	3.7%	-$277,380.08	35
West Perth Power	0.951	-4.9%	-$22,132.61	39	1.036	3.6%	-$16,216.32	36
Sioux Lookout Hydro	0.932	-6.8%	-$56,304.48	36	1.023	2.3%	-$19,369.26	37
Norfolk Power Distribution	0.911	-8.9%	-$341,897.28	29	1.022	2.2%	-$82,806.17	38
Espanola Regional Hydro Distribution	0.929	-7.1%	-$56,907.89	35	1.019	1.9%	-$15,542.46	39
Bluewater Power Distribution	0.971	-2.9%	-$206,700.51	44	1.009	0.9%	-$65,045.75	40
Waterloo North Hydro	0.965	-3.5%	-$283,320.32	42	1.003	0.3%	-$22,253.10	41

Table 6, continued

	Unit Cost Index (Low values suggest good cost management.)				Productivity Index (High values suggest good cost management.)			
	Average / Group Average [A]	Percentage Differences [A - 1]	Excess Cost Per Year	Efficiency Ranking	Average / Group Average [B]	Percentage Differences [B -1]	Excess Cost Per Year	Efficiency Ranking
London Hydro	0.921	-7.9%	-$1,613,648.94	33	0.996	-0.4%	$91,427.97	43
Peninsula West Utilities	0.989	-1.1%	-$43,210.88	46	0.982	-1.8%	$68,705.40	44
Woodstock Hydro Services	0.997	-0.3%	-$7,819.02	47	0.980	-2.0%	$56,112.51	45
Northern Ontario Wires	0.973	-2.7%	-$46,983.06	45	0.978	-2.2%	$38,601.17	46
Fort Frances Power	0.967	-3.3%	-$30,455.34	43	0.966	-3.4%	$31,404.62	47
Milton Hydro Distribution	1.025	2.5%	$89,065.70	50	0.955	-4.5%	$159,426.24	48
Newbury Power	1.034	3.4%	$1,445.78	53	0.949	-5.1%	$2,135.40	49
Enersource Hydro Mississauga	1.027	2.7%	$955,496.90	51	0.936	-6.4%	$2,270,048.34	50
Cooperative Hydro Embrun	1.075	7.5%	$22,652.87	59	0.929	-7.1%	$21,317.68	51
Renfrew Hydro	0.965	-3.5%	-$25,027.61	40	0.928	-7.2%	$51,852.02	52
Orillia Power Distribution	1.076	7.6%	$198,599.29	60	0.925	-7.5%	$197,469.58	53
Kingston Electricity Distribution	1.008	0.8%	$37,744.93	49	0.921	-7.9%	$386,325.84	54
Tillsonburg Hydro	1.054	5.4%	$70,474.17	56	0.912	-8.8%	$114,481.75	55
Fort Erie (CNP)	1.071	7.1%	$223,379.37	58	0.902	-9.8%	$308,216.98	56
Whitby Hydro Electric	1.104	10.4%	$685,234.66	65	0.900	-10.0%	$656,917.22	57
Wellington North Power	1.029	2.9%	$24,611.77	52	0.900	-10.0%	$84,972.72	58
Welland Hydro-Electric System	1.041	4.1%	$150,502.79	54	0.899	-10.1%	$373,639.15	59
Middlesex Power Distribution	1.091	9.1%	$123,508.84	63	0.891	-10.9%	$148,682.44	60
Toronto Hydro-Electric System	1.082	8.2%	$11,377,728.57	62	0.888	-11.2%	$15,556,149.03	61
Essex Powerlines	1.158	15.8%	$876,645.40	70	0.884	-11.6%	$645,797.11	62
Brantford Power	1.078	7.8%	$479,151.74	61	0.873	-12.7%	$783,668.74	63
Newmarket Hydro	1.160	16.0%	$825,951.49	71	0.870	-13.0%	$671,072.20	64
West Nipissing Energy Services	1.053	5.3%	$37,956.27	55	0.861	-13.9%	$100,340.58	65
Midland Power Utility	1.060	6.0%	$96,072.34	57	0.857	-14.3%	$228,959.52	66
Haldimand County Hydro	1.121	12.1%	$604,082.96	67	0.854	-14.6%	$726,213.03	67
Clinton Power	1.118	11.8%	$41,878.44	66	0.838	-16.2%	$57,535.01	68
Rideau St. Lawrence Distribution	1.129	12.9%	$148,327.18	68	0.834	-16.6%	$190,865.77	69
Westario Power	1.100	10.0%	$416,244.07	64	0.833	-16.7%	$694,146.78	70
Brant County Power	1.156	15.6%	$405,733.13	69	0.809	-19.1%	$498,502.09	71
Veridian Connections	1.232	23.2%	$4,618,032.59	74	0.792	-20.8%	$4,135,763.85	72
Parry Sound Power	1.240	24.0%	$205,328.36	75	0.782	-21.8%	$186,491.18	73
Niagara Falls Hydro	1.212	21.2%	$1,503,067.32	72	0.770	-23.0%	$1,630,269.16	74
West Coast Huron Energy	1.262	26.2%	$300,593.36	76	0.766	-23.4%	$268,982.40	75
Terrace Bay Superior Wires	1.230	23.0%	$64,033.12	73	0.764	-23.6%	$65,819.45	76
Centre Wellington Hydro	1.373	37.3%	$529,153.63	77	0.698	-30.2%	$429,043.89	77
Erie Thames Powerlines	1.400	40.0%	$1,500,690.90	78	0.696	-30.4%	$1,139,979.93	78
Grand Valley Energy	1.411	41.1%	$70,455.61	80	0.689	-31.1%	$53,218.09	79
ENWIN Powerlines	1.440	44.0%	$8,830,250.28	81	0.674	-32.6%	$6,539,765.80	80
Chapleau Public Utilities	1.404	40.4%	$189,142.67	79	0.669	-33.1%	$154,688.53	81
Dutton Hydro	1.478	47.8%	$74,476.58	83	0.661	-33.9%	$52,739.25	82
Atikokan Hydro	1.475	47.5%	$350,960.94	82	0.659	-34.1%	$251,745.42	83
Eastern Ontario Power (CNP)	1.496	49.6%	$546,062.59	84	0.635	-36.5%	$401,229.37	84
Great Lakes Power	1.771	77.1%	$4,705,663.70	85	0.511	-48.9%	$2,983,486.88	85

[1]Ranked by comparisons to peer group norms

Table 7

Spearman Rank Correlation Coefficients

METHODOLOGY KEY

UC= Unit Cost Index
PFP= Productivity Index
ET= Translog Cost Function
EDL= Double Log cost Function

	UC	PFP	ET	EDL
UC	1.00			
PFP	0.99	1.00		
ET	0.68	0.67	1.00	
EDL	0.70	0.69	0.94	1.00

similar. The correlation of rank orderings between the indexing and the econometric approaches are also less strong. The unit cost index and the efficiency rankings from the translog and the double log models have correlation coefficients of 0.68 and 0.70, respectively. The values are 0.67 and 0.69 for the correlation coefficients between the productivity index and the translog and the double log rankings. The similarity between the rankings for the unit cost and productivity indexes suggest that the use of peer groups does an adequate job of capturing differences between the input prices of the utilities. The extra complexity of productivity indexes does not seem to be commensurate with the benefits.

Notwithstanding the broad similarity of the indexing and econometric results, the results differ considerably for some companies. In these cases, we believe that the results from direct econometric benchmarking are generally more accurate.

6.9 The Board Staff Methodology

Our review of benchmarking methods in Section 2, combined with the empirical results just presented, provide us with a solid foundation for appraising the benchmarking method developed by Board staff. In this section we first explain the suggested method. Our appraisal immediately follows. A write up, prepared by Board staff, of its methodology is provided in Appendix B.

6.9.1 Staff's Methodology

Board staff's illustrative methodology is detailed in its November notice and the attached data spreadsheets. It features the calculation of an array of simple unit cost metrics. Each metric is the ratio of a certain cost to a certain cost driver. The cost "centres" considered are:

OM&A Expenses — Total
- Distribution
- Customer care, administrative and general

Depreciation and Amortization Expenses

All of the cost data are drawn from Trial Balance filings. Customer care and A&G expenses are grouped together because some distributors reportedly include administrative customer service costs in A&G expenses. The expense data used in the benchmarking excluded bad debt expenses to reduce anomalies.

Four cost drivers are considered:

- Total number of customers served
- Total Retail Delivery Volume (MWh)
- Total circuit km of line
- Total Service Area (km^2)

The data for all of these quantities are drawn from PBR filings. Staff has settled upon the number of customers as the denominator for the results in Appendix B.

For comparison purposes, staff divides the sampled companies into the following 7 groupings based on company size and geographical location:

- Small Northern (*e.g.* Atitokan Hydro)
- Large Northern (*e.g.* Greater Sudbury Hydro)
- Southwestern – Smaller Towns (*e.g.* Brant County Power)
- Southwestern – Midsized Towns (*e.g.* Chatham-Kent Hydro)
- Eastern (*e.g.* Peterborough Distribution)
- GTA Towns (*e.g.* Kitchener-Wilmot Hydro)
- Large City Southern distributors (*e.g.* Toronto Hydro-Electric System)

6.9.2 Appraisal

We feel that staff's illustrative approach to benchmarking has considerable merit if a methodological upgrade is made that takes account of the results of our research for the Board. Staff's peer groups go a considerable way towards controlling for differences between utilities in input prices, forestation, operating scale, and undergrounding. The use of unit cost metrics facilitates cost comparisons between the companies in a peer group that are not highly similar in operating scale. Overall rankings can be obtained by taking the ratio of the unit cost of each company to the average unit cost for its peer group.

Our research points the way to some possible upgrades in staff's methods. Note first that our appraisal of the data suggests that the appropriate focus of benchmarking at the present time should be total OM&A expenses. More detailed benchmarking must await reforms in data collection and the consideration of capital cost benchmarking.

Our econometric research lays the foundation for an important upgrade: the use of unit cost indexes with multi-dimensional output quantity indexes. These would help control for differences in the customer density of service territories. This will be especially useful in the five non-urban peer groups, where there can be considerable variation in the degree of service territory customer density among peers.

Some peer group reassignments appear to be warranted. Eastern Ontario Power, which staff had placed in a southwestern peer group, should be moved to the Eastern peer group. Lakeland Power and Ottawa River should be moved to the small northern group due to the heavy forestation in their service territories. Peninsula West and Halton Hills should be moved to the Southwest small peer group given their comparatively low customer density. Great Lakes Power can be placed in the large northern group if the output measurement reform discussed below is implemented.

The Board should consider, lastly, the use of econometric cost models in lieu of or as a supplement to the unit cost indexes. This is the approach that PEG favors in its work for most clients and is used in power distributor benchmarking by British regulators. Advantages of econometric modeling in the present context include the following.

- Econometric models generally provide better control for external business conditions.
- Benchmarks reflect the exact cost drivers of the subject utility. There is no need to select peer groups and rankings are not sensitive to peer group assignments. This can be a particular advantage when we wish to benchmark companies with few peers. There is, for example, no company in the sample with an operating scale similar to Toronto Hydro. With econometrics we can estimate from data for all of the other companies in the sample, with their varied operating scales, the cost that an unusually large company would incur.
- Sensible statistical tests of efficiency hypothesis have been developed by PEG and made operational. These tests can help the Board determine

when benchmarking results are convincing enough to provide the basis for ratemaking decisions. For example, they provide a rigorous means of determining when results should be discounted because of the atypical character of a company's business conditions.

- Econometric models lend themselves to out of sample projections to bridge years and test years. We need only insert reasonable values for the bridge/test year input prices, output quantities, and other business conditions.
- An econometric model of OM&A expenses can produce benchmarks that are directly comparable to actual costs. The cost surplus or saving revealed by benchmarking is simply the difference between actual costs and the cost projection. There is no need to compute the saving or surplus that is implied by a ratio of unit cost metrics.
- Models will improve as data accumulate. For example, it will be possible to identify additional significant business conditions and to estimate the effect of output on cost more accurately.
- We have developed models with different mixes of complexity and sophistication. This increases the chances that staff can find a level of sophistication that they are comfortable with.[29]
- The University of Toronto and other Ontario universities can easily provide the personnel needed for stakeholder groups and larger provincial utilities to upgrade their skills in the benchmarking area. Given the advances that have been made in benchmarking science in recent years, it should play an important role in a jurisdiction with more than 80 utilities. The accuracy of benchmarking methods and the potential role of benchmarking in regulation should not be limited by the lowest common denominator of expertise in the current regulatory community.
- Given the substantial net benefits of econometric benchmarking, it is hard to imagine how it would be just and reasonable for the Board to make ratemaking decisions based on results from a simpler method when and if

[29] British regulators use models with simple functional forms and estimation procedures.

a good econometric benchmarking model yields results that are substantially different.

Provided that staff moves, at a minimum, to upgrade its unit cost approach in the ways that we have recommended, we believe that benchmarking can and should play a role in the upcoming rate applications. Benchmarking should be used to appraise bridge year and test year costs in addition to recent historical costs. That said, it must be emphasized that none of the methods developed are good enough yet to provide the basis for mechanistic adjustments to initial rates and rate adjustment mechanisms. We are particularly concerned about the inability of current methods to control for differences in capital usage, system age, and the mix of services provided. Serious deficiencies in the data, such as the lack of data on labour cost shares and deliveries to other LDCs, have also been noted.

In view of these constraints we believe that benchmarking with the current results should be used to identify companies that --- thanks to favorable scores --- merit expedited processing of rate applications and those that --- due to poor scores --- should be scheduled for especially thorough prudence reviews. Business conditions that are not properly controlled for in the benchmarking are potentially issues of importance in prudence reviews. For example, a company may have high OM&A expenses per customer because its system is old, it has no large volume customers, and/or it capitalizes very few of its gross OM&A expenses.

The quality of benchmarking results can be materially improved in time for the 2008 EDR applications by updating the benchmarking study to include 2006 data and by improving the quality of data where possible. Based on our experience, we believe that the addition of even one year of additional data should permit us to refine our econometric models considerably. This can improve the accuracy of the indexing as well as the econometric benchmarking methods by providing a better basis for peer group selection. 2006 data are also the freshest and most relevant available to appraise the 2008 EDR filings. The Board should also consider using 2007 and 2008 data to improve performance rankings for the later EDR tranches.

With good methods, additional years of data, and reforms in data collection, benchmarking may reach a level of accuracy that will permit it to play a larger role in ratemaking. Regulators may still undertake some traditional prudence reviews but can rely in part on benchmarking results to set initial rates and the escalation terms of rate adjustment mechanisms. For example, a significantly inferior performer can be assigned a stretch factor that is double the norm, whereas a significantly superior performer may have no stretch factor. This use of benchmarking in ratemaking can materially strengthen performance incentives and thus be considered a component of a broader scheme of incentive regulation. Statistical tests of efficiency hypotheses can help to ensure the reasonableness of regulatory outcomes.

Appendix A: Technical Details

This appendix contains additional details of our benchmarking research for Board staff. Section A.1 discusses the econometric cost research. Section A.2 discusses our indexing research.

A.1 Econometric Cost Research

A.1.1 Form of the Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, the double log and the translog. Here is a simple example of a linear cost model

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot W_{h,t} + e_{h,t}\ . \qquad [A1]$$

Here, for each firm h in year t, cost is a function of the number of customers served ($N_{h,t}$), the prevailing wage rate ($W_{h,t}$), and an error term ($e_{h,t}$). Here is an analogous cost model of double log form.

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + e_{h,t}\ . \qquad [A2]$$

Notice that in this model the dependent variable and both business condition variables have been logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the output quantity. It is also noteworthy that in a double log model, the elasticities are *constant* across every value that the cost and business condition variables might assume.[30]

[30] Cost elasticities are not constant in the linear model that is exemplified by equation 8a.

Here is an analogous cost function of translog form. This very flexible function is common in econometric cost research, and by some accounts the most reliable of several available flexible forms.[31] [32]

$$\begin{aligned}\ln C_{h,t} &= a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} \\ &+ a_4 \cdot \ln W_{h,t} \cdot \ln W_{h,t} + a_5 \cdot \ln W_{h,t} \cdot \ln N_{h,t} + e_{h,t}\end{aligned} \quad \text{[A3]}$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each business condition variable to differ at different values of the variable. Interaction terms like $\ln W_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable.

The general form of the total cost function used in our study is captured by the following formula:

$$\begin{aligned}&\ln C = \alpha_o + \sum_i \alpha_i \ln Y_i + \sum_j \alpha_j \ln W_j + \sum_\ell \alpha_\ell \ln Z_\ell + \alpha_t T \\ &+ \frac{1}{2}\left[\sum_i \sum_m \gamma_{im} \ln Y_i \ln Y_m + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n \right] \\ &+ \sum_i \sum_j \gamma_{ij} \ln Y_i \ln W_j + \varepsilon.\end{aligned} \quad \text{[A4]}$$

Here, Y_i denotes one of several variables that quantify output and W_j denotes one of several input prices. The *Z*'s denote the additional business conditions, *T* is a trend variable, and ε denotes the error term.

Note that in order to preserve degrees of freedom and thereby to permit the recognition of additional business conditions we did not translog the Z variables. This practice is common in econometric cost research.

A.1.2 Estimating Model Parameters

A branch of statistics called econometrics has developed procedures for estimating parameters of economic models using historical data on the dependent and explanatory

[31] The transcendental logarithmic (or translog) cost function can be derived mathematically as a second order Taylor series expansion of the logarithmic value of an arbitrary cost function around a vector of input prices and output quantities.
[32] See Guilkey (1983), et. al.

variables.[33] For example, cost model parameters can be estimated econometrically using historical data on the costs incurred by utilities and the business conditions they faced. The sample used in model estimation can be a time series (consisting of data over several years for a single firm), a cross section (consisting of one observation for each of several firms), or a panel data set that pools time series data for several companies. In this study we have employed panel data. Single equation models were estimated using OLS and GLS.

The results of econometric research are useful in selecting business conditions for cost models. Specifically, tests can be constructed for the hypothesis that the parameter for a business condition variable under consideration equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence. It is sensible to exclude from the model candidate business condition variables that do not have statistically significant parameter estimates, as well as those with implausible parameter estimates. Once such variables have been removed, the model is re-estimated.

A.2 Index Research

This section contains additional details of our index research. Sub-Section 2.1 discusses the formula for output quantity indexes. Sub-Section 2.2 discusses the formula for input quantity indexes.

A.2.1 Output Quantity Indexes

The output quantity index for each company *h* was defined by the formula

$$ln\ Output\ Quantity_{h,t} = \sum_i se_i \cdot (\ln Y_{i,h,t} . - \overline{\ln Y_{i,t}}) \qquad [A5]$$

Here for each company h in year *t*,

$Output\ Quantity_{h,t}$ = output quantity index

$Y_{i,h,t}$ = quantity of output dimension *i*

$\overline{\ln Y_{i,t}}$ = sample mean of the logged quantity of output dimension *i* provided by all utilities

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[33] The estimation of model parameters in this type of model is sometimes called regression. .

se_i = share of output dimension i in the sum of the econometric estimates of the cost elasticities of the output quantities.

A.2.2 Unit Cost Indexes

Each unit cost index was computed using the ratio of a cost index to an output quantity index:

$$Unit\ Cost_{h,t} = Cost_{h,t} / Output\ Quantity_{h,t}\ . \qquad [A6]$$

Here for each company h in year t,

$Cost_{h,t} = cost\ index$

$\ln Cost_{h,t} = \ln C_{h,t} - \overline{\ln C_t}$

$\ln C_{h,t}$ = logged OM&A expenses

$\overline{\ln\ C_t}$ = sample mean of the logged OM&A expenses for all utilities.

A.2.3 Productivity Indexes

The productivity index for each company can be calculated as the ratio of an output quantity index to an input quantity index. It can be calculated, equivalently, as the ratio of an input price index to the company's unit cost index as defined above.

Here for each company h in year t,

$$Productivity\ Index_{h,t} = Input\ Prices_{h,t} / Unit\ Cost_{h,t}\ . \qquad [A7]$$

$$\ln Input\ Prices_{h,t} = \sum_j (1/2)(sc_{j,h,t} + \overline{sc_{j,t}}) \cdot (\ln W_{j,h,t} - \overline{\ln W_{j,t}}) \qquad [A8]$$

$Input\ Prices_{h,t}$ = Input quantity index

$sc_{j,h,t}$ = Share of input category j in the applicable OM&A expenses

$\overline{sc_{j,t}}$ = Sample mean share of input category j in the applicable OM&A expenses of the sampled companies.

$W_{j,h,t}$ = Price of input j

$\overline{\ln W_{j,t}}$ =Sample mean value of the log of price subindex input j for all companies

Appendix B

Board Staff's Illustrative Benchmarking Approach

Rationale for Staff's Grouping Approach

Staff arranged the electricity distributors into groups for comparison and supplied the results to Pacific Economics Group LLC for their consideration. The rationale for the staff grouping of distributors follows:

1) Started with regional groupings of the EDA districts which take into account certain "environmental" characteristics (particularly terrain and weather) that can influence capital investments and operating costs.

2) Placed Hydro One Inc. into its own group similar to the report prepared by Christensen Associates Energy Consulting, LLC (Robert Camfield) due to the fact that Hydro One is obligated to serve the entire province where customers are not being served by other distributors.

3) Did not include First Nation distributors and Hydro One Remote Communities due to unique corporate structure and geographic considerations. Cornwall was not included as the Board does not regulate the rates since this distributor has a franchise agreement with the city.

4) Regrouped within each geographic region small and large distributors, largely using customer counts as a primary characteristic. This somewhat reflects the differences associated with economies of scale, and reflects growth patterns, customer diversity, age of distribution plant, and underground versus aerial line ratios.

5) Scanned distributors within each sub-group using customer density (number of customers per km of line). Moved Great Lakes Power into a group of its own due to low customer density.

6) Moved distributors with the same corporate owner into the same group. For example, Eastern Ontario Power (CNPI) was moved from Eastern group into South-western Midsize group.

7) Moved Oshawa and Whitby into GTA Towns due to economic integration with the rest of the GTA area.

8) Moved distributors serving large cities into a group of their own as they generally serve areas with large populations and diverse economies.

9) Some aspects were not dealt with – for example, the "virtual utility" variable. This variable was used in the first Comparator & Cohort analysis but was not considered significant.

10) Reviewed possible cost drivers for various cost centres; kilometres of line, MWh consumption, peak load, size of service area, and number of customers. Concluded that the number of customers is likely the best single driver of distributors' costs.

11) Used data provided by distributors in the 2006 EDR application models and aggregated data to the same level.

Comparison of Ontario Electricity Distributors' Costs (EB-2006-0268)
Operating, Maintenance & Administrative Costs per Customer

Built from data submitted by distributors via the Reporting and Record-keeping Requirements (RRR)
Data downloaded from database: October 23, 2006

Ontario
Ontario Energy Board Commission de l'énergie de l'Ontario

Distributor	OM&A per Customer				
	Four Year Average	2005	2004	2003	2002
Atikokan Hydro Inc.	$428	$373	$375	$617	$346
Barrie Hydro Distribution Inc.	$134	$119	$136	$153	$127
Bluewater Power Distribution Corporation	$254	$261	$253	$260	$243
Brant County Power Inc.	$340	$365	$348	$334	$312
Brantford Power Inc.	$190	$206	$202	$188	$164
Burlington Hydro Inc.	$218	$225	$234	$228	$185
Cambridge and North Dumfries Hydro Inc.	$162	$170	$169	$153	$157
Centre Wellington Hydro Ltd.	$251	$240	$238	$252	$274
Chapleau Public Utilities Corporation	$367	$389	$359	$370	$349
Chatham-Kent Hydro Inc.	$163	$183	$160	$151	$156
Clinton Power Corporation	$227	$224	$208	$243	$233
CNPI Eastern Ontario Power	$325	$356	$284	$336	N/A
CNPI Fort Erie	$264	$269	$252	$254	$283
CNPI Port Colborne	$236	$443	$186	$173	$141
COLLUS Power Corp.	$190	$196	$194	$181	$190
Cooperative Hydro Embrun Inc.	$184	$199	$170	$189	$178
Dutton Hydro Limited	$273	$266	$382	$232	$212
E.L.K. Energy Inc.	$173	N/A	$159	$185	$175
Enersource Hydro Mississauga Inc.	$219	$238	$216	$208	$212
EnWin Powerlines Ltd.	$287	$259	$280	$284	$326
Erie Thames Powerlines Corporation	$286	$324	$302	$278	$238
Espanola Regional Hydro Distribution Corporation	$246	$237	$223	$237	$285
Essex Powerlines Corporation	$210	$243	$206	$186	$206
Festival Hydro Inc.	$179	$176	$178	$175	$186
Fort Frances Power Corporation	$249	$265	$245	$248	$239
Grand Valley Energy Inc.	$259	$299	$253	$235	$249
Great Lakes Power Limited	$606	$674	$623	$614	$510
Greater Sudbury Hydro Inc.	$207	$210	$223	$195	$198
Grimsby Power Incorporated	$148	$163	$151	$139	$140
Guelph Hydro Electric Systems Inc.	$187	$154	$198	$207	$190
Haldimand County Hydro Inc.	$255	$263	$258	$238	$261
Halton Hills Hydro Inc.	$213	$198	$215	$209	$231
Hearst Power Distribution Company Limited	$195	$214	$213	$173	$181
Horizon Utilities Corporation	$155	$172	$143	$159	$147
Hydro 2000 Inc.	$165	$264	$139	$138	$120
Hydro Hawkesbury Inc.	$133	$145	$123	$135	$128
Hydro One Brampton Networks Inc.	$136	$128	$127	$140	$149
Hydro One Networks Inc.	$300	$309	$288	$302	$303
Hydro Ottawa Limited	$161	$135	$145	$173	$192
Innisfil Hydro Distribution Systems Limited	$212	$200	$234	$225	$189
Kenora Hydro Electric Corporation Ltd.	$211	$209	$215	$215	$205
Kingston Electricity Distribution Limited	$212	$205	$219	$221	$203
Kitchener-Wilmot Hydro Inc.	$138	$141	$136	$139	$137
Lakefront Utilities Inc.	$163	$193	$161	$141	$159
Lakeland Power Distribution Ltd.	$248	$217	$214	$307	$255
London Hydro Inc.	$158	$162	$155	$157	$160
Middlesex Power Distribution Corporation	$218	$244	$188	$232	$208
Midland Power Utility Corporation	$270	$260	$267	$271	$282

Distributor	OM&A per Customer				
	Four Year Average	2005	2004	2003	2002
Milton Hydro Distribution Inc.	$225	$217	$212	$223	$248
Newbury Power Inc.	$237	$215	$259	N/A	N/A
Newmarket Hydro Ltd.	$220	$187	$203	$294	$194
Niagara Falls Hydro Inc.	$221	$240	$215	$215	$214
Niagara-on-the-Lake Hydro Inc.	$196	$192	$203	$187	$203
Norfolk Power Distribution Inc.	$228	$222	$217	$233	$241
North Bay Hydro Distribution Limited	$223	$203	$219	$221	$249
Northern Ontario Wires Inc.	$283	$262	$289	$276	$306
Oakville Hydro Electricity Distribution Inc.	$209	$199	$217	$216	$203
Orangeville Hydro Limited	$179	$178	$173	$188	$176
Orillia Power Distribution Corporation	$239	$273	$241	$232	$210
Oshawa PUC Networks Inc.	$200	$163	$212	$221	$204
Ottawa River Power Corporation	$192	$190	$197	$203	$177
Parry Sound Power Corporation	$274	$304	$283	$287	$223
Peninsula West Utilities Limited	$274	$301	$278	$265	$252
Peterborough Distribution Incorporated	$169	$182	$168	$157	$169
Powerstream Inc.	$179	$195	$183	$178	$158
PUC Distribution Inc.	$204	$217	$223	$195	$180
Renfrew Hydro Inc.	$191	$174	$191	$205	$194
Rideau St. Lawrence Distribution Inc.	$216	$233	$212	$214	$204
Sioux Lookout Hydro Inc.	$314	$373	$344	$242	$296
St. Thomas Energy Inc.	$184	$205	$188	$174	$169
Tay Hydro Electric Distribution Company Inc.	$191	$227	$199	$182	$158
Terrace Bay Superior Wires Inc.	$310	$331	$280	$300	$328
Thunder Bay Hydro Electricity Distribution Inc.	$230	$218	$233	$245	$225
Tillsonburg Hydro Inc.	$212	$217	$215	$212	$206
Toronto Hydro-Electric System Limited	$240	$246	$245	$238	$232
Veridian Connections Inc.	$204	$176	$196	$239	$204
Wasaga Distribution Inc.	$134	$152	$137	$127	$120
Waterloo North Hydro Inc.	$188	$179	$187	$188	$199
Welland Hydro-Electric System Corp.	$186	$178	$205	$189	$173
Wellington North Power Inc.	$265	$281	$262	$246	$273
West Coast Huron Energy Inc.	$314	$373	$295	$299	$288
West Nipissing Energy Services Ltd.	$197	$63	$258	$226	$239
West Perth Power Inc.	$255	$213	$252	$289	$268
Westario Power Inc.	$218	$209	$234	$233	$199
Whitby Hydro Electric Corporation	$205	$206	$191	$215	$209
Woodstock Hydro Services Inc.	$210	$222	$212	$211	$194

Notes:

1. Guelph Hydro Electric Systems Inc. includes data from Wellington Electric Distribution Company Inc.
2. Horizon Utilities Corporation includes Hamilton Hydro Inc. and St. Catherines Hydro Utility Services Inc.
3. PowerStream Inc. includes Aurora Hydro Connections Limited.
4. Peterborough Distribution Incorporated includes Asphodel Norwood and Lakefield.
5. Veridian Connections Inc. includes Gravenhurst and Scugog.
6. Hydro One Remote Communities and First Nation distributors were not included due to the corporate structure, remote locations, economic and other unique factors.

The source data for the average costs shown were provided by the distributors. Board staff makes no assertions about the accuracy of the data. Users should use the data with caution.

Comparison of Ontario Electricity Distributors' Costs (EB-2006-0268)
Staff Grouping: Operating, Maintenance & Administrative Costs per Customer

Built from data submitted by distributors via the Reporting and Record-keeping Requirements (RRR)
Data downloaded from database: October 23, 2006

Distributor	OM&A per Customer				
	Four Year Average	2005	2004	2003	2002
Hydro One Networks Inc.	$300	$309	$288	$302	$303
Great Lakes Power Limited	$606	$674	$623	$614	$510
Small Northern LDCs					
Atikokan Hydro Inc.	$428	$373	$375	$617	$346
Chapleau Public Utilities Corporation	$367	$389	$359	$370	$349
Espanola Regional Hydro Distribution Corporation	$246	$237	$223	$237	$285
Fort Frances Power Corporation	$249	$265	$245	$248	$239
Hearst Power Distribution Company Limited	$195	$214	$213	$173	$181
Kenora Hydro Electric Corporation Ltd.	$211	$209	$215	$215	$205
Northern Ontario Wires Inc.	$283	$262	$289	$276	$306
Sioux Lookout Hydro Inc.	$314	$373	$344	$242	$296
Terrace Bay Superior Wires Inc.	$310	$331	$280	$300	$328
Large Northern LDCs					
Greater Sudbury Hydro Inc.	$207	$210	$223	$195	$198
West Nipissing Energy Services Ltd.	$197	$63	$258	$226	$239
North Bay Hydro Distribution Limited	$223	$203	$219	$221	$249
PUC Distribution Inc.	$204	$217	$223	$195	$180
Thunder Bay Hydro Electricity Distribution Inc.	$230	$218	$233	$245	$225
Southwestern Small Town LDCs					
Brant County Power Inc.	$340	$365	$348	$334	$312
Clinton Power Corporation	$227	$224	$208	$243	$233
COLLUS Power Corp.	$190	$196	$194	$181	$190
Dutton Hydro Limited	$273	$266	$382	$232	$212
Grand Valley Energy Inc.	$259	$299	$253	$235	$249
Grimsby Power Incorporated	$148	$163	$151	$139	$140
Midland Power Utility Corporation	$270	$260	$267	$271	$282
Newbury Power Inc.	$237	$215	$259	N/A	N/A
Niagara-on-the-Lake Hydro Inc.	$196	$192	$203	$187	$203
Norfolk Power Distribution Inc.	$228	$222	$217	$233	$241
Orangeville Hydro Limited	$179	$178	$173	$188	$176
Tay Hydro Electric Distribution Company Inc.	$191	$227	$199	$182	$158
Tillsonburg Hydro Inc.	$212	$217	$215	$212	$206
Wellington North Power Inc.	$265	$281	$262	$246	$273
West Coast Huron Energy Inc.	$314	$373	$295	$299	$288
West Perth Power Inc.	$255	$213	$252	$289	$268
Southwestern Midsize Town LDCs					
Bluewater Power Distribution Corporation	$254	$261	$253	$260	$243
Chatham-Kent Hydro Inc.	$163	$183	$160	$151	$156
CNPI Eastern Ontario Power	$325	$356	$284	$336	N/A
CNPI Fort Erie	$264	$269	$252	$254	$283
CNPI Port Colborne	$236	$443	$186	$173	$141
E.L.K. Energy Inc.	$173	N/A	$159	$185	$175
Erie Thames Powerlines Corporation	$286	$324	$302	$278	$238
Essex Powerlines Corporation	$210	$243	$206	$186	$206
Festival Hydro Inc.	$179	$176	$178	$175	$186
Haldimand County Hydro Inc.	$255	$263	$258	$238	$261
Innisfil Hydro Distribution Systems Limited	$212	$200	$234	$225	$189
Middlesex Power Distribution Corporation	$218	$244	$188	$232	$208
Orillia Power Distribution Corporation	$239	$273	$241	$232	$210
St. Thomas Energy Inc.	$184	$205	$188	$174	$169
Wasaga Distribution Inc.	$134	$152	$137	$127	$120
Westario Power Inc.	$218	$209	$234	$233	$199
Woodstock Hydro Services Inc.	$210	$222	$212	$211	$194

Distributor	OM&A per Customer				
	Four Year Average	2005	2004	2003	2002
Eastern LDCs					
Cooperative Hydro Embrun Inc.	$184	$199	$170	$189	$178
Hydro 2000 Inc.	$165	$264	$139	$138	$120
Hydro Hawkesbury Inc.	$133	$145	$123	$135	$128
Kingston Electricity Distribution Limited	$212	$205	$219	$221	$203
Lakefront Utilities Inc.	$163	$193	$161	$141	$159
Lakeland Power Distribution Ltd.	$248	$217	$214	$307	$255
Ottawa River Power Corporation	$192	$190	$197	$203	$177
Parry Sound Power Corporation	$274	$304	$283	$287	$223
Peterborough Distribution Incorporated	$169	$182	$168	$157	$169
Renfrew Hydro Inc.	$191	$174	$191	$205	$194
Rideau St. Lawrence Distribution Inc.	$216	$233	$212	$214	$204
Large City Southern LDCs					
Enersource Hydro Mississauga Inc.	$219	$238	$216	$208	$212
EnWin Powerlines Ltd.	$287	$259	$280	$284	$326
Horizon Utilities Corporation	$155	$172	$143	$159	$147
Hydro One Brampton Networks Inc.	$136	$128	$127	$140	$149
Hydro Ottawa Limited	$161	$135	$145	$173	$192
London Hydro Inc.	$158	$162	$155	$157	$160
Powerstream Inc.	$179	$195	$183	$178	$158
Toronto Hydro-Electric System Limited	$240	$246	$245	$238	$232
Veridian Connections Inc.	$204	$176	$196	$239	$204
GTA Towns LDCs					
Barrie Hydro Distribution Inc.	$134	$119	$136	$153	$127
Brantford Power Inc.	$190	$206	$202	$188	$164
Burlington Hydro Inc.	$218	$225	$234	$228	$185
Cambridge and North Dumfries Hydro Inc.	$162	$170	$169	$153	$157
Centre Wellington Hydro Ltd.	$251	$240	$238	$252	$274
Guelph Hydro Electric Systems Inc.	$187	$154	$198	$207	$190
Halton Hills Hydro Inc.	$213	$198	$215	$209	$231
Kitchener-Wilmot Hydro Inc.	$138	$141	$136	$139	$137
Milton Hydro Distribution Inc.	$225	$217	$212	$223	$248
Newmarket Hydro Ltd.	$220	$187	$203	$294	$194
Niagara Falls Hydro Inc.	$221	$240	$215	$215	$214
Oakville Hydro Electricity Distribution Inc.	$209	$199	$217	$216	$203
Oshawa PUC Networks Inc.	$200	$163	$212	$221	$204
Peninsula West Utilities Limited	$274	$301	$278	$265	$252
Waterloo North Hydro Inc.	$188	$179	$187	$188	$199
Welland Hydro-Electric System Corp.	$186	$178	$205	$189	$173
Whitby Hydro Electric Corporation	$205	$206	$191	$215	$209

Notes:

1. Guelph Hydro Electric Systems Inc. includes data from Wellington Electric Distribution Company Inc.
2. Horizon Utilities Corporation includes Hamilton Hydro Inc. and St. Catherines Hydro Utility Services Inc.
3. PowerStream Inc. includes Aurora Hydro Connections Limited.
4. Peterborough Distribution Incorporated includes Asphodel Norwood and Lakefield.
5. Veridian Connections Inc. includes Gravenhurst and Scugog.
6. Hydro One Remote Communities and First Nation distributors were not included due to the corporate structure, remote locations, economic and other unique factors.

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