BOARD STAFF RESPONSE TO
ENBRIDGE GAS DISTRIBUTION INC. #7

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: ExhL/T1/S2

I.A1.Staff.EGDI.7

Preamble:
On pages 3-4, PEG States, "CEA relies entirely on a peer group benchmarking approach, which is almost never sufficient to yield robust inferences on utility efficiency."

Request:

a. Has PEG ever relied on peer group benchmarking in prior efficiency studies?
b. Please produce any studies or testimony filed by PEG in regulatory proceedings in North America over the last five years which uses peer group benchmarking.
c. What is PEG's basis for the qualifier, "almost never"?

RESPONSE

a. Yes; PEG has used peer group benchmarking but only in conjunction with, and as an adjunct to, econometric cost benchmarking.

b. In the last five years, PEG has filed testimony (or expert reports tantamount to formal testimony) five times that uses peer group benchmarking.

   - In 2008, in 3rd Generation Incentive Rate Setting for electricity distributors in Ontario and Sensitivity Analysis on Efficiency Ranking and Cohorts for the 2009 Rate year: Update

   - In February 2009, in Direct Testimony for Oklahoma Gas and Electric

   - In October 2009, in Rebuttal Testimony for Public Service Company of Colorado

   - In July 2011, in Direct Testimony for Oklahoma Gas and Electric

Witness: Dr. Lawrence Kaufmann, PEG

- In May 2013, in 4th Generation Incentive Rate Setting for electricity distributors in Ontario

PEG's testimony in these proceedings is attached.

c. In utility regulation, it is prudent to "never say never." There may be extreme situations where there is so much missing or inaccurate data that the only feasible benchmarking measures that can be constructed are simple, partial unit cost metrics. There is no need to rely on simple benchmarking techniques for either Enbridge or the US gas distribution industry, where ample, high quality data are available.

CALIBRATING RATE INDEXING MECHANISMS FOR THIRD GENERATION INCENTIVE REGULATION IN ONTARIO

REPORT TO THE ONTARIO ENERGY BOARD

February 2008

Pacific Economics Group, LLC
Economic and Litigation Consulting

Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario

Report to the Ontario Energy Board

February 2008

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1. Introduction and Executive Summary

Beginning in August 2007, the Ontario Energy Board (OEB, or the Board) began a consultation into the Third Generation Incentive Regulation Mechanism (3rd Generation IRM) for electricity distributors. This consultative process will lead to a Board report setting out the principles and methodology for the 3rd Generation IRM. As the name implies, the current proceeding represents the third time that the Board will develop incentive regulation mechanisms for electricity distributors in the Province.

The First Generation IRM was implemented in 2000. This mechanism had a three-year intended term but, before the plan could run its course, the Provincial Government imposed a freeze on overall retail electricity prices. This cap effectively eliminated any further formula-based distribution price adjustments for distribution services and thus ended the plan.

The Board implemented a second generation incentive regulation mechanism (2nd Generation IRM) in December 2006. The 2nd Generation IRM is essentially a transitional mechanism that applies until rates are "rebased" to reflect each distributor's cost of service in a test year.[1] Thus, either unintentionally (1st Generation) or by design (2nd Generation), previous IRMs have not provided a durable foundation for ongoing incentive regulation of Ontario's electricity distribution industry.

The objective of the 3rd Generation IRM is to provide a more stable basis for ongoing incentive regulation in the Province. Towards this end, the Staff has outlined several criteria that should guide the development of the 3rd Generation IRM to ensure that it is consistent with, and helps to achieve, a long-term vision of comprehensive IR for Ontario's electricity distributors. These criteria are that the IR framework should be sustainable and forward-looking, predictable, effective and practical. Staff further elaborates these criteria in its Discussion Paper:[2]

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[1] Distributors have the choice of filing cost-based rate applications for either the 2007, 2008 or the 2009 rate year. The rate adjustments under the indexing mechanism apply to all distributors for the 2007 rate year. For 2008, index-based rate adjustments apply to those distributors that have not applied for rate rebasing. For the 2009 rate year, the mechanism applies to the remaining distributors that have not yet applied for, or been subject to, rebasing.

[2] Ontario Energy Board, *Staff Discussion Paper on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, February 2008.

- A **sustainable** framework is flexible and reasonably able to handle changing and varied circumstances, while ensuring that the principles underlying the method by which the rate adjustments are determined are consistent between distributors.
- A **predictable** framework facilitates planning and decision-making by ratepayers and electricity distributors.
- An **effective** framework encourages distributors to implement efficiencies and allocates the benefits from greater efficiency fairly between the distributor/shareholder and ratepayers in an appropriate manner. An effective framework also provides for prudent capital investment as required to ensure necessary infrastructure development and to maintain an appropriate level of reliability and quality of service.
- Without sacrificing the other criteria, under a **practical** framework, the distributor's costs of administration should not exceed the benefits.

The Board hired Pacific Economics Group LLC (PEG) to advise Staff on the development of the 3rd Generation IRM. PEG has extensive incentive regulation experience and has advised regulators and utilities in the US, Canada, the Caribbean, Latin America, Europe, Asia, Australia and New Zealand on incentive regulation and benchmarking issues. We have also worked with Board Staff on a number of related initiatives. For example, PEG prepared a report on incentive regulation principles and approaches for Ontario's Natural Gas Forum (NGF). The Board's final report in the NGF expressed a strong preference for IR rather than traditional cost of service methods as the basis for ongoing regulation of gas distributors in the Province. PEG has since been working with Board Staff to develop rate indexing mechanisms in the Gas IRM proceeding. PEG also advised Staff on IR principles and precedents for the 2nd Generation IRM. In addition, PEG has been working on comparative cost benchmarking for Ontario's electricity distributors. This work has produced a number of reports and benchmarking analyses that evaluate distributors' relative operations, maintenance and administration (OM&A) cost performance.

There are two main focuses in PEG's work on 3rd Generation IRM. First, we worked closely with Board Staff to help organize and lead a series of stakeholder Working Group discussions on important topics for the IRM. Among other things, these discussions considered a variety of mechanisms and regulatory approaches for dealing with capital investment, conservation and demand management, and distributor diversity issues in 3rd Generation IRM. These discussions helped inform Staff's thinking and the design of the incentive regulation core plan framework that is presented in its Discussion Paper.

PEG was also asked to develop specific, quantitative recommendations for the X factor, or X factors, to be used in the rate indexing mechanism. Because the goal of the 3rd Generation IRM is to provide an objective foundation for ongoing incentive regulation, PEG endeavored to base our recommendations on rigorous and objective empirical research that could be replicated, refined and extended in future IR applications. Our recommendations were also informed by, and consistent with, the principles for effective incentive regulation and salient regulatory precedents from around the world.

Measures of industry total factor productivity (TFP) trends are critical for calibrating X factors in North American regulation. PEG examined a range of information on electricity distribution TFP trends when developing a recommendation for the productivity factor in 3rd Generation IRM. One relevant source of information was the TFP study that was developed in the 1st Generation IRM. This research was used, in turn, as the basis for the X factor that was approved in that proceeding. For a sample of 48 Ontario electricity distributors, this study estimated average TFP growth of just under 0.9% per annum over the 1988-97 period. This study also estimated that TFP declined somewhat between 1988 and 1993, but then grew by more than 2% per annum on average between 1993 and 1997.

PEG also developed more recent estimates of electric distributor TFP in Ontario. Although high-quality distributor data are available since 2002, there was a paucity of data available to PEG before that year. We therefore estimated the industry's TFP trends between 2002 and 2006. This research showed that TFP was essentially flat over this period, increasing by .01% per annum. This is comparable to, but somewhat greater, than the TFP declines that were experienced during the 1988-93 period and which were therefore considered when setting the X factor in 1st Generation IRM. It should be noted, however, that there were significant data constraints which decreased our confidence in the reliability of these TFP measures. Most importantly, there was a lack of high quality data on historical capital additions, which undermined the quality of any capital input measures that could be calculated in Ontario. Electricity distribution is a capital-intensive industry, so the current lack of high quality capital data decreases the accuracy and reliability of recent TFP trend measures in Ontario.

Because the available TFP data in Ontario are both fragmentary and incomplete, PEG also considered information on TFP trends for US electric distributors. PEG developed an estimate of TFP trends for the US industry between 1988 and 2006. This sample period includes the 1988-97 years used to estimate Ontario distributors' TFP growth in 1st Generation IRM as well as the more recent 2002-2006 period for PEG's Ontario research. Our US sample period also includes the 1997-2002 years for which no data currently exist on Ontario distributors' TFP growth.

PEG's research shows that US power distribution TFP trends appear to be a generally good proxy for contemporaneous TFP trends in Ontario. For example, TFP was essentially flat for the US and Ontario industries between 1988 and 1993. TFP growth turned sharply positive in the US and Ontario for the 1993-97 period, although the TFP acceleration was somewhat greater in Ontario than in the US. TFP growth also slowed considerably in 2002-2006 (compared to 1993-97) for both industries, although the slowdown was more pronounced in Ontario. No TFP information exists for Ontario distributors between 1997 and 2002, so we cannot make direct TFP comparisons between the industries for these years. However, using the available TFP evidence from both the US and Ontario, we can construct some scenarios for plausible TFP growth for Ontario distributors during these years. These scenarios are clearly not definitive, but they do allow us to better understand the TFP experience for US and Ontario distributors over the entire 1988-2006 period. Under nearly any plausible scenario, average TFP growth for Ontario distributors over the entire sample period is equal to or somewhat greater than TFP growth for the US industry.

PEG's current research shows that the long-run TFP trend for US power distributors is 0.88% per annum. Our analysis shows that the TFP experience for the US and Ontario industries have been generally similar. This in turn implies that the US distributors' long-run TFP trend of 0.88% would be a reasonable estimate for a productivity factor in 3rd Generation IRM. It is noteworthy that this value is nearly identical to the TFP growth estimated for Ontario distributors in 1st Generation IRM. PEG believes the similarity of the US industry's long-run TFP trend and the TFP trend that was previously estimated for the Ontario industry increases the robustness and credibility of this estimate.

PEG also believes the Ontario industry's 2002-2006 TFP growth is not a reasonable estimate of the annual TFP gains the Ontario industry can be expected to achieve in 3rd Generation IRM. The 0.01% average TFP gain in these years would not be an appropriate productivity factor for 3rd Generation IRM for four separate reasons. First, we believe there are identifiable biases in the TFP measure which unfortunately cannot be rectified given currently available information. Second, the quality of these TFP measures is diminished by the lack of available capital additions data. Third, 2002-2006 was a period of transition and profound regulatory change. These changes created a number of cost pressures for Ontario distributors that may not persist (on an ongoing, *rate of change* basis) in 3rd Generation IRM. Fourth, the 2002-2006 period includes only four years of TFP changes, which is not a long enough period to compute a reliable, long-run TFP trend. Recall that in the first half of the 1988-97 period, measured TFP growth in Ontario was also essentially flat and, in fact, was slightly negative. If the -0.1% TFP trend for 1988-93 had been the basis for a productivity factor in a hypothetical incentive regulation plan in effect for the following four years, it would have underestimated the industry's average TFP growth in these years by more than 2% per annum. The 1st Generation IRM developed a more reasonable X factor by using data from both the 1988-93 period (where industry TFP declined) and the 1993-97 period (where TFP increased). This experience from Ontario demonstrates the risks of relying on too short a sample period when setting a productivity factor.

The other major component of the X factor is the consumer dividend (also called the productivity "stretch factor"). Incentive regulation is designed to create stronger performance incentives compared with traditional cost of service regulation, and these enhanced incentives should lead to more rapid TFP growth. Consumer dividends are designed to reflect the incremental TFP gains that utilities are expected to achieve, relative to historical norms, when they are subject to incentive regulation. These incremental TFP gains can be expected to be greater for firms that are relatively less efficient, and therefore have more "fat to cut," at the outset of the incentive regulation plan. By the same token, relatively efficient utilities can be expected to register fewer incremental TFP gains compared with historical norms. This implies that it is appropriate to have lower consumer dividends for utilities that are deemed to be relatively efficient cost performers and higher consumer dividends for relatively inefficient utilities.

PEG's method for selecting consumer dividends is informed by our OM&A comparative cost research in Ontario. This report will present an illustrative example of the method that PEG proposes to use to select consumer dividend levels for Ontario distributors. It is currently not possible to provide final recommendations for this component of the X factor because PEG's comparative cost research is still in progress, and our techniques and benchmarking results are being refined. Nevertheless, it is expected that this research will be completed within the time frame of 3rd Generation IRM and can therefore be used as the basis for final consumer dividend recommendations.

As demonstrated in our illustrative example, PEG intends to use the econometric and OM&A productivity *level* benchmarks developed in our comparative cost work to segment Ontario's electricity distribution industry into five efficiency "cohorts." All companies in a designated cohort will be assigned the same value for the consumer dividend, but the values of these dividends will differ between cohorts. In particular, every company in the group identified as being most efficient will receive a consumer dividend of zero. Companies in the second most efficient group will have a consumer dividend of 0.15%. Companies in the third most efficient group will have a consumer dividend of 0.30%. Companies in the fourth most efficient group will have a consumer dividend of 0.45%. Companies in the least efficient group will have a consumer dividend of 0.6%. When these consumer dividend levels are added to the common productivity factor of 0.88%, they will lead to overall recommended X factors of 0.88% (for the most efficient distributors, or Group I firms), 1.03% (for Group II firms), 1.18% (Group III firms), 1.33% (Group IV firms), and 1.48% (Group V firms).

While these specific consumer dividend values are ultimately based on judgment, they are within the range of consumer dividend values that have been approved in North American rate indexing plans. Indeed, PEG's recommended consumer dividends are lower on average than most North American plans because PEG can only benchmark OM&A rather than total costs. Our recommended consumer dividend range is therefore linked to existing precedents but "scaled" to reflect the fact that OM&A accounts for only a share of the incremental TFP gains companies can potentially achieve in 3rd Generation IRM. Our approach for assigning consumer dividends to particular companies also draws on methods and techniques that have been used to select consumer dividend values in other jurisdictions, especially Massachusetts and New Zealand.

PEG believes that the methods used to develop these X factor recommendations in 3rd Generation IRM can provide a solid foundation for future incentive regulation in Ontario. Our approach brings together a wealth of techniques and alternative data sources that can be useful in future IR applications. These techniques include index-based TFP estimates in Ontario and the US, and econometric and index-based benchmarking of Ontario distributors' OM&A cost performance. At the same time, our methodology is flexible enough to allow the techniques used to estimate X factors to evolve and/or be refined as new or additional information becomes available in Ontario. For example, if sufficient time series data are developed on capital additions and other key variables, indexing methods can be used to estimate more reliable long-term TFP trends using Ontario data. Improved capital data could also allow econometric and index-based methods to benchmark Ontario distributors' *total* costs instead of only their OM&A costs. Benchmarking can also in principle be extended to include comparisons between Ontario and US utilities in addition to intra-Ontario comparisons. Overall, PEG believes the methodologies used to determine the X factors in the 3rd Generation IRM strike a reasonable balance between rigor, objectivity and feasibility (given the data constraints), while simultaneously developing a host of empirical techniques and data sources that can provide a foundation for effective IR applications for Ontario in the future.

This report presents details of the work supporting PEG's recommendations values for the TFP trend and consumer dividends for the 3rd Generation IRM. Chapter Two details the basic indexing logic that underpins the calibration of X factors and the relationship between appropriate X factors and appropriate inflation factors. Chapter Three presents our recommendation for the TFP trend component of the X factor. Chapter Four discusses consumer dividends and provides an illustrative example on how PEG intends to select consumer dividend levels. Chapter Five provides concluding remarks and discusses directions for further research in future IR applications. There are also four appendices. Appendix One discusses relevant performance based regulation (PBR) precedents that informed the discussions of the Working Group and which PEG referenced when developing X factor and inflation factor recommendations. The second appendix presents a mathematical decomposition of TFP growth into its various components. Appendix Three presents the details of PEG's calculation of capital costs. Appendix Four presents some technical details of PEG's econometric modeling, which is necessary to develop empirical parameters (*i.e.* cost elasticities for individual outputs) that are used to develop the index-based TFP measures.

2. Inflation and X Factors

This chapter will discuss some of the main issues involved in developing appropriate inflation and X factors in index-based PBR plans. We begin by presenting the indexing logic which illustrates the relationship between the parameters of indexing formulas and just and reasonable rate adjustments. We turn next to specific choices for inflation factors. We then discuss the X factor.

2.1 Indexing Logic

The third generation incentive regulation mechnanism (3rd Generation IRM) will use a price cap index (PCI) formula to restrict the change in electricity distribution prices. While PCIs vary from plan to plan, the PCI growth rate $(growthPCI)$ is typically given by the growth in an inflation factor (P) minus an X-factor (X) plus or minus a Z-factor (Z), as in the formula below:

$$growth\ PCI = P - X \pm Z. \qquad [1]$$

In North American regulation, the terms of the PCI are set so that the change in regulated prices mimics how prices change, in the long run, in competitive markets.[3] This is a reasonable basis for calibrating utility prices since rate regulation is often viewed as a surrogate for the competitive pressures that would otherwise lead to "just and reasonable" rates. Economic theory has also established that competitive markets often create the maximum amount of benefits for society.[4] It follows that effective utility regulation should replicate, to the greatest extent possible, the operation and outcomes of competitive markets. A "competitive market paradigm" is therefore useful for establishing effective regulatory arrangements, and several features of competitive markets have implications for how to calibrate PCI formulas.

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[3] A different approach is taken towards calibrating the terms of indexing plans in British-style incentive regulation. Appendix One discusses some of the details on the British-style approach as it has been implemented in the United Kingdom and the Australian State of Victoria.

[4] This is sometimes known as the "First Fundamental Welfare Theorem" of economics, but it should be noted that the theoretical finding that competition leads to efficient outcomes does not apply under all conditions (*e.g.* if there are externalities whose costs or benefits are not reflected in competitive market prices).

One important aspect of competitive markets is that prices are external to the costs or returns of any individual firm. By definition, firms in competitive markets are not able to affect the market price through their own actions. Rather, in the long run, the prices facing any competitive market firm will change at the same rate as the growth in the industry's unit cost.

Competitive market prices also depend on the *average* performance in the industry. Competitive markets are continually in a state of flux, with some firms earning more and others less than the "normal" rate of return on invested capital. Over time, the average performance exhibited in the industry is reflected in the market price.[5]

Taken together, these features have the important implication that in competitive markets, returns are commensurate with performance. A firm can improve its returns relative to its rivals by becoming more efficient than those firms. Companies are not disincented from improving efficiency by the prospect that such actions will be translated into lower prices because the prices facing any individual firm are external to its performance. Firms that attain average performance levels, as reflected in industry prices, would earn a normal return on their invested capital. Firms that are superior performers earn above average returns, while firms with inferior performance earn below average returns. Regulation that is designed to mimic the operation and outcomes of competitive markets should allow for this important result.

Another implication of the competitive market paradigm bears a direct relationship to the calibration of price cap index (*PCI*) formulas. As noted above, in the long run, competitive market prices grow at the same rate as the industry trend in unit cost. Industry unit cost trends can be decomposed into the trend in the industry's input prices minus the trend in industry total factor productivity (TFP). Thus if the selected inflation measure is approximately equal to the growth in the industry's input prices, the first step in implementing the competitive market paradigm is to calibrate the X factor using the industry's long-run TFP trend.

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[5] This point has also been made in the seminal 1986 article in the Yale Journal of Regulation, *Incentive Regulation for Electric Utilities* by P. Joskow and R. Schmalensee. They write "at any instant, some firms (in competitive markets) will earn more a competitive return, and others will earn less. An efficient competitive firm will expect on average to earn a normal return on its investments when they are made, and in the long run the average firm will earn a competitive rate of return"; *op cit*, p. 11.

This mathematical logic underlying this result merits explanation. We begin by noting that if an industry earns a competitive rate of return in the long run, the growth in an index of the prices it charges (its output prices) will equal its growth in unit cost.

$$trend\ Output\ Prices^{Industry} = trend\ Unit\ Cost^{Industry}. \qquad [2]$$

As stated above, the trend in an industry's unit cost is the difference between trends in its input price index and its total factor productivity (TFP) index. The full logic behind this result is presented below:

$$\begin{aligned} trend\ Unit\ Cost^{Industry} &= trend\ Cost^{Industry} - trendOutput\ Quantities^{Industry} \\ &= \left(trend\ Input\ Prices^{Industry} + trend\ Input\ Quantities^{Industry}\right) \\ &\quad - trend\ Output\ Quantities^{Industry} \\ &= trend\ Input\ Prices^{Industry} \\ &\quad - \left(trend\ Output\ Quantities^{Industry} - trend\ Input\ Quantities^{Industry}\right) \\ &= trend\ Input\ Prices^{Industry} - trend\ TFP^{Industry}. \end{aligned} \qquad [3]$$

Substituting [3] into [2] we obtain

$$trend\ Output\ Prices^{Industry} = trend\ Input\ Prices^{Industry} - trend\ TFP^{Industry} \qquad [4]$$

Equation [4] demonstrates the relationship between the X factor and the industry TFP trend. If the selected inflation measure (*P* in equation [1]) is a good proxy for the industry's trend in input prices, then choosing an X factor equal to the industry's TFP trend causes output prices to grow at the rate that would be expected in a competitive industry in the long run. This is the fundamental rationale for using information on TFP trends to calibrate the X factor in index-based PBR plans.

It should be emphasized that both the input price and TFP indexes above correspond to those for the relevant utility *industry*. This is necessary for the allowed change in prices to conform with the competitive market paradigm. In competitive markets, prices change at the same rate as the industry's trend in unit costs and are not sensitive to the unit cost trend of any individual firm.

There are two main options for selecting inflation factors in index-based PBR plans. One general approach is to use a measure of economy-wide inflation such as those prepared by government agencies. Examples include the Canadian Gross Domestic Product Implicit Price Index (GDP-IPI) or the US Price Index for Gross Domestic Product (GDP-PI). An established alternative is to construct an index of external price trends for the inputs used to provide utility services. This approach is explicitly designed to measure input price inflation of the regulated industry.[6]

The indexing logic developed in equation [4] applies when an industry-based inflation measure, expressly designed to track the *trend Input Prices* ^{Industry} term in this expression, is used as the inflation factor. When this is the case, the X factor should be linked to the trend in TFP for the utility industry. This would lead to allowed rate adjustments for utility prices that are consistent with the competitive market paradigm.

The indexing logic when economy-wide inflation measures are used to track the industry input price trend is somewhat more complex. To make this logic more concrete, assume that the GDP-IPI is used as the inflation factor. If the trend growth in GDP-IPI is both added and subtracted from the right hand side of equation [4] above, this equation is unchanged. Doing so yields the following formula

$$trend\ Unit\ Cost^{Industry} = trend\ GDPIPI - \begin{bmatrix} trend\ TFP^{Industry} \\ + \left(trend\ GDPIPI - trend\ Input\ Prices^{Industry}\right) \end{bmatrix} \quad [5]$$

The items in the bracketed term can be further decomposed by recognizing the GDP-IPI is a measure of *output* price inflation in the overall economy. Given the broadly competitive structure of market economies, the same indexing logic detailed in equation [2] - [4] will also apply to the measures of economy-wide output price inflation. This logic implies that the long-run trend in GDP-IPI is the difference between the trends in input price and TFP indexes for the Canadian economy, or

$$trend\ GDPIPI = trend\ Input\ Prices^{Economy} - trend\ TFP^{Economy}. \quad [6]$$

Substituting [6] into [5] implies that

$$trend\ Unit\ Cost^{Industry} = trend\ GDPIPI - \begin{bmatrix} \left(trend\ TFP^{Industry} - trend\ TFP^{Economy}\right) \\ + \left(trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}\right) \end{bmatrix} \quad [7]$$

If the GDP-IPI is used as an inflation factor, the bracketed expression will correspond to the X factor. This result shows that the X factor should be calibrated to reflect *differences*

[6] A less common approach is to set inflation measures using changes in *output* prices charged by peer utilities. It is important for any such peer-price inflation measure to be constructed carefully so that it reflects the circumstances of companies that are very similar to the utility subject to the PBR plan. Because of the difficulty of developing appropriate peer price indexes for all 80+ electricity distributors in Ontario, this alternative was not pursued in 3rd Generation IRM and will not be discussed in this report.

in the TFP and input price trends of the relevant utility industry and the economy. The productivity differential will be the difference between the TFP trends of the industry and the economy. X is more apt to be positive, slowing allowed price growth, when industry TFP growth exceeds the economy-wide TFP growth embodied in the GDP-IPI. The inflation differential (sometimes also called the input price differential) is the difference between the input price trends of the economy and the industry. X will tend to be larger (smaller) when the input price inflation of the economy is more (less) rapid than that of the industry.[7]

Our exposition of this analytical framework helps to explain some major issues that are addressed in North American X factor proceedings. One is estimating the TFP trend of the utility industry. A second is the success with which proposed inflation measure tracks industry input price inflation and, therefore, whether the X factor should contain a component to better track industry input price trends.

But while industry TFP and input price measures are used to calibrate X factors, in most index-based PBR plans the X factor is somewhat greater than what is reflected in the utility industry's long-run TFP trend. This is because industry TFP trends are usually measured using historical data from utility companies. Utilities have historically not operated under the competitive market pressures that naturally create incentives to operate efficiently, and it is also widely believed that traditional, cost of service regulation does not promote efficient utility behavior. Incentive regulation is designed to strengthen performance incentives, which should in turn encourage utilities to increase their efficiency and register more rapid TFP growth relative to historical norms. It is also reasonable for these performance gains to be shared with customers since PBR is designed to produce "win-win" outcomes for customers and shareholders.

For this reason, nearly all North American PBR plans have also included what are called "consumer dividends" or productivity "stretch factors" as a component of the X factor.

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[7] It should be noted that while productivity-based X factors sometimes focus on the differential between TFP growth rates for the regulated industry and overall economy, it is *not* necessary to have estimates on economy-wide TFP trends to implement this approach. This is evident from equation [5] above, which can be implemented using only industry TFP and input price measures and an economy-wide inflation measure. The relevant issue is how closely the selected inflation measure tracks the industry's input price trend. If there is in fact a close correspondence between these two trends, then a productivity-based X factor is appropriately implemented using information on only the industry's TFP trend. On the other hand, equation [5] as well as the broader indexing logic does show that implementing a productivity-based X factor does require information on input price trends for the utility industry. This point is sometimes overlooked.

The consumer dividend reflects the expected acceleration in TFP relative to historical TFP trends.[8] This implies that, if the PBR plan uses an industry specific inflation measure, the X factor would be the sum of the industry TFP trend and the consumer dividend. If an economy-wide inflation factor is used, X is the sum of three terms: 1) the productivity differential (*i.e.* the difference between the TFP trend of the utility industry and the overall economy); 2) the inflation differential (*i.e.* the difference between the input price trend of the overall economy and the utility industry); and 3) the consumer dividend.

2.2 Inflation Measures

The inflation factor, *P*, provides an automatic adjustment to the PCI for price inflation. It is sometimes fixed in advance but is more commonly updated annually to reflect the recent growth rate in an external price inflation measure. Two kinds of inflation measures have been applied most frequently in approved indexing mechanisms. We consider each in turn.

2.2.1 Macroeconomic Inflation Measures

Macroeconomic inflation measures are summary measures of growth in the prices of a wide range of the economy's goods and services. Those used in PBR plans are typically output price indexes computed by government agencies.[9] Examples include price indexes for gross domestic product (GDP-PIs) and consumer price indexes (CPIs).

In Canada, the GDP-IPI is the federal government's featured index of inflation in the domestic economy's final goods and services. It differs from the CPI chiefly in covering inflation in the prices of capital equipment used by industry as well as inflation in consumer product prices. The GDP-IPI is therefore generally favored over the CPI. Its broader coverage makes it more stable and more reflective of inflation in the prices of base rate inputs than the CPI, which places a heavier weight on price-volatile energy and food products.

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[8] More precisely, the consumer dividend reflects that portion of the expected acceleration of TFP growth that it passed through to the change in customer rates as a form of benefit-sharing under the plan.

[9] The Federal governments of the United States and Canada also produce macroeconomic indexes of inflation in the prices of several kinds of inputs (*e.g.*, labor and producer goods). These have rarely been used as stand-alone inflation measures in PCI construction due in part to the fact that each index covers only some of the relevant inputs. A prominent exception has been the use of a producer price index (PPI) in the indexing plan for US oil pipelines.

Macroeconomic inflation measures are almost universally used in telecom utilities' rate-cap plans. For example, the GDP-PI has been employed in the price cap plans approved by the CRTC. Macroeconomic inflation measures have also been employed in the majority of indexing plans for energy utilities. In Ontario, both the Second Generation IRM and the price cap index for Union Gas used macroeconomic inflation measures. Consumer price indexes such as Britain's retail price index (RPI) are used in almost all overseas indexing plans.

One advantage of macroeconomic inflation measures is their simplicity. Another is their credibility, since they are typically computed with some care by government agencies. Still another is their familiarity to stakeholders in the regulatory process.

The main concern with macroeconomic inflation measures is their ability to track growth in the prices of utility inputs. The input price trends of a utility industry and the economy can differ for a number of reasons. The most important reason is that the industry has a different mix of inputs than the broader economy. In particular, the power distribution industry is more capital intensive than the overall economy, so its costs are more impacted by changes in the price of capital than most enterprises.

As the indexing logic above demonstrates, if the PBR plan uses an economy-wide inflation factor and input price trends differ for the utility industry and the overall economy, the X factor typically contains an inflation differential. This component of the X factor is designed to help the overall indexing formula better track the industry unit cost trend. However, selecting an appropriate inflation differential can be controversial. One contentious issue can be selecting the period over which industry and economy-wide input price inflation are being measured. Historical differentials may also not be accurate during the term of an indexing plan. This would be the case if industry input prices grew at significantly different rates during the years of the PBR plan than during the historical sample period used to calculate the inflation differential.

2.2.2 Industry-Specific Inflation Measures

Industry-specific input price indexes are expressly designed to track inflation in the prices of the utility inputs. Such measures aggregate the growth in inflation subindexes that measure changes in the prices of major input categories. In developing an overall industry inflation measure, the percentage change in each subindex is typically weighted by the share of the associated input category in utility cost.

An industry-specific input price index was first used in the PBR plan for US railroads. The growth rate of this inflation measure - called the rail cost adjustment factor - was a weighted average of the growth rates in indexes of the prices of railroad inputs. The input categories included labor, fuel, materials, equipment rentals, depreciation, interest, and a miscellaneous input category. Each input was assigned a weight that reflected its share of the cost of railroad operations nationwide.

For energy utilities, an industry-specific inflation factor was first approved for the bundled power services of PacifiCorp (CA). Industry-specific inflation measures have since been approved for the gas delivery services of Southern California Gas, the gas and electric power delivery services of San Diego Gas and Electric, and the electricity distribution services of Ontario utilities in the first generation IRM. The index approved by the Ontario Energy Board was called an industry price index (IPI).

By design, an industry-specific input price index tracks industry input price fluctuations better than an economy-wide measure. This advantage is important to the extent that the input price growth of a utility industry differs from that of the economy. For example, energy transmission and distribution are unusually capital intensive businesses and therefore particularly sensitive to changes in the cost of funds. The cost of capital can grow at a different rate, and display more year-to-year fluctuation, than broader inflation measures for extended periods of time.

One disadvantage of the industry-specific approach is that measures of overall industry input indexes for energy utilities are not available from official, government sources. Industry-specific measures must therefore be constructed using data available from public and private sources. The design of the capital price index may be particularly complex and can be controversial.

Another relevant issue for industry-specific inflation measures is their effect on risk and price volatility. Industry specific inflation factors can in principle reduce utilities' risks of unexpected changes in the prices of the inputs that are used to provide utility services. Industry specific factors can also help sidestep controversy over the appropriate value for the inflation differential so that a PCI using a macroeconomic inflation measure better tracks industry input price trends.

On the other hand, industry specific inflation measures tend to be more volatile than economy-wide inflation factors. The industry-specific measures that have been approved for PBR plans therefore often include some means of mitigating rate changes. One example is "smoothing" price changes by measuring inflation in any given as a weighted average of input price inflation (particularly the inflation in capital input prices) over a multi-year period. There is some justification for such smoothing, since utilities procure capital inputs over a multi-year period and can vary the timing of at least some equipment purchases and asset financings in response to changes in prices (*e.g.* deferring capital goods purchases in a year when the prices of commodities embedded in assets are high until a later year when prices are expected to fall). Another approach towards limiting price volatility for customers was taken in the first generation IRM for Ontario power distributors. This plan featured an industry specific inflation measure but counted only half of the calculated growth in the capital price in allowed inflation. This approach is more arbitrary than smoothing all capital input price changes over a multi-year period and, over time, is likely to under-compensate utilities for the growth in their actual input price inflation.

Staff illustrates an industry specific inflation factor that could be used for 3rd Generation IRM. There was overwhelming (but not universal) support for an industry-specific rather than economy-wide inflation factor in the Working Group meetings that preceded the development of this paper. The Working Group believed that there is considerable uncertainty regarding future price changes for a number of utility inputs, especially the prices of commodities embedded in utility assets (either directly or indirectly, such as the costs of equipment used by construction contractors), the cost of funds, and the costs of utility labor. The Working Group also generally believed that there is more uncertainty regarding the trends in these prices over the term of the 3rd Generation IRM plan than has been the case in the recent past. These uncertainties increase the probability that an economy-wide inflation measure will not accurately track the changes in utility input prices.

Staff has developed a concrete illustration for developing an IPI for 3rd Generation IRM. This approach has a number of desirable attributes. For example, Staff's illustrated method for calculating the IPI is simple and uses publicly-available data sources. The illustrated IPI also shows how volatility in capital input prices might be smoothed by computing the allowed change in capital prices as a weighted average of observed inflation in the capital price subindex over previous years. This is a more appropriate method for mitigating potential price volatility than was employed in First Generation IRM. Finally, Staff's illustrative approach can be updated easily and transparently during the term of the 3rd Generation IRM plan.

2.3 X Factors and Productivity Measurement

2.3.1 TFP Basics

The X-factor term of a rate escalation index is an external parameter that typically causes the index to grow more slowly than the inflation measure, to the benefit of customers. Various methods have been used to ensure that the X factor is "external" to the performance of the regulated companies while they are under the PBR plan. Most commonly, its value in each plan year is set in advance and is constant throughout the plan. However, in several approved plans the X-factors are set in advance but scheduled to vary from year to year. For example, X-factors in several cases have been scheduled to rise gradually over the term of the plan.

Another means of making X factors external to company operation is to calibrate them using measures of industry rather than individual company total factor productivity (TFP) growth. Since productivity plays an important role in North American rate indexing, it is valuable to review some basics on TFP measurement. We will also briefly consider the relationship between TFP growth and the various factors that can "drive" changes in productivity over the term of a PBR plan.

A TFP index is the ratio of an output quantity index to an input quantity index.

$$TFP = \frac{Output\ Quantities}{Input\ Quantities}. \qquad [8]$$

TFP therefore represents a comprehensive measure of the extent to which firms convert inputs into outputs. Comparisons can be made between firms at a point in time or for the same firm (or group of firms) at different points in time.

The growth trend in a TFP trend index is the difference between the trends in the component output quantity and input quantity indexes.

$$trend\ TFP = trend\ Output\ Quantities - trend\ Input\ Quantities\ . \qquad [9]$$

The output quantity index of an industry summarizes trends in the workload that it performs. If output is multidimensional, the growth in each output quantity dimension considered is measured by a subindex. The growth in the output quantity index depends on the growth in the quantity subindexes.

The input quantity index of an industry summarizes trends in the amounts of production inputs used. TFP grows when the output quantity index rises more rapidly (or falls less rapidly) than the input quantity index. TFP can rise or fall in a given year but in most industries typically trends upward over time.

As the previous indexing logic showed, a TFP index will capture the effect of all developments that cause the unit cost of an industry to grow more slowly than its input prices. The sources of TFP growth are diverse. Appendix Two of this report presents a technical, algebraic decomposition of TFP growth into its various components. This section provides a non-technical discussion of the sources of TFP growth.

One component is technical change. New technologies permit an industry to produce a given amount of output with fewer inputs. Economies of scale are a second source of TFP growth. Scale economies are realized when cost grows less rapidly than output. A third important source of TFP growth is the elimination of "X inefficiencies", or inefficiencies that arise when companies fail to operate at the maximum efficiency that technology allows. TFP will grow (decline) to the extent that X inefficiency diminishes (increases). A fourth source of TFP growth is the degree of capacity utilization. Changes in production capacity often do not coincide with contemporaneous changes in demand. TFP can therefore fluctuate with the level of capacity utilization. TFP growth can also be affected in the short-run by changes in the pattern of certain expenditures, such as maintenance spending and capital replacement investments. A surge in expenditures can slow productivity growth and even result in a productivity decline. Uneven spending is one of the reasons why the productivity growth of individual utilities is often more volatile than the productivity growth of the corresponding industry.

In most regulatory proceedings where TFP trends have been estimated using indexing methods, long-run TFP trends have been estimated using about 10 years worth of historical data. Such a period is generally considered to be sufficient for smoothing out short-term fluctuations in TFP that can arise because of changes in output (*e.g.* kWh deliveries that are sensitive to changes in weather and economic activity) and the timing of different types of expenditures. This long-run historical TFP trend is then assumed (either implicitly or explicitly) to be a reasonable proxy for the TFP growth that is expected over the term of the indexing plan.[10]

This is not always an appropriate assumption. For example, it is often not warranted to assume that TFP growth measured for short historical periods will be a good proxy for future trends. Shorter sample periods are more likely to be distorted by factors such as the timing of expenditures or unusual output growth. There is accordingly less confidence that past TFP trends are a good proxy for the future trend if the available data only allows TFP to be calculated for a relatively short period. As discussed, a general rule of thumb in regulatory proceedings is that a minimum of 10 years of data are needed to calculate a generally reliable estimate of the industry's long-run TFP trend.

Another instance where the industry's past TFP trend may not be appropriate going forward is when past TFP growth includes substantial, one-time productivity gains that cannot reasonably be expected to persist in the future. An example might be the TFP growth that immediately follows the privatization of a state-owned company. Another possibility is that the utility is subject to exogenous business conditions that influence its potential for TFP growth. For example, a utility may be operating in a particular region where output growth, and hence the potential for TFP to increase through realized scale economies, is lower than for the industry as whole. Similarly, output growth may be expected to be lower in the future than was the case in the past. In these instances, it may be appropriate either to base X factors on historical TFP trends that are adjusted to take account of these circumstances, or to use an alternative method for developing appropriate TFP projections.

2.3.2 Econometric Estimation of TFP Trends

In addition to estimating historical TFP trends using indexing methods, econometric methods can be used to estimate TFP growth. Such an approach is well-suited for projecting TFP growth when there is a lack of historical, time series data. The econometric approach

[10] Although, as discussed before, a consumer dividend is also sometimes added to this historical TFP trend to reflect the expected acceleration in TFP relative to the industry's historical norms when a firm becomes subject to PBR.

essentially uses statistical methods to estimate the underlying "drivers" of TFP growth, such as technological change and the realization of scale economies. Statistical techniques can estimate the impact of each of these sources of TFP growth by using data from electricity distributors operating under a wide variety of business conditions. Once those underlying TFP "drivers" are estimated, they can be combined with data on the changes in the business condition variables that apply for either individual electricity distributors or for groups of distributors. This information can then be brought together using a methodological framework that is detailed in Appendix Two of this report.

The econometric approach to estimating TFP growth has a number of potential advantages. One is that it is rigorous and has a strong foundation in statistical methods and the economics literature. This approach can also be tailored to reflect the specific business conditions, and "TFP drivers," of the Ontario power distribution industry. A TFP decomposition model can be operationalized using data from the electricity distributors themselves on their identified TFP drivers. We can, for example, calculate productivity trends for individual Ontario utilities, or groups of utilities, that are specific to their operating scale and their expectations concerning output growth, undergrounding, and other business conditions. This allows TFP trends to be customized to the special operating conditions of individual utilities while at the same time ensuring that the PCI remains "external," since the TFP driver parameters are estimated using large datasets and are thus insensitive to a company's performance while subject to the PBR plan.

There are also regulatory precedents for using econometric methods to estimate TFP growth. Econometric decompositions of TFP growth have been presented in California regulation. For example, CPUC staff have estimated the expected productivity growth of individual utilities that are specific to their operating scale. The most recent gas distribution IRM in Ontario considered econometric projections of TFP growth for both Enbridge and Union Gas. Econometric methods were also recently used to project partial factor productivity (PFP) growth for gas distribution operating expenditures in Victoria, Australia.

The main disadvantage of the econometric approach is its complexity. Econometrics often involves technically complex statistical methods. The TFP estimates that result from econometric modeling therefore tend to be less transparent and not as easy to understand as those resulting from indexing methods. While unnecessary complexity should be avoided in regulatory proceedings, it is not always practical or desirable to rely on simpler, index-based TFP estimates when calibrating the terms of PCI formulas. This would be the case, for example, if the available time series data was either too short, or distorted by transitory factors, and therefore did not yield reliable estimates of long-term TFP trends.

In the Working Group meetings, there was considerable discussion of the merits of using econometric methods to project TFP growth. PEG ultimately decided not to rely on econometric methods for developing a productivity factor for 3rd Generation IRM. The reasons were the relative complexity of this approach and the limited time available for consultation. Nevertheless, we believe that econometric estimates of TFP growth can be valuable in certain instances and may warrant attention in future IRM proceedings.

2.3.3 Consumer Dividends

The final component of the X factor is the productivity "stretch factor" or consumer dividend. In practice, North American regulators have chosen the values for consumer dividends almost entirely on the basis of judgment. This judgment has led to approved stretch factors in a relatively narrow range, between 0.25% and 1%, with an average value of approximately 0.5%. PEG presented evidence on these approved consumer dividends, and on approved X factors more generally, in our report for 2nd Generation IRM.[11]

In some instances, regulators' judgment on the appropriate consumer dividend has been informed by empirical evidence. Perhaps the best North American examples of this approach come from Massachusetts. For the PBR plan approved for Boston Gas in 2003, the Massachusetts Department of Public Utilities (DPU) chose a consumer dividend of 0.3%. This value was based on an econometric benchmarking study submitted by the Company which showed that, after controlling for other independent variables, Boston Gas achieved incremental cost reductions of 0.3% per annum in its previous PBR plan. The DPU concluded that 0.3% was a reasonable, lower bound estimate of the value of incremental cost reductions the Company could make in the updated PBR plan. In 2005, the DPU approved a 0.4% consumer dividend in the PBR plan for Bay State Gas. This value was greater than that approved for Boston Gas because the Boston Gas benchmarking study showed that the

[11] See M.N. Lowry *et al*, *Second Generation Incentive Regulation for Ontario Power Distributors*, June 13, 2006, Table 1 on p. 55. The average stretch factor in the 11 plans on this table for which there were acknowledged stretch factors was 0.54%.

Company was a significantly superior cost performer (*i.e.* there was a statistically significant difference between the cost of the Company's gas distribution operations and the costs predicted by the econometric model), while Bay State's econometric benchmarking study showed that the Company was an average cost performer (*i.e.* there was no statistically significant difference between the actual and predicted costs of the Company's gas distribution operations). The Department therefore concluded that Bay State had more opportunity to achieve incremental TFP gains under its PBR plan than did Boston Gas and accordingly should have a higher stretch factor.

The 2003 electricity distribution "thresholds" regime in New Zealand represents another potentially relevant precedent for how empirical evidence can be used to inform values for consumer dividends. The "thresholds" regime was similar to a North American-style price cap indexing plan in many respects, and the PCI formulas that were established included values of consumer dividends – called "C1 factors" in the proceeding – that differed by company. The values of these C1 factors were largely determined using a multilateral total factor productivity (MTFP) index that benchmarked TFP *levels* across NZ distributors. MTFP indexes were calculated for each distributor in each year from 1996 through 2002.

The MTFP results ranked companies relative to average TFP in the NZ electricity distribution industry. A company with average TFP levels would therefore have an MTFP value of 1. Values were produced for all years. In 2002, the last year of the sample, MTFP values for sampled companies ranged from a high of 1.781 (*i.e.* productivity 78% above the industry average) to a low of .674 (*i.e.* productivity 32.6% below the industry average).

The MTFP factors were translated into C1 factors by first ranking the distributors from top to bottom in terms of their measured efficiency. Next, distributors were divided into three groups of roughly one-third each. There were 10 distributors in the high efficiency group, 12 in the medium efficiency group, and seven in the low efficiency group. The dividing lines between these groups were ultimately based on judgment. Companies in the high efficiency group were given a C1 factor of -1%, the medium efficiency group had an efficiency factor of 0, and the low efficiency group a C1 factor of 1%.

While judgment was applied in both Massachusetts and New Zealand, both jurisdictions have recognized that the appropriate stretch factor depends in part on the prospects for incremental productivity growth during the plan term. A utility's ability to achieve productivity growth in excess of the industry's long-run TFP trend can be expected to be lower if the company exhibits greater productivity *levels* relative to the industry at the outset of the plan.[12] Massachusetts and New Zealand regulators have used benchmarking studies to shed light on a company's operating efficiency and to set lower productivity stretch targets for relatively more efficient firms.

In addition, in both jurisdictions, the regulators did not establish an *explicit* link between the value of the consumer dividend and the benchmarking evidence. Instead, benchmarking was used to assess the performance of the company in more general terms, and relatively higher stretch factors were set for companies which the analysis revealed were more inefficient performers (and vice versa). This represents a more conservative approach than has been taken by some overseas regulators, which have set X factors so that allowed rate changes eliminate the difference between the utility's measured efficiency level and the industry's efficient cost "frontier" over a defined period of time. While such an approach has some conceptual appeal, it also entails considerable risks. Most importantly, it places great weight on knowledge that is difficult to attain and inherently uncertain, such as the relationship between average and superior performance levels in competitive industries. It also relies heavily on the accuracy of benchmarking methods. These methods are still relatively new in utility regulation, and there is particular uncertainty about what constitutes the industry's performance "frontier." Overall, explicitly and mechanistically linking the value of the consumer dividend to a benchmarking evaluation places a premium on sharing speculative performance gains and therefore puts utilities at risk if these gains do not materialize. The Massachusetts and New Zealand regulators have used benchmarking evidence to inform the values of selected consumer dividends but have avoided the risks that would result by explicitly and mechanistically linking consumer dividend values to the outcomes of benchmarking studies.[13]

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[12] Another potentially relevant consideration for setting stretch factors is that a PBR plan that generates stronger incentives should stimulate better performance, thereby fostering greater incremental productivity gains. Plans that create stronger performance incentives should therefore incorporate higher stretch factors. Analogously, a plan with weaker incentives should have a lower stretch factor. PEG has developed an "incentive power" model that is able to quantify the power of incentives created by different types of PBR plans. This model was used in the Gas IRM proceeding to inform the values of the proposed consumer dividends.

[13] A similar approach was proposed at one time in Massachusetts but rejected. A "frontier" benchmarking study using data envelope analysis (DEA) was undertaken in the merger between Eastern Enterprises (the ex-parent company of Boston Gas) and Colonial Gas. To gain regulatory approval for a merger,

It is also worth noting that Massachusetts and New Zealand used different benchmarking techniques. Massachusetts has relied mostly on econometric methods while the New Zealand proceeding primarily referenced productivity level indexes when selecting consumer dividends. Benchmarking evidence using both techniques has recently been developed for Ontario's electricity distributors.

PEG believes that the Massachusetts and NZ approaches to setting stretch factors could both be valuable in Ontario. These approaches share some similar positive traits (*e.g.* using benchmarking evidence conservatively to inform regulators' decisions rather than mechanistically) but are also different in some respects (the techniques used and how benchmarking evidence was actually applied when selecting consumer dividend values). These precedents may therefore be complementary, as we discuss further in the following Chapter.

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companies must typically demonstrate to regulators that there will be merger savings which will benefit customers. Eastern Enterprises' merger proposal estimated merger savings as the difference between Colonial Gas's actual costs and hypothetical costs, which were developed by applying an escalator annually to Colonial's "cast off revenue requirement." Colonial's proposed escalator was equal to the growth in GDP-PI inflation minus a 1% productivity factor. The productivity factor estimate was based on judgment, founded partly in the first Boston Gas PBR plan.

The Attorney General argued that a 1% productivity factor was too small and presented a counter-estimate of 3.2% based on a DEA study that it commissioned. This study found that Colonial had a DEA score of 80% and concluded that there were accumulated inefficiencies of 20% at the company. The commissioned study also found that Colonials TFP declined by between 1.7% and 2.2% during the 1995-97 period.

The Department rejected the results of the DEA and TFP studies because they failed to control adequately for exogenous factors, especially local weather and load characteristics. There were three output variables in the DEA study: deliveries to residential customers; deliveries to non-residential customers; and number of customers served. Two of these variables are affected by weather, and the Department ruled that efficiency analyses could have been affected by the failure to control for weather. Accordingly, it concluded that "the resultant proposal of a 3.2 percent productivity offset is untenable. Because the (data envelope) analysis failed to make appropriate corrections for local conditions, the Department finds that the conclusions regarding total factor productivity are not reliable" (Order in DTE 98-128, pp. 71-72). This was a fairly strong and unequivocal rejection, and no DEA studies have since been presented in Massachusetts.

3. Calibrating Productivity Factors for Ontario Electricity Distributors

This Chapter presents PEG's recommendations for the productivity trend component of the X factor for 3rd Generation IRM. PEG examined three pieces of evidence when developing a recommendation for the productivity trend. The first was the TFP research for Ontario electric distributors for the 1988-97 period developed in 1st Generation IRM. The second was the TFP experience for Ontario electric distributors in 2002-2006. The third was the TFP experience of US distributors over the 1988-2006 period. This chapter examines each of these pieces of evidence in turn before presenting PEG's recommendation on the productivity factor for 3rd Generation IRM.

3.1 TFP Estimates in First Generation IRM

Ontario first implemented comprehensive incentive regulation or performance-based regulation (PBR) for the Province's electricity distributors. This PBR plan resulted from a Board-sponsored, Province-wide consideration of regulatory issues. Expert opinion was used to guide the process and synthesize input from various parties. These proceedings produced a "Rate Handbook" (Handbook) that presented recommendations for designing PBR for power distributors.

In January 2000, the OEB approved PBR for Ontario's power distributors. In doing so, it wrote that "PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation." Among the desired fundamental shifts was creating incentives that more closely resembled those in a competitive market and making regulated utilities responsible for their investments subject to price cap constraints.

The Rate Handbook developed in this proceeding initially recommended an innovative "menu approach" towards selecting the X factor. Under this approach, a menu of six alternative X factor and allowed return on equity (ROE) combinations were developed, with lower values for X associated with higher allowed ROE levels and *vice versa*. Companies would then be allowed to select the X factor- ROE combination that most appealed to their risk-incentive preferences. However, the OEB rejected this approach as too complex for a first generation PBR plan. It also did not believe that there was a well-developed analytical foundation supporting the specific menu of X factor and ROE combinations. Instead of this menu approach, the OEB opted for a more conventional, PBR plan where a single inflation factor and X factor applied to all electricity distributors.

The first electricity distribution plan used an industry-specific inflation measure rather than an economy-wide inflation measure. Industry-specific inflation measures are specifically tailored to reflect the inflation in prices for inputs that are purchased by the utility industry in question. To reduce potential price volatility under the plan, however, the OEB only allowed one-half of the change of capital input prices to be passed through to prices in a given year.

The initial electricity distribution PBR plan also included a single X factor, which had two separate components. The first was a productivity factor of 1.25%. The second was a consumer dividend or stretch factor of 0.25%,

The value of the productivity factor was based on a TFP study for Ontario's electricity distribution industry that was prepared by experts advising Board Staff.[14] The study estimated the industry's TFP growth over the 1988 through 1997 period. The industry was originally defined as a sample of 40 distributors which had data that were deemed to be of high enough quality for productivity research. This sample was later expanded to 48 electric distributors in the Province. Data was collected from a number of sources, including individual electric distributors, the Municipal Electric Association (MEA), Statistics Canada, and the Municipal Utility Databank (MUDBANK).

As discussed, TFP growth is equal to the growth in output quantity minus the growth in input quantity. Output quantity was computed as a weighted average of the number of customers by class. There were four classes of customers: residential, general service (*i.e.* under 5000 kW), large use (*i.e.* over 5000 kW), and street lighting. Each output was weighted by its share of distribution revenue.

Comprehensive input quantity was measured as a weighted average of four inputs: capital, labor, materials, and line losses. The researchers also developed an associated four-factor, input price index and an alternate, three-factor input price index that excluded line

[14] This work is summarized in Cronin, F.J., M. King, and E. Colleran, *Productivity and Price Performance for Electric Distributors in Ontario*, Report prepared for OEB Staff on July 6, 1999; an addendum that included final productivity results was added to this report on September 10, 1999.

losses. For each factor of production, costs were equal to the input quantity multiplied by the input price. Total electric distribution costs were computed by summing the costs across all inputs, and the weight applied to each input when constructing the comprehensive input quantity index was equal to its share of total distribution costs.

Capital input was constructed using a "benchmark year" capital stock and subsequent capital additions. The benchmark year for the capital stock was 1980. Capital stock in this year was measured as gross fixed distribution assets minus accumulated depreciation, divided by a twenty-year "triangularized" weighted average of asset prices for the years from 1960 to 1979.[15] A perpetual inventory equation was used to update the capital stock, according to the formula below:

$$QK_t = (1-d)QK_{t-1} + \frac{AK_t}{CAP_t} - \frac{R_t}{CAP_{t-n}} \qquad [10]$$

In this equation, QK_t is the value of the capital stock in year t, d is the annual depreciation rate, AK_t is the addition to the capital book value in year t, R_t refers to retirements in year t, and CAP_t was the electric distribution investment price index published by Stats Canada.

Capital costs were computed as the product of capital quantity and a capital service price. The formula for the capital service price was computed as

$$PK_t = (r_t + d)CAP_t \qquad [11]$$

Here, PK_t is the capital service price in year t and r_t was the Canadian long bond rate in year t.

Labor quantity was equal to a distributor's total labor compensation divided by a labor price index. Labor compensation was computed as estimated non-capitalized wages, salaries, payroll taxes and benefits. Using more detailed data from a dozen utilities, the researchers estimated that 15% of labor wages and salaries were capitalized, and this portion was assumed to apply for all distributors. The labor price index was equal to each utility's line crew wage rate, as compiled by the MEA.

Material inputs were defined as all operations, maintenance and administrative (OM&A) costs excluding labor, divided by a materials price index. Data was examined from a dozen utilities to determine the "typical" split between materials and labor in OM&A costs.

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[15] A triangularized weighting gives greater weight to more recent values of this index, reflecting the notion that more recent plant additions have a disproportionate impact on the book value of plant. For example, in a triangularized weighting of 20 years of index values, the oldest index value has a weight of 1/210, the next oldest index has a value of 2/210, and so on. 210 is the sum of the numbers from 1 to 20. A discussion of triangularized weighting of asset price indexes is found in Stevenson (1980).

Based on this analysis, it was estimated that 35% of OM&A costs were for materials, and this portion was assumed to apply for all distributors. The materials price index was the industrial producer price index published by StatsCanada.

Line losses were reported by utilities as part of a survey undertaken as part of 1st Generation IRM. The cost of line losses was equal to the quantity of losses (in kWh) multiplied by the price of purchased power. If these data were not reported to the survey task force, the data needed to calculate the costs of line losses was taken from MUDBANK.

TFP growth was estimated for the 1988-97 period. Using 1993 cost share weights for the full sample of 48 distributors, the estimated TFP trend over the entire period was 0.86%. The estimated TFP trend over the 1993-97 period was estimated to be 2.05%. The researchers did not report the measured TFP trend that was estimated for the 1988-93 period but, given the 1988-97 and 1993-97 estimated trends, it can be determined that the TFP declined by an average of .09% per annum between 1988 and 1997.[16] These results (gleaned from the expert reports referenced in footnote 14) are reported in Table One, along with some further detail on TFP growth for large, medium-sized, and small distributors.

In evaluating this productivity study, the Board believed that some recognition of the industry's most recent productivity experienced should be reflected in the X factor. It therefore applied a two-thirds weight on the overall TFP trend, and a one third weight on 1993-97 TFP trend. This weighted average of industry TFP trends led to a productivity factor of 1.25%.[17]

The PBR plan for Ontario's electricity distributors also included a 0.25% consumer dividend for all distributors. This value was based on judgment and was not discussed in detail in the Order. The final X factor for 1st Generation IRM was therefore 1.5%.

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[16] This calculation is straightforward if logarithmic growth rates are used to calculate TFP growth trends, as PEG does. If growth rates are calculated arithmetically they will still be close to -.09% per annum for the 1988-93 period. The productivity report presented in 1st Generation IRM did not say how it calculated TFP growth trends, nor did it present data on the TFP level indexes in any given year from which growth trends are calculated. However, it can also be shown that if a TFP level index series is calculated using a growth rate of -.0092% in each year between 1988 and 1993, and a growth rate of 2.05% in each year between 1993 and 1997, it would lead to an identical growth rate as an index that is calculated using an average growth rate of 0.86% in each year between 1988 and 1997.

[17] The plan also imposed a single earnings sharing mechanism on all electricity distributors in the Province, with 50/50 sharing above the allowed ROE.

Table One

Estimated TFP Growth in First Generation IRM

Entire Sample: 1988-97

Size Class	Output Quantity Growth	Input Quantity Growth	TFP Growth
Small	0.84%	0.27%	0.57%
Medium	2.05%	1.04%	1.01%
Large	1.08%	0.16%	0.92%
All Utilities	1.40%	0.54%	**0.86%**

"First Half" of Sample Period: 1988-93

Size Class	Output Quantity Growth	Input Quantity Growth	TFP Growth
Small	1.30%	1.77%	-0.45%
Medium	2.91%	2.59%	0.31%
Large	1.38%	1.66%	-0.28%
All Utilities	1.97%	2.06%	**-0.09%**

"Second Half" of Sample Period: 1993-97

Size Class	Output Quantity Growth	Input Quantity Growth	TFP Growth
Small	0.26%	-1.60%	1.85%
Medium	0.98%	-0.90%	1.89%
Large	0.71%	-1.71%	2.42%
All Utilities	0.69%	-1.36%	**2.05%**

PEG believes several aspects of the TFP research are noteworthy. First, output quantity was measured entirely by number of customers served. The study did not include kWh or kW as outputs. We believe this output specification has likely underestimated output quantity growth since, historically, average kWh use per customer tends to increase over time. The lack of a kWh or kW output subindex therefore tended to understate output quantity growth in Ontario which, in turn, would be manifested in an underestimate of the industry's TFP growth. Thus while the TFP estimate developed in 1st Generation IRM for Ontario's industry between 1988 and 1997 is the best that is currently available for this period, we believe it is a conservative estimate of the industry's TFP experience, and an estimate that included deliveries would likely be higher.

Second, the researchers relied on a number of assumptions when constructing their dataset. Data were not available on non-capitalized labor or the split between labor and materials spending in OM&A for more than a dozen utilities. Data from these utilities were therefore used to make assumptions on these values, and these assumptions were used to construct proxy labor and materials costs for other utilities in the sample. In addition, TFP was estimated for only a subset of the industry rather than for the entire industry. While data limitations may have made it necessary to rely on certain assumptions to construct a dataset for productivity research, they do suggest that there are uncertainties associated with these estimates. PEG accepts that these estimates are the best that are currently available of historical TFP trends for Ontario's electric distributors, but they are sensitive to the assumptions that have been made about cost allocations and perhaps also to sample selection. It is not clear whether any sensitivity tests were performed that examine the robustness of these TFP estimates to alternate data assumptions.

Third, it is noteworthy that the TFP experience for the Ontario industry differed markedly in the 1988-93 and 1993-97 periods. Industry TFP declined in the first half of the sample, but it grew somewhat rapidly in the second half. If the -0.09% TFP trend for 1988-93 had been the basis for a productivity factor in a hypothetical incentive regulation plan that applied for the following four years, it would have underestimated the industry's average TFP growth in these years by more than 2% per annum. The 1st Generation IRM developed a more reasonable X factor by using data from both the 1988-93 period (where industry TFP declined) and the 1993-97 period (where TFP increased).

PEG believes that this example demonstrates the risks of relying on too short a sample period when setting a productivity factor. It is common for estimated TFP growth (for a firm, industry or nation) to fluctuate considerably from year to year. To develop a reliable estimate of long-run TFP trends, it is therefore necessary to estimate TFP over a period that is long enough to balance these fluctuations. At the same time, the sample should not be so long that it includes information that is "stale" *i.e.* conditions in the distant past rather than recent TFP developments. In most regulatory proceedings, a sample period of about 10 years has been viewed as providing a reasonable balance of these two considerations. It is also important in regulatory proceedings for the start and end points of the sample period not to be impacted by transitory conditions, such as abnormal economic or weather conditions, which can in turn distort measured TFP trends. In Section 3.3, PEG uses a rigorous methodology for selecting the start point of a TFP sample period that reduces the probability that such transitory factors are impacting measured TFP.

3.2 Recent TFP Growth for Ontario Electricity Distributors

PEG also undertook more recent research on TFP growth for Ontario's electric distributors. This section will briefly discuss these TFP results. We begin by discussing the available data in Ontario. We then present the details of our index-based TFP estimates and TFP results.

3.2.1 Data

Extensive data are available on the operations of Ontario power distributors. The OEB is the primary source of such information. The sample period for which OEB operating data are currently available is 2002-06.

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").

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.

However, no comparable labor cost itemization exists for other distribution functions, or for any customer care or A&G functions.

The trial balances also include highly itemized data on gross plant value. The accumulated "amortization" (*i.e.* depreciation) on electric utility property plant and equipment is reported, as well as the accumulated amortization on intangible plant. Plant value data are also provided under the terms of RRR section 2.1.5. These include data on plant additions, which are not reported in the trial balances. Capital spending data are also provided on distributors' audited financial statements.

An 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 potentially important item in these reports is labor's share of OM&A expenses for operation and maintenance (Distribution OM&A), billing and collection, and administration. Unfortunately, these costs are deemed confidential per section 1.7 of the RRR.

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 five customer classes: residential, general service, large use (>5,000 kW), street lighting, and sentinel lighting. PBR data also include the total wholesale and retail kWh. The wholesale kWh evidently excludes deliveries that a utility may make to other (e.g. embedded) power distributors. Board staff have provided PEG with data on the deliveries of Hydro One to embedded distributors but have not provided the analogous data for any other company that makes such deliveries.

The available OEB data have a number of strengths that support their use in TFP research. Like the data collected on the FERC Form 1 in the US, the trial balance cost data are highly detailed. The use of a USoA also facilitates standardized reporting. The PBR data include detailed data on revenues and output, including data on peak distribution loads that are unavailable for U.S. electric distributors.

At the same time, available OEB data have important limitations. The most serious problem for TFP research is the available information on capital cost. Accurate and standardized capital cost measures require years of consistent, detailed plant additions data. PBR data on plant additions are only available since 2002, which reduces the reliability of the capital cost and quantity measures that can be computed for Ontario distributors. In particular, measured capital costs will be highly sensitive to our estimate of the quantity of capital on hand in 2002. This "benchmark year" calculation requires a suitably weighted index of construction costs over the past forty years.

Another important problem is inconsistencies in the allocation of labor expenses between distributor activities. Staff observed in its November 2006 notice that distributors report most customer care labor expenses as administrative expenses. We have found that this problem also extends to distribution labor expenses for many companies. A related problem is the poor quality of the publicly available data on the salary and wage component of OM&A expenses. On the US FERC Form 1, the salaries and wages assigned directly to OM&A expenses are reported on an itemized basis for all major power distributor activity groups (distribution, customer accounts, customer service and information, and administration and general). Uncertainty regarding the share of labor in OM&A expenses reduces the accuracy of productivity indexes that can be developed for Ontario distributors, since these indexes require information on cost shares.

There are also concerns with the revenue and output data. These data could be improved if the distributors reported their power deliveries to other distributors. There also appear to be inconsistencies in how "billed" retail delivery volumes and peak demand are reported. Some distributors appear to have reported volumes only for service classes with volumetric rates and peak demand only for service classes with demand charges, while others appear to have reported the volumes and peaks that correspond to all services.

These limitations of the OEB data – particularly for capital cost – reduce the quality and reliability of any TFP trend measures that can be constructed for Ontario distributors. Indeed, PEG would typically conclude that the currently available Ontario data are not sufficient to support their use in regulatory proceedings. In this instance, however, many stakeholders have expressed a strong interest in examining information on Ontario distributors' recent TFP trends. This interest is motivated by a desire to understand how recent TFP growth for the industry compares to what was estimated in 1st Generation IRM, as well as better understanding the comparability of the TFP experiences for the Ontario and US electric distribution industries.

To be responsive to these stakeholders' concerns, PEG has developed TFP estimates for Ontario distributors for the 2002-2006 period using available OEB data. We believe these TFP estimates are the best that can be developed given available information for 2002-2006, but we also emphasize that these results fall short of the standards that PEG typically applies to empirical research submitted for regulatory applications. Unfortunately, this was unavoidable given the time and information constraints. Notwithstanding the data limitations, PEG attempted to make the TFP estimates for Ontario as comparable as possible to those that we estimated for the US industry (presented in the following section). This was done by replicating our US methodology for estimating TFP as closely as possible in Ontario. Nevertheless, PEG recommends that the Ontario TFP estimates be interpreted with caution, and we hope the TFP estimates for the Ontario industry can be refined and improved in the future as more information becomes available.

3.2.2 Indexing Methods

PEG calculated TFP indexes in Ontario using the Törnqvist index form. With the Tornqvist form, the annual growth rate of the input quantity index is determined by the formula:

$$\ln\left(Input\ Quantities_t \big/ Input\ Quantities_{t-1} \right) = \sum_j \frac{1}{2} \cdot \left(S_{j,t} + S_{j,t-1} \right) \cdot \ln\left(X_{j,t} \big/ X_{j,t-1} \right). \qquad [12]$$

Here in each year *t*,

$Input\ Quantities_t$ = Input quantity index

$X_{j,t}$ = Input quantity subindex for input category *j*

$S_{j,t}$ = Share of input category *j* in applicable total cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years.

With the Tornqvist form, the annual growth rate of the output quantity index is determined by the formula:

$$\ln\left(Output\ Quantities_t \big/ Output\ Quantities_{t\text{-}1} \right) = \sum_j \ \frac{1}{2} \cdot \left(S_{k,t} + S_{k,t-1} \right) \cdot \ln\left(Y_{k,t} \big/ Y_{k,t-1} \right). \qquad [13]$$

Here in each year *t*,

$Output\ Quantities_t$ = Output quantity index

$Y_{k,t}$ = Output quantity subindex for output category *k*

$S_{k,t}$ = Cost elasticity share for output category *k*.

In both instances, it can be seen that the growth rate of the index is a weighted average of the growth rates of the quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. For the output quantity index, weights are cost elasticity shares *i.e.* the cost elasticity for each quantity subindex divided by the sum of the cost elasticities for all outputs. Cost elasticity shares were estimated using the total cost function that is presented in Appendix Three of this report.[18] For the input quantity indexes, weights are equal to the average shares of each input in the total distribution cost.

The annual growth rate in the TFP index is given by the formula

$$\begin{aligned} \ln\left(TFP_t \big/ TFP_{t-} \right) = {} & \ln\left(Output\ Quantities_t \big/ Output\ Quantities_{t\text{-}1} \right) - \\ & \ln\left(Input\ Quantities_t \big/ Input\ Quantities_{t\text{-}1} \right) \end{aligned}. \qquad [14]$$

We estimated TFP trends for the Ontario electric distributors for the 2002-2006 period. Since the index formulas involve annual growth rates, some method is needed to calculate trends from the annual growth rates. The trend in each TFP index was computed using the formula

[18] When information on the revenue collected from each output are available, it is more appropriate to use revenue shares rather than cost elasticity shares to weight output subindexes in output quantity index calculations for price indexing applications (as opposed to cost indexing applications). However, these revenue share data typically do not exist for US electric distributors, and when this is the case cost elasticity shares represent a feasible alternative which has been examined and approved in several regulatory proceedings. Because our US TFP results use cost elasticity shares, and we wanted the Ontario results to be estimated as comparably as the US results to allow for "apples to apples" comparisons, we used these same cost elasticity shares in the Ontario indexing work.

$$trend\ TFP_t = \frac{\sum_t {}_{2002}^{2006} \ln\left(TFP_t / TFP_{t-1} \right)}{4} = \frac{\ln\left(TFP_{2006} / TFP_{2002} \right)}{4} \qquad [15]$$

It can be seen that the trend is the average annual growth rate during the years of the sample period. The reported trends in other indexes and subindexes that appear in this report are computed analogously.

3.2.3 Output Quantity Variables

The two output quantity subindexes are customer numbers and kWh deliveries. Output quantity growth is a weighted average of the growth in these subindexes, with weights equal to each output's cost elasticity share. These elasticities were estimated econometrically for the US power distribution industry, as reported in Appendix Four. The calculated cost elasticity shares were 0.63 and 0.37 for customer numbers and kWh, respectively.

In response to suggestions from Working Group participants, PEG also adjusted the kWh deliveries for weather over the sample period. Our weather normalization regression was based on the estimated relationship between kWh per customer and heating degree days (HDD).[19] Data on HDD were collected from Environment Canada and mapped to Ontario distributors.

3.2.4 Input Prices and Quantities

PEG developed measures of input quantities for two input quantity subindexes: capital and OM&A inputs. The growth in the overall input quantity index was a weighted average of the growth in these two input quantity subindexes. The weight that applied to each subindex was its share of electric distribution cost.

The cost of a given class of utility plant j in a given year t ($CK_{j,t}$) was measured as the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year (XK_{t-1}).

[19] PEG also investigated the relationship between kWh and cooling degree days for Ontario distributors but it was not statistically significant. Our estimated regression that was used to normalize volumes was ln(kWh) = 8.127 + .982 ln(Customers) + .149 ln (HDD). The t-statistics on the three estimated coefficients were 21.88, 169.84 and 3.51, respectively.

$$CK_{j,t} = WKS_{j,t} \cdot XK_{j,t-1}. \qquad [16]$$

The capital service price index was constructed using a cost of service approach. This methodology is described in Appendix Three of this report. In constructing capital quantity indexes for Ontario, we took 2002 as the benchmark or starting year. This benchmark capital stock was "triangularized" by a 38 year weighted of capital asset prices. Subsequent values of the capital quantity index are constructed using inflation-adjusted data on the value of utility plant. The following formula was used to compute subsequent values of the capital quantity index:

$$XK_{j,t} = (1 - d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [17]$$

Here, the parameter d is the depreciation rate and VI_t is the value of gross additions to utility plant. The asset-price index (WKA_t) was constructed using the Stats Canada Electric Utility Construction Price Index for distribution systems.

The quantity subindex for OM&A was estimated as the ratio of distribution OM&A expenses to an index of OM&A prices. The OM&A price index is identical to that used in PEG's OM&A benchmarking work and is a weighted average of growth in distributors' labor prices and the GDP-IPI. We estimated the change in OM&A inputs using the theoretical result that the growth rate in the cost of any class of input j is the sum of the growth rates in appropriate input price and quantity indexes for that input class. This implies that

$$growth\ Input\ Quantities_j = growth\ Cost_j - growth\ Input\ Prices_j. \qquad [18]$$

3.2.5 Results

PEG applied these techniques to available OEB data to develop estimates of TFP trends for Ontario distributors for the 2002-2006 period. Table 2 lists the Ontario distributors that were included in our sample. Table 3 presents details on the output quantity index that was constructed. Table 4 presents details on the input quantity index. Table 5 presents details on the input price index. Table 6 presents the estimated TFP indexes.

Table 2 shows that PEG's sample included 77 of the 86 electric distributors in Ontario. Companies were excluded from the sample only if they were determined to have bad or missing data for any variables necessary to calculate TFP growth in any year between 2002 and 2006. It was necessary to have accurate data for all such sample years for

Table 2

SAMPLED ONTARIO POWER DISTRIBUTORS FOR PRODUCTIVITY RESEARCH

Company	Customers Served, 2005	Headquarters Location
Atikokan Hydro	1,765	NW, near Quetico Provincial Park
Barrie Hydro Distribution	65,812	SC, on Lake Simcoe
Bluewater Power Distribution	34,736	SW on Detroit River
Brant County Power	9,149	SW 40 km W Hamilton
Brantford Power	35,986	SW, 30 km SW Hamilton
Burlington Hydro	59,537	SW, near Hamilton
Cambridge and North Dumfries Hydro	47,346	SW, 30 km NW Hamilton
Centre Wellington Hydro	6,086	SW, 20 km NW Guelph
Chapleau Public Utilities	1,353	NC, 60 km E Lake Superior Provincial Park
Chatham-Kent Hydro	31,955	SW, 20 km E Lake St. Clair
COLLUS Power	14,124	SW, on Georgian Bay
Cooperative Hydro Embrun	1,791	SE 40 KM ESE of Ottawa
Dutton Hydro	586	SW 10 km N Lake Erie
Enersource Hydro Mississauga	178,140	SC Suburban Toronto
ENWIN Powerlines	84,254	SW on Detroit River
Erie Thames Powerlines	13,570	SW 15 km N Lake Erie
Espanola Regional Hydro Distribution	3,315	NC 40 km N Little Current
Essex Powerlines	27,437	SW 30 KM ESE Windsor
Festival Hydro	18,860	SW 40 km ESE Kitchener
Fort Erie (CNP)	15,230	SC, Niagara Peninsula, near Buffalo
Fort Frances Power	4,040	W, adjacent to International Falls. MN
Grand Valley Energy	682	SW, Between Barrie and Toronto
Great Lakes Power	11,457	NC, on Sault St. Marie
Greater Sudbury Hydro	42,814	NC, Sudbury
Grimsby Power	9,530	SC, on Niagara Peninsula 20 km W Hamilton
Guelph Hydro Electric Systems	44,556	SW, 50 km NW Hamilton
Haldimand County Hydro	20,462	SW, 20 km SW Hamilton
Halton Hills Hydro	19,873	SW, 60 km W Toronto
Hearst Power Distribution	2,780	NC, 300 km NNW Wawa
Horizon Utilities	230,327	SW, 60 km SW Toronto
Hydro 2000	1,130	SE 20 KM west of Hawkesbury (WL), 70 KM east of Ottawa (WK)
Hydro Hawkesbury	5,248	SE, on Ottawa River 60 KM ENE Ottawa
Hydro One Networks	1,151,989	SC, Toronto
Hydro One Brampton Networks	116,166	SC, Suburban Toronto
Hydro Ottawa	278,581	SE, Ottawa
Innisfil Hydro Distribution Systems	13,793	SC, 12 KM south of Barrie
Kenora Hydro Electric	5,847	NW, Kenora on Lake of the Woods
Kitchener-Wilmot Hydro	79,487	SW, 15 km SW Guelph
Lakefront Utilities	8,551	SC, on Lake Ontario 100 km E Toronto
Lakeland Power Distribution	8,995	NE, between Georgian Bay & Algonquin PP
London Hydro	138,046	SW, London
Middlesex Power Distribution	6,829	SW, 80 lm E Windsor
Midland Power Utility	6,516	NC, on Georgian Bay 50 km N Barrie
Milton Hydro Distribution	19,858	SW, 35 km N Hamilton
Newmarket Hydro	26,176	SC, between Toronto & Lake Simcoe
Niagara Falls Hydro	33,683	SC, Niagara Peninsula
Niagara-on-the-Lake Hydro	7,466	SC, Niagara Peninsula 15 km N Niagara Falls
Norfolk Power Distribution	18,171	SW, near Lake Erie
North Bay Hydro Distribution	23,405	NE, on Lake Nipissing 160 km E Sudbury
Northern Ontario Wires	6,202	NC, 105 NNE Timmins
Oakville Hydro Electricity Distribution	54,677	SC, Suburban Toronto on Lake Ontario
Orangeville Hydro	9,927	SW, 80 km NW Toronto
Orillia Power Distribution	12,374	SC, on Lake Simcoe 35 km NE Barrie
Oshawa PUC Networks	49,500	SC, Toronto metro area
Ottawa River Power	10,190	C, on Ottawa River near Algonquin PP
Parry Sound Power	3,265	C, on Georgian Bay 130 km N Barrie
Peninsula West Utilities	14,988	SW, Niagara Peninsula 38 km E Hamilton
Peterborough Distribution	33,531	SE, 70 km ENE Toronto
Port Colborne	9,135	SC, Niagara Peninsula on Lake Erie 60 km W Buffalo
Powerstream	219,788	SC, suburban Toronto
PUC Distribution	32,497	NC, Sault St. Marie
Renfrew Hydro	4,116	SE, 90 km W Ottawa
Rideau St. Lawrence Distribution	5,823	SE, on St. Lawrence River 100 km SSE Ottawa
Sioux Lookout Hydro	2,760	NW, 230 km ENE Kenora
St. Thomas Energy	15,243	SW, 10 km N Lake Erie
Tay Hydro Electric Distribution	3,990	SC, near Georgian Bay 50 KM north of Barrie
Thunder Bay Hydro Electricity Distribution	49,558	NW, on Thunder Bay
Toronto Hydro-Electric System	676,678	SC, at center of Golden Horseshoe on Lake Ontario
Veridian Connections	106,730	SC, on Lake Ontario between Toronto & Oshawa
Wasaga Distribution	10,545	SC, on Georgian Bay 38 km NW Barrie
Waterloo North Hydro	48,041	SW, adjacent to Kitchener 100 km WSW Toronto
Welland Hydro-Electric System	21,430	SC, Niagara Peninsula 70 km W Buffalo
Wellington North Power	3,416	SW, between Kitchener & Owen Sound
West Coast Huron Energy	3,773	SW, on Lake Huron 129 km ENE Sarnia
West Nipissing Energy Services	3,101	NC, on Lake Nipissing 38 km W North Bay
Whitby Hydro Electric	36,235	SC, on Lake Ontario between Ajax and Oshawa
Woodstock Hydro Services	14,195	SW, on Thames River 50 km ENE London

Table Three

OUTPUT QUANTITY GROWTH: ONTARIO POWER DISTRIBUTORS

Year	Output Quantity		Customers		Volume	
	Index	**Growth Rate**	**Index**	**Growth Rate**	**Index**	**Growth Rate**
2002	1.00000		1.00000		1.00000	
2003	1.03055	3.01%	1.01996	1.98%	1.04883	4.77%
2004	1.04165	1.07%	1.03657	1.62%	1.05035	0.14%
2005	1.06892	2.58%	1.05081	1.36%	1.10048	4.66%
2006	1.06545	-0.33%	1.06398	1.25%	1.06795	-3.00%
Average Annual Growth Rate **2002-2006**		**1.58%**		**1.55%**		**1.64%**

Table Four

INPUT QUANTITY GROWTH: ONTARIO POWER DISTRIBUTORS

Year	Input Quantity		OM&A		Capital	
	Index	**Growth Rate**	**Index**	**Growth Rate**	**Index**	**Growth Rate**
2002	1.00000		1.00000		1.00000	
2003	1.01113	1.11%	1.01181	1.17%	1.01065	1.06%
2004	1.01006	-0.11%	0.98394	-2.79%	1.02535	1.44%
2005	1.04058	2.98%	1.03910	5.45%	1.04189	1.60%
2006	1.06516	2.33%	1.05646	1.66%	1.07049	2.71%
Average Annual Growth Rate **2002-2006**		**1.58%**		**1.37%**		**1.70%**

Table Five

INPUT PRICE GROWTH: ONTARIO POWER DISTRIBUTORS

Year	Input Price		OM&A		Capital	
	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
2002	1.00000		1.00000		1.00000	
2003	1.16216	15.03%	1.01924	1.91%	1.26290	23.34%
2004	1.22269	5.08%	1.04135	2.15%	1.35129	6.76%
2005	1.30212	6.29%	1.06637	2.37%	1.47084	8.48%
2006	1.36731	4.89%	1.08618	1.84%	1.57050	6.56%
Average Annual Growth Rate **2002-2006**		**7.82%**		**2.07%**		**11.28%**

Table Six

PRODUCTIVITY RESULTS: ONTARIO POWER DISTRIBUTORS

Year	Output Quantity		Input Quantity		TFP	
	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
2002	1.000		1.000		1.000	
2003	1.031	3.01%	1.011	1.11%	1.019	1.90%
2004	1.042	1.07%	1.010	-0.11%	1.031	1.18%
2005	1.069	2.58%	1.041	2.98%	1.027	-0.39%
2006	1.065	-0.33%	1.065	2.33%	1.000	-2.66%
Average Annual Growth Rate **2002-2006**		**1.58%**		**1.58%**		**0.01%**

appropriate TFP trends to be calculated.

Table 3 shows that the output quantity index grew by an average of 1.58% per annum over the 2002-06 period. Growth in kWh slightly outstripped customer growth, indicating that there has been a modest increase in electricity usage per customer over the sample period. However, there was a substantial decline in (weather adjusted) kWh in 2006, which was responsible for a decline in overall output in that year. In general, kWh have been far more volatile than customer growth from year to year, even after normalizing for weather.

Table 4 shows that overall input quantity also grew by an average of 1.58% per annum over 2002-2006. Capital inputs grew by an average of 1.7% per annum, which is slightly more rapid than the growth in OM&A inputs of 1.37%. There is also some evidence that capital investment is accelerating, since capital has grown at a more rapid rate in each succeeding year of the sample. By contrast, changes in OM&A inputs have been more volatile from year to year.

Table 5 presents details on the changes in input prices. It can be seen that the OM&A input price measure has grown by 2.07% per annum. PEG also estimates that capital input prices have grown by a very rapid 11.28% over the 2002-2006 period. This is primarily due to the increase in earned return on equity over this period, which PEG uses as a component of our cost of service capital service price index. Unlike the OM&A input prices, this input price change does not enter directly into computations of capital inputs and therefore it has a more muted, "second order" effect on measured TFP trends.[20]

Table 6 shows that Ontario distributors' TFP has been essentially flat over the 2002-2006 period, growing at only a .01% average rate. It is worth noting, however, that TFP declined substantially in 2006, primarily because of the decline in output in that year. Prior to 2006, TFP for the Ontario distributors had grown at an average rate of 0.89% per annum between 2002 and 2005. It is fair to say that the 2006 output decline was anomalous, since distributors' output can be expected to increase, on average, over a multi-year period. Because this output decline occurred at the end of the sample, it has also tended to depress

[20] Higher capital service prices will affect measured TFP growth only if they change the share of capital in overall distribution costs, and hence the weight applied to the growth in capital inputs, and capital and OM&A inputs grow at different rates.

measured TFP growth over the 2002-2006 period.[21] This implies that the anomalous output decline in 2006 has almost certainly reduced the distributors' measured TFP growth relative to the industry's long-run TFP trend.

In sum, PEG estimates that Ontario distributors' TFP has grown by .01% per annum over the 2002-2006 period. We also believe this growth rate is less than the industry's long-run TFP trend because of the atypical decline in output at the end of the sample period. Given the available information, however, it is not possible at present to correct for this likely bias and obtain a better estimate of the industry's long-run TFP trend.

Several other factors also reduce the reliability of these TFP trends, or any TFP trends that can presently be estimated for Ontario distributors using indexing methods. First, PEG only had access to high-quality, available data for Ontario electricity distributors for the 2002-2006 period. Given the time available for PEG's work, it was also not feasible to link PEG's existing database with the dataset employed in the 1st Generation IRM and ensure that the series needed to estimate TFP trends were defined consistently across companies (*e.g.* controlling for mergers over the sample period) and across time (*e.g.* similar cost definitions for a given company in all sample years). Accordingly, the available time series data in Ontario only allowed four years of TFP changes to be calculated, which is not a sufficient period for estimating long-run TFP trends.

Another problem with the OEB data is the lack of available capital cost data. Accurately calculating standardized capital costs requires years of consistent and detailed plant additions data. High quality capital additions data for Ontario electricity distributors are currently only available since 2002. Estimates of TFP trends necessarily requires estimates of capital and OM&A inputs but, because of the lack of capital additions data, the former will be highly sensitive to our estimate of the quantity of capital on hand in 2002. Measured TFP trends become more reliable when they are less influenced by such "benchmark year" measures for capital and are calculated, instead, using a relatively lengthy series of capital additions data. For example, in its US TFP work, PEG calculates power distribution trends using a benchmark capital measure of 1964. Current measures of capital input are therefore constructed using more than 40 years of capital additions data, which will incorporate the full

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[21] Output declines at the end of the sample period tend to distort measured TFP growth more than output declines in the middle of a sample period. For example, if output would have declined in 2005, but then been reversed in the following year, the atypical output decline would not have had any measured impact on TFP growth over the entire sample period.

capital investment and replacement cycles for a sizeable share of electricity distribution assets. The lack of time series data on capital additions currently makes it very problematic to calculate TFP trends at all, or to undertake total cost benchmarking (*i.e.* capital plus OM&A costs), for Ontario's power distribution industry.

There have also been a number of unusual pressures on O&M costs in the last several years. Some of these are due to one-time regulatory, policy and structural changes, such as the devolution of certain activities to individual companies that were previously performed by Hydro One for most of the industry. To the extent that these are one-time costs pressures that are not expected to persist, they do not reflect long-run effects that should be incorporated in the long-run TFP trend that is used to calibrate the X factor. Rather than being reflected in the rate *adjustment* mechanism, such one-time distributor costs should instead be recovered in the new rate *levels* that are established when rates are rebased. Among the one-time or relatively transitory cost pressures that may fall into this category are the following:

- New government initiatives such as conservation programs, time of use pricing, smart meters, RPP, bill presentment changes, rebates, and renewable generation programs.
- An increasing number of transactions and interactions with new institutional entities such as the IESO, OPA, MDMR, and third party retailers.
- Increasing costs of complying with new regulations and mandates from the OEB, IESO, ESA, and environmental authorities. Regulatory costs are also increasing due to the need to prepare and file FTY applications.
- The Hydro One Meter Exit Program: when the market first opened, Hydro One was the Default Meter Service Supplier for many or most LDCs in the province. The costs associated with the default service were captured in the Transmission Service Charges. LDCs have now had to secure Meter Service Providers and have annual service contracts which can be (depending on the number of wholesale metering points) a significant OM&A cost.

Given these concerns, PEG recommends that the Ontario TFP estimates be interpreted with caution. We believe 0.01% is the best estimate that can currently be developed for the industry's TFP trend over the 2002-2006 period but, given the bias noted above, we believe there is a high probability that measured TFP growth would increase if a more complete analysis was feasible. We hope the TFP estimates for the Ontario industry can be refined and improved in the future as more information becomes available.

3.3 TFP Growth for US Electricity Distributors

Because the available data for Ontario distributors' were both fragmentary and incomplete, PEG also developed estimates of TFP growth for US electric distributors. These estimates have been developed using standardized techniques applied to a consistent time series that spans several decades for a large sample of diverse utilities. All these factors enhance the reliability of the TFP estimates that can be developed using US data sources.

PEG has estimated TFP trends for the US power distribution industry for the 1988-2006 period. This period subsumes the 1998-97 years examined in IRM1 as well as PEG's more recent TFP estimates for the Ontario industry in 2002-2006. The 1988-2006 trends for the US industry therefore allow comparisons with existing TFP studies for Ontario's electric distributors. To enhance the possibility of such "apples to apples" comparisons, PEG has endeavored to apply a consistent methodology for estimating TFP in the US and (in more recent years) Ontario, notwithstanding the data limitations.

3.3.1 Data

The primary source of the cost and quantity data used to estimate the power distribution cost model was the Federal Energy Regulatory Commission (FERC) Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these Accounts can be found in Title 18 of the Code of Federal Regulations.

FERC Form 1 data are processed by the Energy Information Administration ("EIA") of the U.S. Department of Energy. Selected Form 1 data were for many years published by the EIA and are now made available electronically. These data have been gathered and processed by commercial vendors such as the Utility Data Institute (d/b/a Platts). Form 1 data used in this study for years since 2001 were obtained directly from the electronic forms.

Data were considered for inclusion in the sample from all major U.S. investor-owned power distributors that filed the Form 1 in 2006 and that, together with any important predecessor companies, have reported the necessary data continuously since the mid 1960s. To be included in the study the data were required, additionally, to be plausible. Data from 69 companies met these standards and were used in our TFP research. The included companies are listed in Table Seven.

3.3.2 Indexing Methods

As in Ontario, TFP is measured using a Tornqvist index. Trends are computed in an analogous fashion as previously described in Section 3.2.

3.3.3 Output Quantity Variables

There are two output quantity variables: the number of retail customers, and total kWh deliveries. The growth in each output subindex is weighted by its cost elasticity share. These cost elasticity shares are 0.63 for customer numbers and 0.37 for kWh deliveries.

3.3.4 Input Prices

PEG used a cost of service approach towards estimating capital cost and capital quantities, analogous to what was employed for the Ontario distributors. The cost of a given class of utility plant *j* in a given year *t* ($CK_{j,t}$) is the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year (XK_{t-1}).

$$CK_{j,t} = WKS_{j,t} \cdot XK_{j,t-1}. \qquad [16]$$

Each capital quantity index is constructed using inflation-adjusted data on the value of utility plant. In constructing indexes we took 1964 as the benchmark or starting year. The asset-price index (WKA_t) was measured using Handy Whitman data.

The labor price variable used in this study was constructed by PEG using data from the US Bureau of Labor Statistics (BLS). National Compensation Survey ("NCS") data for 2004 were used to construct average wage rates that correspond to each utility's service territory. The wage levels were calculated as a weighted average of the NCS pay level for each job category using weights that correspond to the Electric, Gas, and Sanitary (EGS) sector for the U.S. as a whole. Values for other years were calculated by adjusting the 2004 level for changes in the employment cost index by region over the 1988 – 2006 period. Prices for other O&M inputs are assumed to be the same in a given year for all companies. They are escalated by growth in the US GDP-PI. Measures of capital cost, capital input prices and capital quantity are

Table Seven

SAMPLED POWER DISTRIBUTORS FOR TFP TREND RESEARCH

Alabama Power
Appalachian Power
Arizona Public Service
Atlantic City Electric
Avista
Baltimore Gas & Electric
Black Hills Power
Boston Edison
Carolina Power & Light
Central Hudson Gas & Electric
Central Illinois Light
Central Maine Power
Central Vermont Public Service
Cincinnati Gas & Electric
CLECO
Cleveland Electric Illuminating
Columbus Southern Power
Duke Power
Edison Sault Electric
El Paso Electric
Empire District Electric
Florida Power & Light
Florida Power
Idaho Power
Kansas City Power & Light
Kansas Gas & Electric
Kentucky Power
Kentucky Utilities
Kingsport Power
Louisville Gas and Electric
Madison Gas and Electric
Maine Public Service
Mississippi Power
Mount Carmel Public Utility
Nevada Power
Northern Indiana Public Service
Northern States Power
Ohio Edison
Ohio Power
Oklahoma Gas and Electric
Orange and Rockland Utilities
Otter Tail Power
Pacific Gas & Electric
PacifiCorp
Potomac Edison
Potomac Electric Power
PSI Energy
Public Service of Colorado
Public Service of New Hampshire
Public Service of Oklahoma
Public Service Electric & Gas
Rochester Gas and Electric
San Diego Gas & Electric
South Carolina Electric & Gas
Southern California Edison
Southern Indiana Gas & Electric
Southwestern Electric Power
Southwestern Public Service
Tampa Electric
Toledo Edison
Tuscon Electric Power
Union Light Heat & Power
United Illuminating
Virginia Electric & Power
West Penn Power
Western Massachusetts Electric
Wisconsin Electric Power
Wisconsin Power and Light
Wisconsin Public Service

Number of Companies: 69

explained in detail in Appendix Three.

3.3.5 Results

PEG's output quantity indexes are presented in Table 8. Details on the input quantity and input price indices are presented in Tables 9 and 10, respectively. Table 11 presents the estimated TFP indexes.

Turning first to the output quantities, it can be seen that overall output quantity has grown by 1.75% for US distributors. This is somewhat more rapid than the 1.58% output trend for the Ontario industry. The difference is almost entirely explained by more rapid increases in electricity usage per customer in the US than in Ontario. Customer growth is very similar in the two samples (1.61% per annum for the US versus 1.55% for Ontario), but kWh deliveries have increased by 1.99% per annum for the US industry but by only 1.64% per annum in Ontario.

Table 9 shows that input quantity has grown at an average rate of 1.04% per annum over the 1988-2006 period. This is substantially below the recent, 1.58% average growth in input quantity for the Ontario industry. US distributors have increased both capital input and OM&A input more slowly than Ontario distributors.

Table 10 presents details on input price growth. It can be seen that the labor input price index has grown by 3.54% per annum over the entire sample period. This is well above the average growth in the GDP-PI, or economy-wide inflation, of 2.38%. The GDP-PI is the input price index chosen to deflate non-labor O&M expenses. It can also be seen that capital input prices have grown at an average annual rate of 4.15% per annum. This is more rapid than the growth in either labor or non-labor O&M input prices but substantially below the estimated capital input price inflation in Ontario.

Table 11 presents the TFP index for US electric distributors. It can be seen that TFP has grown at an average annual rate of 0.72% per annum between 1988 and 2006. This is 0.71% more rapid than what PEG has estimated for the Ontario industry between 2002 and 2006. On the other hand, it is somewhat below the 0.86% TFP trend estimated for Ontario in 1st Generation IRM. The next section will examine the relationship between the US and Ontario TFP trends in more detail.

Table 8

OUTPUT QUANTITY INDEXES: U.S. SAMPLE

Year	Summary Index	Quantity Subindexes	
		Customer Numbers	**Deliveries**
1988	1.000	1.000	1.000
1989	1.040	1.037	1.046
1990	1.060	1.057	1.066
1991	1.077	1.071	1.087
1992	1.089	1.085	1.094
1993	1.111	1.100	1.130
1994	1.131	1.116	1.155
1995	1.152	1.133	1.184
1996	1.171	1.148	1.211
1997	1.190	1.168	1.229
1998	1.213	1.185	1.262
1999	1.233	1.204	1.285
2000	1.260	1.224	1.322
2001	1.272	1.244	1.322
2002	1.291	1.259	1.346
2003	1.309	1.278	1.364
2004	1.333	1.298	1.395
2005	1.357	1.316	1.429
2006	1.371	1.337	1.430
Average Annual Growth Rate **1988-2006**	**1.75%**	**1.61%**	**1.99%**

Table 9

INPUT QUANTITY INDEXES: U.S. SAMPLE

Year	Summary Index	Input Quantity Subindexes: Labor	Input Quantity Subindexes: Materials & Services	Input Quantity Subindexes: Capital
1988	1.000	1.000	1.000	1.000
1989	1.020	1.003	1.020	1.026
1990	1.037	0.988	1.049	1.049
1991	1.064	0.988	1.118	1.071
1992	1.068	0.978	1.090	1.090
1993	1.106	1.003	1.191	1.108
1994	1.114	0.948	1.255	1.123
1995	1.115	0.918	1.258	1.135
1996	1.128	0.908	1.314	1.144
1997	1.123	0.846	1.336	1.154
1998	1.145	0.837	1.437	1.164
1999	1.157	0.841	1.455	1.177
2000	1.158	0.813	1.470	1.185
2001	1.150	0.771	1.448	1.195
2002	1.153	0.747	1.483	1.202
2003	1.181	0.769	1.558	1.216
2004	1.173	0.753	1.510	1.224
2005	1.191	0.772	1.560	1.232
2006	1.205	0.797	1.586	1.237
Average Annual Growth Rate **1988-2006**	**1.04%**	**-1.26%**	**2.56%**	**1.18%**

Table 10

INPUT PRICE INDEXES: U.S. SAMPLE

Year	Summary Index	Input Quantity Subindexes: Labor	Input Quantity Subindexes: Materials & Services	Input Quantity Subindexes: Capital
1988	1.000	1.000	1.000	1.000
1989	1.051	1.043	1.038	1.058
1990	1.100	1.094	1.078	1.110
1991	1.151	1.141	1.115	1.168
1992	1.180	1.182	1.141	1.194
1993	1.230	1.224	1.167	1.258
1994	1.368	1.263	1.191	1.478
1995	1.420	1.297	1.216	1.548
1996	1.453	1.335	1.238	1.584
1997	1.488	1.377	1.259	1.623
1998	1.485	1.427	1.273	1.596
1999	1.575	1.473	1.291	1.731
2000	1.501	1.539	1.319	1.568
2001	1.414	1.603	1.351	1.389
2002	1.474	1.659	1.374	1.469
2003	1.607	1.720	1.403	1.669
2004	1.644	1.787	1.443	1.698
2005	1.798	1.841	1.489	1.927
2006	1.925	1.893	1.536	2.111
Average Annual Growth Rate **1988-2006**	**3.64%**	**3.54%**	**2.38%**	**4.15%**

Table 11

PRODUCTIVITY RESULTS: U.S. SAMPLE

Year	Output Quantity Index	Input Quantity Index	TFP Index
1988	1.000	1.000	1.000
1989	1.040	1.020	1.020
1990	1.060	1.037	1.022
1991	1.077	1.064	1.012
1992	1.089	1.068	1.020
1993	1.111	1.106	1.005
1994	1.131	1.114	1.015
1995	1.152	1.115	1.033
1996	1.171	1.128	1.038
1997	1.190	1.123	1.060
1998	1.213	1.145	1.060
1999	1.233	1.157	1.066
2000	1.260	1.158	1.088
2001	1.272	1.150	1.107
2002	1.291	1.153	1.119
2003	1.309	1.181	1.109
2004	1.333	1.173	1.136
2005	1.357	1.191	1.139
2006	1.371	1.205	1.138
Average Annual Growth Rate **1988-2006**	**1.75%**	**1.04%**	**0.72%**

3.4 Comparing US and Ontario TFP Growth

Three pieces of TFP information have been presented in this Chapter on TFP growth for electric distributors in the US and Ontario. The first is the TFP study done for Ontario's power distribution industry in 1st Generation IRM. The second is PEG's estimate of TFP growth for Ontario distributors between 2002 and 2006. The third is PEG's estimate of TFP growth for US distributors between 1988 and 2006. In this section, we will compare this evidence in an attempt to better understand how TFP compares between the US and Ontario industries since 1988. Clearly, it is only possible to make direct comparisons between three sub-periods of this sample: the 1988-93 and 1993-97 trends highlighted in IRM1; and the 2002-2006 trends estimated by PEG for the US and Ontario.

Listed below are the measured TFP trends for the Ontario and US electric distributors for the three periods for which these trends have been estimated:

Period	Ontario	US	Difference
1988-93	-0.09%	0.09%	-0.19%
1993-97	2.05%	1.33%	0.72%
2002-06	0.01%	0.41%	-0.40%

In PEG's opinion, this table provides some support for the view that TFP trends for US power distributors are a reasonable, although not perfect, proxy for contemporaneous TFP trends in Ontario. For example, TFP was essentially flat for the US and Ontario industries between 1988 and 1993. TFP growth was slightly negative for the Ontario distributors, and slightly positive for US distributors, during these years. TFP growth turned sharply positive in both the US and Ontario for the 1993-97 period, although the TFP acceleration was somewhat greater in Ontario than in the US. TFP growth also slowed considerably in 2002-2006 (compared to 1993-97) for both industries, although the slowdown was more pronounced in Ontario.

No TFP information exists for Ontario distributors between 1997 and 2002, so we cannot make direct TFP comparisons between the industries for these years. However, using the available TFP evidence from both the US and Ontario, it is possible to construct some scenarios for plausible TFP growth for Ontario distributors between 1997 and 2002. These scenarios will clearly not be definitive, but they do allow us to better understand the TFP experience for US and Ontario distributors over the entire 1988-2006 period, which begins with the TFP study conducted for 1st Generation IRM. This understanding can, in turn, shed light on the extent to which TFP trends for US electric distributors are or are not comparable to the trends for the Ontario industry.

PEG has developed four scenarios for TFP growth during the "missing years" between 1997 and 2002 in Ontario. We emphasize that we are not putting forward any of these scenarios as accurate measures of TFP growth during that time. Rather, we are trying to bind the range of possible TFP growth rates for the Ontario industry over the entire 1988-2006 period, which will facilitate comparisons with the US industry over the same period.

Towards that end, given the available evidence in the US and Ontario, our lower bound for Ontario's TFP growth between 1997 and 2002 is zero. This is effectively the TFP growth registered by the Ontario industry between 2002 and 2006. Under this scenario, TFP would have dropped abruptly from its 2.05% growth rate in 1993-97 to, essentially, zero percent for each of the next nine years (1997-2006). PEG believes this is an unrealistically pessimistic scenario, especially because the 1997-2002 period coincides with 1st Generation IRM. Although this plan was terminated prematurely, it would be reasonable to expect it to create strong performance incentives and enhance TFP growth while it was in effect. For these reasons, PEG believes zero TFP growth between 1997 and 2002 (and, by extension, essentially through 2006) can be considered a plausible "worst case" TFP scenario for the Ontario industry.

The second scenario is that the Ontario industry's TFP growth matched that for US distributors over the 1997-2002 period. Because TFP growth for the Ontario distributors exceeded that of their US counterparts between 1993 and 1997, this scenario would actually represent a considerable slowdown in TFP growth for the Ontario industry. Under this scenario, TFP growth for the Ontario distributors is assumed to grow at the same 1.09% rate as the US industry during these years. This is just over half the TFP growth for the Ontario industry in the preceding four years.

The third scenario is that, between 1997 and 2002, the relative relationship between TFP growth for Ontario and US distributors was the same as this ratio between 1993 and 1997. In other words, in the 1993-97 period, TFP growth for the Ontario industry was 2.05% and TFP growth for the US industry was 1.33%. The ratio between these growth rates is (2.05/1.33) = 1.54. The US distributors' TFP growth in 1997-2002 was 1.09%. If the relationship between Ontario and US TFP growth in 1997-2002 remained proportional to the relationship that prevailed in 1993-97, Ontario distributors' TFP growth would have grown at 1.68% (*i.e.* 1.09% * 1.54 = 1.68%) per annum in the 1997-2002 period.

The fourth scenario is that TFP growth in 1997-2002 would have continued at the same rate as the industry's TFP growth between 1993 and 1997. TFP growth for Ontario distributors over the 1993-97 period averaged 2.05% per annum, and under this scenario this same TFP growth would persist through 2002. Given the available TFP evidence for the US and Ontario industries, this can be viewed as a "best case" TFP scenario.

The information on measured TFP growth, and TFP growth under each of these scenarios, is summarized in Table 12. The TFP indexes for Ontario under the four scenarios are presented in the first four columns of the top panel. The TFP index for the US panel is presented in the fifth column of this panel. This top panel also presents the growth rates for the Ontario and US TFP indexes for five separate periods: 1988-93; 1993-97; 1997-2002; 2002-2006; and the entire 1988-2006 period. It should be noted that the growth rates for Ontario distributors for three of these periods (1988-93, 1993-97, and 2002-2006) reflect the growth rates that have been calculated either in 1st Generation IRM or by PEG. The 1997-2002 growth rates for Ontario distributors are those that are assumed under the scenarios, and the 1988-2006 growth rates for Ontario represent a mixture of the measured TFP trends and the TFP experience assumed under the scenarios. The second panel in Table 12 provides information on the difference between the growth rates of the US and Ontario industries over these periods; this panel is essentially an expansion of the tabular information presented on page 53 of this report.

Examining the growth rates for the Ontario distributors, it can be seen that these are identical for the 1988-93, 1993-97, and 2002-2006 periods under each scenario. This is not surprising, because these trends were calculated either by PEG or in 1st Generation IRM and do not depend on the scenarios. The impact of the scenarios is evident in the growth rates reported for the 1997-2002 period. These growth rates are 0 (Scenario 1), 1.09% (Scenario 2), 1.68% (Scenario 3), and 2.05% (Scenario 4). Given the previous TFP experience in Ontario in the preceding four years, PEG believes either Scenarios 2 or 3 are most likely. It can be seen that, if Scenario 2 had transpired, the TFP growth for Ontario's electric distributors would have grown by 0.74% per annum over the entire 1988-2006 period. If

Table 12

Comparison of US and Ontario Electricity Distribution TFP Growth

	TFP Growth				
	Ontario 1 [a]	Ontario 2 [b]	Ontario 3 [c]	Ontario 4 [d]	United States
1988	1.000	1.000	1.000	1.000	1.000
1989	0.999	0.999	0.999	0.999	1.020
1990	0.998	0.998	0.998	0.998	1.022
1991	0.997	0.997	0.997	0.997	1.012
1992	0.996	0.996	0.996	0.996	1.020
1993	0.995	0.995	0.995	0.995	1.005
1994	1.016	1.016	1.016	1.016	1.015
1995	1.037	1.037	1.037	1.037	1.033
1996	1.059	1.059	1.059	1.059	1.038
1997	1.080	1.080	1.080	1.080	1.060
1998	1.080	1.092	1.099	1.103	1.060
1999	1.080	1.104	1.117	1.126	1.066
2000	1.080	1.116	1.136	1.149	1.088
2001	1.080	1.129	1.156	1.173	1.107
2002	1.080	1.141	1.175	1.197	1.119
2003	1.081	1.141	1.175	1.197	1.109
2004	1.081	1.141	1.175	1.197	1.136
2005	1.081	1.141	1.176	1.197	1.139
2006	1.081	1.141	1.176	1.198	1.138
1988 - 2006	0.43%	0.74%	0.90%	1.00%	0.72%
1988 - 1993	-0.09%	-0.09%	-0.09%	-0.09%	0.09%
1993 - 1997	2.05%	2.05%	2.05%	2.05%	1.33%
1997 - 2002	0.00%	1.09%	1.68%	2.05%	1.09%
2002 - 2006	0.01%	0.01%	0.01%	0.01%	0.41%

	Difference between Ontario and US TFP Growth Rates			
	Ontario 1 [a]	Ontario 2 [b]	Ontario 3 [c]	Ontario 4 [d]
1988 - 2006	-0.28%	0.02%	0.18%	0.29%
1988 - 1993	-0.19%	-0.19%	-0.19%	-0.19%
1993 - 1997	0.72%	0.72%	0.72%	0.72%
1997 - 2002	-1.09%	0.00%	0.58%	0.96%
2002 - 2006	-0.40%	-0.40%	-0.40%	-0.40%

[a] Assumes 0% TFP growth 1997 - 2002.
[b] Assumes Ontario TFP growth equal to US TFP growth 1997 - 2002.
[c] Assumes Ontario TFP growth 1997 - 2002 maintains proportion relative to US TFP growth from 1993 - 1997.
[d] Assumes TFP growth 1997 - 2002 matches 2.05% rate as in 1993 - 1997.

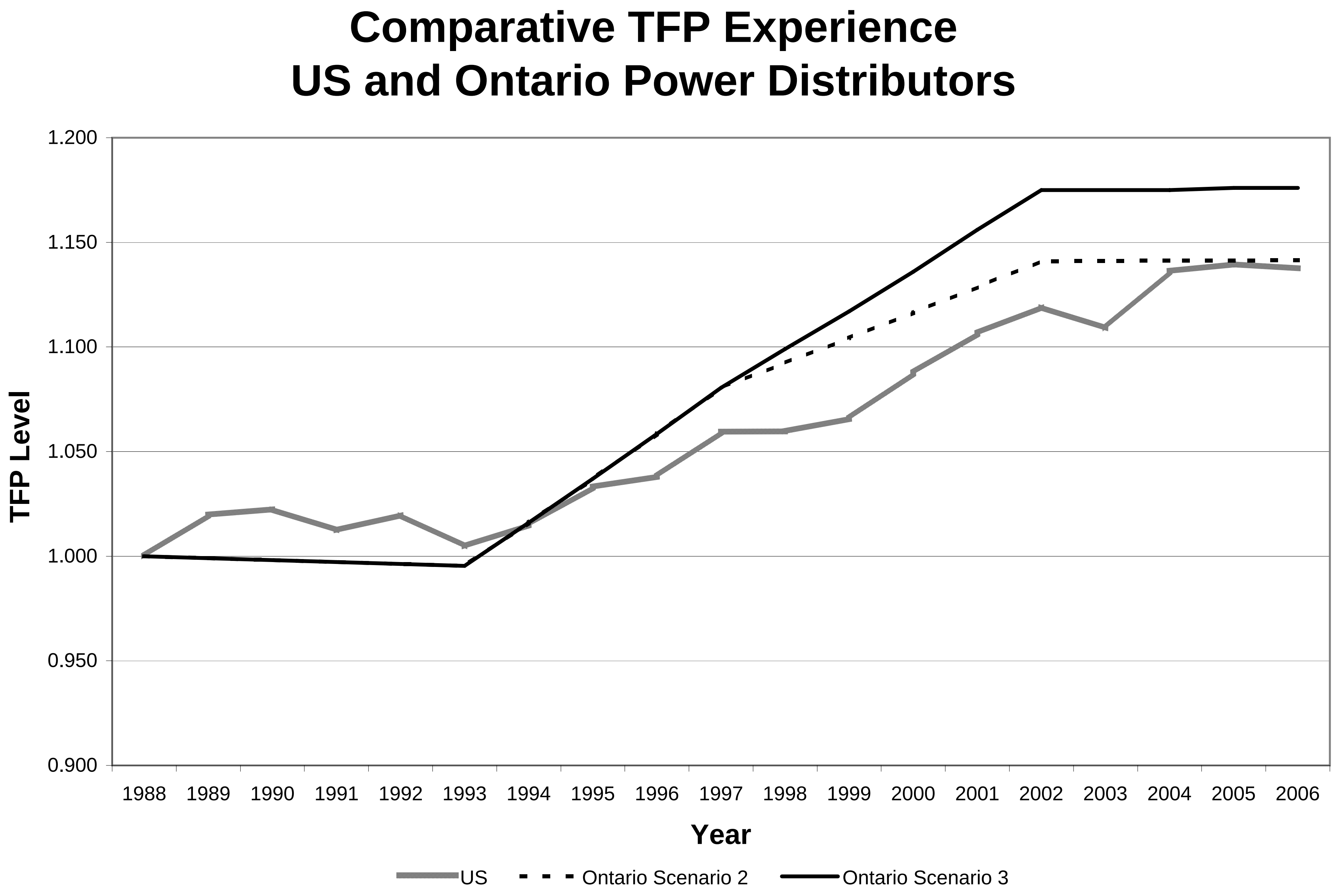
Scenario 3 had transpired, Ontario's distributors would have registered average TFP growth of 0.90% over the 1988-2006 period. The analogous TFP growth rate for US distributors was 0.72% for this period. Figure One compares the TFP experience for the US and Ontario industries under Scenarios Two and Three.

PEG believes that Table 12 and Figure 1 shed some light on the comparative TFP experiences of the US and Ontario industries. The calculated indexes show that TFP growth has moved in the same directions between the US and Ontario industries in the 1988-93, 1993-97 and 2002-2006 periods. TFP was basically flat in the first period, accelerated sharply in the second, and then decelerated in the last period. The magnitudes of average TFP change are also similar over these periods. Over the three periods, which include a total of thirteen observed rates of change, TFP growth for the Ontario electric distributors averaged 0.60% per annum. Over these same three periods, TFP growth for US electric distributors averaged 0.57% per annum. PEG also believes that, under the two most plausible scenarios (Scenario Two and Three), average TFP growth for Ontario distributors over the entire 1988-2006 period has likely been equal to, or somewhat greater than, TFP growth for the US industry.

Our analysis of the TFP evidence in Ontario and US has been limited by the available information. The TFP data that exist on Ontario electric distributors is fragmentary, incomplete and drawn from several sources. However, data and time constraints have made it impossible to undertake a more comprehensive and methodologically consistent analysis. The data that PEG has examined are, accordingly, all the data that currently exist or can be developed for the Ontario electric distributors.

Notwithstanding the data limitations, PEG believes this analysis supports the conclusion that the TFP trend for US distributors is a good proxy for the TFP trend for Ontario electric distributors. In North American PBR plans, the productivity factor is usually calibrated using a measure of the industry's long-run trend in TFP growth. Because the available evidence indicates that the TFP trend for US distributors is a good proxy for the TFP trend for Ontario electric distributors, PEG recommends that the productivity factor for 3rd Generation IRM be calibrated on the basis of US TFP trends. Clearly, it would be ideal if this productivity factor was set directly using Ontario data rather than a US proxy, but this is currently not feasible. Data are currently only available to calculate TFP trends for the

Figure 1


Comparative TFP Experience
US and Ontario Power Distributors
1.200
1.150
1.100
1.050
1.000
0.950
0.900
TFP Level
1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006
Year
US
Ontario Scenario 2
Ontario Scenario 3

Ontario industry since 2002. Data limitations have made it impossible to extend PEG's TFP to earlier years, including the 1988-97 years used to establish the productivity factor in 1st Generation IRM.

It may be argued that the Ontario industry's 2002-2006 TFP growth is a reasonable estimate of the annual TFP gains the Ontario industry can be expected to achieve in 3rd Generation IRM. PEG believes there are at least four reasons that the 0.01% average TFP gain for Ontario distributors in these years would not be an appropriate productivity factor for 3rd Generation IRM. First, we believe there is an identifiable bias in this TFP measure which unfortunately cannot be rectified given currently available information. Second, the quality of these TFP measures is diminished by the lack of available capital additions data. Third, 2002-2006 was a period of transition and profound regulatory change. These changes created a number of cost pressures for Ontario distributors that may not persist (on an ongoing, *rate of change* basis) in 3rd Generation IRM. Fourth, the 2002-2006 period includes only four years of TFP changes, which is not a long enough period to compute a reliable, long-run TFP trend. Recall that in the first half of the 1988-97 period, measured TFP growth in Ontario was also essentially flat and, in fact, was slightly negative. If the -0.1% TFP trend for 1988-93 had been the basis for a productivity factor in a hypothetical incentive regulation plan in effect for the following four years, it would have underestimated the industry's average TFP growth in these years by more than 2% per annum. The 1st Generation IRM developed a more reasonable X factor by using data from both the 1988-93 period (where industry TFP declined) and the 1993-97 period (where TFP increased). This experience from Ontario demonstrates the risks of relying on too short a sample period when setting a productivity factor.

PEG therefore believes the long-run TFP trend for US distributors is the most appropriate estimate of the productivity factor for 3rd Generation IRM. As previously discussed, when selecting an appropriate time period for measuring long-run TFP trends, it is important for TFP to be estimated over a period that is long enough to balance the year-to-year fluctuations in TFP change. At the same time, the sample should not be so long that it includes information that is "stale" *i.e.* conditions in the distant past rather than recent TFP developments. In most regulatory proceedings, a sample period of about 10 years has been viewed as providing a reasonable balance of these two considerations. It is also important in regulatory proceedings for the start and end points of the sample period not to be impacted by transitory conditions, such as abnormal economic or weather conditions, which can in turn distort measured TFP trends.

PEG has used a rigorous methodology for determining the most appropriate "start point" to be used for estimating long-run TFP trends. The end date for our US TFP research is 2006. Our methodology is designed to select a start date where economic and weather conditions are as similar as possible to those that prevailed in 2006. Electric distributors' output (particularly kWh deliveries) in any given year is particularly sensitive to overall economic activity and weather conditions. Economic growth affects the demand for electricity in nearly all end uses, and weather greatly influences customers' demands for space heating and space cooling.[22]

PEG's start date analysis was based on a comparison of economic activity and weather variables in various years relative to the values of those variables in 2006. Our measure of overall economic activity was the US unemployment rate, as reported by the US Bureau of Economic Analysis. We also gathered data on cooling degree days (CDD, a measure of summer weather severity) and heating degree days (HDD, a measure of winter weather severity) from the US Climatic Center and mapped them to individual utilities in our sample. We then regressed each distributor's (natural log) of TFP in a given year on the (natural logs) of the unemployment rate, CDD and HDD. The coefficients on this regression established the relative impact of each of these variables on a distributor's measured TFP level in a given year. We found that there was a statistically significant relationship between all three of these variables and TFP levels, and in all cases the coefficients had the expected signs.

This regression was then used to aggregate the relative importance of these three factors on TFP growth. For the overall sample, we computed how the values for the unemployment rate, CDD and HDD in each year between 1990 and 1996 compared to the values for these variables in 2006.[23] For each variable, this relative difference (in logarithmic terms) was weighted by its regression coefficient. The results were then summed to obtain an

[22] Electricity is the overwhelming energy source for space cooling. Electricity competes with natural gas for space heating in certain parts of the US, particularly in warmer climates.

[23] Our start point analysis did not consider years after 1996 because we believed it was necessary to have at least 10 years of TFP change to compute a long-run TFP trend.

overall measure of the similarity of conditions in each year from 1990 to 1996 and those same conditions in 2006.

This start data analysis is summarized in Table 13. It can be seen that 1995 is the year that is most similar to the end-date for our TFP analysis (2006). Our analysis therefore indicates that the most appropriate period for estimating the long-run TFP trend for US power distributors is 1995-2006. Over this period, TFP growth for the US electric distribution industry grew at 0.88% per annum.

PEG concludes that the long-run TFP trend for US power distributors is 0.88% per annum. Our analysis shows that the TFP experience for the US and Ontario industries have been generally similar. This in turn implies that the US distributors' long-run TFP trend of 0.88% would a reasonable estimate for a productivity factor in 3rd Generation IRM. It is noteworthy that this value is nearly identical to the TFP growth estimated for Ontario distributors in 1st Generation IRM. PEG believes the similarity of the US industry's long-run TFP trend and the TFP trend that was previously estimated for the Ontario industry increases the robustness and credibility of this estimate.

PEG recommends that the 0.88% productivity factor apply to all distributors in the Province. We recognize that this estimate of TFP growth does not account for some factors – especially differences in investment requirements – that can vary across distributors and impact their TFP growth. However, PEG believes it is more appropriate for any diversity in capital requirements among distributors to be accommodated through the capital modules to be established in the 3rd Generation IRM framework rather than adjusting the X factors to reflect these requirements. One reason is that adjusting the X factor and allowing for separate capital modules could lead to a kind of "double counting" in the IRM of the costs of capital replacements. We also believe that it would not be warranted to make arbitrary adjustments to the recommended productivity factor to reflect potential differences in capital investment. Especially because the 3rd Generation IRM is designed to provide a firm foundation for ongoing incentive regulation in the Province, it is important for any proposed productivity factor to be supported by objective, high quality data and rigorous empirical techniques and not to be determined in an arbitrary manner.

Table 13

Start Date Analysis for Determining Long Run TFP Trend

Year	Heating Degree Days	Cooling Degree Days	Unemployment Rate	% Difference from 2006 Conditions
1990	4,016	1,260	5.6	-1.44%
1991	4,200	1,331	6.9	-1.62%
1992	4,441	1,040	7.5	-3.07%
1993	4,700	1,218	6.9	-1.72%
1994	4,483	1,220	6.1	-1.50%
1995	4,531	1,293	5.6	-0.87%
1996	4,713	1,180	5.4	-1.13%
1997	4,542	1,156	4.9	-1.08%
1998	3,951	1,410	4.5	-0.18%
1999	4,169	1,297	4.2	-0.25%
2000	4,460	1,229	4.0	-0.17%
2001	4,223	1,245	4.7	-0.79%
2002	4,284	1,393	5.8	-0.75%
2003	4,460	1,290	6.0	-1.15%
2004	4,224	1,260	5.5	-1.20%
2005	4,290	1,232	5.1	-1.02%
2006	4,315	1,397	4.6	0.00%

Coefficients	lhdd	lcdd	lur
Parameters	0.0352	0.0563	-0.0309
T-statistic	5.0607	7.6498	-1.8291

4. Selecting Consumer Dividends

4.1 Methodological Approach

The second main component of the X factor is the consumer dividend. Our previous discussion shows that there is a merit in choosing higher consumer dividends for relatively less efficient utilities and lower dividends for more efficient firms. Benchmarking evidence can be useful for assessing utilities' relative efficiency and hence for selecting appropriate consumer dividends. However, as discussed in Chapter Two, PEG believes it is usually more appropriate to use benchmarking evidence to inform regulators' judgment on suitable consumer dividends rather than linking dividend levels directly, and mechanistically, to the outcomes of benchmarking studies. PEG therefore believes it is both inevitable and desirable for consumer dividend levels to be based partly on judgment, but judgments will be less arbitrary and more appropriate to individual utilities' circumstances when they are informed by sound benchmarking evidence.

This chapter will present an illustrative example of the method that PEG intends to use to select consumer dividend levels. It is currently not possible to provide final recommendations for this component of the X factor because PEG's comparative cost research is still in progress, and our techniques and benchmarking results are being refined. Nevertheless, it is expected that this research will be completed within the time frame of 3rd Generation IRM and can therefore be used as the basis for final consumer dividend recommendations.

PEG's illustrative consumer dividend levels are informed by our comparative cost analyses of Ontario distributors' OM&A cost levels. PEG has undertaken a number of OM&A benchmarking studies for distributors in Ontario using index-based and econometric techniques. Our assessments of firms' relative cost performance are generally consistent for different types of benchmarking methods. While PEG has examined only OM&A costs rather than total costs, it is currently not possible to undertake rigorous evaluations of capital costs and, therefore, total costs for Ontario electricity distributors because of the paucity of high quality capital data. It is also likely that, in the short run, a substantial portion of utilities' ability to achieve incremental TFP gains will be driven by efficiencies that can be made with respect to OM&A inputs. PEG's OM&A comparative cost analyses can therefore represent a feasible and appropriate source of benchmarking evidence that may be used to inform choices for consumer dividends for the 3rd Generation IRM although, as better information becomes available, it may be desirable to transition to more comprehensive benchmarking evaluations in future IR applications.

Our illustrative consumer dividend analysis has also been informed by the regulatory precedents. In particular, we drew on the approaches that have been used in two very diverse jurisdictions – Massachusetts and New Zealand – for using benchmarking evidence to inform choices for consumer dividend levels. The actual values of consumer dividends for every Ontario distributor are within the range of values selected in other IR plans and, in fact, the average consumer dividend value of 0.28% is below the average consumer dividend in index-based PBR plans in North America. We believe this is appropriate since the benchmarking evidence applies to OM&A costs only and therefore reflects only some of the inputs the distributors can use to achieve incremental TFP gains. PEG has "scaled" its range of intended consumer dividends to reflect the fact our benchmarking studies apply to only a portion of distributors' costs.

4.2 Review of OM&A Cost Benchmarking

PEG has essentially undertaken two types of OM&A benchmarking comparisons. The first was an econometric cost evaluation, and the second was a comparison of OM&A unit cost indexes. Below we briefly describe the results for each of these analyses. [24]

For the econometric benchmarking evaluation, PEG developed two short run cost models in which distributors' OM&A cost model were regressed on business condition variables that were expected to impact OM&A cost levels but were largely beyond management control. The cost models were then used to generate OM&A cost predictions for each distributor using data on its business condition variables. For each model, ninety percent confidence intervals were then constructed around the distributor's OM&A cost prediction, and the distributor's actual OM&A costs were compared to the predicted cost and confidence intervals. If the distributor's actual costs were below the lower confidence level, the firm is a significantly superior cost performer on that model since there is a statistically significant difference between the firm's predicted cost and its (lower) actual cost. By the

[24] Much more detail on PEG's comparative cost methodologies and results can be found in our April 27, 2007 report. This report is available at the Board's website.

same token, if the distributor's actual costs were above the upper confidence level, the firm is a significantly inferior cost performer on that model since there is a statistically significant difference between the firm's predicted cost and its (higher) actual cost. If a utility's actual cost is within the confidence interval, we cannot reject the hypothesis that the firm's actual cost differs from its predicted cost and the utility is said to be an average cost performer.

PEG's econometric benchmarking of Ontario distributors' OM&A costs are summarized in Tables 14 and 15. Table 14 presents the results of our "double log" model. Table 15 presents the results of a translog OM&A cost specification.

Table 16 presents the results of the econometric benchmark evaluations using the translog model. The significantly superior performers appear near the top of this table. Seventeen distributors were found to be significantly superior OM&A cost performers on this model. Twelve distributors were identified as being significantly inferior. The remaining 57 distributors were average OM&A cost performers, meaning it was not possible to reject the hypothesis that these distributors' actual OM&A cost was equal to its predicted cost.

The second benchmarking comparison uses OM&A unit cost and productivity indexes. These unit cost indexes divide each distributors' reported OM&A by an OM&A costs in each year by an associated OM&A input price index for that year. This deflated OM&A cost level is then divided by comprehensive output quantity index for the distributor. We then compared each firm's average OM&A unit cost over the 2002-2006 period to the average OM&A unit cost for its designated peer group. These peer groups are described in detail in PEG's comparative cost report and reflect PEG's econometric results on variables that are significant cost drivers of OM&A costs yet not captured directly in the unit cost or productivity indexes.

Distributors are grouped on the basis of region and peers that are more therefore likely to face similar input price and forestation challenges. Within each region, utilities are grouped by size to reflect the potential for scale economies. They are further sorted to reflect different degrees of undergrounding and whether growth in their territories is rapid or more modest. This informal application of the econometric results resulted in 14 peer groups. The OM&A unit cost and productivity indexes can yield more reliable measures of a distributor's operating performance by taking the ratio of each utility's average index value for the last three years to the average for the corresponding peer group. That is because the peer groups

Table 14

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

Table 15

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

Table 16

Effects of Cost Performance: Translog & Double Log Models

	Years Benchmarked	Translog Model: Actual/Predicted [A]	Translog Model: Deviation Percentage [A-1]	Translog Model: P-Value	Translog Model: Excess Cost in $	Translog Model: Rank	Double Log Model: Actual/Predicted [A]	Double Log Model: Deviation Percentage [A-1]	Double Log Model: P-Value	Double Log Model: Excess Cost in $	Double Log Model: 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 16, continued

Effects of Cost Performance: Translog & Double Log Models

		Translog Model					Double Log Model				
	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).

provide important controls for business conditions that are not provided by the indexes themselves.

Table 17 presents the OM&A and unit cost indexes that are constructed for the distributors. Table 18 presents the outcome of the productivity level benchmarking analysis. Companies here are ranked by the percentage difference between their average OM&A index value to the average OM&A index for their peer group. Companies that have lower OM&A unit cost index values, relative to their peer group average, are judged to be more efficient OM&A cost performers. Hence, using this benchmarking method, Hydro Hawkesbury is judged to the most efficient OM&A cost performer, with an OM&A index value that is 54.1% below its peer group average. It should also be noted that Hydro One does not appear in this Table because it had no identified peers to which it could be compared.

The OM&A unit cost rankings in Table 18 are comparable to those that result from the econometric models, reported in Table 16. Inspecting the results, it can be seen that the rankings from the indexing and econometric work are broadly similar. 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. The coefficient for the two rankings is around 0.70, depending on which models are used. This supports the notion that the rankings are similar but involve some differences. When these results differ, we believe that the results from direct econometric benchmarking are generally more accurate.

4.3 Benchmarking Evidence and Illustrative Consumer Dividends

In our illustrative example, PEG used the two sets of benchmarking results to identify five separate cohorts within the industry that differ in terms of OM&A cost efficiency. These groups were defined below and ranked in descending order of relative efficiency (with the most efficient cohort listed first):

Table 17

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 17, continued

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
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 18

Performance Rankings Based on Unit Cost Indexes

	Average / Group Average[1] [A]	Percentage Differences[1] [A - 1]	Implied Cost Surplus (Savings) per year[1]	Efficiency Ranking[1]
Hydro Hawkesbury	**0.459**	-54.1%	-$361,878	1
Lakefront Utilities	**0.685**	-31.5%	-$495,139	2
Renfrew Hydro	**0.692**	-30.8%	-$234,797	3
Chatham-Kent Hydro	**0.708**	-29.2%	-$1,406,956	4
Hydro Ottawa	**0.714**	-28.6%	-$10,225,580	5
Hydro 2000	**0.717**	-28.3%	-$58,141	6
Hydro One Brampton Networks	**0.753**	-24.7%	-$3,487,297	7
Tay Hydro Electric Distribution	**0.761**	-23.9%	-$185,014	8
Festival Hydro	**0.762**	-23.8%	-$712,162	9
Barrie Hydro Distribution	**0.778**	-22.2%	-$1,723,605	10
Oakville Hydro Electricity Distribution	**0.791**	-20.9%	-$1,959,601	11
Kitchener-Wilmot Hydro	**0.805**	-19.5%	-$1,958,803	12
Hearst Power Distribution	**0.818**	-18.2%	-$103,573	13
Espanola Regional Hydro Distribution	**0.827**	-17.3%	-$141,768	14
Northern Ontario Wires	**0.830**	-17.0%	-$286,793	15
Niagara-on-the-Lake Hydro	**0.848**	-15.2%	-$207,280	16
Tillsonburg Hydro	**0.852**	-14.8%	-$209,218	17
Peterborough Distribution	**0.863**	-13.7%	-$751,589	18
Sioux Lookout Hydro	**0.868**	-13.2%	-$126,617	19
Cambridge and North Dumfries Hydro	**0.873**	-12.7%	-$926,558	20
Oshawa PUC Networks	**0.873**	-12.7%	-$917,945	21
Grimsby Power	**0.882**	-11.8%	-$171,565	22
Norfolk Power Distribution	**0.888**	-11.2%	-$414,967	23
Fort Frances Power	**0.892**	-10.8%	-$105,146	24
Rideau St. Lawrence Distribution	**0.897**	-10.3%	-$125,956	25
Middlesex Power Distribution	**0.901**	-9.9%	-$135,000	26
Parry Sound Power	**0.902**	-9.8%	-$94,924	27
Wellington North Power	**0.903**	-9.7%	-$90,589	28
Lakeland Power Distribution	**0.903**	-9.7%	-$197,119	29
Welland Hydro-Electric System	**0.909**	-9.1%	-$340,795	30
West Nipissing Energy Services	**0.913**	-8.7%	-$58,782	31
Orangeville Hydro	**0.926**	-7.4%	-$122,843	32
Newmarket Hydro	**0.926**	-7.4%	-$352,696	33
Innisfil Hydro Distribution Systems	**0.926**	-7.4%	-$200,934	34
North Bay Hydro Distribution	**0.929**	-7.1%	-$332,269	35
West Perth Power	**0.941**	-5.9%	-$26,599	36
COLLUS Power	**0.952**	-4.8%	-$131,249	37
Guelph Hydro Electric Systems	**0.964**	-3.6%	-$277,181	38
Midland Power Utility	**0.966**	-3.4%	-$54,350	39
Kingston Electricity Distribution	**0.971**	-2.9%	-$142,567	40
E.L.K. Energy	**0.976**	-2.4%	-$40,292	41
Toronto Hydro-Electric System	**0.980**	-2.0%	-$2,810,567	42
Fort Erie	**0.998**	-0.2%	-$5,836	43
PowerStream	**1.002**	0.2%	$72,384	44
Thunder Bay Hydro Electricity Distribution	**1.004**	0.4%	$38,915	45
Wasaga Distribution	**1.006**	0.6%	$9,872	46
Bluewater Power Distribution	**1.009**	0.9%	$66,406	47
Woodstock Hydro Services	**1.011**	1.1%	$33,312	48
Newbury Power	**1.020**	2.0%	$873	49
Greater Sudbury Hydro	**1.021**	2.1%	$177,843	50
St. Thomas Energy	**1.021**	2.1%	$62,282	51
Waterloo North Hydro	**1.026**	2.6%	$211,230	52
Milton Hydro Distribution	**1.027**	2.7%	$103,406	53
Horizon Utilities	**1.033**	3.3%	$1,055,318	54
Haldimand County Hydro	**1.037**	3.7%	$192,145	55

[1] Lower values imply better performance.

Table 18, continued

Performance Rankings Based on Unit Cost Indexes

	Average / Group Average[1] [A]	Percentage Differences[1] [A - 1]	Implied Cost Surplus (Savings) per year[1]	Efficiency Ranking[1]
PUC Distribution	**1.046**	4.6%	$317,784	56
Brant County Power	**1.050**	5.0%	$143,560	57
Veridian Connections	**1.054**	5.4%	$1,014,544	58
Burlington Hydro	**1.055**	5.5%	$573,066	59
Terrace Bay Superior Wires	**1.057**	5.7%	$15,460	60
Orillia Power Distribution	**1.059**	5.9%	$174,579	61
Halton Hills Hydro	**1.070**	7.0%	$275,027	62
Niagara Falls Hydro	**1.079**	7.9%	$591,816	63
Ottawa River Power	**1.079**	7.9%	$150,716	64
London Hydro	**1.081**	8.1%	$1,733,309	65
Peninsula West Utilities	**1.092**	9.2%	$409,765	66
Westario Power	**1.096**	9.6%	$412,169	67
Clinton Power	**1.115**	11.5%	$45,689	68
Atikokan Hydro	**1.127**	12.7%	$82,822	69
Enersource Hydro Mississauga	**1.132**	13.2%	$5,092,480	70
Eastern Ontario Power	**1.142**	14.2%	$170,445	71
Centre Wellington Hydro	**1.165**	16.5%	$228,286	72
Cooperative Hydro Embrun	**1.180**	18.0%	$60,476	73
Whitby Hydro Electric	**1.194**	19.4%	$1,336,172	74
Kenora Hydro Electric	**1.200**	20.0%	$245,993	75
Essex Powerlines	**1.205**	20.5%	$1,210,788	76
Brantford Power	**1.210**	21.0%	$1,350,325	77
Chapleau Public Utilities	**1.231**	23.1%	$104,920	78
ENWIN Powerlines	**1.252**	25.2%	$4,788,536	79
Port Colborne	**1.284**	28.4%	$899,027	80
West Coast Huron Energy	**1.321**	32.1%	$420,591	81
Erie Thames Powerlines	**1.432**	43.2%	$1,805,293	82
Dutton Hydro	**1.471**	47.1%	$80,438	83
Grand Valley Energy	**1.517**	51.7%	$104,339	84
Great Lakes Power	**1.660**	66.0%	$4,423,323	85

[1] Lower values imply better performance.

- Group I: The 17 firms defined as significantly superior cost performers on the econometric cost model
- Group II: The 15 firms that were ranked in the top third on the OM&A unit cost rankings in Table 18 (*i.e.* between numbers 1 and 29) but were not significantly superior cost performers on the econometric cost model
- Group III: The 26 firms that were ranked in the middle third on the OM&A unit cost rankings in Table 18 (*i.e.* between numbers 30 and 58) but were not significantly superior cost performers on the econometric cost model
- Group IV: The 16 firms that were ranked in the lower third on the OM&A unit cost rankings in Table 18 (*i.e.* between numbers 31 and 85) but were not significantly *inferior* cost performers on the econometric cost model
- Group V: The 12 firms that were identified as significantly inferior cost performers on the econometric cost model

This approach combines elements of the New Zealand and Massachusetts approaches for using benchmarking evidence to assess relative efficiency and inform choices for consumer dividends. As in New Zealand, index-based methods were used to rank distributors on the basis of relative efficiency and to split the industry into three groups based on these rankings. In addition, we used the Massachusetts approach of looking to econometric techniques and evidence of statistically significant differences between actual and predicted cost. This benchmarking evidence was used to identify statistically significant superior cost performers in the top third of companies (as determined by the OM&A unit cost rankings) as well as statistically significant inferior cost performers in the bottom third. Because we believe the econometric evidence is more reliable than the unit cost measures, statistical evidence of either significantly superior or significantly inferior cost performance is given primacy over the benchmarking evaluation that would result using only the indexing measures.

Given these identified efficiency cohorts, PEG's methodology is to select consumer dividends that are the same for all firms in a given cohort but differ between cohorts. Smaller dividends will be assigned to the more efficient cohorts. More particularly, PEG's illustrative example uses the following consumer dividend values:

Group Number	Consumer Dividend
Group I	0
Group II	0.15%
Group III	0.3%
Group IV	0.45%
Group V	0.6%

When these values are applied to the specific companies in each group, this illustrative example leads to the consumer dividend levels that are summarized in Table 19.

These particular values obviously reflect a degree of judgment, but they are also supported by precedents from North American PBR plans. Consumer dividends in approved North American PBR plans have ranged from 0 to 1.0% with an average value of about 0.5%. PEG has scaled down both the upper end and the lower end of the approved consumer dividend range by 40% (*e.g.* reducing the maximum consumer dividend from 1% to 0.6%) to reflect the fact that OM&A reflects somewhat less than half of overall distribution cost but, because many capital costs are fixed in the short run, somewhat more than half of the inputs that can likely be varied immediately to achieve incremental TFP gains. The average consumer dividend that results from our illustrative example is 0.28%, which is also about 40% below the average dividend in approved plans. PEG therefore believes that the approach outlined here is a reasonable means for setting appropriate consumer dividends Our approach also leads to results that are well within the mainstream of North American regulation and appropriately scaled to the inputs examined in the benchmarking studies that are used to inform the selection of dividend levels.

Table 19

Assigned Consumer Dividends: Illustrative Example

Company	Group Number	Value Consumer Dividend (%)	Group Members
Hydro 2000	I	0.00	
Hydro One Brampton Networks	I	0.00	
Hydro Hawkesbury	I	0.00	
Hearst Power	I	0.00	
Kitchener-Wilmot Hydro	I	0.00	
Lakefront Utilities	I	0.00	
Lakeland Power	I	0.00	
Port Colborne (CNP)	I	0.00	
Barrie Hydro	I	0.00	
Grimsby Power	I	0.00	
Cooperative Hydro Embrun	I	0.00	
Oshawa PUC Networks*	I	0.00	
Cambridge & North Dumfries	I	0.00	
Niagara-on-the-Lake Hydro	I	0.00	
Chatham-Kent Hydro	I	0.00	
Renfrew Hydro	I	0.00	
Orangeville Hydro	I	0.00	17
Halton Hills Hydro	II	0.15	
Festival Hydro	II	0.15	
Wasaga Distribution	II	0.15	
Tay Hydro Electric Distribution	II	0.15	
North Bay Hydro Distribution	II	0.15	
PUC Distribution	II	0.15	
Hydro Ottawa	II	0.15	
Greater Sudbury Hydro	II	0.15	
COLLUS Power	II	0.15	
Thunder Bay Hydro Electricity Dist.	II	0.15	
Peterborough Distribution	II	0.15	
Powerstream	II	0.15	
Ottawa River Power	II	0.15	
Horizon Utilities	II	0.15	
Burlington Hydro	II	0.15	15
Innisfil Hydro Distribution Systems	III	0.30	
E.L.K. Energy	III	0.30	
St. Thomas Energy	III	0.30	
Oakville Hydro Electricity Distribution	III	0.30	
Kenora Hydro Electric	III	0.30	
Guelph Hydro Electric Systems	III	0.30	
West Perth Power	III	0.30	
Sioux Lookout Hydro	III	0.30	
Norfolk Power Distribution	III	0.30	
Espanola Regional Hydro Distribution	III	0.30	
Bluewater Power Distribution	III	0.30	
Waterloo North Hydro	III	0.30	

Table 19, continued

Assigned Consumer Dividends: Illustrative Example

Company	Group Number	Value Consumer Dividend (%)	Group Members
Hydro One Networks	III	0.30	
London Hydro	III	0.30	
Peninsula West Utilities	III	0.30	
Woodstock Hydro Services	III	0.30	
Northern Ontario Wires	III	0.30	
Fort Frances Power	III	0.30	
Milton Hydro Distribution	III	0.30	
Newbury Power	III	0.30	
Enersource Hydro Mississauga	III	0.30	
Orillia Power Distribution	III	0.30	
Kingston Electricity Distribution	III	0.30	
Fort Erie (CNP)	III	0.30	
Whitby Hydro Electric	III	0.30	
Wellington North Power	III	0.30	26
Welland Hydro-Electric System	IV	0.45	
Middlesex Power Distribution	IV	0.45	
Brantford Power	IV	0.45	
Newmarket Hydro	IV	0.45	
West Nipissing Energy Services	IV	0.45	
Haldimand County Hydro	IV	0.45	
Clinton Power	IV	0.45	
Rideau St. Lawrence Distribution	IV	0.45	
Parry Sound Power	IV	0.45	
Terrace Bay Superior Wires	IV	0.45	
Centre Wellington Hydro	IV	0.45	
Grand Valley Energy	IV	0.45	
Dutton Hydro	IV	0.45	
Atikokan Hydro	IV	0.45	
Eastern Ontario Power (CNP)	IV	0.45	
Great Lakes Power	IV	0.45	16
Westario Power	V	0.60	
Niagara Falls Hydro	V	0.60	
Toronto Hydro-Electric System	V	0.60	
Essex Powerlines	V	0.60	
Veridian Connections	V	0.60	
ENWIN Powerlines	V	0.60	
West Coast Huron Energy	V	0.60	
Brant County Power	V	0.60	
Tillsonburg Hydro	V	0.60	
Chapleau Public Utilities	V	0.60	
Midland Power Utility	V	0.60	
Erie Thames Powerlines	V	0.60	12
Weighted average consumer dividend	**All**	**0.28**	

5. Concluding Remarks

PEG's illustrative, overall X factors are presented in Table 20. This table combines the two elements of the X factor. The first is a common TFP trend of 0.88%. The second is a consumer dividend that varies by company between 0 and 0.6%. The overall X factor would therefore vary between 0.88% and 1.48% and, for the industry as a whole, would average 1.16%.

PEG's recommendations are based on empirical techniques that we believe strike an appropriate balance between rigor, objectivity and feasibility given the data currently available in Ontario. Our recommendations have also been informed by economic reason, approved precedents in North America and valuable regulatory approaches around the world. Our methods have also built on information sources and techniques that PEG has developed in our comparative cost work for Ontario electricity distributors, although it should be emphasized that this work is not complete. The consumer dividend values presented in this report are for illustrative purposes only, although they do demonstrate PEG's intended approach and a first approximation of the outcome.

It may also be instructive to compare PEG's recommendations with the X factors that were approved in 1st Generation and 2nd Generation IRM. In the first incentive regulation plan, the Board approved an X factor of 1.5% for all distributors. Under PEG's approach, the X factor for every distributor would be below this value. The 2nd Generation IRM selected a 1% X factor for all distributors, based largely on judgment rather than any independent empirical analysis undertaken specifically in that proceeding. Under PEG's approach, all companies that are deemed to be significantly superior cost performers would see their X factor reduced from its current 1% value. Companies in Group II would see a very small .03% increase in their X factor. It is not known at present how many or which companies will be in these groups, but in the illustrative example a total of 32 distributors, or nearly 40% of the industry, would be in these two groups and therefore experience a reduction, or minimal increase, in their X factors. On average, PEG's proposed X factor for 3rd Generation IRM would be between those approved in the previous two incentive regulation applications.

PEG also believes that the methods used to develop these X factor recommendations in 3rd Generation IRM can provide a solid foundation for future incentive regulation

Table 20

Assigned X Factors: Illustrative Example

Company	Group Number	Value Consumer Dividend (%)	Group Members
Hydro 2000	I	0.88	
Hydro One Brampton Networks	I	0.88	
Hydro Hawkesbury	I	0.88	
Hearst Power	I	0.88	
Kitchener-Wilmot Hydro	I	0.88	
Lakefront Utilities	I	0.88	
Lakeland Power	I	0.88	
Port Colborne (CNP)	I	0.88	
Barrie Hydro	I	0.88	
Grimsby Power	I	0.88	
Cooperative Hydro Embrun	I	0.88	
Oshawa PUC Networks*	I	0.88	
Cambridge & North Dumfries	I	0.88	
Niagara-on-the-Lake Hydro	I	0.88	
Chatham-Kent Hydro	I	0.88	
Renfrew Hydro	I	0.88	
Orangeville Hydro	I	0.88	17
Halton Hills Hydro	II	1.03	
Festival Hydro	II	1.03	
Wasaga Distribution	II	1.03	
Tay Hydro Electric Distribution	II	1.03	
North Bay Hydro Distribution	II	1.03	
PUC Distribution	II	1.03	
Hydro Ottawa	II	1.03	
Greater Sudbury Hydro	II	1.03	
COLLUS Power	II	1.03	
Thunder Bay Hydro Electricity Dist.	II	1.03	
Peterborough Distribution	II	1.03	
Powerstream	II	1.03	
Ottawa River Power	II	1.03	
Horizon Utilities	II	1.03	
Burlington Hydro	II	1.03	15
Innisfil Hydro Distribution Systems	III	1.18	
E.L.K. Energy	III	1.18	
St. Thomas Energy	III	1.18	
Oakville Hydro Electricity Distribution	III	1.18	
Kenora Hydro Electric	III	1.18	
Guelph Hydro Electric Systems	III	1.18	
West Perth Power	III	1.18	
Sioux Lookout Hydro	III	1.18	
Norfolk Power Distribution	III	1.18	
Espanola Regional Hydro Distribution	III	1.18	
Bluewater Power Distribution	III	1.18	
Waterloo North Hydro	III	1.18	

Table 20, continued

Assigned X Factors: Illustrative Example

Company	Group Number	Value Consumer Dividend (%)	Group Members
Hydro One Networks	III	1.18	
London Hydro	III	1.18	
Peninsula West Utilities	III	1.18	
Woodstock Hydro Services	III	1.18	
Northern Ontario Wires	III	1.18	
Fort Frances Power	III	1.18	
Milton Hydro Distribution	III	1.18	
Newbury Power	III	1.18	
Enersource Hydro Mississauga	III	1.18	
Orillia Power Distribution	III	1.18	
Kingston Electricity Distribution	III	1.18	
Fort Erie (CNP)	III	1.18	
Whitby Hydro Electric	III	1.18	
Wellington North Power	III	1.18	26
Welland Hydro-Electric System	IV	1.33	
Middlesex Power Distribution	IV	1.33	
Brantford Power	IV	1.33	
Newmarket Hydro	IV	1.33	
West Nipissing Energy Services	IV	1.33	
Haldimand County Hydro	IV	1.33	
Clinton Power	IV	1.33	
Rideau St. Lawrence Distribution	IV	1.33	
Parry Sound Power	IV	1.33	
Terrace Bay Superior Wires	IV	1.33	
Centre Wellington Hydro	IV	1.33	
Grand Valley Energy	IV	1.33	
Dutton Hydro	IV	1.33	
Atikokan Hydro	IV	1.33	
Eastern Ontario Power (CNP)	IV	1.33	
Great Lakes Power	IV	1.33	16
Westario Power	V	1.48	
Niagara Falls Hydro	V	1.48	
Toronto Hydro-Electric System	V	1.48	
Essex Powerlines	V	1.48	
Veridian Connections	V	1.48	
ENWIN Powerlines	V	1.48	
West Coast Huron Energy	V	1.48	
Brant County Power	V	1.48	
Tillsonburg Hydro	V	1.48	
Chapleau Public Utilities	V	1.48	
Midland Power Utility	V	1.48	
Erie Thames Powerlines	V	1.48	12
Weighted average X factor	**All**	**1.16**	

proceedings in Ontario. Our approach brings together a wealth of techniques and alternative data sources that can be useful in future IR applications. These techniques include index-based measures of industry TFP trends in the US and Ontario and econometric and index-based benchmarking of Ontario distributors' OM&A cost performance. At the same time, our methodology is flexible enough to allow the techniques used to estimate X factors to evolve and/or be refined as new or additional information becomes available in Ontario. For example, if sufficient time series data are developed on capital additions and other key variables, indexing methods can be used to estimate long-run TFP trends using Ontario data. Improved capital data could also allow econometric and index-based methods to benchmark Ontario distributors' *total* costs instead of only their OM&A costs. Benchmarking can also in principle be extended to include comparisons between Ontario and US utilities in addition to intra-Ontario comparisons.

Towards these ends, PEG believes it would be valuable to improve data sources in Ontario. Data enhancements are especially warranted for capital additions and other variables needed to develop measures of TFP trends and total electricity distribution costs. It would also be valuable to try to link the more recent data in Ontario with the data sources used to estimate TFP trends in the 1st Generation IRM. Doing so should make it more feasible to rely entirely on Ontario data for estimating TFP trends in future applications of electricity distribution incentive regulation in the Province. Improved capital cost measures could also enable total cost benchmarking, rather than OM&A benchmarking, to inform the choices for future consumer dividends.

Appendix One: Review of Important Incentive Regulation Precedents

A1.1 Ontario

In recent years, regulatory authorities in Ontario have generally encouraged PBR as an alternative to cost of service regulation. The first application of PBR in Ontario was for Consumers (now Enbridge) Gas. In 1999 the Ontario Energy Board (OEB) approved a targeted performance based regulation (TPBR) plan for Consumers Gas's operating expenses (opex). At the time, the OEB described this as the next step on the transition to comprehensive PBR. The TPBR plan adjusted Enbridge's opex costs using an indexing formula. The inflation factor in the formula was the Ontario CPI, although the OEB said that, in principle, it supported using industry-specific inflation measures.

The general X factor in Enbridge's TPBR plan was equal to the 0.63%. This value was computed as the company's own trend in partial factor productivity (PFP) for opex inputs. Partial factor productivity growth is analogous to TFP except it applies to only a single set of inputs (in this case opex) rather than all inputs.

The X factor in the TPBR also included a stretch factor of 0.47%. This value was based on judgment and was not discussed explicitly in the OEB Order. The final X factor in this plan was therefore 1.1%. The plan did not feature an ESM and had a three year term, running from 2000-2002.

When the plan expired, Enbridge did not present an updated PBR proposal. One reason was that the TPBR generated considerable controversy. Enbridge changed its operations significantly while the TPBR was in effect, outsourcing several opex services to unregulated affiliates. The plan also did not have an earnings sharing mechanism (ESM), which led some parties to believe that the plan did not generate any tangible, explicit benefits for customers. Because of the controversies it created and its relatively short term, the plan also failed to result in any significant regulatory cost savings for Enbridge. Since the TPBR terminated, and prior to the Gas IRM proceeding, Enbridge has filed a series of traditional cost of service rate cases.

Ontario first implemented comprehensive PBR (*i.e.* PBR that applies to both capital and operating costs) for the Province's electricity distributors. This PBR plan resulted from a Board-sponsored, Province-wide consideration of regulatory issues. Expert opinion was used to guide the process and synthesize input from various parties. These proceedings produced a "Rate Handbook" (Handbook) that presented recommendations for designing PBR for power distributors.

In January 2000, the OEB approved PBR for Ontario's power distributors. In doing so, it wrote that "PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation." Among the desired fundamental shifts was creating incentives that more closely resembled those in a competitive market and making regulated utilities responsible for their investments subject to price cap constraints.

The Rate Handbook developed in this proceeding initially recommended an innovative "menu approach" towards selecting the X factor. Under this approach, a menu of six alternative X factor and allowed return on equity (ROE) combinations were developed, with lower values for X associated with higher allowed ROE levels and *vice versa*. Companies would then be allowed to select the X factor- ROE combination that most appealed to their risk-incentive preferences. However, the OEB rejected this approach as too complex for a first generation PBR plan. It also did not believe that there was a well-developed analytical foundation supporting the specific menu of X factor and ROE combinations. Instead of this menu approach, the OEB opted for a more conventional, PBR plan where a single inflation factor and X factor applied to all electricity distributors.

The first electricity distribution plan used an industry-specific inflation measure rather than an economy-wide inflation measure. Industry-specific inflation measures are specifically tailored to reflect the inflation in prices for inputs that are purchased by the utility industry in question. But to reduce potential price volatility under the plan, the OEB only allowed one-half of the change of capital input prices to be passed through to prices in a given year.

The initial electricity distribution PBR plan also included was a single X factor, which had two separate components. The first was a productivity factor of 1.25%. This value was based on the TFP trend that was estimated for 48 electric distributors in the Province. The estimated TFP trend over the most recent 10 year period was estimated to be 0.86%. The estimated TFP trend over the most recent five year period was estimated to be 2.05%. The OEB believed that some recognition of the industry's most recent productivity experienced should be reflected in the X factor. It therefore set a two-thirds weight on the ten year TFP trend, and a one third weight on the five year TFP trend. This weighted average of industry TFP trends led to a productivity factor of 1.25%.[25]

The PBR plan for Ontario's electricity distributors included a 0.25% consumer dividend for all distributors. The final X factor in this plan was therefore 1.5%. This value was based on judgment.

The electric PBR plan had a three year term, from 2000 to 2002. However, before the plan could run its course, the Provincial government imposed a cap on overall retail electric prices. This cap effectively eliminated any further formula-based distribution price adjustments for distribution services and thus ended the plan.

In 2001, the OEB approved a price indexing PBR plan for Union Gas's gas storage and delivery services. Union had proposed a CPI-X indexing plan with an overall X factor of –0.3%, which would have led to regulated prices rising more rapidly than the rate of CPI inflation. Union's proposed X factor was comprised of a –0.4% TFP trend for the Company's southern operations less a 0.3% economy-wide TFP trend, plus a 0.4% stretch factor. The inflation factor was the GDP-PI. Union's proposal did not include an ESM, but did propose pricing flexibility within two separate baskets of services. Union also recommended that PBR be maintained after the plan's proposed five-year initial term, with the update focusing only on adjusting the parameters of the PBR formula rather than resetting rates on the basis of a COS filing.

The OEB approved a price indexing plan for Union with much different terms than Union had proposed. The approved X factor was equal to 2.5% and was comprised of a 0.9% productivity differential (*i.e.* the industry TFP trend minus the TFP trend for the overall economy), plus a 0.5% stretch factor, and an input price differential of 1.1%.

The OEB said that it relied on a range of TFP measures proposed by intervenors as well as the company's own study when deciding on the productivity trend, although it did not say how its final TFP differential estimate was determined from the specific evidence

[25] The plan also imposed a single earnings sharing mechanism on all electricity distributors in the Province, with 50/50 sharing above the allowed ROE.

presented. One of the reasons the productivity studies presented by intervenors produced generally higher TFP trends than that presented by Union was the weight placed on volumes vis-à-vis customer numbers as outputs in the TFP trend measures. The intervenor studies put less weight on volumes than did the Union Gas TFP study. Volumes per customer have recently been declining in the Province, so all else equal, placing greater weight on volumes will tend to reduce measured TFP growth.

For the input price differential, the OEB relied on Union's evidence showing that its input prices were growing 1.1% less rapidly on average than the GDP-PI. The OEB said that such an input price differential was needed for the plan to reflect the expected input price inflation of the industry. The OEB also rejected Union's pricing flexibility proposal, saying it was not persuaded that such flexibility was needed. The OEB also added an ESM to the plan, with 50/50 sharing of earnings outside a deadband of +/- 100 basis points around the allowed ROE.

The PBR approved for Union Gas included a stretch factor of 0.5%, which was not much different from the 0.4% value proposed by the Company. The OEB did not discuss the basis for this value. The final X factor in this plan of 2.5% therefore differed substantially from that proposed by Union Gas because of two reasons: the incorporation of a substantial input price differential; and a productivity differential that was significantly greater than that proposed by the Company.

The term of the Union PBR plan was three years, from 2001 to 2003. The OEB said it would not limit the scope of factors it might consider when updating the PBR plan, but said it would expect such an update to include a COS study as well as an industry-wide TFP study that included separate TFP trend measures for gas transmission, storage, and distribution. When the plan expired, Union did not present an updated PBR proposal, but rather filed a traditional cost of service case.

In 2004, the OEB undertook another Province-wide examination of regulation for Ontario's natural gas industry that was called the Natural Gas Forum (NGF). The NGF evaluated a number of structural, competitive and regulatory issues for Ontario's natural gas market. As the experience recounted above illustrates, Ontario's natural gas industry experimented with PBR in the years prior to the NGF, but those plans were not updated when they expired and there was instead a move back to cost of service regulation (COSR). One of the threshold issues in the NGF was therefore whether COSR or PBR was a more appropriate framework for Ontario's natural gas industry.

The OEB issued its final report and recommendations on regulation in the Province on March 30, 2005.[26] The OEB concluded, fairly unequivocally, that PBR is superior to COSR. The OEB said its legislated objectives are promoted by a regulatory framework that creates incentives for efficiency improvements, encourages appropriate service quality levels, and facilitates infrastructure investment. It noted that "COSR, as it has been applied in Ontario, presents fewer risks in some respects, but it also lacks strong incentives to increase operating efficiencies and to reduce costs. The regulatory burden of annual or bi-annual rate cases associated with COSR is also high. In contrast, PBR can be designed to create strong performance incentives and to reduce regulatory costs…"[27] At the same time, the OEB pointed out that the parameters of PBR plans must be designed carefully to ensure that they operate effectively. The OEB then laid down several broad guidelines for developing PBR plans. Most importantly, the OEB has said that PBR should:

- Apply to a utility's comprehensive regulated operations rather than being targeted to specific costs (*e.g.* operations and maintenance costs)
- Apply for longer periods than has typically been the case in Ontario
- Be permanent, in the sense that utilities do not have the option of switching back and forth between PBR and COSR plans
- Not involve earnings sharing during the term of a plan
- Examine costs at the end of a plan, and prior to the commencement of a new PBR plan, to see whether cost-based rate adjustments are warranted

Taken together, these guidelines signal a movement towards greater reliance on PBR mechanisms in Ontario.

Since the completion of the NGF, there have been two significant developments in incentive regulation in the Province. The first was the implementation of a second generation incentive regulation mechanism (2nd Generation IRM) for electricity distributors. The details

[26] Ontario Energy Board, *Natural Gas Regulation in Ontario: A Renewed Policy Framework*, A Report on the Ontario Energy Board Natural Gas Forum, March 30, 2005.

[27] Ontario Energy Board, *op cit*, p. 20.

of this mechanism were presented in a Board Report on December 20, 2006. Distribution rates would be subject to index-based changes. The inflation factor used for these changes was the GDP-IPI. The Board noted that this differed from the industry-specific inflation factor used for the first generation incentive regulation plan but decided in favor of economy-wide inflation factors because they were viewed as less controversial and easier to implement. The X factor was 1%, which was considered to be generally consistent with the X factor precedents for energy utility PBR plans in North America.

Some distributors also proposed that there an additional component of the indexing mechanism to recover the costs of incremental capital spending. In its Report, "the Board concludes that there is no need for a capital investment factor in this 2nd Generation IRM plan. Those distributors with an inordinate capital spending program can be accommodated through rebasing."[28] The Board also reiterated its policy, as expressed in the NGF Report, that it does not support earnings sharing mechanisms.

The 2nd Generation IRM is essentially a transitional PBR mechanism that applies until 3rd Generation IRM takes effect. The 2nd Generation IRM will remain in effect until its final application in the 2009 rate year. The rate adjustments under the indexing mechanism apply to all distributors for the 2007 rate year. For 2008, index-based rate adjustments apply to those distributors that have not applied for rate rebasing. For the 2009 rate year, the mechanism applies to the remaining distributors that have not yet applied for, or been subject to, rebasing.

Beginning in 2006, there was also an investigation into calibrating incentive regulation mechanisms for Ontario's gas distribution utilities. The indexing mechanism in these plans will use the GDP-IPI as the inflation factor. The X factors for Union and Enbridge, as well as other components of the incentive regulation framework, have not been determined at the time this report.

A1.2 Massachusetts

The Massachusetts Department of Public Utilities (DPU, or the Department) has traditionally regulated energy utilities in Massachusetts using cost of service regulatory

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[28] *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, December 20, 2006, p. 37.

methods, but it has officially encouraged incentive regulation for energy utilities in Massachusetts. In a statewide proceeding it initiated in 1994, the DPU examined the merits of incentive regulation (also referred to as performance-based regulation in the docket) and cost of service/rate of return (COS/ROR) regulation as alternative means for advancing its traditional goals of safe, reliable and least-cost energy service and for promoting the objectives of economic efficiency, cost control, lower rates and reduced administrative burdens. The DPU noted that

> the defects of traditional COS/ROR regulation are well known. The "cost plus" approach under COS/ROR regulation contributes to (1) lack of incentive for cost control, through its inherent bias favoring expenditures which can be passed through to customers; (2) inflexible and less than efficient pricing; (3) persistent cross-subsidies among service classifications; (4) inefficient allocation of resources; (5) poor asset management; (6) risk-averse management; and (7) disincentives for innovation. COS/ROR is also a costly method of regulation, and is characterized by long lags both in reflecting and controlling actual utility operations and their costs.[29]

Compared with cost of service regulation, the DPU concluded that "five broad classes of potential benefits are associated with incentive regulation: improved X-efficiency; improved allocative efficiency; improved dynamic efficiency; facilitation of new services; and reduced administrative costs."[30] Because of all these potential benefits, the DPU has officially encouraged energy utilities in the State to present performance-based regulatory proposals as part of any rate case that they file.

There have to date been seven PBR plans approved for energy utilities in Massachusetts: 1) Boston Gas in 1997; 2) National Grid in 2000; 3) Berkshire Gas in 2002; 4) Boston Gas in 2003; 5) Blackstone Gas in 2004; 6) NStar Electric in 2005; and 7) Bay State Gas in 2005.[31] All plans apply to unbundled energy distribution operations, as formally-vertically integrated electric utilities in that State were required to divest their generation assets following the restructuring of the Massachusetts electric utility industry in 1998.

[29] DPU Docket 94-158 , p. 9.

[30] DPU Docket 94-158, pp. 52-53.

[31] PEG personnel have testified or provided expert reports in support of the PBR plans of Boston Gas (1997), Boston Gas (2003), Bay State Gas and Nstar Electric. The only other PBR proposal to use expert witness testimony was Berkshire Gas, which relied on the empirical research of PEG personnel to support its proposed X factor.

The X factor approved for Boston Gas in 1997 had four components: (1) a total factor productivity (TFP) differential (i.e., the difference between industry and economy-wide TFP trends); (2) an input price differential (i.e., the difference between economy-wide and industry input prices); (3) a consumer dividend/stretch factor; and (4) an accumulated inefficiencies factor. The first two components reflect the indexing logic presented earlier when an economy-wide inflation measure was employed as the inflation factor. This was the case for Boston Gas, whose proposed inflation factor was the US gross domestic product price index (GDP-PI).

For the 1997 Boston Gas plan, the DPU approved a TFP trend for the gas distribution industry of 0.4%. The "industry" was defined to be gas distributors operating in the Northeast United States. The Department concluded that a regional definition of the industry was appropriate since a cost study was presented which showed that, all else equal, there were statistically significant cost pressures associated with operating in the Northeast. The economy-wide TFP trend was 0.3%, so the TFP differential between the industry and the economy was 0.1%. The input price differential was measured to be –0.1%. The sum of the TFP and input price differentials was therefore zero. The approved consumer dividend/stretch factor was 0.5%; this value was based on judgment. The DPU also added a 1% accumulated inefficiencies (AI) factor, which Boston Gas appealed to the Courts. The Massachusetts Supreme Court ultimately ruled that there was no evidentiary basis for the AI factor and ordered it to be eliminated. The final X factor in the Boston Gas plan was therefore 0.5%. No subsequent PBR plans in the State have featured either proposed or approved accumulated inefficiencies factors.

The industry TFP and input price evidence approved in the Boston Gas proceeding was later used in the indexing proposal from Berkshire Gas. Unlike Boston Gas, Berkshire Gas is a relatively small gas distributor. Berkshire Gas argued that it would not be cost effective for it to undertake a separate TFP study to support its X factor, and that the outcome of such a study would probably not differ dramatically from that presented by Boston Gas in any case. The Department agreed with this position, so the general X factor for Berkshire Gas was the same zero value determined for the TFP and input differentials in the Boston Gas case. The Berkshire plan also included a consumer dividend of 1%, which is the highest approved for a Massachusetts utility. The value of this consumer dividend was based on judgment rather than any explicit empirical evidence.

An updated indexing plan was approved for Boston Gas in 2003. The approved TFP trend for the Northeast gas distribution industry was 0.56%. The TFP trend for the US economy was 0.77%, so the TFP differential was -0.21%. The input price differential approved by the Commission was 0.3%. The approved consumer dividend was equal to 0.3%. This value was based on an econometric benchmarking study submitted by the Company which showed that, after controlling for other independent variables, Boston Gas achieved incremental cost reductions of 0.3% per annum in its previous PBR plan. The Department concluded that 0.3% was a reasonable, lower bound estimate of the value of incremental cost reductions the Company could make in the updated PBR plan.[32] The overall X factor in the updated Boston Gas plan was therefore 0.41%.

A PBR plan was approved for Blackstone Gas in 2004. Unlike the Boston Gas plans in 1997 and 2003, or the Berkshire Gas plan in 2002, the Blackstone plan did not result from formal testimony and a typical rate case proceeding before the DTE. Rather, Blackstone and a number of other intervenors in the case reached a settlement agreement on an appropriate PBR plan. The Blackstone settlement included an overall X factor of 0.5% but did not detail the values for each of the components of the X factor. In light of the recent decision in the Boston Gas case, however, it is reasonable to conclude that the "general" X factor in the Blackstone plan (*i.e.* the value of the X factor excluding the stretch factor, or the sum of the productivity and input price differentials) is approximately equal to the 0.11% value approved in the updated Boston Gas plan.

Both of the PBR plans for Massachusetts power distributors (National Grid and NStar Electric) were also based on settlements. The National Grid PBR plan featured a five year rate freeze followed by five years of rate adjustments that were set based on changes in the power distribution rates of a group of northeast utilities. "Peer price" adjustment mechanisms of this type typically do not require TFP evidence to be calibrated. The plan also included provisions for how rates would be updated when the PBR plan expired. Rates would be rebased on the basis of both a cost of service study and a continued application of the rate indexing mechanism, with a defined sharing of any difference between rates based on

[32] PEG developed and testified in support of this study.

continued application of the existing PBR mechanism and those that would result from purely cost of service methods.

Evidence on the input price and TFP trends of northeast power distributors was presented by NStar. The settlement featured six years of index-based rate adjustments over the 2007-2013 period, where electric rates were adjusted by the growth in GDP-PI minus an X factor. The initial X factor was set at 0.5% and increased by .05% increments in each plan year, reaching a maximum value of 0.75% in the last index-based rate adjustment in 2012. The values of the settlement X factors were broadly supported by and consistent with NSTAR's indexing research.

The most recent PBR plan approved for a Massachusetts gas distributor is for Bay State Gas in 2005. Like Berkshire Gas, Bay State Gas argued that it would not be cost effective for it to undertake a separate TFP study to support its X factor, and that the outcome of such a study would probably not differ dramatically from that presented by Boston Gas in any event. Bay State therefore proposed that the value of its general X factor should be the same 0.11% approved for Boston Gas in 2003. The DTE agreed, and this was the value of the general X factor approved for Bay State Gas. The Department also added a 0.4% consumer dividend. This value was greater than that approved for Boston Gas because the BoGas benchmarking study showed that the Company was a significantly superior cost performer, while Bay State's econometric benchmarking study showed that the Company was an average cost performer. The Department therefore concluded that Bay State had greater opportunity to achieve incremental TFP gains under its PBR plan than did Boston Gas and accordingly should have a higher stretch factor.

There are several unique characteristics of incentive regulation plans in Massachusetts. One is that the State has used a regional rather than national definition of the relevant industry when selecting appropriate TFP trends for PBR plans. This decision dates from the first PBR plan for Boston Gas, where the DPU agreed with the Company that the regional (the Northeast United States) industry was distinct from that of the rest of the country due to evidence of different cost pressures in the Northeast. This evidence was developed using an econometric cost model, and econometrics has since been an important tool in PBR, particularly for setting the values of productivity stretch factors.

The DPU has also demonstrated a strong preference for longer-term PBR plans.

While the approved term for the initial PBR plan for Boston Gas was five years, the plans for the National Grid, Berkshire, Boston Gas update, and Bay State plans have all been 10 years. Bay State actually proposed a shorter, five year term, but this proposal was rejected by the DPU.

Massachusetts has also standardized service quality regulation among regulated utilities more than perhaps any other US State. In 2000, the DPU undertook a statewide, generic review of service quality issues which established a list of common service quality indicators and method for establishing associated benchmarks for each gas and electric power distributor. The benchmarks would be based entirely on the company's past, average performance on a service quality indicator. For all electricity indicators except the system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI), benchmarks were based on 10 years' worth of data. Benchmarks for SAIFI and SAIDI were originally based on five years' worth of data.[33] There was a statewide review of Massachusetts' service quality regulation in 2006, and this update led to only modest revisions in policy. The most important change was that SAIFI and SAIDI benchmarks would be based on ten year average performance on the respective indicator.

Most PBR plans have not included separate provisions related to capital expenditures (capex) requirements under the plan. The one exception is the settlement for NStar Electric, which allows the company to recover the costs (subject to prudence review) of a set of narrowly-defined projects, primarily designed to maintain safety and reliability.[34] These costs are recovered in the same manner, and involve the same filing requirements, as those recovered through the Z factor. It should also be noted that Bay State's PBR plan originally proposed a tracker mechanism that would allow the Company to recover the costs (subject to prudence review) of replacing its bare steel distribution facilities. Although the Department rejected this proposal, Bay State has recently re-filed it, and the Department has not yet issued a decision in this proceeding.

Massachusetts currently allows lost revenue recovery related to the conservation activities of gas distributors but not electricity distributors. However, in the summer of 2007, the DPU initiated a new proceeding to investigate whether regulatory changes were necessary

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[33] If a company did not have ten years of data on an indicator, new data would be used to update benchmarks until 10 years of data were available.

[34] This detailed list of projects is called the Capital Projects Scheduling List (CPSL).

to promote more effective conservation and deployment of demand side resources. The DPU has developed a "strawman" proposal that would implement full decoupling of revenues from consumption for both power and gas distributors in the State. The Department also asked parties to comment on whether the implementation of decoupling would necessitate a change in the PBR framework used in the State. The subsequent submissions, as well as a series of expert "panel" discussions on the subject, indicated near-universal support for maintaining the PBR framework.[35]

PEG believes the experience with PBR in Massachusetts has been successful. Evidence supporting this conclusion comes from the fact that the DPU has found that PBR plans have benefited ratepayers and thereby reaffirmed its commitment to PBR (*e.g.* in the updated Boston Gas plan). The DPU has also progressively extended PBR to most of the State's energy utilities. The comments in the decoupling proceeding also show that PBR enjoys the support of all utilities, and nearly all consumer groups and other government agencies, in the State. Massachusetts has also employed a well developed framework for analyzing the PBR proposals from different companies but has never attempted to impose a "one size fits all" PBR model throughout the State. Diversity among companies is accommodated through the establishment of initial (cost based) rates at the outset of the plan, different stretch factors, and the ability to propose innovative regulatory mechanisms such as the plan termination provision for National Grid (which is designed to encourage longer-term efficiencies) and the CPSL approved for NStar Electric. Developments in the current decoupling proceeding and Bay State filing could have implications for regulatory policy in the State, however, and merit attention.

A1.3 California

California's large investor owned energy utilities [Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and Southern California Gas (SoCalGas)] have been subject to a variety of incentive regulation plans since the early 1990s. Incentive regulation was first applied to bundled power distributors in the State but, following the restructuring of the electric power industry in 1996, has been applied

[35] Larry Kaufmann of PEG participated in these panel discussions and was retained by a coalition of (most) energy distributors in the State to prepare a submission on the relationship between PBR and decoupling.

to unbundled gas and electricity distributors. California's incentive regulation experience grew out of its earlier application of hybrid, Attrition Rate Mechanisms (ARAs) that were designed to extend the interval between general rate cases (GRCs). In the early 1990s, California abandoned the ARA framework and moved towards comprehensive, index-based PBR. Comprehensive PBR used a single index-based rate adjustment mechanism that applied to overall base rates, and the X factors in these index-based mechanisms were calibrated using TFP trends.

The first indexing plan for energy utilities in California was approved in late 1993 for PacifiCorp. The X-factor in this plan was based on the company's own long-run TFP trend. This TFP trend was computed was computed by the Office of the Ratepayer Advocates, which is a part of the California Public Utilities Commission (CPUC). The initial X-factor was set at the company's long-term TFP trend of 1.4%. In 1997, this TFP trend was updated to include the three most recent years of Pacificorp's TFP performance. The resulting X-factor was 1.5%. This plan also featured an industry-specific inflation factor that was tailored to reflect changes in the prices of electric utility inputs. No consumer dividend was added to this long-run TFP trend when setting the X factor.

The first index-based PBR plan approved for a North American power distributor was for Southern California Edison (SCE). This plan took effect in 1997 and used the US CPI as the inflation factor. The X factor in this plan rises from 1.2% in 1997 to 1.4% in 1998 and 1.6% in 1999-2001.

This X factor was based on a TFP study that the company conducted of its TFP growth. This study showed that SCE's long-term TFP growth trend was 0.9% per annum. The Commission accepted this estimate. The overall X factor therefore reflects this TFP trend plus consumer dividends that rise from 0.3% to 0.7% over the plan, with an average value of 0.56%.

In approving this plan, the CPUC said it would have preferred to use industry TFP measures as the basis for the X factor. However, no party in SCE's proceeding presented evidence on industry TFP. The CPUC espoused a competitive market standard as the rationale for its preferred approach. It wrote:

> The price and productivity values should come from national or industry measures and not from the utility itself. The independence of the update rule from the utility's own costs allows PBR regulation to resemble the unregulated market where the firm faces market prices which develop independently of its

> own cost and productivity. The productivity measure should come from a forecast of industry specific productivity.[36]

The PBR plan approved for Southern California Gas (SCG) represents the first approved for a California energy utility that used industry TFP research. The indexing mechanism was applied to revenue per customer rather than prices, as in the SCE plan. The approved industry TFP trend was 0.5% per annum, based on a study of the US gas distribution industry. The CPUC concluded that the TFP study supporting the proposed X factor "elicited little criticism from outside parties."[37] The plan also included a stretch factor that rose in 0.1% increments from 0.6% to 1% over the term of the plan and an additional 1% factor to reflect the expectation of declining rate based while the plan was in effect. The SCG plan also included an industry-specific inflation factor based on a weighted average of changes in input price indices for gas distribution capital, labor, and non-labor operations and maintenance inputs.

San Diego Gas and Electric (SDG&E) was the first indexing plan approved for both the gas and power distribution operations of a combination utility. The company commissioned studies on industry TFP trends in both power distribution and gas distribution. The estimated TFP trends were 0.68% and 0.92% per annum for gas and power distribution, respectively. The CPUC accepted this evidence and added an average consumer dividend of 0.55% per annum. The average X factors for power and gas distribution were therefore 1.47% and 1.23%, respectively. As with the SCG plan, the inflation factors in both of these plans were measures of industry-specific inflation factors.

Several index-based revenue per customer plans have recently been approved in California. In 2005, PBR plans for three Sempra companies (SoCalGas, SDG&E-gas distribution, and SDG&E-electric distribution) were all updated. The final plans emerged from a partial settlement between these companies and most, but not all, of the intervenors in the case. The original PBR plan for SoCalGas was a revenue per customer plan, but both

[36] Application of Southern California Edison to adopt a Performance Based Rate Making Mechanism Effective January 1, 1995, Alternate Order of Commissioners Fessler and Duque, July 21, 1996.

[37] Decision 97-07-054, *In the Matter of the Application of Southern California Gas Company to Adopt Performance Based Regulation for Base Rates*, July 16, 1997. This study was prepared by PEG personnel. PEG personnel have also testified in support of the PBR plans for San Diego Gas and Electric's gas and electric operations and has testified in support of TFP studies for PG&E. The PBR proposals for SCE and Pacificorp did not rely on outside, expert witness testimony.

SDG&E utilities were originally subject to rate indexing. These plans were changed to margin per customer indexing largely because of a change in California's Public Utilities Code which said that "the Commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or undercollections of the electrical corporations." Sempra argued that this law required some type of balancing account arrangement, which was not disputed by other parties. However, some intervenors argued unsuccessfully that the PBR plan should apply to overall margins rather than margins per customer. The difference is that the former application does not update revenue requirements based on customer growth.

The term of each plan was four years. All of the Sempra plans used the same CPI inflation measure. The X factor in each plan was also equal to zero, although the settlement contained limits on the maximum and minimum price change for each company. These maximum and minimum limits varied by year and by company.

California also has extensive experience with lost revenue recovery mechanisms related to energy conservation. The first such mechanism was implemented for Pacific Gas and Electric's (PG&E's) gas distribution operations in 1978 and for the company's electric rates in 1982. Decoupling was subsequently extended to the gas distribution operations of SDG&E, Southern California Gas and Southwest Gas, and to the electric rates of SDG&E and Southern California Edison.[38] Until very recently, California was the only State to have decoupling for both its gas and electric utilities.[39] Unlike other States like Maine and New York that were also early decoupling pioneers, California has retained decoupling for nearly three decades (albeit with occasional interruptions, primarily because of structural changes resulting from the introduction of retail competition for electricity).

California's experience under incentive regulation has been generally successful. Incentive regulation has been retained in various forms for over two decades. One of the most interesting features from California PBR is the use of industry specific inflation factors.

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[38] It is worth noting that, on the electric side, the first decoupling plans originally applied to utilities' bundled generation, transmission and distribution operations. After industry restructuring in the 1990s, these decoupling plans applied to electric utilities' distribution operations.

[39] To the best of our knowledge, the only other State that currently has decoupling for some of its gas and electric utilities is Maryland. Decoupling has been in effect for the gas rates of Baltimore Gas and Electric since 1998 and for Washington Gas Light's gas rates in Maryland since 2005. In July 2007, decoupling plans were approved for the electric rates of Delmarva Power and Light and Potomac Electric Power in Maryland.

Industry specific inflation factors have been constructed using both public and private data sources for gas and power distributors. These plans have also included smoothing of capital price changes, to limit price volatility.

California regulation has also been very diverse. A wide variety of PBR mechanisms have been approved over the years, including indexed price cap plans, indexed revenue per customer plans (*i.e.* index based adjustments of allowed revenues per customer), indexed total revenue requirement plans (*i.e.* index based adjustments of overall allowed utility revenues, not just revenues per customer), and hybrid approaches that adjust operation and maintenance expenses using an indexing mechanism and set allowed capital expenditures based on either forward-looking projections or historical, multi-year averages for capital spending One factor that facilitates a diversity of regulatory approaches in the State is that California has a small number of very large utilities. This reduces the relative burden on Staff and the companies from detailed reviews of new and, potentially, innovative filings proposed by individual companies. This is very different from Ontario, which has more than 80 electricity distributors serving a much smaller market.

A1.4 British Columbia

British Columbia has applied incentive regulation to energy utilities for more than a dozen years. BCGas (later Terasen Gas) became subject to index-based caps for certain categories of base rate revenue in 1994. The caps pertained to OM&A expenses and small capital expenditures. The inflation measure was the Canadian CPI while the X-factor was 3.0% in early years, but fell to 1% in later years of the plan. BC Gas also operated under a revenue decoupling mechanism called the Revenue Stabilization Adjustment Mechanism, which applied only to revenues from residential and commercial sales.

An updated partial indexing plan for Terasen Gas was approved for the 2004-2007 period; this update was later extended to include 2008-09. Allowed revenues were adjusted by customer growth during the plan. The X factor in the updated plan was also expressed as a fraction of the CPI inflation measure rather than a fixed number, as in the earlier plan. The value of X was set at 50% of inflation in the first two years of the updated plan and 66% of inflation in the last two years of the plan. There was also 50/50 sharing of earnings that were either above or below allowed ROE.

Like the earlier plans for BCGas, large capital additions that require a certificate of public need and convenience or CPCN (typically only for projects exceeding $5 million) were excluded from the mechanism. Unlike the earlier plans, however, a common X factor was applied to index-based adjustments for O&M and small capital additions. Base capital expenditures were not rebased during the term of the plan. There was also an end of term capital incentive mechanism that was designed to encourage efficient capital spending in all years of the plan. This mechanism compares the difference between the cumulative, formula-based capital expenditures over the plan with actual base capital expenditures. Two-thirds of this difference is phased out (*i.e.* returned to customers if actual spending is less than formula-based expenditures; recovered from customers if actual spending is greater than formula-based expenditures) in the first year after the plan expires. The remaining third is phased out in the second year following plan termination.

The most recent Terasen plan also includes an extensive list of service quality indicators and associated benchmarks. The Company is not penalized or rewarded during the plan for its service quality performance. However, the Company's service quality performance is reviewed annually, and a failure to comply with service quality standards can lead to limits on incentive payments Terasen is allowed to retain.

A targeted incentive plan for West Kootenay Power (later FortisBC) in British Columbia was approved in 1996. Indexing applied only to components of cost that are viewed as subject to management control. Different inflation measures, X-factors, and output factors applied to different cost categories. The CPI for British Columbia was used as the inflation measure applicable to most cost categories, including labor, materials, vehicles, other income, DSM, and small capital expenditures on transmission, distribution, and general plant capital spending. Productivity Improvement Factors slow the targeted growth of some cost categories. They range from 2% for small capital expenditures to 4% for labor and materials. An Incentive Adjustment Mechanism reduces business risk by sharing differences between Target Cost and Actual Cost with customers.

The most recent incentive plan for FortisBC is for the 2006-2008 period. Rates were rebased in 2006 and index-based adjustments applied for 2007 and 2008. There is also an option to extend the plan through 2009 if the Company and stakeholders agree.

Opex per customer is adjusted by the growth in the BC CPI minus productivity improvement factors (PIFs). The PIFs are 1% in 2007, 2% in 2008 and 3% in 2009. Total opex is also adjusted for customer growth during the plan. The Company's annual Capital expenditure plans are approved as part of a separate annual filing, with CPCN applications required for major projects. The amount of net additions to rate base, along with an allowance for funds used during construction (AFUDC), are examined at the Revenue Requirements Workshop and approved by the Commission's subsequent Order. Capitalized overhead is also set at 20% of forecast gross O&M during the term of the PBR plan.

The FortisBC plan also includes a "collared ROE" earnings sharing mechanism. Earnings within 200 basis points of allowed ROE (above or below) are shared 50/50 between customers and shareholders. All earnings differences outside this band of plus or minus 200 basis points are placed in a deferral account for review and disposition at the next Annual Review.

The plan also includes service quality indicators and standards. To be eligible for incentive payments, Fortis must show that it did not achieve additional earnings as a direct result of deterioration in its service quality performance. At the same time, a failure to meet one or more service quality standards does not necessarily lead to a disallowance of any incentive payment.

The PBR experience in British Columbia is generally positive. Plans have been updated and approved several times, and parties appear to be generally satisfied with the outcomes of past plans. One factor that promotes satisfaction is the emphasis on using settlement discussions rather than hearings to reach decisions on PBR plans. Effective settlement negotiations necessarily lead to outcomes that are satisfactory for the parties involved. It is not clear, however, that settlements can play as large a role in the regulation of electricity distribution in Ontario as they have for BC energy regulation. One reason is simply that there are many more regulated companies in Ontario, and separate negotiations with each will raise regulatory burdens on both Staff and companies.

There are both similarities and differences among the approved PBR plans in BC. One interesting feature of PBR in BC is that opex and capital are often subject to different regulatory mechanisms. Opex (or opex per customer) is indexed using inflation trends and productivity factors; small capital additions are sometimes indexed and sometimes regulated through cost of service-type procedures. Large capital expenditures are subject to CPCN requirements. Again, relying on more cost-based approaches for capital regulation is likely to prove more costly in Ontario than BC because of the greater number of companies and applications that would be involved.

The end of term capital incentive mechanism approved for Terasen Gas is also noteworthy. One of the concerns of applying incentive regulation between scheduled "rebasing" reviews is that companies will simply defer their capital expenditures until the test year on which rebased rates will be set. Such deferrals of capital spending do not represent real efficiency gains of the kind that incentive regulation is designed to encourage. Terasen's end of term capital incentive mechanism is relatively simple but can still provide an incentive for utilities to undertake efficient capital expenditures in all years of a PBR plan. A similar type of mechanism merits consideration for 3rd Generation IRM.

A1.5 United Kingdom

Utilities in the UK have been subject to incentive regulation since the early 1980s. Most British utilities were formerly public enterprises and were subject to privatization and formal regulation beginning in 1984 with British Telecom (BT). Since then, privatization has extended to the nation's electric, gas, water, airport and rail utilities.

The decision to use rate indexing in British utility regulation was strongly influenced by the recommendations of Stephen Littlechild of the University of Birmingham, in a report released in 1983.[40] He proposed to adjust BT's rates using an index with an "RPI-X" formula. The RPI term is the inflation in the Retail Price Index (RPI). A specific value for X was not recommended, nor was there significant discussion in Littlechild's paper of the appropriate framework to be used to determine X. Rather, the value for X was described vaguely as "a number to be negotiated."

Following its application to BT in 1984, RPI-X regulation was first applied to the gas industry in 1986 and to the electric utility industry in 1990. The electricity industry in England and Wales was unbundled into a separate power transmission firm (National Grid) and twelve distribution network operators (DNOs) when industry restructuring was completed in 1990. The two DNOs serving Scotland were originally part of vertically-integrated firms. The gas utility industry was initially served by a single regulated firm, British Gas, which also had gas production and other interests. In the mid 1990s, the gas

[40] Stephen Littlechild, *Regulation of British Telecommunications' Profitability: Report to the Secretary of State*, February 1983.

transmission and distribution operations of British Gas were functionally unbundled into a firm called Transco. UK gas distribution operations were later formally unbundled into eight separate local gas distributors, four of which were retained by the original entity (which had since merged with National Grid) and four of which became stand-alone utilities. The first price review for the UK's unbundled gas distributors was recently completed in 2007.

RPI-X regulation for UK energy distributors has employed a "building block" approach that calibrates the terms of the indexing formula based on forward-looking revenue requirements of each regulated firm over the term of the price controls. The earliest energy price reviews were rather opaque and did not provide much detail on the regulators' specific determinations on particular "building block" elements. Over time, however, UK regulatory reviews have become more transparent and followed a more clearly defined and organized process.

The first fully articulated statement of the British approach towards price cap regulation is contained in the 1997 price cap plan for Transco. To determine the price controls for Transco, the regulator took as a "starting point" a long term net present value (NPV) calculation.[41] This calculation determined "a level of revenue which, when set against expected expenditure (over the term of the controls) and discounted at the company's cost of capital, would produce a net present value (NPV) of zero".[42] In other words, price controls were based on a projected forward-looking revenue requirement that just recovers the sum of opex and capital costs (return on and depreciation of existing assets plus costs of new capital expenditures) for the price cap period. More specifically, the basic components of the basic building method are:

1. Defining the regulatory asset base (RAB). The approach that ultimately developed was based essentially on the (conventional) historic cost of assets.
2. Estimating depreciation of the RAB
3. Assessing future capital expenditure (capex) and its depreciation
4. Estimating the weighted average cost of capital (WACC).
5. Determining a reasonable level of future operating expenditure (opex)

[41] There were separate regulators of the gas and electricity industries until 1999, when the regulatory agencies were merged to form the Office of Gas and Electricity Markets (Ofgem).

[42] Office of Gas Supply, *Price Control Review, British Gas' Transportation and Storage: A Consultation Document*, June 1995, p. 22.

New price controls are almost always affected via two price adjustments: an initial price (P_0) change in the first year of the plan; and an X factor that applies during the subsequent plan years, when index-based price changes take effect. The building block approach used in the UK can lead to any number of initial price adjustment-X factor combinations for a company that are consistent with that company's allowed revenue adjustment over the term of the controls. Any revenue neutral reallocation between initial price adjustments and X factors (*i.e.* any change between the P_0 and X factor that does not affect the NPV of the company's expected revenues over the term of the price control) is consistent with the regulator's building block computations.

The UK incentive regulation experience is extremely rich and diverse, but the most relevant precedents in the context of 3rd Generation IRM in Ontario are the plans that have been approved for the UK power distribution industry. Five-year price cap plans were instituted for the DNOs upon their privatization in 1990. Initial rates were set at the levels charged by the companies just before privatization, even though these rates presumably reflected inefficiencies under state ownership. Different X-factors were established for each DNO, ranging from 0 to -2.5% with an average value of -1.3%. Therefore, DNOs' distribution prices were allowed to *increase* by an average of 1.3% per annum in real terms during the five years of the first price cap plan. The reasons for allowing real price increases were not made explicit. However, the companies were being sold to private investors. The terms of the indexing plans were likely set, in part, to spur investor interest and extend share ownership.

DNO price controls were first reviewed in 1994. This review focused on four considerations when re-setting allowed revenues over the upcoming price control term: operating expenses, planned capital expenditures, the valuation of the capital stock used in power distribution, and the allowed return on that capital stock. The Office of Electricity Regulation (Offer) reviewed these factors by analyzing the DNOs' cost and sales data and by soliciting independent evaluations of REC operations. For example, consultants provided opinions on "best practice" for different distribution functions, and outside analysts estimated the costs of network expansions given projected changes in the number and location of customers. Statistical benchmarking studies were undertaken to estimate the efficient levels of operating costs for individual DNOs given various factors beyond management control.

These included the number of customers served, volumes distributed at low and high voltage, and customer density within the territory served. The results of these benchmarking studies were not made public, nor did the regulator detail how the benchmarking results specifically affected the final X factors.

The outcome of this review was an initial price cut for each of the DNOs and a common X-factor of 2%. Distribution rates were cut either 11%, 14%, or 17% in the initial year of the new plan, depending on what the benchmarking and other analyses indicated were efficient cost levels for the company. Revenue reductions were divided between an initial rate cut and a higher X because it was believed that both customers and utilities preferred this approach.

The new price cap plan took effect in April 1995 and was widely viewed as too generous for the Companies. Public dissatisfaction was heightened when outside investor groups responded to the new price controls with takeover bids for several DNOs, allegedly because the new price controls offered the opportunity for unexpected profits. Only one month after the distribution price cap plan went into effect, the Director General (DG) re-opened the plan, which led to an additional, up-front price cut of 9% and an increase in the X factor to 3%.

The DNOs distribution price control was updated again in 2000. This led to another initial price cut that varied between 19%, and 33% between companies. The X factor in the other four years remained at 3%. The methods used to update the control were similar to those used in 1995.

The 2005 update of DNOs distribution prices included an initial price increase that averaged about 1% per company and an X factor of 0 for the remaining four years of the control. Unlike the earlier power distribution price reviews, prices did not decline in real terms as a result of this review. The main reason was that Ofgem allowed substantial increases in capital spending for many of the distributors.

Over time, benchmarking has played an increasingly important role in the regulation of opex in UK RPI-X plans. Ofgem has primarily relied on econometric benchmarking in its price reviews. Its econometric benchmarking approach is a variant of corrected ordinary least squares (COLS). For price controls taking effect in both 2000 and 2005, Ofgem regressed a "normalized" measure of opex on what it called a "comprehensive scale variable" (CSV).

Distributors' opex data were normalized by ensuring that these data were defined and collected comparably across all DNOs. The CSV was based on each DNO's number of customers served, kWh distributed, and network length. The weights applied to these variables in developing each DNO's CSV were 25%, 25%, and 50%, respectively. These weights differed from those used in the 1999 COLS study, which were 50% for customers served, 25% for kWh and 25% for network length. These weights were considered roughly proportional to the impact of each scale measure as a "driver" of distribution opex.

In two dimensional space, COLS is normally applied by running an OLS regression and shifting the intercept of that regression until the line passes through the minimum observation. Any gap between a DNO's opex and this COLS line would therefore reflect that DNO's inefficiency, or the excess of its opex costs over the observed minimum regression line. For the 2000 review, however, Ofgem's COLS benchmarking was done by shifting the *slope* of the estimated function and not the intercept. The slope was shifted until the line passed through the *second* lowest observation. This approach was taken because Ofgem believed a conventional COLS application would have led to implausible results. That is, the intercept from a regression of (normalized) opex on the CSV could be interpreted as the fixed operating costs of a DNO, independent of the size of its operations. In the 2000 review, Ofgem believed that if the intercept was shifted as in a typical COLS procedure, it would have produced a fixed opex cost estimate that was implausibly low from an engineering perspective, so Ofgem shifted the slope as an alternative.

For the 2005 review, Ofgem did shift the intercept in its COLS application as is typically the case. However, the intercept was shifted so that the line passed through the upper quartile opex performance rather than minimum performance. Upper quartile performance was effectively determined as the midpoint between the third and fourth lowest opex cost observation of the 14 DNOs.

In the 2000 review, Ofgem set opex targets by assuming that companies would catch-up to the opex target determined by the COLS procedure by closing 75% of the gap between their (normalized) operating cost and the normalized opex of the second most efficient firm in the UK by the second year of the price review.[43] In the 2005 review, each REC's allowed

[43] Office of Gas and Electricity Markets, *Electricity Distribution Price Control Review: Initial Proposals*, June 2004, p. 66. "Normalized" cost here refers to costs that are adjusted for scale of output and other factors that are quantified through econometric benchmarking.

opex is based on an upper quartile benchmark within the UK. Ofgem's rationale for this decision is that an "upper quartile benchmark…provides a more robust and sustainable benchmark than a frontier based on one company."[44] The 2005 review also undertook some data envelope analysis (DEA) as a "cross check" on the econometric results. However, Ofgem concluded that the DEA results "are not plausible so it (DEA) has not been incorporated directly."[45]

The regulation of capex has also changed considerably since the initial RPI-X controls but has evolved in a different direction. In the 2005 price review, Ofgem applied a sliding scale mechanism to the UK distribution companies' capital expenditures. A similar type of mechanism was applied in the most recent energy price control review for the gas distributors but was called an "information quality incentive." These mechanisms were motivated by Ofgem's view that the distributors have incentives to inflate their forecast capex during the next price control period but then "underspend" once an allowed capex is used to set the value of X. Ofgem believes some utilities have actually behaved in this way, although others have not. The aims of the sliding scale mechanism are to:

- retain incentives for efficient capital spending during all years of the control
- reduce the emphasis on Ofgem's or its consultant's view of the appropriate level of capex
- reduce the perceived risk that the price control causes under-investment
- allow but not encourage expenditure in excess of the allowance
- reduce the possibility that companies submitting high capex projections will make very high returns from underspending
- reward companies making "low" capex forecasts
- avoid incentives to underspend in ways that reduce service quality or create service quality problems in subsequent years

The sliding scale mechanism essentially gives companies a choice between:

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[44] Ofgem, *op cit*, p.67.

[45] Office of Gas and Electricity Markets, *Electricity Distribution Price Control Review: Final Proposals*, November 2004, p. 70.

- a lower allowance for capex reflected in the controls, but with a higher- powered incentive that allows them to retain a greater share of "underspend" relative to the allowance and collect a greater share of "overspend"; or

- a higher allowance for capex in the controls, but with a lower-powered incentive that lets companies keep a lower share of "underspend" and collect a lower share of "overspend."

Companies also get an additional reward if they do choose the lower allowed capex option, but do not receive this reward if they select higher allowed capex. If the sliding scale mechanism is designed correctly, it is "incentive compatible" and removes incentives for the company to inflate its projected capex. The mechanics of Ofgem's proposed sliding scale mechanism are as follows:

- Ofgem determines a benchmark level of projected capex over the price control period for each DNO; in the 2005 distribution price review, these benchmarks were determined by the engineering consulting firm PB Power

- Each REC presents its actual capex projections over the price control period

- Ofgem determines a capex *allowance rate*, *additional income* and a capex *incentive rate* depending on the relationship between benchmark and forecast capex. The allowance rate is the total amount of capex that will be allowed in the controls; this number is specified as a multiple over the benchmark level. The additional income term is an addition to the distributor's allowed revenue. The incentive rate is equal to the portion of capital "underspend" the company is allowed to retain. The allowance rate, additional income and incentive rate each increase as the company's forecast gets closer to the benchmark level, and vice versa. This approach therefore rewards companies for keeping their capex forecasts low.

For example, if a company's projects its capex to be 140% of the PB Power benchmark, their capex allowance rate is 115% of the PB Power forecast value. If they over- or underspend relative to this forecast, they get to keep or bear 20% of the difference *i.e.* the marginal incentive rate is 20%. Alternatively, for companies whose capex forecasts are equal to or less than the PB Power benchmarks, their allowance is set at 105% of the PB Power capex forecast. Companies keep or bear 40% of any over- or under-spend relative to the allowed capex level, so their marginal incentive rate is 40%.

Ofgem established the sliding scale mechanism as a matrix which displays the values of the key parameters and how they vary with the forecast/benchmark relationship. The table below captures the main features of the sliding scale matrix.

Forecast (F)/ Bench (B)	Δ	Allowance Rate (AR)	Δ	Incentive Rate (IR)	Δ	Additional Income (AI)	Δ
100		105		0.4		2.5	
105	5	106.25	1.25	0.38	-0.02	2.1	-0.4
110	5	107.5	1.25	0.35	-0.03	1.6	-0.5
115	5	108.75	1.25	0.33	-0.02	1.1	-0.5
120	5	110	1.25	0.3	-0.03	0.6	-0.5
125	5	111.25	1.25	0.28	-0.02	-0.1	-0.7
130	5	112.5	1.25	0.25	-0.03	-0.8	-0.7
135	5	113.75	1.25	0.23	-0.02	-1.6	-0.8
140	5	115	1.25	0.2	-0.03	-2.4	-0.8

The first column shows the ratio between forecast and benchmark capex (in percentage terms). The second column (the "delta") presents the change in the forecast/benchmark ratio from the row above. The third column presents the allowance rate (AR, also in percentage terms) associated with a given forecast/benchmark ratio; this allowance rate is multiplied by the benchmark capex value, and the product determines allowed capex. The fourth column presents the change in the AR from the row above. The fifth column presents the incentive rate (IR) for a given forecast/benchmark ratio; this incentive rate is multiplied by the difference between allowed and actual capex value. The sixth column presents the change in the IR from the row above. The seventh column presents the additional income (AI) associated with a given forecast/benchmark ratio. The eighth column presents the change in the AI from the row above.

In some ways, the UK approach to incentive regulation must be seen as a success. It is indisputable that price cap regulation in the UK has delivered considerable benefits to British consumers. There have been substantial declines in prices for all regulated utility services in Britain (except water, where there has been substantial new investment to comply with EU water quality standards) since RPI-X controls took effect. The British "building block approach" to price cap regulation can create some incentives for firms to pursue efficiency gains and, over time, these efficiency gains have been distributed to customers in the form of price reductions.

Other aspects of the British approach are also appealing. The sliding scale mechanism that is being applied to capex should help to diminish the incentives to game capex forecasts.

Developments regarding the actual operation of this scheme merit attention.

The econometric approach to benchmarking opex has also worked reasonably well, although the econometric models and methods have been extremely simple because of the regulator's decision to rely only on data from the limited sample of UK DNOs. Richer econometric specifications (for both opex and total distribution cost) can be estimated using the much more ample data from North America. The upper quartile benchmarking standard that was applied in the 2005 distribution price review is also appealing and generally consistent with a competitive market paradigm. It is not reasonable for regulators to expect all firms in their industry to be performing at frontier levels, or to set the terms of price controls so that firms earn their cost of capital only by achieving frontier performance standards. In competitive markets, firms that are on the frontier earn above average returns. If regulation is designed to emulate the operation of competitive markets, then the appropriate performance standards must also be set at less than the frontier. Equivalently, firms must have "room" to outperform the standards reflected in the price controls for them to have incentives to boost their efficiency and thereby earn more than their weighted average cost of capital. The upper quartile standard chosen by Ofgem is ultimately based on judgment, but it is generally consistent with this competitive market paradigm.

There are also disadvantages associated with UK, building block regulation. One is that the building block model is susceptible to gaming on the part of companies. Prices are based on a company's projected costs. Companies therefore clearly have incentives to game the estimates of their projected costs that they present at the outset of the regulatory process. Regulators must attempt to "de-game" these forecasts and ascertain the "truth" about how much costs are actually expected to increase over the term of the controls. This is an inherently imprecise exercise which necessarily exposes regulators to the well-known "information asymmetry" problem, since regulators will know far less about the company's actual and projected costs than the companies themselves. Ironically, economists have long believed that information asymmetries are at the heart of problems with cost of service regulation. Incentive regulation is therefore designed to create regulatory institutions that encourage companies to use their superior information in a socially beneficial manner; it should not allow companies to profit by gaming this information through other channels. The UK has created elaborate sliding scale or information quality incentive mechanisms to counter this problem, but developing and implementing such mechanisms is likely to be difficult and costly in Ontario, particularly since separate capex benchmarks would need to be developed for more than 80 distributors.

This reflects a more fundamental concern, which is the information-intensiveness and regulatory burdens of the building block approach. Building block regulation requires detailed cost information, on both a historical and prospective basis, for each regulated company. Implementing this approach for a large number of regulated energy networks could place considerable burdens on the regulatory process and increase the cost and complexity of regulation for all parties involved (companies, regulatory staff and intervenors). The costs of a UK-type approach to incentive regulation are therefore considerably higher than a North American-style approach, and these incremental administrative and regulatory costs would likely outweigh the incremental benefits of implementing a full, building block methodology in Ontario.

A1.6 Victoria, Australia

There are five electricity distribution businesses (DBs) and three gas distribution businesses (GDBs) in the State of Victoria. All of the GDBs and three of the five DBs serve primarily urban territories centered around the Melbourne metropolitan area. All these firms are privately owned and subject to incentive regulation (since 1995 for the DBs and since 1998 for the GDBs) by the Essential Services Commission (ESC, originally called the Office of the Regulator General). There is also full retail contestability in the Victorian electricity market, which is in fact one of the most active retail energy markets in the world.

One of the chief documents framing the ESC's regulation of electricity distribution tariffs is the *Victorian Electricity Supply Industry Tariff Order* (the "Tariff Order"). Section 5.10 of the Tariff Order is titled "Restrictions on Review of Price Control Arrangements by the Regulator-General." This section imposes various constraints on decisions the ESC could make when updating controls. The first of these constraints is that the regulator must "utilize price based regulation adopting a CPI-X approach and not rate of return regulation." This particular clause has had a substantial impact on Victoria's regulatory debates and figured prominently in the first review of electricity distribution prices undertaken by the regulator, in 2000.

Like other Australian states, Victoria has traditionally employed a variant of the UK building block model. This model was first applied by the government, and not the ESC, when index-based price adjustments were announced for the DBs for the 1995- 2000 period. Each DB's distribution charges was restricted by a CPI - X formula, where each company's X-factor was chosen so that its expected revenue over the time period would recover each its expected costs over the five year period.

During the initial term of the price controls, the DBs announced their support for an alternative to the building block approach to update the CPI-X controls. Instead of the building block method, the DBs advocated that a productivity-based approach like that used in North America. The ORG considered the DBs' proposal but ultimately decided to retain the building block approach. However, the ORG modified this basic model significantly in its 2000 determination by adding an efficiency carry-over mechanism (ECM) and a service quality incentive plan, reflected in an S-factor adjustment to the CPI-X formula. The ECM allowed companies to retain the efficiencies they achieved in either opex or capex for five years regardless of the year in which these efficiencies were attained. Under the ECM, either opex or capex "efficiencies" were measured as the difference between projected and actual spending. The projected opex and capex spending increases were incorporated directly into the updated price controls.

In the first EDPR, and the regulator recommended initial price (P_0) reductions of between 12.9% and 21.8% in 2001 and a common X factor of 1% on all DBs for the remaining years of the control. The distributors appealed this determination to an Appeal Panel specially constituted to evaluate whether the ESC made "errors of fact" in its determination. In this case, the Appeal Panel found several errors of fact, many of which related to the details of the efficiency carry over mechanism. The Appeal Panel remitted the decision to the ORG for Re-Determination, which led to initial P_0 reductions of between 9.1% and 18.4%. The X factor remained 1%.

This Re-Determination was appealed again, in a prominent proceeding before the Supreme Court of Victoria. One of the distributors, TXU (now SPAusNet) said the regulator's final decision did not comply with Section 5.10 of the Tariff Order, particularly the requirement to "utilize price based regulation adopting a CPI-X approach and not rate of return regulation." TXU argued that, because the building block model is based on each company's own costs, it is effectively a form of "rate of return regulation" that is prohibited by law. TXU retained several prominent economists to testify in support of this position. One of these witnesses was Stephen Littlechild, the former regulator of Ofgem and one of the main architects of the building block incentive regulation model.

The Court ultimately ruled in favor of the regulator. The Judge ruled that the regulator must have considerable discretion in interpreting the relevant law. He also noted a number of differences between the approach adopted by the ORG and the traditional practice of rate of return regulation. These differences included a pre-determined period between regulatory reviews, allowed pricing flexibility for individual tariffs subject to an overall price cap, and targeted incentives to improve service quality. The Judge concluded that these features were designed at providing incentives to improve quality and efficiency, as mandated by Victorian law.

The second EDPR was completed in October 2005. This review was more complicated than the earlier review, in part because metering became subject to a separate price control and there were targeted price adjustments to reflect the planned roll-out of interval meters across Victoria. A host of accounting problems were also identified in the 2005 EDPR. The most prominent included different capitalization policies among DBs, changes in provision policies for accrued liabilities (*e.g.* pensions), and outsourcing contracts to related parties.

The ESC was concerned that these accounting issues stemmed from the DBs' attempts to manipulate their reported costs. For example, the United Energy (UE) outsourcing arrangement transferred nearly all opex to an unregulated affiliate over which the ESC technically had no jurisdiction. UE refused to provide more information on this affiliate's costs, and the ESC had to bring UE before an Appeal Panel to try to compel the company to provide this information. In addition, changes in capitalization policies, the timing of provisions, and regulatory depreciation rates could all be manipulated in ways that increased the distributors' reported costs and hence allowed prices over the control period.

These difficulties led directly to changes in the incentive regulation model that the ESC applied in the 2005 EDPR. The ESC modified the efficiency carry over mechanism (ECM) it implemented in the last price review so that it applied only to opex and not capex for the 2006-2011 period. This change was made because the ESC believed reported capex could be manipulated via capitalization and related policies in an effort to increase a company's reported "efficiencies" in capital spending. An ECM that is applied to capex could thereby reward accounting manipulations rather than true capex efficiencies.

The Draft Decision in the 2005 EDPR proposed P_0 reductions of between 14% and 25.5%, with X factors of between 0.8% and 2.1% in the following years. The DBs reacted negatively to these proposals, particularly the ESC's downward adjustments to their proposed capex budgets over the upcoming control period. The ESC modified its proposals in light of these comments, and the Final Determination led to P_0 reductions of between 3.1% and 16.4%, with X factors of between 0.8% and 1.5% thereafter. This decision was also appealed to a specially constituted Appeal Panel (but not to the Courts), which led to only modest adjustments to the Determination.

It should also be noted that the ESC employed productivity trend measures in setting allowed operating expenditures in the EDPR. The ESC set the allowed change in opex using a mathematical formula. This formula included allowed rate changes for input price inflation (principally wage growth) and output growth minus industry trends in opex partial factor productivity (PFP). The ESC estimated industry PFP trends using 2000-2004 data for the Victorian power distribution industry.

The ESC has also used a "rate of change" formula to update allowed opex in the new price controls for Victoria's GDBs. This formula also features adjustments for input price inflation, output growth and changes in opex PFP. However, the GDBs' opex had been growing at a rate of more than 7% in the years immediately prior to the review, and this PFP growth trend was not considered to be sustainable over the term of the upcoming controls. Accordingly, opex PFP trends were estimated using an econometric model that estimated the sources of opex PFP growth. The parameters of this econometric model were estimated using US GDB data, but this fitted econometric model was applied to Victoria by using estimates of the projected change in each Victorian GDB's PFP "driver" variables over the term of the upcoming controls. The econometric model projected opex PFP growth for the Victorian GDBs of about 2.5% per annum during the price controls. This is close to the recent opex PFP trends for US gas distributors and represents a considerable deceleration from the 7% PFP trend that the Victorian GDBs have recently experienced and which would have been used for the rate of change formula if only historical, index-based methods had been employed. The ESC has implemented PEG's recommendation in its Draft Determination, and its Final Determination should be released shortly.

Because the regulatory approach in Victoria is similar to that of the UK, the assessment of the advantages and disadvantages of this approach will be very similar to those highlighted for the UK. However, it should be noted that some of recent innovations of in the UK, like the sliding scale mechanism for capex and the explicit adoption of an upper quartile benchmarking standard, have not been implemented in Victoria. The latter is in fact largely irrelevant in Victoria, since the ESC has used estimates of opex PFP trends (determined either through indexing or econometric methods) rather than benchmarking evaluations for the purpose of setting allowed opex.

The recent gas distribution decision also represents an innovative application of econometrics for setting allowed opex. In the UK, econometric cost models were used to benchmark opex. The ESC has used econometric cost models to project opex PFP growth, which is then used as an element for adjusting an initial, allowed opex level over the term of the indexing plan. Similar econometric models have been used to inform the values of TFP trends for Ontario's recent gas incentive regulation plans. Econometric modeling of this nature can be very useful for projecting either TFP or opex PFP growth over the term of a PBR plan for jurisdictions there is either a lack of historical, time series data, or where recent observed TFP or PFP trends may not be representative of the future. These conditions currently apply for Ontario's electricity distributors.

The ESC has integrated other positive and innovative elements into its version of building block regulation. One is the use of an ECM to create more consistent incentives throughout the price control period. This is similar to, but somewhat more complex than, the end of period mechanism approved in British Columbia. A second is the early establishment of a well-developed service quality incentive mechanism. In both instances, the ESC has shown that it is willing to refine the details of these mechanisms in later price determinations to ensure that they operate more effectively and consistently with sound economic principles (*e.g.* linking rewards and penalties for service quality performance to the actual value of changes in quality to customers).

Even more fundamentally, the ESC's desire to continuously upgrade the quality of their regulatory methods is evident in the fact that they have undertaken extensive research on the viability of alternative regulatory approaches. The ESC believes that building blocks were necessary immediately after privatization and helped the regulator understand the costs of regulated companies. Customers have also benefited from efficiency gains that companies made while subject to this model. Nevertheless, the ESC has grown increasingly disenchanted with the building block approach. Among the problems that the ESC believes have been manifested by this model are the following:

- The building block approach is a cost-based model that gives companies strong incentives to manipulate their reported costs through a variety of avenues, including:
  - Changes in cost allocations between regulated and unregulated services
  - Outsourcing arrangements to related corporate parties
  - Payments for the purchase of "management" services from corporate parents (either domestic or overseas)
  - Changes in capitalization policies, *i.e.* capitalize costs that were previously expensed
  - Changes in companies' provision adjustments, or accounting for future liabilities
  - Changes in regulatory depreciation policies
- The building block model is based on company projections of operating and capital expenditures, which they have inherent incentives to "game" and overstate; relatedly, companies have incentives to understate their expected growth in output (customers, peak demand) since, for a given allowed revenue requirement, lower output growth translates into greater price growth
- Gaming distorts utility managers' overall incentives, and regulators' attempts to uncover gaming increase the antagonism of the entire regulatory process
- It is difficult for benchmarking to identify "efficient" costs and thereby eliminate the company's excess forecasts from their allowed costs; one of the most difficult issues to control for in benchmarking is differences in the quality and reliability of utility services and the extent to which these differences are reflected in different costs.

Because of these concerns, the ESC commenced a major research project coincident with the second EDPR evaluating the use of productivity-based approaches to regulation. The ESC hired PEG to undertake this research, and our work included an estimate of TFP and input price trends for Victoria's electricity distribution industry since privatization. This work was completed in December 2004 and was updated in 2005 and 2006, with a further update scheduled for February 2008. PEG also developed an "incentive power model" that quantified the incentives inherent in different regulatory approaches, including the basic productivity-based and building block models. This work was completed in May 2005. Based on this and related work, the ESC believes that a productivity-based approach to incentive regulation may mitigate some of its concerns with the building block model, and it has sponsored further studies on the viability of implementing productivity-based regulation throughout Australia.

A1.7 New Zealand

For many years, New Zealand (NZ) practiced very light handed regulation of its energy utility industries. Information disclosure was the main protection against abuse of utility's monopoly power. Regulated utilities were required to make a wide array of cost and performance information available to the public. Parties could examine this information and, if they felt their prices were not justified by the reported costs, file a complaint with the government.

This framework was modified when Part 4A of the Commerce Act came into effect on August 8, 2001. Among other things, Part 4A requires New Zealand's Commerce Commission to implement a "targeted control regime" for electricity lines (distribution and transmission) businesses.[46] There are a number of distinct elements in the targeted control regime, the most important of which are setting thresholds, assessing and monitoring distributor performance, inquires of threshold breaches, and establishing control itself.

The Commission must publish "thresholds" for NZ lines businesses. The thresholds are intended to be a screening mechanism for identifying lines companies whose performance may warrant further examination by the Commission. Further examination could lead, in turn, to formal control of lines business prices and/or service quality levels. However, control

[46] Retailing functions have been completely unbundled from electricity lines businesses.

is *targeted* in the sense that a company can only become subject to control by breaching an established threshold.

On June 6, 2003, the Commission set two initial thresholds. The first is a CPI-X price path threshold. The initial X factor that was set was effectively equal to the CPI *i.e.* the threshold was that lines business prices remain constant in nominal terms. The initial quality threshold was the businesses' own service quality performance, as measured by SAIFI and SAIDI (the system average frequency and duration of interruptions, respectively, per customer).

From April 1 2004, the Commission established new thresholds for a five year regulatory period. These are termed "reset thresholds" and have the same form as the initial thresholds. However, the X factor now varies by lines business and can take a value of -1%, 0, 1% or 2%.

Although the thresholds regime is not formal regulation, it was modeled on North-American style, "productivity based" approach to index-based regulation (as opposed to a UK-style, building block approach). This decision resulted after extensive debate on the merits of theses paradigms. The Commission ultimately ruled that a productivity-based approach would be superior, in part because it was much less burdensome than the building block model. However, if the thresholds are breached, the Commission undertakes a detailed review of the company's costs that is similar to a building block investigation, except it is focused entirely on historical costs rather than projected cost over the term of the controls.

In the electricity thresholds regime, the "general" X factor is called the B factor. This has the same form as the general X factor in Massachusetts and is computed as the sum of the productivity differential (the TFP trend for the relevant lines industry [transmission or distribution] minus the TFP trend for the New Zealand economy) plus the input price differential (input price inflation for the NZ economy minus input price inflation for the relevant lines industry). The TFP and input price trends for the New Zealand power distribution industry were estimated using data for all 29 (at the time) NZ distributors over the 1996-2002 period. The TFP and input prices trends for the national transmission utility, Transpower, were also calculated over the 1996-2002 period. The final values that were approved for the components of the B factor for electricity distribution and transmission were as follows:

Industry TFP trend	NZ TFP trend	Input Price Differential	B factor
2.1%	1.1%	0	1.0%

The electricity thresholds regime for the distributors also determined two other components of the overall X factor(s) that were added to the threshold formulas. The first was called a C1 factor. This was essentially a company specific efficiency factor that took a value of -1%, 0 or 1% depending on the outcome of a benchmarking analysis (explained below). There was also a C2 factor, which was designed to reflect differences in profitability across companies. Companies were assigned a C2 factor of -1%, 0 or 1% depending on the outcome of a returns analysis.

A number of benchmarking analyses were performed in the thresholds proceeding. However, the main benchmark that was constructed was a multilateral total factor productivity (MTFP) index that compared TFP *levels* across NZ distributors. This work was complementary to the TFP trend analysis used to set the B factor and used the same dataset and definitions for inputs and outputs. MTFP indexes were calculated for each distributor in each year from 1996 through 2002.

The MTFP results ranked companies relative to average TFP in the NZ electricity distribution industry. A company with average TFP levels would therefore have an MTFP value of 1. Values were produced for all years. In 2002, the last year of the sample, MTFP values for sampled companies ranged from a high of 1.781 (*i.e.* productivity 78% above the industry average) to a low of .674 (*i.e.* productivity 32.6% below the industry average).

The MTFP factors were translated into C1 factors by first ranking the distributors from top to bottom in terms of their measured efficiency. Next, distributors were divided into three groups of roughly one-third each. There were 10 distributors in the high efficiency group, 12 in the medium efficiency group, and seven in the low efficiency group. The dividing lines between these groups were ultimately based on judgment. Companies in the high efficiency group were given a C1 factor of -1%, the medium efficiency group had an efficiency factor of 0, and the low efficiency group a C1 factor of 1%.

There are some intriguing aspects of the NZ thresholds regime which could prove valuable in Ontario. One is basing a type of consumer dividend (*i.e.* the C1 factor) on distributor's performance relative to average performance in the industry. Ranking companies from top to bottom and dividing them into different thirds represents a practical and relatively low-cost method for developing stretch factors. A second is the use of TFP index levels as a benchmarking technique. While TFP levels are less powerful and cannot control for as many business conditions as econometrics benchmarking techniques, they nevertheless represent a well-established empirical technique that could provide valuable information on relative performance levels in Ontario. Finally, it is worth noting that the thresholds regime integrated this benchmarking framework into a basic, North-American style indexing approach. This is obviously pertinent to Ontario, which will employ the same basic paradigm for setting the terms of PCI formulas in 3rd Generation IRM.

Appendix Two: Econometric Decomposition of TFP Growth

There are rigorous ways to set X factors so that they are tailored to utility circumstances that differ materially from industry norms (either historically or at a given point in time). This can be done by developing information on the sources of TFP growth and adjusting the X factor to reflect the impact on TFP resulting from differences between a utility's particular circumstances and what is reflected in historical TFP trends. To provide a conceptual foundation for such adjustments, below we consider how the broad TFP aggregate discussed above can be decomposed into various sources of productivity change.

Our analysis begins by assuming a firm's cost level is the product of the minimum attainable cost level C^* and a term η that may be called the inefficiency factor.

$$C = C^* \cdot \eta . \qquad \text{[A2.1]}$$

The inefficiency factor takes a value greater than or equal to 1 and indicates how high the firm's actual costs are above the minimum attainable level.[47]

Minimum attainable cost is a function of the firm's output levels, the prices paid for production inputs, and business conditions beyond the control of management. Let the vectors of input prices facing a utility, output quantities and business conditions be given by $\boldsymbol{W}$ (= $W_1,W_2\ldots W_J$), $\boldsymbol{Y}$ (= $Y_1,Y_2\ldots Y_I$), and $\boldsymbol{Z}$ (= $Z_1,Z_2\ldots Z_N$), respectively. We also include a trend variable (T) that allows the cost function to shift over time due to technological change. The cost function can then be represented mathematically as

$$C^* = g(\boldsymbol{W}, \boldsymbol{Y}, \boldsymbol{Z}, T). \qquad \text{[A2.2]}$$

Taking logarithms and totally differentiating Equation [A2.2] with respect to time yields

$$\dot{C} = \left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j \varepsilon_{W_j} \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} \right) + \dot{g}. \qquad \text{[A2.3]}$$

---

47 A firm that has attained the minimum possible cost has no inefficiency and an inefficiency factor equal to 1. The natural logarithm of 1 is zero, so if a firm is operating at minimum cost, the inefficiency factor drops out of the analysis that follows.

Equations [A2.1] and [A2.3] imply that the growth rate of *actual* (not minimum) cost is given by

$$\dot{C} = \left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j \varepsilon_{W_j} \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} \right) + \dot{g} + \dot{\eta}. \qquad \text{[A2.4]}$$

The term ε_{Y_i} in equation [A.4] is the elasticity of cost with respect to output i. It measures the percentage change in cost due to a small percentage change in the output. The other ε terms have analogous definitions. The growth rate of each output quantity i is denoted by $\dot{Y}$. The growth rates of input prices and the other business condition variables are denoted analogously.

Shephard's lemma holds that the derivative of minimum cost with respect to the price of an input is the optimal input quantity. The elasticity of minimum cost with respect to the price of each input *j* can then be shown to equal the optimal share of that input in minimum cost (SC_j^*). Equation [A2.4] may therefore be rewritten as

$$\begin{aligned} \dot{C} &= \sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j SC_j^* \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} + \dot{g} + \dot{\eta}. \\ &= \sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \dot{W}^* + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} + \dot{g} + \dot{\eta}. \end{aligned} \qquad \text{[A2.5]}$$

The W^* term above is the growth rate of an input price index, computed as a weighted average of the growth rates in the price subindexes for each input category. The *optimal* (cost-minimizing) cost shares serve as weights. We will call W^* the optimal input price index.

Recall from the indexing logic presented earlier that

$$T\dot{F}P = \dot{Y} - \dot{X} \qquad \text{[A2.6]}$$

And

$$\dot{X} = \dot{C} - \dot{W} \qquad \text{[A2.7]}$$

The input price index above is weighted using actual rather than optimal cost shares. Substituting equations [A2.6] and [A2.7] into [A2.4], it follows that

$$
\begin{aligned}
T\dot{F}P &= \dot{Y} - \left(\dot{C} - \dot{W}\right) \\
&= \dot{Y} - \left[\left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_n \varepsilon_{Z_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right) - \dot{W}\right] \\
&= \dot{Y} - \left[\left\{\left[\left(1 - \frac{1}{\sum \varepsilon_{Y_i}}\right) \cdot \sum \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_i \frac{\varepsilon_{Y_i}}{\sum_i \varepsilon_{Y_i}} \cdot \dot{Y}_i\right] + \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right\} - \dot{W}\right] \quad \text{[A2.8]} \\
&= \dot{Y} - \left\{\left[\left(\frac{1}{\sum \varepsilon_{Y_i}} - 1\right) \cdot \sum \varepsilon_{Y_i} \cdot \dot{Y}_i + \dot{Y}^{\varepsilon} + \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right] - \dot{W}\right\} \\
&= \cdot\left(1 - \sum \varepsilon_{Y_i}\right) \cdot \dot{Y}_i + \left(\dot{Y} - \dot{Y}^{\varepsilon}\right) - \left(W^* - \dot{W}\right) - \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n - \dot{g} - \dot{\eta}
\end{aligned}
$$

The expression above shows that growth rate in TFP has been decomposed into six terms. The first is the **scale economy effect**. Economies of scale are realized if, when all other variables are held constant, changes in output quantities lead to reductions in the unit cost of production. This will be the case if the sum of the cost elasticities with respect to the output variables is less than one.

The second term is the **nonmarginal cost pricing effect**. This is equal to the difference between the growth rates of two output quantity indexes. One is the index used to compute TFP growth. The other output quantity index, denoted by $\dot{Y}^{\varepsilon}$, is constructed using cost elasticity weights. The Tornqvist index that we use to measure TFP should theoretically be constructed by weighting outputs by their shares of revenues. It can be shown that using cost elasticities to weight outputs is appropriate if the firm's output prices are proportional to its marginal costs, but revenue-based weights will differ from cost elasticity shares if prices are not proportional to marginal costs. Accordingly, this term is interpreted as the effect on TFP growth resulting from departures from marginal cost pricing.[48]

The third term is the **cost share effect**. This measures the impact on TFP growth of differences in the growth of input price indexes based on optimal and actual cost shares. This term will have a non-zero value if the firm utilizes inputs in non-optimal proportions.

The fourth term is the **Z variable effect.** It reflects the impact on TFP growth of changes in the values of the Z variables that are beyond management control.

[48] See Denny, Fuss and Waverman *op cit*, p. 197.

The fifth term is **technological change**. It measures the effect on productivity growth of a proportional shift in the cost function. A downward shift in the cost function due to technological change will increase TFP growth.

The sixth term is the **inefficiency effect**. This measures the effect on productivity growth of a change in the firm's inefficiency factor. A decrease in a firm's inefficiency will reduce cost and accelerate TFP growth. Firms decrease their inefficiency as they approach the cost frontier, which represents the lowest cost attainable for given values of output quantities, input prices, and other business conditions.

Appendix Three: Capital Cost

This Appendix discusses the COS approach to the calculation of capital costs and quantities. The basic idea is to decompose the cost of capital as computed under traditional COS accounting into a price and a quantity index. The hallmarks of this accounting approach are straight line depreciation and book (historic) valuation of plant.

Glossary of Terms

For each utility in each year, t, of the sample period let

ck_t = Total non-tax cost of capital

$ck_t^{Opportunity}$ = Opportunity cost of capital

$ck_t^{Depreciation}$ = Depreciation cost of capital

VK_{t-s}^{add} = Gross value of plant installed in year t-s

WKA_{t-s} = Cost per unit of plant construction in year t-s (the "price" of capital assets)

a_{t-s} = Quantity of plant additions in year $t-s = VK_{t-s}^{add} / WKA_{t-s}$

xk_t = Total quantity of plant available for use and that results in year t costs

xk_t^{t-s} = Quantity of plant available for use in year t that remains from plant additions in year t-s

VK_t = Total value of plant at the end of last year

N = Average service life of plant

WKS_t = Price of capital service

Basic Assumptions

The analysis is based on the assumption that depreciation and opportunity cost is incurred in year t on the amount of plant remaining at the end of year t-1, as well as on any plant added in year t. This is tantamount to assuming that plant additions are made at the beginning of the year. We make this assumption to increase the sensitivity of the capital price index to the latest developments in construction costs.

Theory

The non-tax cost of capital is the sum of depreciation and the opportunity cost paid out to bond and equity holders:

$$ck_t = ck_t^{opportunity} + ck_t^{depreciation}.$$

Assuming straight line depreciation and book valuation of utility plant, the cost of capital can be expressed as

$$\begin{aligned} ck_t &= \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot I_t + \sum_{s=0}^{N-1} WKA_{t-s} \left(1/N\right) \cdot a_{t-s} \\ &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot I_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{\left(1/N\right) \cdot a_{t-s}}{xk_t} \end{aligned} \qquad [A3.1]$$

where

$$xk_t = \sum_{s=0}^{N-1} xk_{t-s}.$$

Under straight line depreciation we posit that in the interval $\left[N-1, 0\right]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}. \qquad [A3.2]$$

The formula for the capital quantity index is thus

$$xk_t = \sum_{s=1}^{N-1} \frac{N\text{-}S}{N} a_{t-s}. \qquad [A3.3]$$

The size of the addition in year t-s of the interval (t-1, t-N) can then be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \qquad [A3.4]$$

Equations [A3.1] and [A3.4] together imply that

$$\begin{aligned} ck_t &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot I_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \\ &= xk_t \cdot WKS_t \end{aligned} \qquad [A3.5]$$

where

$$WKS_t = \sum_{s=0}^{N-1} \frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot I_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s}. \qquad [A3.6]$$

It can be seen that the cost of capital is the product of a capital service price and a capital quantity index. The capital service price in a given year is a function of the construction cost index values in the *N* most recent years (including the current year). The importance of each WKA_{t-s} depends on the share, in the total amount of plant that contributes to cost, of plant remaining from additions in that year. This share is larger the more recent the plant addition year (since there is less depreciation) and the larger the plant additions in that year. Absent a decline in I, *WKS* is apt to rise each year as the WKA_{t-s} for each of the *N* years is replaced with the generally higher value for the following year. Note also that the depreciation rate varies with the age of the plant. For example, the depreciation rate in the last year of an asset's service life is 100%.[49]

In constructing the indexes we took 1964 as the benchmark or starting year for our cost research. The value of the asset-price index, WKA_t, is the applicable regional Handy-Whitman index of utility construction costs for the relevant asset category.[50] The opportunity cost of capital is developed using S&P data on equity returns and Moody's and US Treasury bond yields.

[49] Recall that the depreciation rate is constant under the geometric decay approach to capital costing.

[50] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

Appendix Four: Econometric Research

A.4.1 Form of the Cost Model

The functional form selected for this study was the translog.[51] This very flexible function is the most frequently used in econometric cost research, and by some account the most reliable of several available alternatives.[52] The general form of the translog cost function is:

$$\begin{aligned}\ln C = \alpha_0 &+ \sum_h \alpha_h \ln Y_h + \sum_j \alpha_j \ln W_j \\ &+ \frac{1}{2}\left(\sum_h \sum_k \gamma_{h,k} \ln Y_h \ln Y_k + \sum_j \sum_n \gamma_{j,n} \ln W_j \ln W_n \right) \qquad [A4.1] \\ &+ \sum_h \sum_j \gamma_{i,j} \ln Y_i \ln W_j\end{aligned}$$

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

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

Business conditions other than input prices and output quantities can contribute to differences in the costs of LDCs. To help control for other business conditions the logged values of some additional explanatory variables were added to the model in Equation [A4.1] above.

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

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[51] 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.

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

$$\begin{aligned}\ln C \;=\; & \alpha_o + \sum_h \alpha_h \ln Y_h + \sum_j \alpha_j \ln W_j \\ + \; & \frac{1}{2}\left[\sum_h \sum_k \gamma_{hk} \ln Y_h \ln Y_k + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n \right] \\ + \; & \sum_h \sum_j \gamma_{ij} \ln Y_h \ln W_j + \sum_h \alpha_h \ln Z_h + \alpha_t T + \varepsilon\end{aligned} \qquad [A4.2]$$

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

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

$$\sum_{h=1}^{N} \frac{\partial \ln C}{\partial \ln W_h} = 1 \qquad [A4.3]$$

$$\sum_{h=1}^{N} \frac{\partial^2 \ln C}{\partial \ln W_h \partial \ln W_j} = 0 \qquad \forall j = 1,\ldots, N \qquad [A4.4]$$

$$\sum_{h}^{N} \frac{\partial^2 \ln C}{\partial \ln Y_h \partial \ln Y_j} = 0 \qquad \forall j = 1,\ldots, K \qquad [A4.5]$$

Imposing the above $(1 + N + K)$ restrictions implied by Equations [21-23] allow us to reduce the number of parameters that need be estimated by the same amount. Estimation of the parameters in Equation [20] is now possible but this approach does not utilize all information available in helping to explain the factors that determine cost. More efficient estimates can be obtained by augmenting the cost equation with the set of cost share equations implied by Shepard's Lemma. The general form of a cost share equation for a representative input price category, j, can be written as:

$$S_j = \alpha_j + \sum_i \gamma_{h,j} \ln Y_h + \sum_n \gamma_{jn} \ln W_n \qquad [A4.6]$$

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

A.4.2 Estimation Procedure

We estimated this system of equations using a procedure first proposed by Zellner (1962).[53] It is well known that if there exists contemporaneous correlation between the errors in the system of regressions, more efficient estimates can be obtained by using a Feasible Generalized Least Squares (FGLS) approach. To achieve even a better estimator, PEG iterates this procedure to convergence.[54] Since we estimate these unknown disturbance matrices consistently, the estimators we eventually compute are equivalent to Maximum Likelihood Estimation (MLE).[55] Our estimates would thus possess all the highly desirable properties of MLE's.

Before proceeding with estimation, there is one complication that needs to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[56] This does not pose a problem since another property of the MLE procedure is that it is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

A.4.3 Data and Cost Function Specification

The cost function was estimated using largely the same dataset used to estimate TFP trends for US electric distributors. A few additional companies were added to the econometric dataset because they had generally accurate data, except in 2006 where the data were problematic for estimating TFP trends (*e.g.* utilities in Louisiana and Mississippi whose customer bases and costs were severely impacted by Hurricane Katrina). PEG used an "unbalanced panel" dataset in which any of these problematic observations were not included in the econometric work.

The cost function included two output quantities: customer numbers and kWh deliveries. These were the same outputs used in the TFP research. The cost function also

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

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

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

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

included input prices for capital and labor inputs, which were again defined and measured in the same way as in the TFP research.

The model also contained other business condition variables that can impact power distribution costs. One such variable included in the model is the percentage of the total value of distribution plant that is not under ground. This variable is calculated from FERC Form 1 data. The extent of undergrounding varies greatly across US distribution systems but is generally greater in urban areas and where it is encouraged by state and local governments. Underground assets provide a higher quality service than overhead plant, but they also tend to involve markedly higher capital costs which are, in most instances, only partially offset by lower operating costs. Since the variable in our model effectively measures the extent of plant that is not underground, we expect the coefficient on this variable to be negative.

A second additional business condition variable is the number of gas distribution customers served by the utility. This variable is intended to capture the extent to which the company has diversified into gas distribution. Such diversification will typically lower cost due to the realization of "economies of scope," or the ability to share inputs (e.g., personnel, computer systems, meter readers) between the two services. Higher values for this variable indicate greater levels of diversification and potential scope economies. We would therefore expect the value of this coefficient to be negative.

A third business condition was the percentage of deliveries to residential and commercial customers. It can be more costly to serve residential and commercial customers for a number of reasons. One is that they tend to have worse load factors. We therefore expect the coefficient on this variable to be positive.

A fourth business condition variable added to the model is a measure of service territory forestation. This variable was calculated using U.S. Forest Service data. We expect greater forestation to increase the maintenance and perhaps capital cost of electricity distribution. We therefore expect this coefficient to be positive.

A fifth business condition variable is the total miles of distribution line. For a given number of customers, a utility with more miles of line will have a more extensive delivery network. This is expected to raise OM&A costs, so we expect this coefficient to be positive.

The model also contains a trend variable. It permits predicted cost to shift over time for reasons other than changes in the specified business conditions. A trend variable captures the net effect on cost of diverse conditions, including technological change. It may also reflect the failure of the included business condition variables to measure the trends in relevant cost drivers properly. The model may, for instance, exclude an important cost driver or do a poor job of measuring such a driver. The trend variable might then capture the impact on cost of the trend in the driver.

A.4.4 Estimation Results

Estimation results for our power distribution cost model are reported in Table A1. The parameter values for the five additional business conditions and for the first order terms of the output variables are elasticities of the cost of the sample mean firm with respect to the basic variable. The first order terms are the terms that do not involve squared values of business condition variables or interactions between different variables. The table shades the results for these terms for reader convenience.

The tables also report the values for the corresponding asymptotic t ratios. These were also generated by the estimation program and were used to assess the range of possible values for parameters that are consistent with the data. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the asymptotic *t* ratio. In this study, we employed critical values that are appropriate for a 95% confidence level given a large sample.

Examining the results in Table A1, it can be seen that the cost function parameter estimates were plausible as to sign and magnitude. Cost was found to increase for higher values of labor prices and output quantities. At the sample mean, a 1% increase in the number of customers raised cost by 0.50%. A 1% hike in kWh deliveries raised cost by about 0.29%. The number of customers served was clearly the dominant output-related cost driver.

The coefficients on the additional business condition variables were also sensible and statistically significant.

- Cost was lower for distributors that had a greater share of assets overhead.
- Cost was lower as the number of gas customers served by a distributor increased.
- Cost was higher for distributors that had a greater number of line miles
- Cost was higher for distributors delivering a greater share of kWh to residential and commercial customers

- Cost was greater as the amount of forestation in the distributor's territory increased.

Table A1

U.S. Econometric Results

VARIABLE KEY

L= Labor Price
K= Capital Price
N= Number Retail Customers
V= Total Volumes
OH= Percent of Overhead Plant
G= Number of Gas Customers
M= Line Miles
F= Percent of Territory that is Forested
VRC= Percent of Deliveries that are Residential and Commercial

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC [1]	EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC
L	0.148	128.12	**V**	0.292	13.29
LL	-0.041	-3.62	VV	0.092	7.34
LK	-0.026	-4.27			
LN	0.030	7.75	**OH**	-0.650	-13.50
LV	-0.048	-12.34			
			G	-0.006	-6.61
K	0.594	269.00			
KK	0.098	8.72	**M**	0.197	14.04
KN	-0.070	-9.28			
KV	0.092	12.58	**F**	0.028	4.52
N	0.497	20.82	**VRC**	0.232	7.06
NN	-0.086	-7.03			
Constant	15.171	1765.17			
Trend	-0.021	-19.83			

Other Results

Rbar-Squared	0.977
Sample Period	1991-2006
Number of Observations	1048

[1] The critical value for the t statistic is around 1.648 for a 90% confidence level and two-tailed hypothesis tests.

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SENSITIVITY ANALYSIS ON EFFICIENCY RANKING AND COHORTS FOR THE 2009 RATE YEAR: UPDATE

In July 2008, Pacific Economics Group (PEG) updated its benchmarking evaluations of the operations, maintenance and administrative (OM&A) costs of Ontario's electricity distributors to include 2007 data. We computed updated econometric benchmarks and unit cost benchmarks. These benchmarking evaluations were used to divide the Ontario industry into three efficiency "cohorts" for the purpose of assigning stretch factors to distributors for the 2009 rate year using a methodology described in the July 14, 2008 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. The Board issued the results of our work on July 22, 2008.

Subsequent to the release of the September 17, 2008 Supplemental Report of the Board, Board staff asked PEG to undertake a sensitivity analysis of our July 2008 results to address two potential issues. The first was the sensitivity of benchmarking results where a firm may be incorrectly identified as being on the Canadian Shield; specifically, for the purposes of this test, Renfrew Hydro. The second was the treatment of charges billed by Hydro One to distributors "embedded" within its network for the use of low voltage (LV) facilities. In both cases, our benchmarking models were identical to those used in our original March 20, 2008 report and our July 2008 update. Any changes in results would therefore reflect the impact of changes in distributor data only and not any changes in benchmarking techniques. The results of these sensitivity tests were released publicly on November 21, 2008.

As part of the consultation on our November 2008 benchmarking results, PEG was asked to present updated versions of the tables which detail our proposed peer groups

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and the unit cost indexes for each individual distributor within each peer group. This information was previously presented in Tables 5 and 6, respectively, in our March 2008 report. In responding to this request, PEG noticed a data processing error in the 2007 update (*i.e.* for some companies, the unit cost benchmarks that were computed were based on 2004-2006 data rather than 2005-2007 data). This error affects both the 2007 benchmarking update as well as any tests of the sensitivity of these results to LV charge allocation and whether firms are incorrectly identified as being on the Canadian shield. PEG has therefore produced a new set of benchmarking results that corrects this data processing error. These tables are presented here, and they supersede the Tables previously presented by PEG in July 2008 (the update to include 2007 data) and November 2008 (the sensitivity tests). This memorandum will describe the results of these analyses, which do not materially impact the conclusions of our previous (November 2008) memorandum.

2007 Update

The results of the 2007 update are attached. Table One presents PEG's proposed peer groups; this is an update of what was Table 5 in the March 2008 report. The peer groups have not been altered since that report. Table Two presents the OM&A unit cost indexes for all distributors and all peer groups; this is an update of what was Table 6 in the March 2008 report. Table Three presents the econometric benchmarking results that include 2007 data. Table Four presents the unit cost benchmarking results; these benchmarks are calculated using 2005-2007 data for each distributor. Table Five presents the stretch factor assignments for each distributor using the methodology approved by the Board.

The Canadian Shield Sensitivity Test

With respect to the Canadian Shield sensitivity, Staff selected Renfrew Hydro since there was a possibility that it could have been misclassified based on the physiography reference maps used. Our review of Ontario geography and Renfrew's service territory indicated that there was some uncertainty about whether Renfrew should or should not have been categorized as serving territory on the Canadian Shield. We therefore investigated the sensitivity of our benchmarking results to this uncertainty by estimating an econometric model in which Renfrew was classified as being "off" rather than "on" the Canadian Shield (*i.e.* the value of the Canadian Shield dummy variable for Renfrew was changed from a 1 to a zero). It should be noted that this sensitivity test affected the econometric benchmarking results only because the unit cost benchmarking results do not depend on the Canadian Shield variable.

It should also be noted that, even though this sensitivity test did not lead to changes in the econometric model itself, using different data for even a single company can lead to changes in the coefficients that are estimated for the independent variables in an econometric model. Carrying out this test did affect the coefficients. After making the change in Renfrew's data for the Canadian Shield variable, the coefficients in PEG's econometric model were very similar, although not identical, to what were obtained earlier and presented in our March 2008 report.

The results of the Renfrew Canadian Shield variable sensitivity test are summarized in Table 6. The groups of "statistically superior" and "statistically inferior" cost performers are demarcated by the bold lines in the table. It can be seen that there are 15 statistically superior distributors (*i.e.* those distributors above the first bold line), 12 statistically inferior distributors (*i.e.* those distributors below the second bold line), and the remaining 56 distributors are statistically average cost performers. In our July 2008 update, there were 17 statistically superior cost performers, 13 statistically inferior cost performers, and 53 statistically average cost distributors. Thus this sensitivity test moved two distributors (Kingston Electricity Distribution and Horizon Utilities) from statistically superior to average cost performance, and one distributor (Fort Frances Power) from statistically inferior to average cost performance. This change in the econometric benchmarks would cause Kingston and Horizon to move from the top to the middle efficiency cohort, and Fort Frances from the bottom to the middle efficiency cohort.[1]

[1] As described in the July 14 Report of the Board, a company will be in efficiency cohort 1 if it is statistically superior on the econometric benchmarking model and in the top quartile on the unit cost benchmarking model. A company will be in efficiency cohort 3 if it is statistically inferior on the econometric benchmarking model and in the bottom quartile on the unit cost benchmarking model. All other companies will be in efficiency cohort 2.

In all three cases, the companies that moved were just on the edge of being classified in one cohort vis-à-vis another in our July 2008 study. The new Renfrew data used to re-estimate the econometric model led to small changes in estimated coefficients, and standard errors, which were nevertheless material enough to move these three distributors from one identified cohort into another. The classification for Renfrew itself was not impacted by this sensitivity test; the company was in the top efficiency cohort in the July 2008 update and in our current results, although the difference between its actual and predicted cost widened from -19.3% in July to -24.8% with the new data.

Low Voltage Charges

The second set of sensitivity tests concerned Hydro One's charges to distributors embedded within its territory for the use of low voltage (LV) facilities. A number of embedded distributors are currently charged by Hydro One for the use of its LV assets, but these charges are not reported as O&M costs in the distributors' RRR filings which were used as the basis for PEG's benchmarking results. This accounting treatment may lead to a lack of comparability among sampled companies, since the reported OM&A for non-embedded distributors in the Province do include the costs of LV facilities, which the non-embedded firms own, operate and maintain themselves.

Hydro One does not segregate its charges for LV facilities into the associated capital and O&M costs so, to control for these costs in OM&A benchmarking, it was necessary to develop proxies for the O&M component of Hydro One's charges. OEB Staff developed two separate proxies for these O&M costs, using data from Hydro One's 2006 and 2008 electricity distribution rate (EDR) proceedings. The first proxy was equal to 26% of LV charges to each distributor. The second proxy was equal to 26% of LV charges for each distributor, divided by 2.354. Further details on these proxies are

The forthcoming Tables 9 and 12 display the efficiency cohorts under two different sensitivity tests, for two different measures of LV costs. For both Table 9 and Table 12, the ordering of firms in the top and bottom cohorts is identical to that presented for the econometric rankings in the associated Tables Seven and Ten, respectively, although it will be noted that not all firms identified as being statistically superior or inferior necessarily achieve top or bottom cohort performance. The rank ordering of companies within an efficiency cohort should also not itself be interpreted as evidence of relative performance *i.e.* the first firm appearing in the top efficiency cohort in Table 12 is not necessarily the "most" efficient, and the last firm appearing in the bottom cohort in Table 12 is not necessarily the "least" efficient, distributor in Ontario.

provided as part of the accompanying letter to this note. For both proxies, the proxy O&M costs were added to the OM&A costs which were benchmarked originally for each embedded distributor. After the proxy O&M costs were added in, PEG re-estimated the econometric model, re-computed unit cost indexes, and re-determined the efficiency cohorts for all distributors in the sample (again, separately for each of the proxy O&M costs associated with LV assets).

The results of the sensitivity tests for the first LV proxy (26% of LV charges) are presented in Tables 7, 8 and 9. Table 7 presents the updated econometric benchmarks, Table 8 the updated unit cost benchmarks, and Table 9 the updated efficiency cohort/stretch factor assignments. Comparing our July 2008 results (presented above) with the results of the sensitivity test for the first LV proxy, PEG finds that efficiency cohort classifications have changed for four of the 83 distributors. Hydro 2000 was in the top cohort in our July 2008 update but moved to the middle cohort when these proxy LV charges are included in the analysis. Eastern Ontario Power, Centre Wellington and Niagara Falls Hydro move from the bottom cohort to the middle cohort. Overall, with this sensitivity test, there are 10 distributors in the top efficiency cohort, 8 distributors in the bottom cohort, and 65 distributors in the middle cohort.

The results of the sensitivity tests for the second LV proxy (26% of LV charges, divided by 2.354) are presented in Tables 10, 11 and 12. Table 10 presents the updated econometric benchmarks, Table 11 the updated unit cost benchmarks, and Table 12 the updated efficiency cohort/stretch factor assignments. Comparing the results of the second sensitivity test for the LV proxy to the July 2008 results, PEG finds that efficiency cohort classifications have changed for two of the 83 distributors. Hydro 2000 moves from the top cohort in our July 2008 to the middle cohort in the current results. Centre Wellington Hydro moves from the bottom cohort to the middle cohort. Overall, with this sensitivity test, there are 10 distibutors in the top efficiency cohort, 10 distributors in the bottom cohort, and 63 distributors in the middle cohort.

Concluding Comments

Overall, PEG believes that these sensitivity analyses show that the efficiency cohorts identified in our July 2008 update are robust. Our sensitivity tests show that relatively few distributors move from one efficiency cohort to another based on changes in accounting for LV charges or for whether or not Renfrew is classified as being on the Canadian Shield. These factors have a relatively small impact on any given firm's efficiency ranking. A principal reason is that LV costs and changes in Renfrew's Canadian Shield classification have little impact on the estimated coefficients for customer numbers, kWh, and km of line in our econometric model, and these variables continue to be the major drivers of distributors' OM&A costs. PEG's benchmarking models also control for labour prices and dimensions of capital cost (system undergrounding and asset age). Our previous econometric research also investigated whether distributors' ownership of high voltage transmission assets impacted OM&A cost performance, but we found that there was no statistically significant relationship between this variable and distributors' OM&A costs. However, PEG believes that further research on this, and on related issues, is warranted in the total cost benchmarking analysis to be undertaken.

Table 1

PEG Proposed Peer Groups for Ontario LDCs

Peer Group Designation	Distributor	Customers[1,2,3,4]	% Undergrounding[1,5,6,7,8]	Canadian Shield	Customer Growth/Output Index[1,9]
Small Northern Low Undergrounding	Atikokan Hydro	1,711	0.5%	Yes	-1,470
Small Northern Low Undergrounding	Chapleau Public Utilities	1,338	3.7%	Yes	-2,346
Small Northern Low Undergrounding	Espanola Regional Hydro Distribution	3,316	8.0%	Yes	691
Small Northern Low Undergrounding	Fort Frances Power	3,864	9.5%	Yes	650
Small Northern Low Undergrounding	Great Lakes Power	11,522	0.1%	Yes	236
Small Northern Low Undergrounding	Northern Ontario Wires	6,112	1.4%	Yes	-772
Small Northern Low Undergrounding	Parry Sound Power	3,365	8.6%	Yes	716
Small Northern Low Undergrounding	Renfrew Hydro	4,149	3.6%	Yes	323
Small Northern Low Undergrounding	Sioux Lookout Hydro	2,754	2.8%	Yes	105
Small Northern Medium Undergrounding	Hearst Power Distribution	2,772	16.2%	Yes	209
Small Northern Medium Undergrounding	Kenora Hydro Electric	5,642	10.2%	Yes	226
Small Northern Medium Undergrounding	Lakeland Power Distribution	9,135	19.7%	Yes	789
Small Northern Medium Undergrounding	Ottawa River Power	10,230	13.0%	Yes	869
Mid-Size Northern	Greater Sudbury Hydro & West Nippissing	46,451	20.1%	Yes	90
Mid-Size Northern	North Bay Hydro Distribution	23,642	15.6%	Yes	408
Mid-Size Northern	PUC Distribution	32,512	15.7%	Yes	255
Mid-Size Northern	Thunder Bay Hydro Electricity Distribution	49,421	19.9%	Yes	428
Large Northern	Hydro One Networks	1,173,360	3.5%	Yes	855
Small Southern Low & Medium Undergrounding	Brant County Power	9,339	13.1%	No	2,164
Small Southern Low & Medium Undergrounding	Clinton Power	1,639	19.0%	No	331
Small Southern Low & Medium Undergrounding	Dutton Hydro	600	14.3%	No	2,755
Small Southern Low & Medium Undergrounding	Eastern Ontario Power	3,552	11.2%	No	313
Small Southern Low & Medium Undergrounding	Grand Valley Energy	677	11.1%	No	1,203
Small Southern Low & Medium Undergrounding	Hydro 2000	1,159	14.3%	No	1,106
Small Southern Low & Medium Undergrounding	Hydro Hawkesbury	5,428	13.8%	No	2,044
Small Southern Low & Medium Undergrounding	Lakefront Utilities	9,057	16.7%	No	1,967
Small Southern Low & Medium Undergrounding	Port Colborne	9,159	4.5%	No	391
Small Southern Low & Medium Undergrounding	Rideau St. Lawrence Distribution	5,864	10.3%	No	197
Small Southern Low & Medium Undergrounding	Wellington North Power	3,486	12.3%	No	857
Small Southern Medium-High Undergrounding	Middlesex Power Distribution	6,957	23.6%	No	1,809
Small Southern Medium-High Undergrounding	Midland Power Utility	6,709	31.3%	No	1,751
Small Southern Medium-High Undergrounding	Newbury Power	199	25.0%	No	1,168
Small Southern Medium-High Undergrounding	Tillsonburg Hydro	6,571	33.3%	No	1,596
Small Southern Medium-High Undergrounding	West Coast Huron Energy	3,853	20.0%	No	1,002
Small Southern Medium-High Undergrounding	West Perth Power	2,034	30.6%	No	1,530
Small Southern Medium-High Undergrounding with Rapid Growth[10]	Centre Wellington Hydro	6,239	47.3%	No	3,522
Small Southern Medium-High Undergrounding with Rapid Growth	Cooperative Hydro Embrun	1,882	44.4%	No	6,605
Small Southern Medium-High Undergrounding with Rapid Growth	Grimsby Power	9,792	24.3%	No	3,588
Small Southern Medium-High Undergrounding with Rapid Growth	Niagara-on-the-Lake Hydro	7,778	26.7%	No	2,800
Small Southern Medium-High Undergrounding with Rapid Growth	Orangeville Hydro	10,134	41.5%	No	3,582
Mid-size Southern Low & Medium Undergrounding	Fort Erie	15,494	8.4%	No	503
Mid-size Southern Low & Medium Undergrounding	Haldimand County Hydro	20,698	4.7%	No	780
Mid-size Southern Low & Medium Undergrounding	Innisfil Hydro Distribution Systems	14,120	18.2%	No	2,244
Mid-size Southern Low & Medium Undergrounding	Norfolk Power Distribution	18,641	12.5%	No	3,174
Mid-size Southern Low & Medium Undergrounding	Orillia Power Distribution	12,648	18.9%	No	1,199
Mid-size Southern Low & Medium Undergrounding	Peninsula West Utilities	15,491	7.9%	No	1,639
Mid-size Southern Medium-High Undergrounding	Bluewater Power Distribution	35,906	22.7%	No	837
Mid-size Southern Medium-High Undergrounding	Chatham-Kent Hydro	32,007	27.4%	No	401
Mid-size Southern Medium-High Undergrounding	COLLUS Power	14,325	33.9%	No	2,761
Mid-size Southern Medium-High Undergrounding	E.L.K. Energy	10,719	38.4%	No	2,233
Mid-size Southern Medium-High Undergrounding	Erie Thames Powerlines	14,181	19.1%	No	1,468
Mid-size Southern Medium-High Undergrounding	Essex Powerlines	27,789	50.3%	No	2,809
Mid-size Southern Medium-High Undergrounding	Festival Hydro	19,262	32.8%	No	1,605
Mid-size Southern Medium-High Undergrounding	Kingston Electricity Distribution	26,632	30.5%	No	-68
Mid-size Southern Medium-High Undergrounding	Niagara Falls Hydro	34,704	40.4%	No	1,225
Mid-size Southern Medium-High Undergrounding	Peterborough Distribution	34,161	29.5%	No	1,371
Mid-size Southern Medium-High Undergrounding	St. Thomas Energy	15,919	33.3%	No	2,591
Mid-size Southern Medium-High Undergrounding	Wasaga Distribution	11,311	45.4%	No	6,308
Mid-size Southern Medium-High Undergrounding	Welland Hydro-Electric System	21,389	24.9%	No	770
Mid-size Southern Medium-High Undergrounding	Westario Power	21,297	29.0%	No	1,188
Mid-size Southern Medium-High Undergrounding	Woodstock Hydro Services	14,441	43.3%	No	1,730
Large City Southern Medium-High Undergrounding	ENWIN Powerlines	84,757	36.2%	No	1,332
Large City Southern Medium-High Undergrounding	Hydro Ottawa	287,006	49.5%	No	2,653
Large City Southern Medium-High Undergrounding	Toronto Hydro-Electric System	679,913	45.5%	No	457
Large City Southern Medium-High Undergrounding	Veridian Connections	109,225	32.9%	No	2,837
Large City Southern High Undergrounding	Enersource Hydro Mississauga	183,715	65.3%	No	2,511
Large City Southern High Undergrounding	Horizon Utilities	232,493	55.0%	No	1,302
Large City Southern High Undergrounding	Hydro One Brampton Networks	126,026	70.4%	No	5,800
Large City Southern High Undergrounding	London Hydro	142,105	51.2%	No	2,265
Large City Southern High Undergrounding	PowerStream	236,220	69.3%	No	4,617
Mid-size GTA Medium-High & High Undergrounding	Barrie Hydro Distribution	68,535	54.9%	No	5,188
Mid-size GTA Medium-High & High Undergrounding	Brantford Power	37,108	44.3%	No	2,160
Mid-size GTA Medium-High & High Undergrounding	Burlington Hydro	61,776	40.2%	No	3,192
Mid-size GTA Medium-High & High Undergrounding	Cambridge and North Dumfries Hydro	48,944	33.9%	No	2,712
Mid-size GTA Medium-High & High Undergrounding	Guelph Hydro Electric Systems	47,720	58.6%	No	3,331
Mid-size GTA Medium-High & High Undergrounding	Halton Hills Hydro	20,078	34.4%	No	2,533
Mid-size GTA Medium-High & High Undergrounding	Kitchener-Wilmot Hydro	82,599	43.3%	No	2,730
Mid-size GTA Medium-High & High Undergrounding	Milton Hydro Distribution	22,811	35.2%	No	6,256
Mid-size GTA Medium-High & High Undergrounding	Newmarket Hydro & Tay Hydro	31,193	43.9%	No	2,746
Mid-size GTA Medium-High & High Undergrounding	Oakville Hydro Electricity Distribution	59,883	61.0%	No	4,067
Mid-size GTA Medium-High & High Undergrounding	Oshawa PUC Networks	50,980	46.2%	No	1,643
Mid-size GTA Medium-High & High Undergrounding	Waterloo North Hydro	49,558	31.5%	No	2,932
Mid-size GTA Medium-High & High Undergrounding	Whitby Hydro Electric	38,278	51.9%	No	5,447

[1] Latest year of available data.
[2] Small is defined as less than 10,000 customers with the exception of Great Lakes Power and Ottawa River Power, who have more than 10,000 customers but are defined as "small."
[3] Mid-size is defined as between 10,000 and 82,000 customers.
[4] Large is defined as more than 82,000 customers.
[5] Low undergrounding is defined as 0% to 10%.
[6] Medium undergrounding is between 10% and 20%.
[7] Medium-high undergrounding is between 20% and 50%.
[8] High undergrounding is over 50%.
[9] Rapid growth is defined as a value for (Customer Growth/Output Index) that exceeds 2,000.
[10] Centre Wellington is in the GTA but no GTA peer group is appropriate.

Table 2

Unit OM&A Cost Indexes

	2002	2003	2004	2005	2006	2007	Average of Last 3 Available Years[1]	Average / Group Average[2] [A]	Percentage Differences[2] [A - 1]	Implied Cost Surplus (Savings) per year[2]
Small Northern Low Undergrounding										
Renfrew Hydro	0.928	0.996	0.921	0.809	0.999	1.094	0.967	**0.584**	-41.6%	-$350,347
Espanola Regional Hydro Distribution	1.410	1.171	1.092	1.155	1.495	1.483	1.378	**0.832**	-16.8%	-$156,347
Northern Ontario Wires	1.375	1.223	1.369	1.192	1.270	1.374	1.279	**0.772**	-22.8%	-$395,437
Parry Sound Power	1.013	1.200	1.214	1.275	1.333	1.303	1.303	**0.787**	-21.3%	-$215,508
Fort Frances Power	1.197	1.213	1.236	1.305	1.346	1.442	1.365	**0.824**	-17.6%	-$192,252
Sioux Lookout Hydro	1.086	0.877	1.259	1.359	1.390	1.528	1.426	**0.861**	-13.9%	-$149,138
Atikokan Hydro	1.443	2.729	1.758	1.618	1.619	2.022	1.753	**1.058**	5.8%	$40,163
Chapleau Public Utilities	1.615	1.668	1.720	1.907	1.833	2.380	2.040	**1.231**	23.1%	$128,185
Great Lakes Power	2.983	2.924	3.116	3.308	3.412	3.476	3.399	**2.052**	105.2%	$8,371,020
GROUP AVERAGE							**1.657**			
Small Northern Medium Undergrounding										
Hearst Power Distribution	0.630	0.609	0.764	0.745	0.826	0.868	0.813	**0.799**	-20.1%	-$127,595
Lakeland Power Distribution	1.076	1.296	0.905	0.909	1.083	0.977	0.990	**0.972**	-2.8%	-$58,301
Ottawa River Power	0.940	1.043	1.020	0.989	1.070	1.200	1.087	**1.067**	6.7%	$141,026
Kenora Hydro Electric	1.098	1.117	1.155	1.114	1.149	1.284	1.183	**1.162**	16.2%	$208,696
GROUP AVERAGE							**1.018**			
Mid-Size Northern										
North Bay Hydro Distribution	1.126	1.005	0.991	0.878	1.147	1.007	1.010	**0.906**	-9.4%	-$487,201
PUC Distribution	0.866	0.937	1.070	1.046	1.028	1.166	1.080	**0.969**	-3.1%	-$225,144
Thunder Bay Hydro Electricity Distribution	1.087	1.178	1.130	1.016	1.070	1.179	1.088	**0.976**	-2.4%	-$262,212
Greater Sudbury Hydro & West Nippissing	1.034	0.996	1.121	1.003	1.069	1.769	1.280	**1.149**	14.9%	$1,743,696
GROUP AVERAGE							**1.115**			
Large Northern										
Hydro One Networks	n/a	1.015	0.969	1.042	1.252	1.465	1.253	**NA**	NA	NA
GROUP AVERAGE							**1.253**			
Small Southern Low & Medium Undergrounding										
Hydro Hawkesbury	0.495	0.517	0.473	0.568	0.537	0.581	0.562	**0.398**	-60.2%	-$450,834
Lakefront Utilities	0.669	0.594	0.681	0.807	0.876	0.890	0.858	**0.608**	-39.2%	-$710,739
Hydro 2000	0.572	0.649	0.648	1.164	0.930	0.989	1.028	**0.728**	-27.2%	-$65,796
Rideau St. Lawrence Distribution	1.029	1.060	1.058	1.157	1.198	1.257	1.204	**0.853**	-14.7%	-$200,189
Wellington North Power	1.179	1.077	1.121	1.170	1.237	1.213	1.207	**0.855**	-14.5%	-$143,409
Brant County Power	1.259	1.441	1.504	1.507	1.633	0.688	1.276	**0.904**	-9.6%	-$260,269
Clinton Power	1.244	1.302	1.119	1.229	1.599	1.795	1.541	**1.092**	9.2%	$42,543
Eastern Ontario Power	n/a	1.736	1.297	1.565	1.936	1.826	1.776	**1.258**	25.8%	$348,530
Dutton Hydro	1.310	1.428	2.325	1.592	1.538	n/a	1.818	**1.288**	28.8%	$49,469
Grand Valley Energy	1.623	1.461	1.600	1.814	2.294	2.012	2.040	**1.445**	44.5%	$98,248
Port Colborne	0.781	0.856	0.938	2.143	2.149	2.353	2.215	**1.570**	57.0%	$2,406,782
GROUP AVERAGE							**1.411**			
Small Southern Medium-High Undergrounding										
Middlesex Power Distribution	0.952	1.097	0.899	1.070	0.898	0.886	0.952	**0.842**	-15.8%	-$230,272
West Perth Power	1.087	1.129	1.044	0.886	1.137	1.103	1.042	**0.923**	-7.7%	-$38,634
Midland Power Utility	1.102	1.069	1.049	0.974	1.089	1.065	1.042	**0.923**	-7.7%	-$133,315
Tillsonburg Hydro	0.793	1.437	1.425	1.618	0.966	0.955	1.180	**1.044**	4.4%	$67,583
Newbury Power	n/a	n/a	1.320	1.030	1.216	1.477	1.241	**1.099**	9.9%	$4,889
West Coast Huron Energy	1.124	1.122	1.096	1.376	1.414	1.170	1.320	**1.169**	16.9%	$225,336
GROUP AVERAGE							**1.129**			
Small Southern Medium-High Undergrounding with Rapid Growth										
Grimsby Power	0.731	0.745	0.819	0.856	0.823	0.898	0.859	**0.876**	-12.4%	-$192,942
Orangeville Hydro	0.836	0.894	0.830	0.844	0.826	0.907	0.859	**0.876**	-12.4%	-$224,279
Niagara-on-the-Lake Hydro	0.885	0.830	0.915	0.838	0.929	1.028	0.932	**0.950**	-5.0%	-$79,402
Centre Wellington Hydro	1.196	1.146	1.083	1.079	1.095	1.109	1.094	**1.116**	11.6%	$171,344
Cooperative Hydro Embrun	0.979	1.056	0.945	1.112	1.128	1.237	1.159	**1.182**	18.2%	$67,523
GROUP AVERAGE							**0.981**			
Mid-Size Southern Low & Medium Undergrounding										
Norfolk Power Distribution	1.162	1.126	1.062	1.046	1.033	1.223	1.101	**0.894**	-10.6%	-$447,089
Peninsula West Utilities	1.090	1.133	1.184	1.295	1.174	0.871	1.114	**0.905**	-9.5%	-$376,880
Innisfil Hydro Distribution Systems	1.039	1.210	1.261	1.057	1.135	1.212	1.135	**0.922**	-7.8%	-$229,937
Orillia Power Distribution	0.934	1.041	1.074	1.200	1.174	1.264	1.213	**0.985**	-1.5%	-$50,688
Haldimand County Hydro	n/a	n/a	n/a	1.163	1.247	1.576	1.328	**1.079**	7.9%	$478,050
Fort Erie	1.437	1.281	1.299	1.357	1.510	1.619	1.496	**1.215**	21.5%	$979,789
GROUP AVERAGE							**1.231**			

[1] Last three years of available data.
[2] Lower values imply better performance.

Table 2 (cont'd)

Unit OM&A Cost Indexes

	2002	2003	2004	2005	2006	2007	Average of Last 3 Available Years[2]	Average / Group Average[2] [A]	Percentage Differences[2] [A - 1]
Mid-Size Southern Medium-High Undergrounding									
Chatham-Kent Hydro	0.668	0.665	0.700	0.690	0.702	0.721	0.704	**0.724**	-27.6%
Festival Hydro	0.754	0.709	0.724	0.698	0.782	0.774	0.752	**0.773**	-22.7%
Peterborough Distribution	0.794	0.739	0.802	0.778	0.884	0.914	0.859	**0.883**	-11.7%
Welland Hydro-Electric System	0.817	0.907	0.981	0.841	0.789	1.016	0.882	**0.907**	-9.3%
COLLUS Power	0.834	0.796	0.844	0.847	1.024	1.063	0.978	**1.005**	0.5%
E.L.K. Energy	0.960	1.011	0.856	0.579	0.846	0.873	0.766	**0.787**	-21.3%
Woodstock Hydro Services	0.831	0.898	0.923	0.932	0.969	1.008	0.969	**0.997**	-0.3%
Wasaga Distribution	0.843	0.892	0.971	1.070	1.147	1.114	1.110	**1.142**	14.2%
St. Thomas Energy	0.784	0.818	0.882	0.962	1.099	1.041	1.034	**1.063**	6.3%
Kingston Electricity Distribution	0.911	1.004	0.993	0.917	0.832	0.827	0.859	**0.883**	-11.7%
Niagara Falls Hydro	0.985	1.019	1.017	1.065	1.093	1.152	1.103	**1.135**	13.5%
Westario Power	0.988	1.140	1.165	1.017	1.003	0.958	0.993	**1.021**	2.1%
Bluewater Power Distribution	n/a	1.045	1.014	1.034	1.108	1.048	1.063	**1.093**	9.3%
Essex Powerlines	1.055	0.958	1.068	1.177	1.166	1.079	1.141	**1.173**	17.3%
Erie Thames Powerlines	1.054	1.248	1.277	1.323	1.270	1.534	1.376	**1.415**	41.5%
GROUP AVERAGE							**0.973**		
Large City Southern Medium-High Undergrounding									
Hydro Ottawa	0.838	0.760	0.641	0.595	0.723	0.695	0.671	**0.760**	-24.0%
Veridian Connections	0.951	1.122	0.930	0.829	0.875	0.774	0.826	**0.937**	-6.3%
Toronto Hydro-Electric System	0.844	0.876	0.905	0.850	0.846	0.915	0.870	**0.987**	-1.3%
ENWIN Powerlines	1.213	1.080	1.083	0.996	1.045	1.442	1.161	**1.316**	31.6%
GROUP AVERAGE							**0.882**		
Large City Southern High Undergrounding									
Hydro One Brampton Networks	0.574	0.563	0.518	0.514	0.561	0.526	0.534	**0.742**	-25.8%
Horizon Utilities	0.601	0.695	0.623	0.744	0.660	0.746	0.717	**0.997**	-0.3%
London Hydro	0.737	0.724	0.718	0.721	0.792	0.827	0.780	**1.084**	8.4%
PowerStream	0.634	0.725	0.751	0.772	0.703	0.765	0.747	**1.039**	3.9%
Enersource Hydro Mississauga	n/a	n/a	0.746	0.776	0.819	0.861	0.819	**1.138**	13.8%
GROUP AVERAGE							**0.719**		
Mid-Size GTA Medium-High Undergrounding									
Barrie Hydro Distribution	0.607	0.740	0.650	0.547	0.604	0.601	0.584	**0.739**	-26.1%
Cambridge and North Dumfries Hydro	0.617	0.609	0.657	0.594	0.597	0.685	0.625	**0.791**	-20.9%
Kitchener-Wilmot Hydro	0.599	0.615	0.613	0.626	0.690	0.703	0.673	**0.852**	-14.8%
Guelph Hydro Electric Systems	0.736	0.825	0.771	0.731	0.737	0.844	0.771	**0.976**	-2.4%
Waterloo North Hydro	0.836	0.812	0.813	0.766	0.785	0.760	0.770	**0.975**	-2.5%
Oshawa PUC Networks	0.920	0.989	0.971	0.725	0.741	0.796	0.754	**0.954**	-4.6%
Milton Hydro Distribution	0.859	0.815	0.796	0.808	0.792	0.805	0.801	**1.014**	1.4%
Burlington Hydro	0.738	0.771	0.797	0.782	0.858	0.889	0.843	**1.067**	6.7%
Newmarket Hydro & Tay Hydro	0.841	0.949	0.921	0.859	0.859	0.846	0.855	**1.082**	8.2%
Oakville Hydro Electricity Distribution	0.773	0.858	0.858	0.814	0.884	0.826	0.841	**1.065**	6.5%
Halton Hills Hydro	0.995	0.896	0.918	0.850	1.015	0.910	0.925	**1.171**	17.1%
Brantford Power	0.727	0.833	0.889	0.870	0.775	0.951	0.865	**1.095**	9.5%
Whitby Hydro Electric	0.927	1.002	0.898	0.916	0.966	1.007	0.963	**1.219**	21.9%
GROUP AVERAGE							**0.790**		
AVERAGE: ALL COMPANIES	**0.977**	**1.034**	**1.031**	**1.046**	**1.098**	**1.140**	**1.100**	**1.000**	**0.000**

[1] Last three years of available data.
[2] Lower values imply better performance.

Table 3

Updated Performance Rankings Based on Econometric Benchmarks

	Years Benchmarked	Actual/Predicted[1]	Deviation Percentage [A-1][1]	P-Value	Rank[1]
Hydro Hawkesbury	2005-2007	**0.643**	-0.357	0.000	1
Chatham-Kent Hydro	2005-2007	**0.691**	-0.309	0.001	2
Northern Ontario Wires	2005-2007	**0.711**	-0.289	0.001	3
Cambridge and North Dumfries Hydro	2005-2007	**0.715**	-0.285	0.002	4
E.L.K. Energy	2005-2007	**0.729**	-0.271	0.003	5
Grimsby Power	2005-2007	**0.764**	-0.236	0.008	6
Oshawa PUC Networks	2005-2007	**0.787**	-0.213	0.017	7
Lakeland Power Distribution	2005-2007	**0.789**	-0.211	0.018	8
Hydro One Brampton Networks	2005-2007	**0.793**	-0.207	0.020	9
Kitchener-Wilmot Hydro	2005-2007	**0.805**	-0.195	0.027	10
Renfrew Hydro	2005-2007	**0.807**	-0.193	0.028	11
Barrie Hydro Distribution	2005-2007	**0.814**	-0.186	0.034	12
Festival Hydro	2005-2007	**0.822**	-0.178	0.041	13
Welland Hydro-Electric System	2005-2007	**0.834**	-0.166	0.054	14
Hydro 2000	2005-2007	**0.840**	-0.160	0.060	15
Kingston Electricity Distribution	2005-2007	**0.860**	-0.140	0.090	16
Horizon Utilities	2005-2007	**0.864**	-0.136	0.098	17
Hydro Ottawa	2005-2007	**0.873**	-0.127	0.113	18
Lakefront Utilities	2005-2007	**0.874**	-0.126	0.115	19
Peninsula West Utilities	2005-2007	**0.878**	-0.122	0.123	20
Waterloo North Hydro	2005-2007	**0.880**	-0.120	0.127	21
Niagara-on-the-Lake Hydro	2005-2007	**0.894**	-0.106	0.158	22
Rideau St. Lawrence Distribution	2005-2007	**0.899**	-0.101	0.173	23
Kenora Hydro Electric	2005-2007	**0.904**	-0.096	0.185	24
Innisfil Hydro Distribution Systems	2005-2007	**0.908**	-0.092	0.194	25
Halton Hills Hydro	2005-2007	**0.914**	-0.086	0.212	26
Peterborough Distribution	2005-2007	**0.914**	-0.086	0.213	27
North Bay Hydro Distribution	2005-2007	**0.919**	-0.081	0.226	28
Atikokan Hydro	2005-2007	**0.927**	-0.073	0.250	29
Hearst Power Distribution	2005-2007	**0.932**	-0.068	0.265	30
Newmarket & Tay Hydro Electric	2005-2007	**0.933**	-0.067	0.268	31
Orangeville Hydro	2005-2007	**0.938**	-0.062	0.283	32
Enersource Hydro Mississauga	2005-2007	**0.958**	-0.042	0.351	33
Espanola Regional Hydro Distribution	2005-2007	**0.962**	-0.038	0.367	34
PUC Distribution	2005-2007	**0.966**	-0.034	0.378	35
Wellington North Power	2005-2007	**0.967**	-0.033	0.384	36
Middlesex Power Distribution	2005-2007	**0.970**	-0.030	0.392	37
Newbury Power	2005-2007	**0.977**	-0.023	0.416	38
Wasaga Distribution	2005-2007	**0.984**	-0.016	0.445	39
Veridian Connections	2005-2007	**0.991**	-0.009	0.469	40
Hydro One Networks	2005-2007	**0.996**	-0.004	0.485	41
Burlington Hydro	2005-2007	**1.008**	0.008	0.472	42
Brantford Power	2005-2007	**1.011**	0.011	0.461	43
Haldimand County Hydro	2005-2007	**1.016**	0.016	0.444	44
Westario Power	2005-2007	**1.017**	0.017	0.441	45
Tillsonburg Hydro	2005-2007	**1.019**	0.019	0.435	46
Toronto Hydro-Electric System	2005-2007	**1.021**	0.021	0.427	47
London Hydro	2005-2007	**1.028**	0.028	0.404	48
Woodstock Hydro Services	2005-2007	**1.037**	0.037	0.373	49
Ottawa River Power	2005-2007	**1.044**	0.044	0.350	50
Milton Hydro Distribution	2005-2007	**1.047**	0.047	0.342	51
Norfolk Power Distribution	2005-2007	**1.050**	0.050	0.332	52
Bluewater Power Distribution	2005-2007	**1.050**	0.050	0.331	53
Thunder Bay Hydro Electricity Distribution	2005-2007	**1.053**	0.053	0.324	54
Grand Valley Energy	2005-2007	**1.056**	0.056	0.314	55
Parry Sound Power	2005-2007	**1.063**	0.063	0.293	56
West Perth Power	2005-2007	**1.064**	0.064	0.290	57
COLLUS Power	2005-2007	**1.073**	0.073	0.265	58
Oakville Hydro Electricity Distribution	2005-2007	**1.077**	0.077	0.255	59
Cooperative Hydro Embrun	2005-2007	**1.080**	0.080	0.248	60
Clinton Power	2005-2007	**1.083**	0.083	0.238	61
Brant County Power	2005-2007	**1.087**	0.087	0.230	62
Orillia Power Distribution	2005-2007	**1.087**	0.087	0.229	63
St. Thomas Energy	2005-2007	**1.088**	0.088	0.228	64
Dutton Hydro	2004-2006	**1.096**	0.096	0.208	65
Sioux Lookout Hydro	2005-2007	**1.101**	0.101	0.197	66
Fort Erie (CNP)	2005-2007	**1.115**	0.115	0.167	67
Powerstream	2005-2007	**1.121**	0.121	0.155	68
Greater Sudbury-West Nipissing	2005-2007	**1.123**	0.123	0.151	69
Guelph Hydro Electric Systems	2005-2007	**1.131**	0.131	0.137	70
Fort Frances Power	2005-2007	**1.158**	0.158	0.097	71
Eastern Ontario Power (CNP)	2005-2007	**1.173**	0.173	0.079	72
Niagara Falls Hydro	2005-2007	**1.183**	0.183	0.068	73
Midland Power Utility	2005-2007	**1.202**	0.202	0.051	74
Centre Wellington Hydro	2005-2007	**1.203**	0.203	0.051	75
ENWIN Powerlines	2005-2007	**1.232**	0.232	0.032	76
Essex Powerlines	2005-2007	**1.247**	0.247	0.025	77
Whitby Hydro Electric	2005-2007	**1.261**	0.261	0.020	78
Chapleau Public Utilities	2005-2007	**1.328**	0.328	0.006	79
Erie Thames Powerlines	2005-2007	**1.365**	0.365	0.003	80
West Coast Huron Energy	2005-2007	**1.385**	0.385	0.002	81
Great Lakes Power	2005-2007	**1.441**	0.441	0.001	82
Port Colborne (CNP)	2005-2007	**1.515**	0.515	0.000	83

[1] Lower values imply better performance.

Table 4

Updated Performance Rankings Based on Unit Cost Indexes

	Average / Group Average[1] [A]	Percentage Differences[1] [A - 1]	Efficiency Ranking[1]
Hydro Hawkesbury	**0.398**	-60.2%	1
Renfrew Hydro	**0.584**	-41.6%	2
Lakefront Utilities	**0.608**	-39.2%	3
Chatham-Kent Hydro	**0.724**	-27.6%	4
Hydro 2000	**0.728**	-27.2%	5
Barrie Hydro Distribution	**0.739**	-26.1%	6
Hydro One Brampton Networks	**0.742**	-25.8%	7
Hydro Ottawa	**0.760**	-24.0%	8
Northern Ontario Wires	**0.772**	-22.8%	9
Festival Hydro	**0.773**	-22.7%	10
Parry Sound Power	**0.787**	-21.3%	11
E.L.K. Energy	**0.787**	-21.3%	12
Cambridge and North Dumfries Hydro	**0.791**	-20.9%	13
Hearst Power Distribution	**0.799**	-20.1%	14
Fort Frances Power	**0.824**	-17.6%	15
Espanola Regional Hydro Distribution	**0.832**	-16.8%	16
Middlesex Power Distribution	**0.842**	-15.8%	17
Kitchener-Wilmot Hydro	**0.852**	-14.8%	18
Rideau St. Lawrence Distribution	**0.853**	-14.7%	19
Wellington North Power	**0.855**	-14.5%	20
Sioux Lookout Hydro	**0.861**	-13.9%	21
Grimsby Power	**0.876**	-12.4%	22
Orangeville Hydro	**0.876**	-12.4%	23
Peterborough Distribution	**0.883**	-11.7%	24
Kingston Electricity Distribution	**0.883**	-11.7%	25
Norfolk Power Distribution	**0.894**	-10.6%	26
Brant County Power	**0.904**	-9.6%	27
Peninsula West Utilities	**0.905**	-9.5%	28
North Bay Hydro Distribution	**0.906**	-9.4%	29
Welland Hydro-Electric System	**0.907**	-9.3%	30
Innisfil Hydro Distribution Systems	**0.922**	-7.8%	31
West Perth Power	**0.923**	-7.7%	32
Midland Power Utility	**0.923**	-7.7%	33
Veridian Connections	**0.937**	-6.3%	34
Niagara-on-the-Lake Hydro	**0.950**	-5.0%	35
Oshawa PUC Networks	**0.954**	-4.6%	36
PUC Distribution	**0.969**	-3.1%	37
Lakeland Power Distribution	**0.972**	-2.8%	38
Waterloo North Hydro	**0.975**	-2.5%	39
Guelph Hydro Electric Systems	**0.976**	-2.4%	40
Thunder Bay Hydro Electricity Distribution	**0.976**	-2.4%	41
Orillia Power Distribution	**0.985**	-1.5%	42
Toronto Hydro-Electric System	**0.987**	-1.3%	43
Woodstock Hydro Services	**0.997**	-0.3%	44
Horizon Utilities	**0.997**	-0.3%	45
COLLUS Power	**1.005**	0.5%	46
Milton Hydro Distribution	**1.014**	1.4%	47
Westario Power	**1.021**	2.1%	48
PowerStream	**1.039**	3.9%	49
Tillsonburg Hydro	**1.044**	4.4%	50
Atikokan Hydro	**1.058**	5.8%	51
St. Thomas Energy	**1.063**	6.3%	52
Oakville Hydro Electricity Distribution	**1.065**	6.5%	53
Burlington Hydro	**1.067**	6.7%	54
Ottawa River Power	**1.067**	6.7%	55
Haldimand County Hydro	**1.079**	7.9%	56
Newmarket Hydro & Tay Hydro	**1.082**	8.2%	57
London Hydro	**1.084**	8.4%	58
Clinton Power	**1.092**	9.2%	59
Bluewater Power Distribution	**1.093**	9.3%	60
Brantford Power	**1.095**	9.5%	61
Newbury Power	**1.099**	9.9%	62
Centre Wellington Hydro	**1.116**	11.6%	63
Niagara Falls Hydro	**1.135**	13.5%	64
Enersource Hydro Mississauga	**1.138**	13.8%	65
Wasaga Distribution	**1.142**	14.2%	66
Greater Sudbury Hydro & West Nippissing	**1.149**	14.9%	67
Kenora Hydro Electric	**1.162**	16.2%	68
West Coast Huron Energy	**1.169**	16.9%	69
Halton Hills Hydro	**1.171**	17.1%	70
Essex Powerlines	**1.173**	17.3%	71
Cooperative Hydro Embrun	**1.182**	18.2%	72
Fort Erie	**1.215**	21.5%	73
Whitby Hydro Electric	**1.219**	21.9%	74
Chapleau Public Utilities	**1.231**	23.1%	75
Eastern Ontario Power	**1.258**	25.8%	76
Dutton Hydro	**1.288**	28.8%	77
ENWIN Powerlines	**1.316**	31.6%	78
Erie Thames Powerlines	**1.415**	41.5%	79
Grand Valley Energy	**1.445**	44.5%	80
Port Colborne	**1.570**	57.0%	81
Great Lakes Power	**2.052**	105.2%	82

[1] Lower values imply better performance.
[2] Hydro One Networks has no peer group and is not included in this analysis.

Table 5

Stretch Factor Results: 2007 Data Update

Company	Group	Stretch Factor
Hydro Hawkesbury	1	0.20%
Chatham-Kent Hydro	1	0.20%
Northern Ontario Wires	1	0.20%
Cambridge and North Dumfries Hydro	1	0.20%
E.L.K. Energy	1	0.20%
Hydro One Brampton Networks	1	0.20%
Kitchener-Wilmot Hydro	1	0.20%
Renfrew Hydro	1	0.20%
Barrie Hydro Distribution	1	0.20%
Festival Hydro	1	0.20%
Hydro 2000	1	0.20%
Grimsby Power	2	0.40%
Oshawa PUC Networks	2	0.40%
Lakeland Power Distribution	2	0.40%
Welland Hydro-Electric System	2	0.40%
Kingston Electricity Distribution	2	0.40%
Horizon Utilities	2	0.40%
Hydro Ottawa	2	0.40%
Lakefront Utilities	2	0.40%
Peninsula West Utilities	2	0.40%
Waterloo North Hydro	2	0.40%
Niagara-on-the-Lake Hydro	2	0.40%
Rideau St. Lawrence Distribution	2	0.40%
Kenora Hydro Electric	2	0.40%
Innisfil Hydro Distribution Systems	2	0.40%
Halton Hills Hydro	2	0.40%
Peterborough Distribution	2	0.40%
North Bay Hydro Distribution	2	0.40%
Atikokan Hydro	2	0.40%
Hearst Power Distribution	2	0.40%
Newmarket & Tay Hydro Electric	2	0.40%
Orangeville Hydro	2	0.40%
Enersource Hydro Mississauga	2	0.40%
Espanola Regional Hydro Distribution	2	0.40%
PUC Distribution	2	0.40%
Wellington North Power	2	0.40%
Middlesex Power Distribution	2	0.40%
Newbury Power	2	0.40%
Wasaga Distribution	2	0.40%
Veridian Connections	2	0.40%
Hydro One Networks	2	0.40%
Burlington Hydro	2	0.40%
Brantford Power	2	0.40%
Haldimand County Hydro	2	0.40%
Westario Power	2	0.40%
Tillsonburg Hydro	2	0.40%
Toronto Hydro-Electric System	2	0.40%
London Hydro	2	0.40%
Woodstock Hydro Services	2	0.40%
Ottawa River Power	2	0.40%
Milton Hydro Distribution	2	0.40%
Norfolk Power Distribution	2	0.40%
Bluewater Power Distribution	2	0.40%
Thunder Bay Hydro Electricity Distribution	2	0.40%
Grand Valley Energy	2	0.40%
Parry Sound Power	2	0.40%
West Perth Power	2	0.40%
COLLUS Power	2	0.40%
Oakville Hydro Electricity Distribution	2	0.40%
Cooperative Hydro Embrun	2	0.40%
Clinton Power	2	0.40%
Brant County Power	2	0.40%
Orillia Power Distribution	2	0.40%
St. Thomas Energy	2	0.40%
Dutton Hydro	2	0.40%
Sioux Lookout Hydro	2	0.40%
Fort Erie (CNP)	2	0.40%
Powerstream	2	0.40%
Greater Sudbury-West Nipissing	2	0.40%
Guelph Hydro Electric Systems	2	0.40%
Fort Frances Power	2	0.40%
Midland Power Utility	2	0.40%
Eastern Ontario Power (CNP)	3	0.60%
Niagara Falls Hydro	3	0.60%
Centre Wellington Hydro	3	0.60%
ENWIN Powerlines	3	0.60%
Essex Powerlines	3	0.60%
Whitby Hydro Electric	3	0.60%
Chapleau Public Utilities	3	0.60%
Erie Thames Powerlines	3	0.60%
West Coast Huron Energy	3	0.60%
Great Lakes Power	3	0.60%
Port Colborne (CNP)	3	0.60%

Table 6

Updated Performance Rankings Based on Econometric Benchmarks (Renfrew off the Canadian Shield)

	Years Benchmarked	Actual/Predicted[1]	Deviation Percentage [A-1][1]	P-Value	Rank[1]
Hydro Hawkesbury	2005-2007	**0.644**	-0.356	0.000	1
Chatham-Kent Hydro	2005-2007	**0.694**	-0.306	0.001	2
Northern Ontario Wires	2005-2007	**0.714**	-0.286	0.001	3
Cambridge and North Dumfries Hydro	2005-2007	**0.718**	-0.282	0.002	4
E.L.K. Energy	2005-2007	**0.733**	-0.267	0.003	5
Renfrew Hydro	2005-2007	**0.752**	-0.248	0.006	6
Grimsby Power	2005-2007	**0.769**	-0.231	0.010	7
Oshawa PUC Networks	2005-2007	**0.781**	-0.219	0.014	8
Lakeland Power Distribution	2005-2007	**0.787**	-0.213	0.017	9
Hydro One Brampton Networks	2005-2007	**0.792**	-0.208	0.019	10
Kitchener-Wilmot Hydro	2005-2007	**0.804**	-0.196	0.027	11
Barrie Hydro Distribution	2005-2007	**0.810**	-0.190	0.031	12
Festival Hydro	2005-2007	**0.827**	-0.173	0.046	13
Welland Hydro-Electric System	2005-2007	**0.839**	-0.161	0.060	14
Hydro 2000	2005-2007	**0.845**	-0.155	0.068	15
Kingston Electricity Distribution	2005-2007	**0.868**	-0.132	0.105	16
Horizon Utilities	2005-2007	**0.872**	-0.128	0.113	17
Hydro Ottawa	2005-2007	**0.873**	-0.127	0.114	18
Kenora Hydro Electric	2005-2007	**0.875**	-0.125	0.118	19
Peninsula West Utilities	2005-2007	**0.877**	-0.123	0.123	20
Waterloo North Hydro	2005-2007	**0.878**	-0.122	0.125	21
Lakefront Utilities	2005-2007	**0.878**	-0.122	0.125	22
Hearst Power Distribution	2005-2007	**0.891**	-0.109	0.154	23
Niagara-on-the-Lake Hydro	2005-2007	**0.898**	-0.102	0.170	24
Rideau St. Lawrence Distribution	2005-2007	**0.906**	-0.094	0.190	25
Halton Hills Hydro	2005-2007	**0.908**	-0.092	0.196	26
Innisfil Hydro Distribution Systems	2005-2007	**0.911**	-0.089	0.204	27
North Bay Hydro Distribution	2005-2007	**0.916**	-0.084	0.217	28
Peterborough Distribution	2005-2007	**0.919**	-0.081	0.228	29
Atikokan Hydro	2005-2007	**0.922**	-0.078	0.237	30
Newmarket & Tay Hydro Electric	2005-2007	**0.930**	-0.070	0.260	31
Orangeville Hydro	2005-2007	**0.940**	-0.060	0.291	32
Espanola Regional Hydro Distribution	2005-2007	**0.946**	-0.054	0.310	33
Enersource Hydro Mississauga	2005-2007	**0.956**	-0.044	0.344	34
PUC Distribution	2005-2007	**0.965**	-0.035	0.377	35
Middlesex Power Distribution	2005-2007	**0.973**	-0.027	0.405	36
Newbury Power	2005-2007	**0.982**	-0.018	0.436	37
Wasaga Distribution	2005-2007	**0.984**	-0.016	0.444	38
Wellington North Power	2005-2007	**0.991**	-0.009	0.468	39
Veridian Connections	2005-2007	**0.995**	-0.005	0.483	40
Burlington Hydro	2005-2007	**1.007**	0.007	0.474	41
Haldimand County Hydro	2005-2007	**1.012**	0.012	0.457	42
Ottawa River Power	2005-2007	**1.015**	0.015	0.448	43
Brantford Power	2005-2007	**1.018**	0.018	0.438	44
Toronto Hydro-Electric System	2005-2007	**1.019**	0.019	0.433	45
Westario Power	2005-2007	**1.022**	0.022	0.424	46
London Hydro	2005-2007	**1.026**	0.026	0.411	47
Tillsonburg Hydro	2005-2007	**1.027**	0.027	0.406	48
Hydro One Networks	2005-2007	**1.037**	0.037	0.375	49
Parry Sound Power	2005-2007	**1.038**	0.038	0.372	50
Woodstock Hydro Services	2005-2007	**1.043**	0.043	0.356	51
Milton Hydro Distribution	2005-2007	**1.043**	0.043	0.354	52
Norfolk Power Distribution	2005-2007	**1.051**	0.051	0.329	53
Thunder Bay Hydro Electricity Distribution	2005-2007	**1.057**	0.057	0.313	54
Bluewater Power Distribution	2005-2007	**1.059**	0.059	0.305	55
Grand Valley Energy	2005-2007	**1.060**	0.060	0.302	56
West Perth Power	2005-2007	**1.066**	0.066	0.285	57
Oakville Hydro Electricity Distribution	2005-2007	**1.075**	0.075	0.260	58
COLLUS Power	2005-2007	**1.076**	0.076	0.257	59
Cooperative Hydro Embrun	2005-2007	**1.077**	0.077	0.254	60
Clinton Power	2005-2007	**1.084**	0.084	0.236	61
St. Thomas Energy	2005-2007	**1.092**	0.092	0.218	62
Dutton Hydro	2004-2006	**1.092**	0.092	0.217	63
Brant County Power	2005-2007	**1.096**	0.096	0.207	64
Sioux Lookout Hydro	2005-2007	**1.097**	0.097	0.206	65
Orillia Power Distribution	2005-2007	**1.098**	0.098	0.204	66
Powerstream	2005-2007	**1.110**	0.110	0.178	67
Greater Sudbury-West Nipissing	2005-2007	**1.126**	0.126	0.147	68
Fort Erie (CNP)	2005-2007	**1.127**	0.127	0.145	69
Guelph Hydro Electric Systems	2005-2007	**1.129**	0.129	0.141	70
Fort Frances Power	2005-2007	**1.129**	0.129	0.141	71
Niagara Falls Hydro	2005-2007	**1.185**	0.185	0.066	72
Eastern Ontario Power (CNP)	2005-2007	**1.198**	0.198	0.055	73
Centre Wellington Hydro	2005-2007	**1.205**	0.205	0.049	74
Midland Power Utility	2005-2007	**1.207**	0.207	0.048	75
Essex Powerlines	2005-2007	**1.253**	0.253	0.023	76
ENWIN Powerlines	2005-2007	**1.253**	0.253	0.023	77
Whitby Hydro Electric	2005-2007	**1.257**	0.257	0.021	78
Chapleau Public Utilities	2005-2007	**1.273**	0.273	0.017	79
Erie Thames Powerlines	2005-2007	**1.376**	0.376	0.002	80
West Coast Huron Energy	2005-2007	**1.392**	0.392	0.002	81
Great Lakes Power	2005-2007	**1.475**	0.475	0.000	82
Port Colborne (CNP)	2005-2007	**1.540**	0.540	0.000	83

[1] Lower values imply better performance.

Table 7

Updated Performance Rankings Based on Econometric Benchmarks (26% allocation for LV charges)

	Years Benchmarked	Actual/Predicted[1]	Deviation Percentage [A-1][1]	P-Value	Rank[1]
Hydro Hawkesbury	2005-2007	**0.657**	-0.343	0.000	1
Northern Ontario Wires	2005-2007	**0.712**	-0.288	0.001	2
Chatham-Kent Hydro	2005-2007	**0.713**	-0.287	0.001	3
Cambridge and North Dumfries Hydro	2005-2007	**0.718**	-0.282	0.001	4
Grimsby Power	2005-2007	**0.754**	-0.246	0.005	5
E.L.K. Energy	2005-2007	**0.764**	-0.236	0.007	6
Oshawa PUC Networks	2005-2007	**0.773**	-0.227	0.009	7
Hydro One Brampton Networks	2005-2007	**0.790**	-0.210	0.015	8
Kitchener-Wilmot Hydro	2005-2007	**0.800**	-0.200	0.020	9
Renfrew Hydro	2005-2007	**0.811**	-0.189	0.026	10
Welland Hydro-Electric System	2005-2007	**0.825**	-0.175	0.037	11
Lakeland Power Distribution	2005-2007	**0.826**	-0.174	0.038	12
Festival Hydro	2005-2007	**0.827**	-0.173	0.039	13
Barrie Hydro Distribution	2005-2007	**0.841**	-0.159	0.055	14
Horizon Utilities	2005-2007	**0.865**	-0.135	0.090	15
Niagara-on-the-Lake Hydro	2005-2007	**0.865**	-0.135	0.090	16
Waterloo North Hydro	2005-2007	**0.873**	-0.127	0.105	17
Hydro Ottawa	2005-2007	**0.875**	-0.125	0.109	18
Atikokan Hydro	2005-2007	**0.877**	-0.123	0.113	19
Kingston Electricity Distribution	2005-2007	**0.879**	-0.121	0.115	20
Kenora Hydro Electric	2005-2007	**0.883**	-0.117	0.124	21
Peninsula West Utilities	2005-2007	**0.896**	-0.104	0.154	22
Lakefront Utilities	2005-2007	**0.909**	-0.091	0.189	23
Hydro 2000	2005-2007	**0.910**	-0.090	0.190	24
North Bay Hydro Distribution	2005-2007	**0.911**	-0.089	0.193	25
Newmarket & Tay Hydro Electric	2005-2007	**0.918**	-0.082	0.214	26
Rideau St. Lawrence Distribution	2005-2007	**0.919**	-0.081	0.217	27
Innisfil Hydro Distribution Systems	2005-2007	**0.925**	-0.075	0.236	28
Hearst Power Distribution	2005-2007	**0.926**	-0.074	0.237	29
Peterborough Distribution	2005-2007	**0.926**	-0.074	0.239	30
Halton Hills Hydro	2005-2007	**0.926**	-0.074	0.240	31
Espanola Regional Hydro Distribution	2005-2007	**0.957**	-0.043	0.343	32
Wellington North Power	2005-2007	**0.958**	-0.042	0.347	33
PUC Distribution	2005-2007	**0.961**	-0.039	0.358	34
Newbury Power	2005-2007	**0.963**	-0.037	0.363	35
Orangeville Hydro	2005-2007	**0.966**	-0.034	0.374	36
Middlesex Power Distribution	2005-2007	**0.969**	-0.031	0.387	37
Enersource Hydro Mississauga	2005-2007	**0.979**	-0.021	0.424	38
Tillsonburg Hydro	2005-2007	**0.985**	-0.015	0.443	39
Hydro One Networks	2005-2007	**0.988**	-0.012	0.456	40
Wasaga Distribution	2005-2007	**0.988**	-0.012	0.456	41
Haldimand County Hydro	2005-2007	**1.001**	0.001	0.498	42
Burlington Hydro	2005-2007	**1.004**	0.004	0.485	43
Toronto Hydro-Electric System	2005-2007	**1.004**	0.004	0.484	44
Brantford Power	2005-2007	**1.007**	0.007	0.472	45
Veridian Connections	2005-2007	**1.011**	0.011	0.460	46
Woodstock Hydro Services	2005-2007	**1.017**	0.017	0.437	47
London Hydro	2005-2007	**1.022**	0.022	0.419	48
Milton Hydro Distribution	2005-2007	**1.031**	0.031	0.387	49
Westario Power	2005-2007	**1.045**	0.045	0.343	50
Norfolk Power Distribution	2005-2007	**1.045**	0.045	0.340	51
Cooperative Hydro Embrun	2005-2007	**1.047**	0.047	0.334	52
Bluewater Power Distribution	2005-2007	**1.050**	0.050	0.326	53
Grand Valley Energy	2005-2007	**1.050**	0.050	0.324	54
Thunder Bay Hydro Electricity Distribution	2005-2007	**1.051**	0.051	0.324	55
Ottawa River Power	2005-2007	**1.060**	0.060	0.293	56
West Perth Power	2005-2007	**1.064**	0.064	0.282	57
Brant County Power	2005-2007	**1.068**	0.068	0.270	58
Parry Sound Power	2005-2007	**1.070**	0.070	0.267	59
St. Thomas Energy	2005-2007	**1.073**	0.073	0.258	60
Oakville Hydro Electricity Distribution	2005-2007	**1.078**	0.078	0.243	61
Fort Erie (CNP)	2005-2007	**1.097**	0.097	0.196	62
Dutton Hydro	2004-2006	**1.101**	0.101	0.187	63
COLLUS Power	2005-2007	**1.103**	0.103	0.182	64
Orillia Power Distribution	2005-2007	**1.104**	0.104	0.181	65
Powerstream	2005-2007	**1.117**	0.117	0.153	66
Fort Frances Power	2005-2007	**1.124**	0.124	0.139	67
Guelph Hydro Electric Systems	2005-2007	**1.125**	0.125	0.138	68
Greater Sudbury-West Nipissing	2005-2007	**1.127**	0.127	0.133	69
Clinton Power	2005-2007	**1.133**	0.133	0.123	70
Eastern Ontario Power (CNP)	2005-2007	**1.141**	0.141	0.111	71
Sioux Lookout Hydro	2005-2007	**1.144**	0.144	0.107	72
Niagara Falls Hydro	2005-2007	**1.169**	0.169	0.074	73
Centre Wellington Hydro	2005-2007	**1.181**	0.181	0.061	74
Midland Power Utility	2005-2007	**1.229**	0.229	0.028	75
ENWIN Powerlines	2005-2007	**1.234**	0.234	0.026	76
Whitby Hydro Electric	2005-2007	**1.257**	0.257	0.017	77
Essex Powerlines	2005-2007	**1.272**	0.272	0.013	78
Chapleau Public Utilities	2005-2007	**1.280**	0.280	0.011	79
West Coast Huron Energy	2005-2007	**1.340**	0.340	0.003	80
Erie Thames Powerlines	2005-2007	**1.388**	0.388	0.001	81
Great Lakes Power	2005-2007	**1.402**	0.402	0.001	82
Port Colborne (CNP)	2005-2007	**1.484**	0.484	0.000	83

[1] Lower values imply better performance.

Table 8

Updated Performance Rankings Based on Unit Cost Indexes (26% Allocation for LV charges)

	Average / Group Average[1] [A]	Percentage Differences[1] [A - 1]	Efficiency Ranking[1]
Hydro Hawkesbury	**0.402**	-59.8%	1
Renfrew Hydro	**0.602**	-39.8%	2
Lakefront Utilities	**0.616**	-38.4%	3
Chatham-Kent Hydro	**0.735**	-26.5%	4
Hydro One Brampton Networks	**0.740**	-26.0%	5
Hydro Ottawa	**0.759**	-24.1%	6
Barrie Hydro Distribution	**0.763**	-23.7%	7
Festival Hydro	**0.769**	-23.1%	8
Northern Ontario Wires	**0.774**	-22.6%	9
Cambridge and North Dumfries Hydro	**0.793**	-20.7%	10
Hearst Power Distribution	**0.801**	-19.9%	11
Hydro 2000	**0.804**	-19.6%	12
Parry Sound Power	**0.809**	-19.1%	13
Fort Frances Power	**0.815**	-18.5%	14
E.L.K. Energy	**0.825**	-17.5%	15
Middlesex Power Distribution	**0.830**	-17.0%	16
Wellington North Power	**0.836**	-16.4%	17
Kitchener-Wilmot Hydro	**0.844**	-15.6%	18
Espanola Regional Hydro Distribution	**0.845**	-15.5%	19
Rideau St. Lawrence Distribution	**0.852**	-14.8%	20
Brant County Power	**0.862**	-13.8%	21
Grimsby Power	**0.867**	-13.3%	22
Peterborough Distribution	**0.880**	-12.0%	23
Welland Hydro-Electric System	**0.885**	-11.5%	24
Norfolk Power Distribution	**0.889**	-11.1%	25
Kingston Electricity Distribution	**0.890**	-11.0%	26
Orangeville Hydro	**0.903**	-9.7%	27
North Bay Hydro Distribution	**0.906**	-9.4%	28
Sioux Lookout Hydro	**0.909**	-9.1%	29
Peninsula West Utilities	**0.919**	-8.1%	30
Niagara-on-the-Lake Hydro	**0.924**	-7.6%	31
West Perth Power	**0.933**	-6.7%	32
Midland Power Utility	**0.935**	-6.5%	33
Oshawa PUC Networks	**0.939**	-6.1%	34
Innisfil Hydro Distribution Systems	**0.939**	-6.1%	35
Veridian Connections	**0.950**	-5.0%	36
Waterloo North Hydro	**0.965**	-3.5%	37
PUC Distribution	**0.968**	-3.2%	38
Thunder Bay Hydro Electricity Distribution	**0.973**	-2.7%	39
Guelph Hydro Electric Systems	**0.973**	-2.7%	40
Woodstock Hydro Services	**0.976**	-2.4%	41
Toronto Hydro-Electric System	**0.978**	-2.2%	42
Tillsonburg Hydro	**0.997**	-0.3%	43
Horizon Utilities	**0.998**	-0.2%	44
Lakeland Power Distribution	**0.999**	-0.1%	45
Orillia Power Distribution	**1.004**	0.4%	46
Milton Hydro Distribution	**1.012**	1.2%	47
COLLUS Power	**1.027**	2.7%	48
Atikokan Hydro	**1.035**	3.5%	49
PowerStream	**1.039**	3.9%	50
Westario Power	**1.041**	4.1%	51
St. Thomas Energy	**1.041**	4.1%	52
Haldimand County Hydro	**1.056**	5.6%	53
Burlington Hydro	**1.063**	6.3%	54
Oakville Hydro Electricity Distribution	**1.069**	6.9%	55
Newmarket Hydro & Tay Hydro	**1.070**	7.0%	56
Bluewater Power Distribution	**1.074**	7.4%	57
Ottawa River Power	**1.074**	7.4%	58
London Hydro	**1.079**	7.9%	59
Brantford Power	**1.095**	9.5%	60
Niagara Falls Hydro	**1.106**	10.6%	61
Centre Wellington Hydro	**1.112**	11.2%	62
Kenora Hydro Electric	**1.125**	12.5%	63
West Coast Huron Energy	**1.128**	12.8%	64
Wasaga Distribution	**1.135**	13.5%	65
Clinton Power	**1.144**	14.4%	66
Enersource Hydro Mississauga	**1.145**	14.5%	67
Greater Sudbury Hydro & West Nippissing	**1.153**	15.3%	68
Newbury Power	**1.177**	17.7%	69
Essex Powerlines	**1.188**	18.8%	70
Halton Hills Hydro	**1.193**	19.3%	71
Fort Erie	**1.193**	19.3%	72
Cooperative Hydro Embrun	**1.195**	19.5%	73
Eastern Ontario Power	**1.204**	20.4%	74
Whitby Hydro Electric	**1.222**	22.2%	75
Chapleau Public Utilities	**1.240**	24.0%	76
ENWIN Powerlines	**1.313**	31.3%	77
Dutton Hydro	**1.327**	32.7%	78
Erie Thames Powerlines	**1.427**	42.7%	79
Grand Valley Energy	**1.467**	46.7%	80
Port Colborne	**1.486**	48.6%	81
Great Lakes Power	**1.972**	97.2%	82

[1] Lower values imply better performance.
[2] Hydro One Networks has no peer group and is not included in this analysis.

Table 9

Stretch Factor Results: 2007 Data Update (26% Allocation for LV Charges)

Company	Group	Stretch Factor
Hydro Hawkesbury	1	0.20%
Northern Ontario Wires	1	0.20%
Chatham-Kent Hydro	1	0.20%
Cambridge and North Dumfries Hydro	1	0.20%
E.L.K. Energy	1	0.20%
Hydro One Brampton Networks	1	0.20%
Kitchener-Wilmot Hydro	1	0.20%
Renfrew Hydro	1	0.20%
Festival Hydro	1	0.20%
Barrie Hydro Distribution	1	0.20%
Grimsby Power	2	0.40%
Oshawa PUC Networks	2	0.40%
Welland Hydro-Electric System	2	0.40%
Lakeland Power Distribution	2	0.40%
Horizon Utilities	2	0.40%
Niagara-on-the-Lake Hydro	2	0.40%
Waterloo North Hydro	2	0.40%
Hydro Ottawa	2	0.40%
Atikokan Hydro	2	0.40%
Kingston Electricity Distribution	2	0.40%
Kenora Hydro Electric	2	0.40%
Peninsula West Utilities	2	0.40%
Lakefront Utilities	2	0.40%
Hydro 2000	2	0.40%
North Bay Hydro Distribution	2	0.40%
Newmarket & Tay Hydro Electric	2	0.40%
Rideau St. Lawrence Distribution	2	0.40%
Innisfil Hydro Distribution Systems	2	0.40%
Hearst Power Distribution	2	0.40%
Peterborough Distribution	2	0.40%
Halton Hills Hydro	2	0.40%
Espanola Regional Hydro Distribution	2	0.40%
Wellington North Power	2	0.40%
PUC Distribution	2	0.40%
Newbury Power	2	0.40%
Orangeville Hydro	2	0.40%
Middlesex Power Distribution	2	0.40%
Enersource Hydro Mississauga	2	0.40%
Tillsonburg Hydro	2	0.40%
Hydro One Networks	2	0.40%
Wasaga Distribution	2	0.40%
Haldimand County Hydro	2	0.40%
Burlington Hydro	2	0.40%
Toronto Hydro-Electric System	2	0.40%
Brantford Power	2	0.40%
Veridian Connections	2	0.40%
Woodstock Hydro Services	2	0.40%
London Hydro	2	0.40%
Milton Hydro Distribution	2	0.40%
Westario Power	2	0.40%
Norfolk Power Distribution	2	0.40%
Cooperative Hydro Embrun	2	0.40%
Bluewater Power Distribution	2	0.40%
Grand Valley Energy	2	0.40%
Thunder Bay Hydro Electricity Distribution	2	0.40%
Ottawa River Power	2	0.40%
West Perth Power	2	0.40%
Brant County Power	2	0.40%
Parry Sound Power	2	0.40%
St. Thomas Energy	2	0.40%
Oakville Hydro Electricity Distribution	2	0.40%
Fort Erie (CNP)	2	0.40%
Dutton Hydro	2	0.40%
COLLUS Power	2	0.40%
Orillia Power Distribution	2	0.40%
Powerstream	2	0.40%
Fort Frances Power	2	0.40%
Guelph Hydro Electric Systems	2	0.40%
Greater Sudbury-West Nipissing	2	0.40%
Clinton Power	2	0.40%
Eastern Ontario Power (CNP)	2	0.40%
Sioux Lookout Hydro	2	0.40%
Niagara Falls Hydro	2	0.40%
Centre Wellington Hydro	2	0.40%
Midland Power Utility	2	0.40%
ENWIN Powerlines	3	0.60%
Whitby Hydro Electric	3	0.60%
Essex Powerlines	3	0.60%
Chapleau Public Utilities	3	0.60%
West Coast Huron Energy	3	0.60%
Erie Thames Powerlines	3	0.60%
Great Lakes Power	3	0.60%
Port Colborne (CNP)	3	0.60%

Table 10

Updated Performance Rankings Based on Econometric Benchmarks (26% allocation for LV charges divided by 2.35)

	Years Benchmarked	Actual/Predicted[1]	Deviation Percentage [A-1][1]	P-Value	Rank[1]
Hydro Hawkesbury	2005-2007	**0.648**	-0.352	0.000	1
Chatham-Kent Hydro	2005-2007	**0.700**	-0.300	0.001	2
Northern Ontario Wires	2005-2007	**0.712**	-0.288	0.001	3
Cambridge and North Dumfries Hydro	2005-2007	**0.716**	-0.284	0.001	4
E.L.K. Energy	2005-2007	**0.743**	-0.257	0.004	5
Grimsby Power	2005-2007	**0.759**	-0.241	0.006	6
Oshawa PUC Networks	2005-2007	**0.781**	-0.219	0.013	7
Hydro One Brampton Networks	2005-2007	**0.792**	-0.208	0.017	8
Kitchener-Wilmot Hydro	2005-2007	**0.803**	-0.197	0.024	9
Lakeland Power Distribution	2005-2007	**0.804**	-0.196	0.024	10
Renfrew Hydro	2005-2007	**0.810**	-0.190	0.028	11
Festival Hydro	2005-2007	**0.822**	-0.178	0.038	12
Barrie Hydro Distribution	2005-2007	**0.826**	-0.174	0.042	13
Welland Hydro-Electric System	2005-2007	**0.829**	-0.171	0.045	14
Horizon Utilities	2005-2007	**0.865**	-0.135	0.094	15
Kingston Electricity Distribution	2005-2007	**0.866**	-0.134	0.096	16
Hydro 2000	2005-2007	**0.870**	-0.130	0.103	17
Hydro Ottawa	2005-2007	**0.876**	-0.124	0.114	18
Waterloo North Hydro	2005-2007	**0.877**	-0.123	0.117	19
Niagara-on-the-Lake Hydro	2005-2007	**0.880**	-0.120	0.123	20
Peninsula West Utilities	2005-2007	**0.886**	-0.114	0.136	21
Lakefront Utilities	2005-2007	**0.888**	-0.112	0.141	22
Kenora Hydro Electric	2005-2007	**0.895**	-0.105	0.157	23
Rideau St. Lawrence Distribution	2005-2007	**0.907**	-0.093	0.187	24
Atikokan Hydro	2005-2007	**0.908**	-0.092	0.191	25
North Bay Hydro Distribution	2005-2007	**0.914**	-0.086	0.208	26
Innisfil Hydro Distribution Systems	2005-2007	**0.915**	-0.085	0.209	27
Peterborough Distribution	2005-2007	**0.918**	-0.082	0.219	28
Halton Hills Hydro	2005-2007	**0.918**	-0.082	0.219	29
Newmarket & Tay Hydro Electric	2005-2007	**0.926**	-0.074	0.242	30
Hearst Power Distribution	2005-2007	**0.930**	-0.070	0.255	31
Orangeville Hydro	2005-2007	**0.949**	-0.051	0.317	32
Espanola Regional Hydro Distribution	2005-2007	**0.960**	-0.040	0.356	33
Wellington North Power	2005-2007	**0.962**	-0.038	0.362	34
PUC Distribution	2005-2007	**0.962**	-0.038	0.364	35
Enersource Hydro Mississauga	2005-2007	**0.966**	-0.034	0.377	36
Middlesex Power Distribution	2005-2007	**0.968**	-0.032	0.384	37
Newbury Power	2005-2007	**0.970**	-0.030	0.391	38
Wasaga Distribution	2005-2007	**0.986**	-0.014	0.448	39
Veridian Connections	2005-2007	**1.001**	0.001	0.496	40
Tillsonburg Hydro	2005-2007	**1.002**	0.002	0.491	41
Burlington Hydro	2005-2007	**1.006**	0.006	0.478	42
Hydro One Networks	2005-2007	**1.007**	0.007	0.476	43
Brantford Power	2005-2007	**1.008**	0.008	0.472	44
Haldimand County Hydro	2005-2007	**1.010**	0.010	0.463	45
Toronto Hydro-Electric System	2005-2007	**1.015**	0.015	0.445	46
London Hydro	2005-2007	**1.026**	0.026	0.409	47
Westario Power	2005-2007	**1.027**	0.027	0.405	48
Woodstock Hydro Services	2005-2007	**1.027**	0.027	0.403	49
Milton Hydro Distribution	2005-2007	**1.040**	0.040	0.361	50
Norfolk Power Distribution	2005-2007	**1.048**	0.048	0.334	51
Bluewater Power Distribution	2005-2007	**1.049**	0.049	0.333	52
Thunder Bay Hydro Electricity Distribution	2005-2007	**1.050**	0.050	0.328	53
Grand Valley Energy	2005-2007	**1.051**	0.051	0.327	54
Ottawa River Power	2005-2007	**1.051**	0.051	0.325	55
West Perth Power	2005-2007	**1.062**	0.062	0.292	56
Cooperative Hydro Embrun	2005-2007	**1.064**	0.064	0.286	57
Parry Sound Power	2005-2007	**1.066**	0.066	0.280	58
Oakville Hydro Electricity Distribution	2005-2007	**1.077**	0.077	0.251	59
Brant County Power	2005-2007	**1.078**	0.078	0.247	60
St. Thomas Energy	2005-2007	**1.080**	0.080	0.244	61
COLLUS Power	2005-2007	**1.084**	0.084	0.232	62
Orillia Power Distribution	2005-2007	**1.093**	0.093	0.210	63
Dutton Hydro	2004-2006	**1.096**	0.096	0.201	64
Clinton Power	2005-2007	**1.103**	0.103	0.186	65
Fort Erie (CNP)	2005-2007	**1.107**	0.107	0.178	66
Powerstream	2005-2007	**1.121**	0.121	0.151	67
Sioux Lookout Hydro	2005-2007	**1.121**	0.121	0.151	68
Greater Sudbury-West Nipissing	2005-2007	**1.124**	0.124	0.145	69
Guelph Hydro Electric Systems	2005-2007	**1.127**	0.127	0.139	70
Fort Frances Power	2005-2007	**1.144**	0.144	0.112	71
Eastern Ontario Power (CNP)	2005-2007	**1.158**	0.158	0.092	72
Niagara Falls Hydro	2005-2007	**1.175**	0.175	0.072	73
Centre Wellington Hydro	2005-2007	**1.191**	0.191	0.056	74
Midland Power Utility	2005-2007	**1.211**	0.211	0.041	75
ENWIN Powerlines	2005-2007	**1.232**	0.232	0.029	76
Essex Powerlines	2005-2007	**1.257**	0.257	0.019	77
Whitby Hydro Electric	2005-2007	**1.260**	0.260	0.018	78
Chapleau Public Utilities	2005-2007	**1.310**	0.310	0.007	79
West Coast Huron Energy	2005-2007	**1.363**	0.363	0.003	80
Erie Thames Powerlines	2005-2007	**1.373**	0.373	0.002	81
Great Lakes Power	2005-2007	**1.432**	0.432	0.001	82
Port Colborne (CNP)	2005-2007	**1.502**	0.502	0.000	83

[1] Lower values imply better performance.

Table 11

Updated Performance Rankings Based on Unit Cost Indexes (26% allocation for LV charges divided by 2.35)

	Average / Group Average[1] [A]	Percentage Differences[1] [A - 1]	Efficiency Ranking[1]
Hydro Hawkesbury	**0.399**	-60.1%	1
Renfrew Hydro	**0.592**	-40.8%	2
Lakefront Utilities	**0.610**	-39.0%	3
Chatham-Kent Hydro	**0.728**	-27.2%	4
Hydro One Brampton Networks	**0.741**	-25.9%	5
Barrie Hydro Distribution	**0.750**	-25.0%	6
Hydro Ottawa	**0.760**	-24.0%	7
Hydro 2000	**0.762**	-23.8%	8
Festival Hydro	**0.771**	-22.9%	9
Northern Ontario Wires	**0.772**	-22.8%	10
Cambridge and North Dumfries Hydro	**0.791**	-20.9%	11
Parry Sound Power	**0.796**	-20.4%	12
Hearst Power Distribution	**0.799**	-20.1%	13
E.L.K. Energy	**0.804**	-19.6%	14
Fort Frances Power	**0.820**	-18.0%	15
Middlesex Power Distribution	**0.836**	-16.4%	16
Espanola Regional Hydro Distribution	**0.838**	-16.2%	17
Wellington North Power	**0.846**	-15.4%	18
Kitchener-Wilmot Hydro	**0.848**	-15.2%	19
Rideau St. Lawrence Distribution	**0.852**	-14.8%	20
Grimsby Power	**0.872**	-12.8%	21
Sioux Lookout Hydro	**0.880**	-12.0%	22
Peterborough Distribution	**0.881**	-11.9%	23
Brant County Power	**0.884**	-11.6%	24
Kingston Electricity Distribution	**0.886**	-11.4%	25
Orangeville Hydro	**0.887**	-11.3%	26
Norfolk Power Distribution	**0.892**	-10.8%	27
Welland Hydro-Electric System	**0.897**	-10.3%	28
North Bay Hydro Distribution	**0.906**	-9.4%	29
Peninsula West Utilities	**0.910**	-9.0%	30
Midland Power Utility	**0.927**	-7.3%	31
West Perth Power	**0.927**	-7.3%	32
Innisfil Hydro Distribution Systems	**0.930**	-7.0%	33
Niagara-on-the-Lake Hydro	**0.938**	-6.2%	34
Veridian Connections	**0.944**	-5.6%	35
Oshawa PUC Networks	**0.948**	-5.2%	36
PUC Distribution	**0.969**	-3.1%	37
Waterloo North Hydro	**0.971**	-2.9%	38
Guelph Hydro Electric Systems	**0.974**	-2.6%	39
Thunder Bay Hydro Electricity Distribution	**0.974**	-2.6%	40
Toronto Hydro-Electric System	**0.981**	-1.9%	41
Lakeland Power Distribution	**0.983**	-1.7%	42
Woodstock Hydro Services	**0.988**	-1.2%	43
Orillia Power Distribution	**0.993**	-0.7%	44
Horizon Utilities	**0.997**	-0.3%	45
Milton Hydro Distribution	**1.014**	1.4%	46
COLLUS Power	**1.015**	1.5%	47
Tillsonburg Hydro	**1.024**	2.4%	48
Westario Power	**1.030**	3.0%	49
PowerStream	**1.038**	3.8%	50
Atikokan Hydro	**1.049**	4.9%	51
St. Thomas Energy	**1.054**	5.4%	52
Burlington Hydro	**1.065**	6.5%	53
Oakville Hydro Electricity Distribution	**1.066**	6.6%	54
Haldimand County Hydro	**1.069**	6.9%	55
Ottawa River Power	**1.071**	7.1%	56
Newmarket Hydro & Tay Hydro	**1.077**	7.7%	57
London Hydro	**1.083**	8.3%	58
Bluewater Power Distribution	**1.083**	8.3%	59
Brantford Power	**1.096**	9.6%	60
Centre Wellington Hydro	**1.114**	11.4%	61
Clinton Power	**1.115**	11.5%	62
Niagara Falls Hydro	**1.121**	12.1%	63
Newbury Power	**1.137**	13.7%	64
Enersource Hydro Mississauga	**1.140**	14.0%	65
Wasaga Distribution	**1.142**	14.2%	66
Kenora Hydro Electric	**1.147**	14.7%	67
West Coast Huron Energy	**1.149**	14.9%	68
Greater Sudbury Hydro & West Nippissing	**1.151**	15.1%	69
Essex Powerlines	**1.180**	18.0%	70
Halton Hills Hydro	**1.181**	18.1%	71
Cooperative Hydro Embrun	**1.190**	19.0%	72
Fort Erie	**1.206**	20.6%	73
Whitby Hydro Electric	**1.221**	22.1%	74
Eastern Ontario Power	**1.234**	23.4%	75
Chapleau Public Utilities	**1.237**	23.7%	76
Dutton Hydro	**1.309**	30.9%	77
ENWIN Powerlines	**1.315**	31.5%	78
Erie Thames Powerlines	**1.420**	42.0%	79
Grand Valley Energy	**1.459**	45.9%	80
Port Colborne	**1.531**	53.1%	81
Great Lakes Power	**2.016**	101.6%	82

[1] Lower values imply better performance.
[2] Hydro One Networks has no peer group and is not included in this analysis.

Table 12

Stretch Factor Results: 2007 Data Update (26% allocation of LV charges divided by 2.35)

Company	Group	Stretch Factor
Hydro Hawkesbury	1	0.20%
Chatham-Kent Hydro	1	0.20%
Northern Ontario Wires	1	0.20%
Cambridge and North Dumfries Hydro	1	0.20%
E.L.K. Energy	1	0.20%
Hydro One Brampton Networks	1	0.20%
Kitchener-Wilmot Hydro	1	0.20%
Renfrew Hydro	1	0.20%
Festival Hydro	1	0.20%
Barrie Hydro Distribution	1	0.20%
Grimsby Power	2	0.40%
Oshawa PUC Networks	2	0.40%
Lakeland Power Distribution	2	0.40%
Welland Hydro-Electric System	2	0.40%
Horizon Utilities	2	0.40%
Kingston Electricity Distribution	2	0.40%
Hydro 2000	2	0.40%
Hydro Ottawa	2	0.40%
Waterloo North Hydro	2	0.40%
Niagara-on-the-Lake Hydro	2	0.40%
Peninsula West Utilities	2	0.40%
Lakefront Utilities	2	0.40%
Kenora Hydro Electric	2	0.40%
Rideau St. Lawrence Distribution	2	0.40%
Atikokan Hydro	2	0.40%
North Bay Hydro Distribution	2	0.40%
Innisfil Hydro Distribution Systems	2	0.40%
Peterborough Distribution	2	0.40%
Halton Hills Hydro	2	0.40%
Newmarket & Tay Hydro Electric	2	0.40%
Hearst Power Distribution	2	0.40%
Orangeville Hydro	2	0.40%
Espanola Regional Hydro Distribution	2	0.40%
Wellington North Power	2	0.40%
PUC Distribution	2	0.40%
Enersource Hydro Mississauga	2	0.40%
Middlesex Power Distribution	2	0.40%
Newbury Power	2	0.40%
Wasaga Distribution	2	0.40%
Veridian Connections	2	0.40%
Tillsonburg Hydro	2	0.40%
Burlington Hydro	2	0.40%
Hydro One Networks	2	0.40%
Brantford Power	2	0.40%
Haldimand County Hydro	2	0.40%
Toronto Hydro-Electric System	2	0.40%
London Hydro	2	0.40%
Westario Power	2	0.40%
Woodstock Hydro Services	2	0.40%
Milton Hydro Distribution	2	0.40%
Norfolk Power Distribution	2	0.40%
Bluewater Power Distribution	2	0.40%
Thunder Bay Hydro Electricity Distribution	2	0.40%
Grand Valley Energy	2	0.40%
Ottawa River Power	2	0.40%
West Perth Power	2	0.40%
Cooperative Hydro Embrun	2	0.40%
Parry Sound Power	2	0.40%
Oakville Hydro Electricity Distribution	2	0.40%
Brant County Power	2	0.40%
St. Thomas Energy	2	0.40%
COLLUS Power	2	0.40%
Orillia Power Distribution	2	0.40%
Dutton Hydro	2	0.40%
Clinton Power	2	0.40%
Fort Erie (CNP)	2	0.40%
Powerstream	2	0.40%
Sioux Lookout Hydro	2	0.40%
Greater Sudbury-West Nipissing	2	0.40%
Guelph Hydro Electric Systems	2	0.40%
Fort Frances Power	2	0.40%
Centre Wellington Hydro	2	0.40%
Midland Power Utility	2	0.40%
Eastern Ontario Power (CNP)	3	0.60%
Niagara Falls Hydro	3	0.60%
ENWIN Powerlines	3	0.60%
Essex Powerlines	3	0.60%
Whitby Hydro Electric	3	0.60%
Chapleau Public Utilities	3	0.60%
West Coast Huron Energy	3	0.60%
Erie Thames Powerlines	3	0.60%
Great Lakes Power	3	0.60%
Port Colborne (CNP)	3	0.60%

BEFORE THE
CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	Cause No. PUD 200800398
AUTHORIZING APPLICANT TO MODIFY ITS	)	
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

FILED
FEB 27 2009
COURT CLERK'S OFFICE – OKC
CORPORATION COMMISSION
OF OKLAHOMA

Direct Testimony

of

Mark Newton Lowry

On behalf of

Oklahoma Gas and Electric Company

February 27, 2009

Mark Newton Lowry
Direct Testimony

I. INTRODUCTION

Q. **Please state your name and business address.**

A. My name is Mark Newton Lowry. My business address is 22 E. Mifflin St., Suite 302, Madison, WI 53703.

Q. **By whom are you employed and in what capacity?**

A. I am a partner in the Madison, Wisconsin office of Pacific Economics Group ("PEG") and President of Pacific Economics Group Research LLC. In addition to my managerial responsibilities, I supervise an extensive program of statistical cost research, design alternative regulation ("Altreg") plans, and provide expert witness testimony.

Q. **Please discuss your background and experience in the energy and utility industries.**

A. I have been an energy economist for twenty five years and have spent the last twenty as a consultant on utility regulation. Before joining PEG I worked at Christensen Associates in Madison, first as a Senior Economist and later as Vice President for Regulatory Strategy. The primary focus of my consulting research has been the cost of gas and electric service. I was a pioneer in the use of statistical cost research in energy utility benchmarking and Altreg plan design. My practice is international in scope and has to date included projects in seven countries.

Clients have included regulatory commissions as well as utilities. For example, power distributors in the Canadian province of Ontario operate under multiyear rate plans with terms that are linked to a benchmarking study I directed for the Ontario Energy Board.

Before becoming a consultant I spent five years as an academic economist. I was an Assistant Professor of Mineral Economics at the Pennsylvania State University, where I taught energy economics. I also worked as a Visiting Professor at l'Ecole des Hautes Etudes Commerciales in Montreal. My academic research and teaching stressed the use of economic theory and statistics in petroleum market analysis.

I have served as a referee for several scholarly journals and have an extensive record of professional publications and public appearances. My publications include articles on benchmarking in recent issues of the *Electricity Journal* and the *Energy Journal.* I hold a Ph.D. in applied economics from the University of Wisconsin, which is noted for its strength in economic statistics. My experience is described in more detail in Exhibit MNL-1 to my testimony.

Q. **Have you appeared as an expert witness in other utility proceedings?**

A. Yes. I have testified many times on benchmarking and Altreg issues, and most of this testimony has involved statistical cost research. In addition to Oklahoma, where I have previously testified on Altreg and benchmarking issues for Oklahoma Gas & Electric Company ("OG&E" or "Company"), I have testified in Alberta, British Columbia, California, Georgia, Hawaii, Illinois, Kentucky, Maine, Massachusetts, Missouri, Oklahoma, New York, Ontario, Quebec, and Vermont. Further details of my testimony can be found in Exhibit MNL-1.

II. PURPOSE OF TESTIMONY

Q. **What is the purpose of your direct testimony?**

A. I have been asked by OG&E to conduct a study of its efficiency in managing base rate operation and maintenance expenses ("O&M Cost Performance Study"). This testimony provides a summary of the study, which is described in greater detail in the report provided as Exhibit MNL-2.

Q. **Why is such a study important?**

A. Efforts to effectively manage costs are always important to the Company, its customers and the Commission. At a time when consumer budgets are pinched by a worsening recession, efforts to manage costs are even more critical. Base rate O&M expenses are the largest component of base rate costs that the Company can attempt to control in the short run. My study assesses the results of OG&E's base rate O&M expense management.

Q. **What are the general conclusions of your O&M Cost Performance Study?**

A. OG&E is exceptional at managing its base rate O&M expenses. The study uses two well established statistical benchmarking methods. Under the first benchmarking method, the econometric model, OG&E is 30 percent below where its costs were predicted to have been. When compared to similar benchmarks of 37 other utilities across the United States, OG&E is the third best cost performer. Under the second benchmarking method, peer group unit cost analysis, OG&E's costs are 23 percent below the average of past and present members of the Southwest Power Pool ("SPP").

III. SUMMARY OF STUDY

Q. **What is statistical benchmarking and how is it useful in measuring utility performance?**

A. Statistical benchmarking uses statistics to establish benchmarks that can be used in quantitative performance appraisals. Cost benchmarks can be used to gauge a particular utility's efficiency. The primary set of statistics used to establish cost benchmarks is utility operating data. These data are available from many forms and reports that utilities file with federal government agencies.

Accurate benchmarking is complicated because the costs of utilities vary more because of differences in the business conditions they face than because of differences in their operating efficiency. A cost benchmark for a particular utility should therefore reflect the typical performance that might be expected of managers given the local business conditions which that particular utility faced. Statistical cost research can identify important cost drivers and use such cost drivers to establish better performance metrics and benchmarks.

Q. **What component of the Company's cost did you address in the study?**

A. We addressed the efficiency of OG&E in managing its base rate O&M expenses. Base rate O&M expenses were defined as total O&M expenses less expenses for generation fuels, purchased power, employee pensions and benefits, load dispatching, transmission services by others, and regional market management. These expenses were excluded from the study because they are characteristically volatile, and/or are significantly subject to external influences and as such are substantially beyond the Company's control.

Q. **Please summarize the benchmarking methods that you used in your study of OG&E.**

A. The cost performance of OG&E was appraised using two well-established benchmarking methods: econometric modeling and unit cost indexing. Using both methods, we calculated average performance results for the three most recent years, in keeping with good benchmarking practice.

Q. **Please describe the econometric modeling.**

A. The econometric modeling involved the use of a model designed to explain the impact of various quantifiable business conditions on the base rate O&M expenses of vertically integrated electric utilities. The parameters of the model, which measure cost impact, were estimated statistically using historical data on utility operations. A model fitted with econometric parameter estimates and the specific business conditions faced by OG&E during the appraisal years was used to generate cost benchmarks.

The econometric model was based on a sample of good quality data for 38 U.S. vertically integrated electric utilities (including OG&E). The sample period for model estimation was 1995 to 2007. The year 2007 is the latest for which the requisite data are currently available for most sampled companies. All data were drawn from respected public sources. The sample was more than adequate for the development of a credible cost model. The model had high explanatory power and all estimates of the key model parameters were plausible and highly significant. Once the model estimation was completed, the business conditions facing OG&E for 2006, 2007 and 2008 were inputted into the model to determine the cost benchmarks.

Q. **What are the key empirical results of the econometric modeling?**

A. The base rate O&M expenses of OG&E were found to be about 30% below the benchmark generated by our econometric cost model on average from 2006 to 2008. This performance was in the top quartile and third best in the sample. We conclude that OG&E was a significantly superior cost performer.

Q. **Please describe the unit cost indexing.**

A. As I stated earlier, the other benchmarking method we employed involved the comparison of the base rate O&M expenses of OG&E to those of a peer group using unit cost indexes. A unit cost index is the ratio of a cost index to an output index. Parameter estimates from our cost model were used to design an output index that was a weighted average of comparisons of sales volumes and customers served. We chose investor-owned utilities that were current or former members of the SPP as a sensible peer group. The year 2008 could not be appraised using the indexing method because of the lack of data for peers, so we instead focused on the 2005-2007 period.

Q. **What are the key empirical results of the unit cost indexing?**

A. OG&E's unit cost index was about 23% below the mean for the sampled peer group on average from 2005 to 2007. This performance was good for a virtual tie as the best in the peer group. The unit cost results are consistent with the econometric results and support a finding of superior cost management.

Q. **Does this conclude your direct testimony?**

A. Yes, it does.

Exhibit MNL-1

RESUME OF MARK NEWTON LOWRY

February 2009

Home Address: 1511 Sumac Drive
Madison, WI 53705
(608) 233-4822

Business Address: 22 E. Mifflin St., Suite 302
Madison, WI 53703
(608) 257-1522 Ext. 23

Date of Birth: August 7, 1952

Education: High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Agricultural and Resource Economics, University of Wisconsin-Madison, May 1984

Relevant Work Experience, Primary Positions:

Present Position — **President, Pacific Economics Group Research LLC, Madison WI**

Leads internationally recognized practice in the field of statistical cost research for energy utility benchmarking and alternative regulation ("Altreg"). Other research specialties include utility industry restructuring, codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include project management and expert witness testimony.

October 1998-February 2009 — **Partner, Pacific Economics Group, Madison, WI**

Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

January 1993-October 1998 — **Vice President**
January 1989-December 1992 — **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility Altreg and benchmarking.

Aug. 1984-Dec. 1988 — **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

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

August 1983-July 1984 — **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 **Research Assistant to Dr. Peter Helmberger, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

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

March 1981-March 1982 **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.

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

Relevant Work Experience, Visiting Positions:

May-August 1985 **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in metal markets.

Major Consulting Projects:

1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
2. Impact of the Natural Gas Policy Act on U.S. Production and Wellhead Prices. New England Fuel Institute, 1981
3. Modeling Customer Response to Curtailable Service Programs. Electric Power Research Institute, 1989.
4. Customer Response to Interruptible Service Programs. Southern California Edison, 1989.
5. Measuring Load Relief from Interruptible Services. New England Electric Power Service, 1989.
6. Design of Time-of-Use Rates for Residential Customers. Iowa Power, 1989.
7. Incentive Regulation: Can it Pay for Interstate Gas Companies? Southern Natural Gas, 1989.
8. Measuring the Productivity Growth of Gas Transmission Companies. Interstate Natural Gas Association of America, 1990.
9. Measuring Productivity Trends in the Local Gas Distribution Industry. Niagara Mohawk Power, 1990.
10. Measurement of Productivity Trends for the U.S. Electric Power Industry. Niagara Mohawk Power, 1990-91.
11. Comprehensive Performance Indexes for Electric and Gas Distribution Utilities. Niagara Mohawk Power, 1990-1991.
12. Workshop on PBR for Electric Utilities. Southern Company Services, 1991.
13. Economics of Electric Revenue Adjustment Mechanisms. Niagara Mohawk Power, 1991.
14. Sales Promotion Policies of Gas Distributors. Northern States Power-Wisconsin, 1991.
15. Productivity Growth Estimates for U.S. Gas Distributors and Their Use in PBR. Southern California Gas, 1991.

16. Cost Performance Indexes for Gas and Electric Utilities. Niagara Mohawk Power, 1991.
17. Efficient Rate Design for Interstate Gas Transporters. AEPCO, 1991.
18. Benchmarking Gas Supply Services and Testimony. Niagara Mohawk Power, 1992.
19. Gas Supply Cost Indexes for Incentive Regulation. Pacific Gas & Electric, 1992.
20. Gas Transportation Strategy for an Arizona Electric Utility. AEPCO, 1992.
21. Design and Negotiation of a Comprehensive Benchmark Incentive Plans for Gas Distribution and Bundled Power Service. Niagara Mohawk Power, 1992.
22. Productivity Research, PBR Plan Design, and Testimony. Niagara Mohawk Power, 1993-94.
23. Development of Incentive Regulation Options. Southern California Edison, 1993.
24. Review of the Southwest Gas Transportation Market. Arizona Electric Power Cooperative, 1993.
25. Productivity Research and Testimony in Support of a Price Cap Plan. Central Maine Power, 1994.
26. Productivity Research for a Natural Gas Distributor, Southern California Gas, 1994.
27. White Paper on Price Cap Regulation For Electric Utilities. Edison Electric Institute, 1994.
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O&M COST PERFORMANCE OF OKLAHOMA GAS & ELECTRIC

Pacific Economics Group Research, LLC

O&M Cost Performance of Oklahoma Gas & Electric

26 February 2009

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1. Introduction and Summary

1.1 Introduction

Statistical benchmarking has in recent years become a widely used tool in the assessment of utility operating performance. Managers use benchmarking to gauge how well their companies are doing. Benchmarking also plays a growing role in regulation. Such studies can, for instance, be used to assess the reasonableness of utility proposals to establish new rates or rate adjustment mechanisms.

The benchmarking of utilities is facilitated by the extensive data that they report to regulators. However, accurate performance appraisals are still difficult to make. There are important differences between utilities in the character of services that they provide, the overall scale of their operations, the prices they pay for inputs, and other business conditions that influence their cost.

The personnel of Pacific Economics Group ("PEG") Research have been active for more than a decade in the field of utility benchmarking. We pioneered the use of rigorous benchmarking methods in U.S. regulation. Senior author Mark Newton Lowry has testified on benchmarking issues in numerous proceedings.

Oklahoma Gas & Electric ("OG&E" or "the Company") is filing in this proceeding for an increase in the base rates that recover the cost of its nonfuel inputs. Evidence of good cost management is highly relevant to the proceeding. The Company has retained PEG to benchmark its base rate operation and maintenance ("O&M") expenses. These expenses account for the bulk of the cost of base rate inputs over which the Company can exercise control in the short run.

Following a brief summary of the work below, Section 2 provides an introduction to benchmarking methods. Section 3 discusses our research for OG&E. More technical details of our research are presented in the Appendix.

1.2 Summary of Research

We addressed the efficiency of OG&E in managing its base rate O&M expenses. Cost was defined as total O&M expenses less expenses for generation fuel, purchased power, employee pensions and benefits, transmission dispatching, transmission services by others, and regional market management. Expenses were excluded on the grounds that they, were exceptionally volatile, or were substantially beyond the control of OG&E.

The cost performance of OG&E was appraised using two well established benchmarking methods: econometric modeling and unit cost indexing. Guided by economic theory, we developed a model of the impact that various quantifiable business conditions have on the base rate O&M expenses of vertically integrated electric utilities ("VIEUs"). The parameters of the model, which measure cost impact, were estimated statistically using historical data on the operations of VIEUs. A model fitted with econometric parameter estimates was used to benchmark the recent historical cost of OG&E given the business conditions that it faced.

The study was based on a sample of good quality data for 38 U.S. VIEUs. The sample period was 1995 to 2007.[1] All data were drawn from respected public sources. The sample was more than adequate for the development of a credible cost model. The model had high explanatory power and all estimates of the key model parameters were plausible and highly significant.

The base rate O&M cost of OG&E was found to be about 30% below the benchmark generated by the econometric model on average from 2006 to 2008. This performance was the third best in the sample. The hypothesis that OG&E was an average or inferior cost performer during these years can be rejected at a high level of confidence. We conclude that OG&E was a significantly superior cost performer.

PEG has also compared the unit cost of OG&E to those of a peer group using unit cost indexes. A unit cost index is the ratio of a cost index to an output index. We chose investor-owned utilities that are currently or historically participants in the Southwest Power Pool (SPP) as the peer group. OG&E's unit cost index was about 23% below the mean for

[1] PEG also incorporated preliminary 2008 data provided by OG&E in the benchmarking study. 2008 data for the other sampled companies are as yet unavailable.

the sampled utilities on average during the 2005-2007 period. This result placed the Company in a virtual tie for the best performance in the peer group. The unit cost results are consistent with the econometric results and support a finding of superior cost management.

2. An Introduction to Benchmarking

In this section of the report we provide a non-technical discussion of some important benchmarking concepts. The two benchmarking methods used in the study are explained. More technical details of our methodology are discussed in the Appendix.

2.1 What is Benchmarking?

The word benchmark originally 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 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 sometimes called key performance indicators ("KPIs") or metrics. 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 process of drawing conclusions about performance from benchmark comparisons. An approach to benchmarking that prominently features statistical methods is called statistical benchmarking.

Various performance standards can be used in benchmarking. These standards often reflect statistical concepts. One sensible standard is the average performance of the utilities in the sample. An alternative standard that is popular is the performance that would define the margin of the top quartile of performers.

These concepts are usefully illustrated by the process through which decisions are made to elect athletes to the Pro Football Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Running backs, for example, are evaluated using multiple performance indicators that include touchdowns, rushing yardage, and fumbles. The values achieved by Hall of Fame members like Barry Sanders are useful benchmarks. These values reflect a Hall of Fame performance standard.

2.2 Importance of Business Conditions

For costs and many other kinds of business performance indicators, it is widely recognized that differences in the values of the indicators that companies achieve depend as much or more on differences in the business conditions that they face than on differences in performance. In cost research these conditions are sometimes called cost "drivers". The cost performance of a company depends on the cost that it achieves given the business conditions that it faces. Benchmarks must reflect local business conditions if they are to reflect a chosen performance standard faithfully.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. Under certain reasonable assumptions, cost functions exist that relate the minimum cost of an enterprise to business conditions in its service territory. When the focus of benchmarking is a subset of total cost such as base rate O&M expenses, the relevant business conditions include the prices of base rate O&M inputs, the operating scale of the company and, additionally, the amounts of *other inputs* that the company uses.

The existence of other input variables in 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 opportunities exist for the substitution of inputs in production. Suppose, for example, that the focus of benchmarking is a utility's base rate O&M expenses. Theory indicates that the level of these expenses depends on the amounts of fuel, purchased power, and capital that the company uses. Another reason that "other inputs" matter is that there are inconsistencies in the manner in which utilities classify costs. Utilities may, for instance, differ in the way that they categorize certain expenditures between administrative and direct operating expenses. This discussion suggests that benchmarking will tend to be simpler and more accurate to the extent that the scope of costs under consideration is comprehensive. It will, for example, be easier to accurately benchmark *total* base rate O&M expenses than it will be to accurately benchmark *labor* expenses.

Whichever cost function is applicable, economic 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 a VIEU, for instance, depends on the number of customers that it serves as well as its sales volume. It is also noteworthy that theory allows for the possibility that numerous business conditions other than input prices and output quantities affect the minimum cost of service.

2.3 Benchmarking Methods

In this section we discuss the two benchmarking methods that we used in our study for OG&E: econometric modeling and unit cost indexing. The econometric approach is discussed first to establish a context for the appraisal of the index approach. The section concludes by discussing the merits of averaging benchmark results over several years.

2.3.1 Econometric Modeling

Basic Assumptions

Relationships between the costs of utilities and the business conditions that they face can be estimated using statistics. A branch of statistics called econometrics has developed procedures for estimating the parameters of economic models using historical data.[2] The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions that they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a cross section consisting of one observation for each of several companies, or a panel data set that pools time series data for several companies.

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

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. In a benchmarking study used in utility regulation 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.

Cost Predictions and Performance Appraisals

A cost function 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. Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year and company by the econometric model.

Suppose, for example, that we wish to benchmark the cost of a hypothetical electric utility called Southwest Power. We might then predict the cost of Southwest in period *t* using the following model.

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

Here $\hat{C}_{Southwest,t}$ denotes the predicted cost of the Company, $N_{Southwest,t}$ is the number of customers it served, and $W_{Southwest,t}$ 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

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

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 performance standard and properly controls for the impact of business conditions on cost.

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. It is therefore desirable to include in an econometric benchmarking model all business conditions which are believed to be relevant, for which good data are available at reasonable cost, and which have plausible and statistically significant parameter estimates.

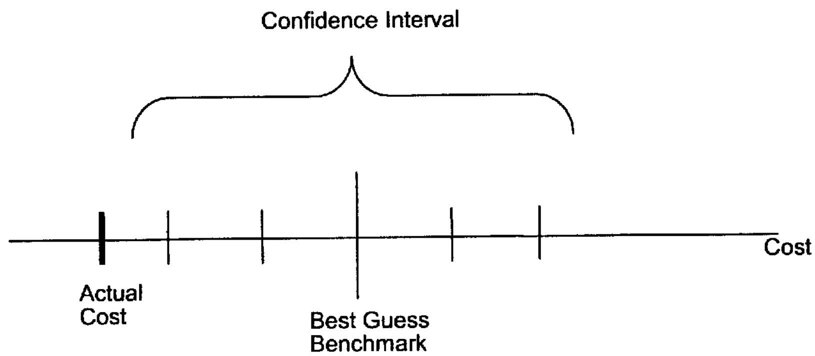
Even when an econometric benchmarking model is unbiased it can be imprecise, yielding predictions that are sometimes too high and on other occasions too low. Statistical theory provides the foundation for the construction of confidence intervals that represent the full range of possible predictions that are consistent with the sample data at a given level of confidence. In general, it can be shown that confidence intervals are wider, suggesting greater uncertainty, 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 sampled 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 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 benchmarks are more likely to be biased. It follows that it will generally be preferable to use panel data when these are available instead of a single cross section of data. Panel sets of data on the operations of electric utilities are, fortunately, readily available in the United States. Notice also that the precision of an econometric benchmarking exercise is *enhanced* by using data from companies with diverse operating conditions.

Testing Efficiency Hypotheses

Confidence intervals developed from econometric results permit us to test hypotheses regarding cost efficiency. Suppose, for example, that we use a sample average performance 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 is less than the benchmark generated by the model but nonetheless lies within the confidence interval, this hypothesis cannot be rejected. In other words, the company is not a *significantly* superior 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, as in the figure below. We may then conclude that the company is a *significantly superior* cost performer.



An important advantage of efficiency hypothesis tests is that they take into account the accuracy of the benchmarking exercise. As we have just discussed, there is uncertainty involved in the calculation 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 larger the greater is the uncertainty regarding the true benchmark value. If uncertainty is great, our ability to draw conclusions about operating efficiency is hampered. Accurate benchmarking of companies facing business conditions that are atypical of the sample can be problematic. But with econometric benchmarking regulators at least have a notion of how much they don't know.

2.3.2 Benchmarking Indexes

The index-based approach to benchmarking is the one that 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 indexes.

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)".[3] In utility performance benchmarking, indexing involves the calculation of ratios of the values of KPIs for a subject utility to the corresponding values for a sample of utilities. The group of companies represented in the sample is sometimes called a peer group.

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 commonly summarize the inflation (year to year comparisons) in the prices of hundreds of goods and services. The weight for the inflation in the price of each product is its share of the value of all of the products considered.

To better appreciate the advantages of multi-category indexes in benchmarking, recall from our discussion in Section 2.2 that multiple variables are often needed to accurately measure utility workload. We might, then, wish to construct an output index that takes a weighted average of two or three output comparisons. In a cost benchmarking application, it makes sense for the weights of an output index to reflect the relative importance of the individual output variables as cost drivers. The importance of each variable is conventionally measured by its cost elasticity. The elasticity of cost with respect to the number of customers served, for instance, is the percentage change in cost that results from a 1% change in the number. It is straightforward to estimate the required elasticities

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

using econometric estimates of cost function parameters. We can then use as the weight for each output variable in the index its share in the sum of the estimated cost elasticities of the included output variables.

Unit Cost Indexes

A unit cost index is the ratio of a cost index to an output index. The output index may be multicategory. Unit cost indexes are effectively cost performance indicators that have a built in control for differences between companies in one of the most important cost drivers: operating scale.

Unit cost indexes by themselves do not control for all of the other cost drivers that are known to vary between utilities. Our discussion in Section 2.2 revealed that cost depends on input prices and miscellaneous other business conditions in addition 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 additional business conditions are similar on balance to those facing the subject utility. The choice of the peer group is thus an important step in a unit cost benchmarking exercise. Econometric research is useful for identifying the cost conditions that should be similar.

2.3.3 Averaging

Utilities plan their systems for expected business conditions over a series of years and not for conditions in a single year. Appraisals of cost efficiency are, therefore, best made over a multiyear timeframe. For this reason, we routinely assess efficiency over the most recent three years over which data have been gathered.

3. EMPIRICAL RESEARCH FOR OG&E

3.1 Data

The primary source of the cost and quantity data used in our benchmarking work for OG&E was the Federal Energy Regulatory Commission (FERC) Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

Data were considered for inclusion in the sample from all major U.S. investor-owned utilities that filed the Form 1 continuously over the years of the sample period and had substantial involvement in power production, transmission, distribution, and customer care functions during the sample period. To be included in the study the data were required, additionally, to be plausible and not unduly burdensome to process. Data from 39 companies were used in the econometric work. These companies are listed in Table 1. Companies included in the SPP peer group are noted. Notice that two of these companies, Entergy Arkansas and Entergy Louisiana, are former members of the SPP RTO. We included these companies because their size was similar to OG&E's.

The sample period was 1995-2007. The year 2007 is the latest for which the data needed for the study are currently available. The resultant data set has 489 observations on each model variable.[4] This sample is large and varied enough to permit the recognition of a number of O&M cost drivers.

Other sources of data were also accessed in the research. These were used primarily to measure input prices. The supplemental data sources included the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce; the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor; and Form 861 and Form 423 of the U.S. Energy Information Administration ("EIA"). 2008 data for OG&E were based upon preliminary data provided to PEG by the Company.

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[4] Some observations for companies with data included in the sample were excluded due to data problems.

Table 1

SAMPLE OF VERTICALLY INTEGRATED ELECTRIC UTILITIES USED FOR ECONOMETRIC RESEARCH

Utility	2007 Customers	Utility	2007 Customers
Alabama Power	1,425,243	Louisville Gas & Electric	400,703
Appalachian Power	951,693	Nevada Power	817,587
Arizona Public Service	1,086,328	Northern Indiana Public Service	454,471
Avista	347,097	Northern States Power (MN)	1,327,035
Carolina Power & Light	1,423,759	Ohio Power	711,406
Cleco Power*	273,046	Oklahoma Gas and Electric*	759,575
Columbus Southern Power	745,133	Otter Tail Power	129,175
Dayton Power & Light	514,405	Public Service Company of Colorado	1,355,715
Duke Energy	2,330,251	Public Service Company of Oklahoma*	522,419
Empire District Electric*	166,473	Pacificorp	1,683,619
Entergy Arkansas*	685,502	Puget Sound Energy	1,048,402
Entergy Louisiana*	653,493	Sierra Pacific Power	363,422
Florida Power & Light	4,496,593	South Carolina Electric & Gas	633,567
Florida Power	1,632,430	Southern Indiana Gas & Electric	146,473
Georgia Power	2,324,874	Southwestern Electric Power*	464,792
Idaho Power	477,094	Southwestern Public Service*	391,510
Kansas City Power & Light*	506,502	Tampa Electric	666,354
Kentucky Power	175,705	Tucson Electric Power	395,063
Kentucky Utilities	533,512	Virginia Electric & Power	2,362,318

* Southwest Power Pool peer group.

3.2 Definition of Variables

3.2.1 Cost

Cost figures play a key role in both of our benchmarking methods. Our approach to calculating cost is therefore important. The applicable base rate O&M expenses were defined as total electric O&M expenses less all expenses for fuel, purchased power, employee pensions and benefits, transmission dispatching, transmission by others, and market monitoring.[5] We routinely exclude pension and benefit expenses from our cost benchmarking work on the grounds that they are volatile and, to a considerable degree, beyond the control of utility management. Dispatching and market monitoring expenses were excluded because these services have in recent years been provided increasingly by regional transmission organizations.

3.2.2 Output Measures

Two output measures are utilized in both benchmarking approaches. One is the annual average number of customers served. The other is the total annual megawatt hours of power sold to customers. The sales volume variable includes sales for resale. To better capture the cost impact of variations in operating scale, we include in the cost model squared terms for each of the output variables (*e.g.* customers^2) and an interaction term (customers * sales volume).

3.2.3 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. We therefore included in the model an index of the prices of base rate O&M inputs. The O&M input price for each utility is constructed by combining the labor and non-labor prices by utility specific cost share weights. In estimating the model we divide cost by this input price index.

[5] In addition to Purchased Power expenses as reported on the FERC Form 1, we also exclude the Other Expenses category of Other Power Supply Expenses. We believe that power purchase expenses are sometimes reported in this category.

The labor price component of the input price index was constructed by PEG using data from the BLS. National Compensation Survey ("NCS") data for 2004 were used to construct average wage rates that correspond to each utility's service territory. The wage levels were calculated as a weighted average of the NCS pay level for each job category using weights that correspond to the electric, gas, and sanitary (EGS) sector for the U.S. as a whole. Values for other years were calculated by adjusting the 2004 level for changes in regional indexes of employment cost trends for the EGS sector. These indexes were also constructed from publicly available BLS data.

Prices for other O&M inputs are assumed to be the same in a given year for all companies. They are escalated by the U.S. gross domestic product price index. This index is calculated by the BEA and is the federal government's featured measure of inflation in the prices of final goods and services.

3.2.4 Other Business Conditions

Six other business condition variables are included in the cost model. One is the number of customers per transmission line mile. This variable does not change greatly from year to year and was fixed at its 2003 level for all companies. The source of our transmission line mile data is a directory that is currently entitled *Directory of Electric Power Producers and Distributors*, an annual publication of McGraw-Hill. This variable accounts for the extensiveness of the transmission system relative to the number of customers served. We would expect that as the number of customers per transmission line mile (*i.e.* customer "density") increases cost would decrease.

A second additional business condition variable is the percent generation that was not derived from hydroelectric resources. It is intended to capture the extent to which the company does not benefit from the low costs of hydroelectric generation. We would expect a VIEU that produces less electricity from hydro resources to have higher costs.

A third business condition that has been added to the model is the megawatt hours of power that were purchased. Recall that our measure of base rate O&M expenses excludes the costs of purchased power but includes the sales volume. The inclusion of this variable in the model levels the playing field for those utilities that generate most of their power, and thus incur more O&M production expenses than companies that purchase a lot of power.

Since purchasing power allows a utility to save on O&M production expenses we would expect that the higher the number of purchased megawatt hours the lower costs would be.

A fourth business condition variable added to the model is a measure of the quantity of fossil fuel used by a utility. This variable controls for the possible substitution effects that might exist between fuel and base rate O&M inputs. There is a considerable amount of such substitution inasmuch as gas-fired generation uses a comparatively high value fuel but economizes on base rate O&M inputs. As such, we would expect that the higher the fuel quantity the lower base rate O&M expenses would be.

The quantity of fuel is measured as the ratio of the fuel expenses to a fuel price index. The fuel price index is a cost-weighted average of the prices of coal, gas, and petroleum products. Data on the average prices of these three fuels in each state were used in these indexes. These were drawn primarily from Form EIA-423. The corresponding cost shares were utility specific and drawn from that form and FERC Form 1.

A fifth business condition variable that has been added to the model is the total generation capacity measured in megawatts. Data for this variable were processed from FERC Form 1 data on individual power plants. Our research team aggregated the nameplate capacity of each sampled utility's operational power plants to arrive at a total capacity figure. We would expect that as the amount of capacity increases the O&M costs of maintaining and operating that capacity would also increase.

A sixth business condition variable added to the model is a measure of the demand side management (DSM) work being done by each utility. Due to a lack of explicit itemization of DSM expenses on the FERC Form 1, this variable is estimated by the percentage of total distribution and customer care expenses that is not attributable to customer service, information, and sales. This is, effectively, a measure of the *lack* of DSM work. Given this form, we would expect that the higher the value of the variable the lower total base rate O&M expenses would be.

The model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of changes in diverse business conditions, including technological change, that are otherwise excluded from the model. Parameters for such variables typically have a negative sign in statistical cost research.

3.3 Parameter Estimates

Estimation results for the cost model are reported in Table 2. The parameter estimates for the first order terms of the two output variables and for the six additional business conditions are elasticities of cost, under sample mean values of the business conditions, with respect to the basic variable.[6] The table shades the results for these terms for reader convenience.

The table also reports the values of the asymptotic t ratios that correspond to each parameter estimate. These were also generated by the estimation program and were used to assess the range of possible values for parameters that are consistent with the data. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the asymptotic t statistic. In this study, we employed a critical value that is appropriate for a 90% confidence level given a large sample. The value of the t statistic corresponding to this confidence level was about 1.65.

The t statistics were used in model specification. All first order terms were required to have statistically significant and sensibly-signed parameter estimates. Examining the results in Table 2, it can be seen that the cost function parameter estimates were plausible as to sign and magnitude. Cost was found to be higher the higher were output quantities. At the sample mean, a 1% increase in the number of customers was estimated to raise cost by about 0.51%. A 1% hike in the delivery volume was estimated to raise cost by about 0.40%.

The parameter estimates for the additional business condition variables were also sensible.

- Cost was lower the greater was the number of customers per transmission line mile.

[6] The first order terms are the terms that do not involve squared values of variables or interactions between these variables. See Appendix Section A.1.1 for further discussion.

Table 2

ECONOMETRIC COST MODEL OF O&M BUNDLED POWER SERVICE

Variable Key

N= Number Retail Customers
V = Total Deliveries
NMT= Customers per Transmission Line Mile
GNH= % of Generation Non-Hydro
XF= Fossil Fuel Quantity
XP= Quantity of Purchased Power
CAP= Total Generation Capacity
PNC= % of Distribution and Customer Care Expenses Not Attributable to Customer Service and Sales

O&M Cost for Bundled Power Distributors

EXPLANATORY VARIABLE	ESTIMATED ELASTICITY	T-STATISTIC
N	**0.512**	**12.92**
NN	-0.355	-2.72
NV	0.346	2.41
V	**0.395**	**8.57**
VV	-0.272	-1.69
NMT	**-0.113**	**-6.46**
GNH	**0.185**	**3.95**
XF	**-0.106**	**-4.63**
XP	**-0.064**	**-4.82**
CAP	**0.270**	**8.05**
PNC	**-0.417**	**-6.97**
Trend	**-0.0089**	**-6.07**
Constant	**19.752**	**1380.66**
R-squared	0.937	
Number of Observations	476	
Sample Period	1995-2007[1]	

[1] The sample also includes 2008 data for OG&E.

- Cost was higher the higher was the percentage of generation that was not derived from hydro.
- Cost was lower the greater was the amount of power purchased.
- Cost was lower the greater was the fossil fuel quantity.
- Cost was higher the greater was the amount of generation capacity that the utility owned.
- Cost was lower the lower was the apparent amount of DSM work undertaken.
- The estimate of the trend variable parameter suggests a 0.89% annual downward shift in cost for reasons other than the trends in the business condition variables.

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 costs of distributors. Its value was about 0.94, suggesting that the explanatory power of the model was high.

3.4 Business Conditions of OG&E

OG&E is a VIEU based in Oklahoma City. The heart of its service territory is a broad corridor running from north to south across the center of the state. OG&E also serves customers in corridors to the east and west of this main axis. The eastern corridor extends into northwest Arkansas and includes Fort Smith, the second largest city in that state. In total, the Company currently serves about 760,000 customers in a region of about 30,000 square miles. Most of the company's 7,000 MW of nameplate generation capacity is fueled by low sulfur western coal. The Company also owns substantial gas-fired generation capacity.

The Company operates approximately 4,300 miles of transmission lines in Oklahoma and Arkansas. Operational authority over the transmission system has been transferred to the SPP regional transmission organization. The SPP provides certain dispatching, planning, and regional market services.

Table 3 compares the average values over the 2005-2007 period of cost model

Table 3

Comparison of OG&E Business Conditions To National Sample Norms, 2005-2007

Business Condition	Units	OG&E / National Mean, 2005-2007
Bundled Power Service O&M Cost	Dollars	0.60
Number of Retail Customers	Count	0.84
Total Deliveries	MWh	0.79
Price of Labor and Materials	Index Number	0.98
Customers per Transmission Line Mile	Ratio	0.69
Percent of Generation Not Hydro	Percent	1.04
Fossil Fuel Quantity	Index	1.53
Purchased Power Quantity	MWh	0.47
Total Generation Capacity	MW	1.11
% of Distribution Cost Not Attributable to Customer Service and Sales	Percent	0.97

business conditions for OG&E to the sample mean values of these variables during the same years. It can be seen that the cost of OG&E was only 0.60 times the sample mean. In other words, cost was about 40% below the mean. The number of customers served was, meanwhile, 0.84 times the mean, while the sales volume was 0.79 times the sample mean. Turning next to input prices, the table shows that the O&M input prices faced by OG&E were about 2% below the mean.

As for the other business condition variables, the number of customers per transmission line mile was about 0.69 times the sample mean, suggesting that the company had below average customer density. The percentage of generation that is not hydro was 1.04 times the mean. This reflects the shortage of good opportunities for hydroelectric generation in the Company's service territory. The fossil fuel quantity of OG&E was 1.53 times the mean. The amount of power purchased was 0.47 times the mean, whereas the total generation capacity of OG&E was 1.11 times the mean. These statistics suggest that the Company generated an unusually large percentage of the power that it sold, using fuel intensive technology, and owns extra capacity to meet summer demand surges. The DSM control variable for OG&E was 0.97 times the U.S. sample mean, suggesting that the Company does not have a large DSM program.

3.5 Econometric Benchmarking Results

Table 4 presents the results of our appraisals of the base rate O&M cost of OG&E using the econometric model. The Company's cost was found to be about 30% below its predicted value on average over the 2006-2008 period. This was the third best score amongst the 38 sampled utilities. The hypothesis that OG&E was an average or inferior cost performer was rejected at a high level of confidence. It is reasonable to conclude from this test that OG&E was a significantly superior performer in the management of base rate O&M expenses.

3.6 Unit Cost Results

OG&E has compared its base rate O&M expenses to those of other Southwest Power Pool member utilities in past proceedings. Based on our experience and the results of our

Table 4

Econometric Comparison of Actual and Predicted O&M Cost for OG&E, 2006-2008

Year	Difference (%)	t-Statistic*	P-Value*
2006	-32.6%	-1.899	0.029
2007	-30.9%	-1.779	0.038
2008	-27.9%	-1.577	0.058
Average	**-30.46%**	**-3.025**	**0.001**

*t-Statistic and P-values are computed separately for the averages and are not simple averages of the annual values.

econometric research on the drivers of base rate O&M expenses, we believe that the past and present members of the SPP constitute a good peer group for unit cost comparisons. There are notable similarities between OG&E and peer group utilities in the business conditions that drive base rate O&M expenses. Most peer group utilities face cost drivers that are similar to those of OG&E. For example, they

- have an operating scale that is below the national sample norm;
- face labor prices below the national average;
- use extensive amounts of low sulfur western coal and natural gas in generation;
- generate most of the power that they sell;
- have low load factors that encourage the companies to have extensive generation capacity relative to typical loads;
- do not have large hydroelectric generation; and
- had limited DSM activity during the sample period.

Table 5 summarizes key results of our unit cost comparisons to the SPP peer group. There are results for the cost, output quantity, and unit cost indexes. Results are presented for each of the three most recent years for which data are available for all companies. An average of these three years is also displayed.

For the average of the 2005-2007 period, we find that OG&E's cost was about 8% above the peer group norm. Its output index was, meanwhile, 41% above the peer group norm. OG&E's unit cost was 23% below the norm. This placed OG&E in a virtual tie for the best performance in the peer group sample. These results substantiate the findings of our econometric benchmarking results and suggest that OG&E has been a superior cost performer in recent years.

Table 5

O&M Unit Cost Index Results for OG&E, 2005-2007

Company	O&M Unit Cost - Percent Difference from Peer Group Norm			Average	Performance Rank
	2005	2006	2007		
Oklahoma Gas & Electric	-18.6%	-22.6%	-27.3%	-22.83%	2

Company	Output Quantity Index[1] - Percent Difference from Peer Group Norm			Average
	2005	2006	2007	
Oklahoma Gas & Electric	40.4%	40.4%	40.7%	40.50%

Company	O&M Cost - Percent Difference from Peer Group Norm			Average
	2005	2006	2007	
Oklahoma Gas & Electric	14.3%	8.6%	2.3%	8.41%

[1] The output quantity index is a cost elasticity-weighted index of customer numbers and total delivery volumes. Elasticity estimates were drawn from the econometric cost model (Table 2).

APPENDIX

This section provides additional and more technical details of our benchmarking work. We first consider the form of the cost model and our econometric work. There follow discussions of the index-based approach to benchmarking.

A.1 Econometric 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.

$$C = a_0 + a_1 \cdot N + a_2 \cdot W \qquad [A1]$$

Cost is a function of the number of customers served (*N*) and the wage rate (*W*). Here is an analogous cost model of double log form.

$$\ln C = a_0 + a_1 \cdot \ln N + a_2 \cdot \ln W \qquad [A2]$$

In this form, the value of each variable has been converted to its natural logarithm. It can be shown that this specification has the effect of making 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* in the sense that they are the same for every value that the cost and business condition variables might assume.[7]

Here is an analogous model of translog form[8]

$$\begin{aligned} \ln C &= a_0 + a_1 \cdot \ln N + a_2 \cdot \ln W + a_3 \cdot \ln N \cdot \ln N \\ &\quad + a_4 \cdot \ln W \cdot \ln W + a_5 \cdot \ln W \cdot \ln N \end{aligned} \qquad [A3]$$

---

[7] Cost elasticities are not constant in the linear model that is exemplified by equation A1.

[8] 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.

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as $\ln N \cdot \ln N$ permit the elasticity of cost with respect to each business condition variable to differ at different values of the variable. The elasticity of cost with respect to the output variable may, for example, be lower for a small utility than for a large utility that has exhausted its opportunities to realize incremental scale economies. Interaction terms like $\ln W \cdot \ln N$ permit the elasticity of cost with respect to the business condition variable to depend on the labor price. When model data are mean scaled for convenience, the parameters of each first order term (the term that does not involve squares or interactions) is the elasticity of cost with respect to the basic variable at sample mean values of the business conditions.

The translog form is an example of a "flexible" functional form and is by some accounts the most reliable of several available alternatives. Flexible forms can accommodate a greater variety of possible relationships between cost and the business condition variables. They are especially useful in capturing differences between utilities in the realization of scale economies. A disadvantage of the translog form is that it involves many more variables than simpler forms such as the double log. As the number of variables increases, the precision of a model's cost predictions falls. We have for this reason chosen to limit the translog treatment to the output variables of our model.

A.1.2 Estimation Procedure

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 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. 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.

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.

In order to achieve a more efficient estimator, we corrected for autocorrelation and heteroskedasticity in the error terms of our model for OG&E using a custom in house regression procedure developed with Gauss software. Since we estimated these unknown disturbance matrices consistently, the estimators we eventually computed are equivalent to Maximum Likelihood Estimators (MLE).[9] Our estimates thus possess all the highly desirable properties of MLEs.

Note, finally, that the model specification was determined using the data for all sampled companies, including OG&E. However, computation of model parameters and standard errors for the prediction required that the values for OG&E be dropped from the sample. The estimates used in developing the cost model will vary slightly from those in the model used for benchmarking.

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

A.2 Unit Cost Indexes

A.2.1 Cost Indexes

The cost index for OG&E in each year t was defined by the formula

$$Cost\ Index_{OG\&E,t} = \frac{Cost_{OG\&E,t}}{\overline{Cost_t}} \qquad [A4]$$

where $\overline{Cost_t}$ is the mean value of cost for the peer group in year t.

A.2.2 Output Quantity Indexes

The output quantity index in each year t was defined by the formula

$$Output\ Quantity_{OG\&E,t} = \sum_i SE_i * \frac{Y_{OG\&E,i,t}}{\overline{Y_{i,t}}}. \qquad [A5]$$

Here,

$Y_{OG\&E,i,t}$ = Quantity of output i for OG&E

$\overline{Y_{i,t}}$ = Peer group mean of the quantity of output i.

SE_i = Share of output i in the sum of the econometric estimates of the cost elasticities of the output quantities under sample mean business conditions.

In Table 2, the elasticities of cost with respect to the sales volume and the number of customers served were estimated to be .51 and .40 respectively. The corresponding elasticity-share weights for the output index were 56% and 44%, respectively.

A.2.3 Unit Cost Indexes

The unit cost index is the ratio of the cost index to the output quantity index.

$$Unit\ Cost_{OG\&E,t} = \frac{Cost_{OG\&E,t}}{Output\ \ Quantity_{OG\&E,t}} \qquad [A6]$$

Then

$$Unit\ Cost_{OG\&E,t} = (\frac{Cost_{OG\&E,t}}{\overline{Cost_t}}) / (\sum_i SE_i * \frac{Y_{OG\&E,i,t}}{\overline{Y_{i,t}}}).$$

The percentage difference between the unit cost of OG&E and that of the peer group is then calculated using the formula $100*(\mathit{Unit\ Cost}_{OG\&E,t}-1)$.

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Lowry

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 1535 FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 7 ELECTRIC TARIFF TO REFLECT REVISED RATES AND RATE SCHEDULES TO BE EFFECTIVE ON JUNE 5, 2009.	DOCKET NO. 09AL-299E

REBUTTAL TESTIMONY AND EXHIBIT OF MARK NEWTON LOWRY

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

October 13, 2009

LIST OF EXHIBITS

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 1535 BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 7 ELECTRIC TARIFF TO REFLECT REVISED RATES AND RATE SCHEDULES TO BE EFFECTIVE ON JUNE 5, 2009.	**DOCKET NO. 09AL-299E**

<u>REBUTTAL TESTIMONY AND EXHIBIT OF MARK NEWTON LOWRY</u>

I. <u>INTRODUCTION AND QUALIFICATIONS</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark Newton Lowry. My business address is 22 E. Mifflin St., Suite 302, Madison, WI 53703.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the President of Pacific Economics Group ("PEG") Research LLC, a company in the Pacific Economics Group consortium that specializes in incentive regulation and cost research for the energy utility industry.

Our personnel, which include three PhD economists, have more than fifty man-years of experience in these fields, which share a foundation in economic statistics. Our practice is international in scope and has to date included projects in twelve countries. Most of our staff was trained at the University of Wisconsin, which is renowned for its strength in economic statistics.

A diverse mix of utilities and regulators has given our practice a reputation for objectivity and dedication to economic science. For example, we have advised the Canadian Electricity Association and major Canadian electric utilities on benchmarking issues for many years, but we also benchmark more than 80 power distributors in the Canadian province of Ontario each year for the Ontario Energy Board. I am currently working for Public Service Company of Colorado ("Public Service" or the "Company") in this proceeding, but last year submitted an (unsuccessful) bid to advise this Commission on incentive regulation.

Q. PLEASE BRIEFLY EXPLAIN YOUR DUTIES AND RESPONSIBILITIES?

A. In addition to my managerial responsibilities as the President of PEG Research, I supervise benchmarking and other kinds of utility cost research, design incentive regulation plans, and provide expert witness testimony.

Q. HAVE YOU APPEARED AS AN EXPERT WITNESS IN OTHER UTILITY PROCEEDINGS?

A. Yes. I have testified many times on benchmarking and incentive regulation issues. Most of my testimony has involved statistical cost research. Venues for my testimony have included Alberta, British Columbia, California, Georgia, Hawaii, Illinois, Kentucky, Maine, Massachusetts, Missouri, Oklahoma, New York, Ontario, Quebec, Rhode Island, and Vermont. My resume is attached as Attachment A.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am appearing on behalf of Public Service Company of Colorado ("Public Service" or "Company")

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Public Service recently filed for an increase in their base rates that recover the cost of its nonfuel inputs, excluding purchased power costs, demand-side management costs, the incremental costs of complying with the state of Colorado's renewable energy standards, and certain costs of incremental transmission investments. The Company has used a forward test year ("FTY") to calculate its proposed revenue requirement. In their Answer Testimony, various intervenors expressed concerns about the difficulty of verifying the reasonableness of a FTY revenue requirement and the impact of a FTY on utility incentives to operate efficiently.

Public Service has retained PEG Research to help substantiate its FTY filing in two ways. One is to benchmark the company's proposed 2010 O&M expenses – one of the most important sources of uncertainty in the rate filing. The other is to use our statistical methods and the same sample used in our benchmarking work to consider whether FTYs weaken utility performance incentives.

Q. WHY IS A FOCUS ON THE COMPANY'S PROPOSED O&M EXPENSES APPROPRIATE?

A. Where utilities are subject to cost-of-service rates, a utility's ability to effectively manage its costs is an important consideration for the Commission in setting rates. O&M expenses are the largest component of a utility's cost structure that a utility can attempt to control in the short run. They are also one of the biggest sources of intervenor uncertainty regarding a utility's projections.

Q. HOW DOES YOUR TESTIMONY RELATE TO THE TESTIMONY OF OTHER COMPANY WITNESSES?

A. Company witness Mr. Scott Wilensky is providing an explanation of why the Company's proposed 2010 expenses are reasonable in light of historical trends. My testimony and the attached study, Exhibit No. MNL-1, provide a quantitative assessment of the reasonableness of these expenses, which is based almost entirely on research on the costs of *other* utilities. My study of the incentive impact of FTYs is, similarly, an attempt to shed some light from a national perspective on this important issue, which Mr. Wilensky discusses in more qualitatitive terms.

Q. WHAT ARE THE GENERAL CONCLUSIONS OF YOUR O&M COST PERFORMANCE STUDY?

A. Using two well established statistical benchmarking methods, my study prompts me to conclude that the Company's proposed 2010 test-year O&M expenses are low by industry standards.

Q. WHAT ARE YOUR GENERAL CONCLUSIONS REGARDING THE FTY INCENTIVES RESEARCH?

A. After examining differences in the unit cost trends of the utilities operating under different types of test years – i.e., historic or forward – I find no support for the assertion that forward test years weaken performance incentives.

III. REASONABLENESS OF 2010 O&M EXPENSES

Q. WHAT IS STATISTICAL BENCHMARKING AND HOW IS IT USEFUL IN MEASURING UTILITY PERFORMANCE?

A. Statistical benchmarking uses statistics to establish benchmarks that can be used in quantitative performance appraisals. Cost benchmarks can be used to gauge a particular utility's efficiency. The primary set of statistics used to establish cost benchmarks is utility operating data. This data is available from the many forms and reports that utilities file with federal government agencies.

Accurate benchmarking is complicated because the costs of utilities vary more because of differences in the business conditions they face than because of differences in their operating efficiency. A cost benchmark for a particular utility should, therefore, reflect the typical performance that might be expected of managers given the local business conditions, which that particular utility faces. Statistical cost research can identify important cost drivers and use such cost drivers to establish better performance metrics and benchmarks.

Q. WHAT COMPONENT OF THE COMPANY'S COST DID YOU ADDRESS IN YOUR STUDY?

A. As mentioned above, we addressed the efficiency inherent in the Company's proposed non-fuel O&M expenses for 2010. In the study, cost was defined as total O&M expenses less expenses for generation fuels, purchased power, employee pensions and benefits, transmission dispatching, transmission services by others, and regional market management. Expenses were excluded from the study if they were not base rate costs, were uncharacteristically volatile, and/or were substantially beyond the Company's control. For example, pension contributions were excluded because, for many companies, they swing wildly with changes in stock market prices.

Q. PLEASE SUMMARIZE THE BENCHMARKING METHODS THAT YOU USED IN YOUR STUDY OF PUBLIC SERVICE.

A. The proposed expenses were appraised using two well-established benchmarking methods: econometric modeling and unit cost indexing. The econometric modeling we did involved the use of a model designed to explain the impact of various quantifiable business conditions on the non-fuel O&M expenses of vertically integrated electric utilities. The parameters of the model, which measure cost impact, were estimated statistically using historical data on utility operations. A model fitted with econometric parameter estimates and the specific business conditions that Public Service expects to face in 2010 was used to generate cost benchmarks.

The other benchmarking method we employed involved the comparison of the base rate O&M expenses of Public Service to those of other utilities using unit cost indexes. A unit cost index is the ratio of a cost index to an output index. Estimates of cost elasticities from our econometric work were used to design a unit cost index that is a weighted average of comparisons using simpler metrics that individually feature generation volume, generation capacity, and the number of customers served. We compared the unit costs of Public Service in 2010 with the 2008 costs for all sampled utilities and for sampled utilities in the Western Interconnection.

The study was based on a sample of high-quality data for forty-eight vertically integrated U.S. electric utilities. The sample period for the econometric and indexing work was 1995 to 2008. The sample permitted the development of a credible cost model. All data were drawn from respected public sources such as the Federal Energy Regulatory Commission ("FERC") Form 1. The model had high explanatory power and all estimates of the key model parameters were plausible and highly significant.

Q. WHAT ARE THE KEY EMPIRICAL RESULTS?

A. The proposed non-fuel expenses of Public Service were found to be more than 17% below the benchmark generated by our econometric cost model. This performance is normally commensurate with a top quartile status in our research. Public Service's unit cost index was about 16% below the mean for the full sample and 24% below the mean for utilities in the Western Interconnection. We conclude that the Company's proposed expenses are remarkably low by industry standards.

IV. IMPACT OF FORWARD TEST YEARS ON UTILITY OPERATING EFFICIENCY

Q. PLEASE SUMMARIZE THE METHODS YOU USED TO STUDY THE INCENTIVE IMPACT OF FORWARD TEST YEARS.

A. We compared the trends, over the 1995-2008 period, in the unit cost of the utilities in our sample that operated under historic and forward test years. As in the benchmarking work, we considered cost per customer, cost per MWh of generation, and cost per MW of generation capacity, as well as a summary unit cost index. We used unit cost metrics in order to control for different trends in the workload of the utilities. The sample included 31 utilities operating under historic test years and 9 utilities operating under future or forward test years.

Q. WHAT WERE THE KEY EMPIRICAL RESULTS?

A. The unit cost index for forward test years grew at a 1.6% average annual rate whereas the unit cost index for historic test year utilities grew at a 2.2% average annual rate. The utilities operating under *forward* test years thus experienced unit cost growth trends that were very similar to (and a little slower than) those of utilities operating under historic test years. The results of this research support the view that a forward test year does not erode utility incentives to operate efficiently. This squares with my conviction, developed over almost two decades of incentive regulation research, that the type of test year does not significantly drive performance incentives in a regulatory system.

Q. DOES THIS CONCLUDE YOUR PREPARED REBUTTAL TESTIMONY?

A. Yes, it does.

STATISTICAL SUPPORT FOR PUBLIC SERVICE OF COLORADO'S FORWARD TEST YEAR PROPOSAL

13 October 2009

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TABLE OF CONTENTS

1. INTRODUCTION AND SUMMARY

1.1 Introduction

Public Service of Colorado ("Public Service" or "the Company") recently filed for an increase in the base rates that recover the cost of its non-fuel inputs. The Company has used a forward test year ("FTY") to calculate its proposed revenue requirement. FTYs are allowed by law in Colorado but are not widely used and the Company's approach has been opposed by several witnesses in the Answer Testimony. Witnesses complain of the difficulty of verifying the reasonableness of an FTY revenue requirement. Some express concern about the impact of the FTY approach on utility performance incentives.

The personnel of Pacific Economics Group ("PEG") Research LLC have extensive experience in utility cost research and incentive regulation, fields with a common foundation in economic statistics. Testimony quality benchmarking studies are a company specialty. We pioneered the use of scientific benchmarking methods in North American regulation. Company president and senior author Mark Newton Lowry has testified on benchmarking and incentive regulation issues in numerous proceedings.

Public Service has retained PEG Research to help substantiate its FTY filing in two ways. One is to benchmark the company's proposed O&M expenses --- one of the most important sources of uncertainty in the rate filing. We were also asked to use statistical methods to address the issue of whether an FTY weakens utility cost performance incentives.

Following a brief summary of the work below, Section 2 provides an introduction to benchmarking methods. Section 3 discusses our empirical research for Public Service. Some technical details of the research are presented in the Appendix.

1.2 Summary of Research

We addressed the reasonableness of the Company's forecasted 2010 O&M expenses using statistical benchmarking methods. For Public Service and all companies in the sample, cost was defined as total O&M expenses less reported expenses for fuel, purchased power, certain transmission services, regional market management, and pensions and benefits. We also produced results with pension and benefit expenses included, although these are more difficult to benchmark accurately.

The 2010 expenses were appraised using two well established benchmarking methods: econometric modeling and unit cost indexing. Guided by economic theory, we developed a mathematical model of the impact that various quantifiable business conditions have on the base rate O&M expenses of vertically integrated electric utilities ("VIEUs") like Public Service. The parameters of the model, which measure cost impact, were estimated statistically using historical data on utility operations. A model fitted with econometric parameter estimates and the business conditions that Public Service expects to face in 2010 was used to benchmark the proposed test year expenses.

The econometric research was based on a sample of good quality data for 47 U.S. VIEUs. The sample period was 1995 to 2008. The sample is large and varied enough to permit the development of a highly credible cost model. The data used in model estimation were drawn from the Federal Energy Regulatory Commissions ("FERC") Form 1 and other respected public sources. All estimates of model parameters were plausible and highly significant. The non-fuel O&M expenses proposed by Public Service for 2010 were found to be more than 17% below the benchmark generated by the econometric model. This kind of performance is ordinarily commensurate with a top quartile ranking.

As for the unit cost benchmarking, we compared the proposed 2010 expenses of Public Service to the *2008* costs of sampled utilities using three simple unit cost metrics and a summary unit cost index. Comparisons were made to the full sample and the sampled utilities in the Western Interconnection. The unit cost implied by Public Service's 2010 forecast is well below those of both utility groups. We conclude from the assembled evidence that the proposed expenses reflect a good level of operating performance.

The same data set was used to consider the effect of alternative kinds of test years used in rate cases, on operating performance. We compared the trends, over the 1995-2008 period, in various O&M unit cost metrics for the utilities in our sample that operated under historic and forward test years. We found that utilities operating under forward test years had unit cost growth trends that were similar to (and a little slower than) those of utilities operating under historic test years. The results of this research support the view that an FTY does not erode utility cost containment incentives.

2. AN INTRODUCTION TO BENCHMARKING

In this section of the report we provide a non-technical discussion of some important benchmarking concepts. The two benchmarking methods used in the study are explained. More technical details of our methodology are discussed in the Appendix.

2.1 What is Benchmarking?

The word benchmark originally 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 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 sometimes called key performance indicators ("KPIs"). The value of each indicator achieved by an entity under scrutiny is compared to a benchmark value that reflects a performance standard. Given data on the cost of Public Service and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$\text{Cost Performance} = \text{Cost}^{\text{PSCo}}/\text{Cost}^{\text{Benchmark}}.$$

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 the comparison process. An approach to benchmarking that prominently features statistical methods is called statistical benchmarking.

Various performance standards can be used in benchmarking. These often reflect statistical concepts. One sensible standard is the average performance of the utilities in the sample. An alternative standard is the performance that would define the margin of the top quartile of performers.

These concepts are usefully illustrated by the process through which decisions are made to elect athletes to the Pro Football Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Quarterbacks, for example, are evaluated using multiple performance indicators that include touchdowns, passing yardage, and interceptions. The values achieved by Hall of Fame members like John Elway are useful benchmarks. These values reflect a Hall of Fame performance standard.

2.2 External Business Conditions

For costs and many other kinds of business 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 the business conditions that they face. In cost research these conditions are sometimes called cost "drivers". The cost performance of a company depends on the cost that it achieves (or, in the case of Public Service, *proposes*) given the business conditions that it faces. Benchmarks must therefore reflect business conditions if they are to reflect a chosen performance standard faithfully.

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 now that, under certain reasonable assumptions, cost functions exist that relate the minimum cost of an enterprise to business conditions in its service territory. When the focus of benchmarking is a subset of the entire series of inputs, the minimum cost depends on the prices of the included inputs, output quantities, and on the amounts of other inputs that the company uses. This 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. For example, a utility's *O&M* expenses depends on the quantities of different kinds of *capital* inputs that it owns.

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

Whichever cost function is applicable, economic 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 a vertically integrated electric utility like Public Service, for instance, depends on the number of customers that it serves as well as its generation volume. 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.

2.3 Benchmarking Methods

In this section we discuss at some length the two benchmarking methods that we used in our study for Public Service: econometric modeling and unit cost indexing. The econometric approach is discussed first to establish a context for the discussion of the index approach.

2.3.1 Econometric Modeling

Basic Assumptions

Relationships between the costs of utilities and the business conditions that they face can be estimated using statistics. A branch of statistics called econometrics has developed procedures for estimating the parameters of economic models using historical data.[2] The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions that they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a cross section consisting of one observation for each of several companies, 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

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

assumed to be independent in the sense that their values are not influenced by the values of dependent variables.

The error term in an econometric cost model is the difference between actual cost and the cost 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 underlying 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. 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.

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. In a benchmarking study used in utility regulation 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.

Cost Predictions and Performance Appraisals

A cost function 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.[3] These predictions are econometric

[3] Suppose, for example, that we wish to benchmark the cost of a hypothetical electric utility called Western Power. We might then predict the cost of Western in period t using the following model.

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

Here $\hat{C}_{Western,t}$ denotes the predicted cost of the company, $N_{Western,t}$ is the number of customers it serves, and $W_{Western,t}$ 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

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

benchmarks. Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year by the econometric model. The year in question can, in principle, be in the past or the future.

2.3.2 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 indexes.

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)".[4] In benchmarking, indexing involves the calculation of ratios of the values of KPIs for a subject utility to the corresponding values for a sample of utilities. The group of companies represented in the sample is sometimes called a "peer" group.[5]

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 numerous consumer products. The weight for the inflation in the price of each product is its share of the value of all of the products considered.

To better appreciate the advantages of multidimensional indexes in utility benchmarking, recall from our discussion in Section 2.3 that multiple variables are often needed to accurately measure the workload of utilities. Suppose, by way of example, that we are benchmarking the O&M expenses of a VIEU like Public Service. It would be desirable in this case to consider the number of customers it serves as well as its sales volume. If we separately calculate the company's cost per customer and per megawatt hour of generation we could come up with two very different assessments depending, among other things, on a company's propensity to search for bargains in bulk power markets instead of self-generating all power requirements. A final reckoning of performance then

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

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

requires a sensible weighting of assessments using the two metrics. This can be provided by a unit cost *index*[6] .

In cost benchmarking, it makes sense for the weights corresponding to each output variable in a unit cost index to reflect the relative importance of the individual output variables as cost drivers. The importance of each variable is conventionally measured by its cost "elasticity". The elasticity of cost with respect to the number of customers served, for instance, is the percentage change in cost that results from a 1% change in the number of customers served. It is straightforward to estimate the required elasticities using econometric estimates of cost function parameters. We can, for example, use as the weight for each output measure its share in the sum of the estimated cost elasticities for the output variables.

Unit cost indexes by themselves do not control for all of the other cost drivers that are known to vary between utilities. Our discussion in Section 2.2 revealed that cost depends on input prices and miscellaneous other business conditions in addition 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 choice of the peer group is thus an important step in a unit cost benchmarking exercise. It can be difficult to find a peer group for an individual VIEU in which all companies face similar business conditions but the peer group averages are not dominated by the results for a handful of companies.

[6] Summary input price indexes are also useful in cost benchmarking. We might, for example, want an index of the prices of O&M inputs. In the construction of input price 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 prices on cost.

3. EMPIRICAL RESEARCH FOR PUBLIC SERVICE

3.1 Data

The primary source of the cost and quantity data used in our empirical research for Public Service was the Federal Energy Regulatory Commission ("FERC") Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

Data were considered for inclusion in the sample from all major U.S. investor-owned electric utilities that filed the Form 1 electronically in 2008 and had substantial involvement in power production as well as power transmission, distribution, and customer care during the sample period. To be included in the study the data were required, additionally, to be plausible and not unduly burdensome to process. Data from forty eight companies were used in the research. These companies are listed in Table 1. The sample period was 1995-2008. The resultant data set has 642 observations on each model variable.[7] This sample is large and varied enough to permit econometric identification of numerous O&M cost drivers and reasonably accurate estimation of their likely cost impact.

Other sources of data were also accessed in the research. Data on generation capacity originated in Form EIA – 860 ("Annual Electric Report") and a predecessor data source, Form EIA – 767 ("Steam Electric Plant Operation and Design Report"). Some data sources were used to measure input prices. These sources included Global Insight and the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. 2010 forecast data for Public Service were provided by the Company. These data are consistent with the Company's recent rate case filing.

[7] Some observations for companies with data included in the sample were excluded due to data problems.

3.2 Definition of Variables

3.2.1 Cost

Cost figures play a key role in our research for Public Service. The base rate O&M expenses addressed in the featured benchmarking work were total electric O&M expenses less all reported expenses in the FERC Form 1 categories devoted to fuel, purchased power, transmission dispatching, transmission by others, regional market management, and employee pensions and benefits.[8] We routinely exclude pension and benefit expenses from our cost benchmarking work on the grounds that they are volatile, vary with accounting practices, and are to a considerable degree beyond the control of utility management. Expenses for transmission by others were excluded because they depend on a utility's power trade and the terms of transmission services provided by others are largely beyond utility control. Transmission dispatch and regional market expenses are excluded because these depend greatly on whether a utility operates under a regional transmission organization.

3.2.2 Output Measures

Two output measures were utilized in both benchmarking approaches. One is the annual average number of customers served. The other is the total annual megawatt hours of net generation. An additional variable that varies with operating scale, generation capacity, is discussed further below.

3.2.3 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. We therefore included in the model an index of the prices of base rate O&M inputs. In estimating the model we divide cost by this input price index. This is commonly done in econometric cost research because this simplifies model estimation and ensures that the relationship between cost and input prices that is predicted by economic theory holds.

[8] In addition to Purchased Power expenses as reported on the FERC Form 1, we also exclude the Other Expenses category of Other Power Supply Expenses. We believe that large and volatile commodity-related costs are sometimes reported in this category.

The O&M input price index was constructed by PEG Research and is a weighted average of price indexes for labor and materials and services. The labor price component of our input price index was constructed by PEG Research personnel using BLS data. National Compensation Survey ("NCS") data for one recent year were used to construct average wage rates that correspond to each utility's service territory. The wage levels were calculated as a weighted average of the NCS pay level for each job category using weights that correspond to the electric, gas, and sanitary (EGS) sector for the U.S. as a whole. Values for other years were calculated by adjusting the level in the focus year for changes in regional indexes of employment cost trends for the EGS sector. These indexes were also constructed from publicly available BLS data.

Prices for material and service ("M&S") O&M inputs are assumed to have a 25% local labor content and therefore tend to be a little higher in regions with higher labor prices. They are escalated by a summary M&S input price index constructed by PEG Research from detailed Global Insight electric utility M&S indexes. The O&M input price for each utility is then constructed by combining the labor and non-labor prices using utility-specific cost share weights.

3.2.4 Other Business Conditions

Nine other business condition variables are included in the cost model. Four pertain to power generation activity. One is the total nameplate generation capacity owned by the company, measured in megawatts (MWs). Capacity is an important supplemental cost driver because the O&M of capacity is costly even when it is idle. Data on capacity were processed from FERC Form 1 data on individual power plants. Our research team aggregated the nameplate capacity of each sampled utility's operational power plants to arrive at a total capacity figure. We expect that O&M expenses will be higher the higher is the amount of generation capacity.

The model also contains variables that measure the share of generating capacity owned by each company that is coal-fired and the share that is not nuclear fueled[9]. These variables are designed to capture any tendency for O&M expenses to vary with the kind of

[9] We sometimes use "not" variables in our studies to avoid situations where the variables have a value of zero for some utilities.

generating plant that companies own. The impact of these variables cannot be predicted in advance.

The fourth generation-related variable in the model is the percentage of total generating capacity that doesn't have scrubbing facilities. This variable takes account of the fact that utilities vary in the extent to which they scrub their generation emissions. We expect that O&M expenses will be lower the lower is the percentage of generating capacity that is not scrubbed.

Four model variables address conditions that affect the cost of providing power delivery and customer care services. One of these measures the extent of system overheading. System overheading involves higher O&M expenses in most years because lines are more exposed to the challenges posed by local weather (*e.g.* high winds and ice storms), flora, and fauna[10].

A second model variable related to delivery and customer care services is the number of customers per transmission line mile[11]. The source of our transmission line mile data is a directory that is currently entitled *Directory of Electric Power Producers and Distributors.* This is an annual publication of McGraw-Hill. This variable accounts for the extensiveness of the transmission system relative to the number of customers served. We would expect that as the number of customers per transmission line mile --- sometimes called customer "density" --- increases, cost would decrease.

A third model variable related to delivery and customer care services is a measure of the demand side management ("DSM") work being done by each utility. Due to a lack of explicit itemization of DSM expenses on the FERC Form 1, these expenses cannot be removed from the costs subject to benchmarking. A control variable is therefore needed and we use for this purpose the share of total distribution, customer care, and sales expenses that is not classified as customer service and information ("CS&I"). This approach makes sense because DSM expenses are usually reported as a CS&I expense and loom large in these expenses when they are large. The variable is, effectively, a measure of the *lack* of DSM

[10] Maintenance of underground delivery facilities occurs less frequently but can be quite costly.

[11] Due to data limitations the value of this variable is frozen at its 1999 value for all companies in the model's estimation.

work. Given this form, we would expect that the higher the value of the variable the lower cost would be.

The fourth model variable related to delivery and customer care services is the number of customers for which a utility provides gas service. Simultaneous provision of delivery and customer care services to gas and electric customers involves opportunities to share inputs that economists call economies of scope. We therefore expect electric O&M expenses to be lower the higher is the number of gas customers served.

The econometric model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model. Parameters for such variables typically have a negative sign in statistical cost research. The inclusion of this variable in the model means that our benchmark for 2010 includes an expectation of productivity growth.

3.3 Parameter Estimates

Estimation results for the cost model are reported in Table 2. Due to the chosen form of the cost function, the parameter estimates for the nine additional business conditions and for the "first order" terms of the output variables are elasticities of the cost of the sample mean firm with respect to the basic variable[12]. The table shades the results for these terms for reader convenience.

The table also reports the values of the asymptotic t-ratios that correspond to each parameter estimate. These were also generated by the estimation program and were used to assess the range of possible values for parameters that are consistent with the data. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value 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 that is appropriate for a 90% confidence level given a large sample. The value of the t-ratio corresponding to this confidence level was t value was about 1.7.

[12] The first order terms are the terms that do not involve squared values of output variables or interactions between these variables. The "translog" form of the cost function is discussed in the Appendix.

The t-ratios were used in model specification. All the output quantities (which were translogged in model specification, as discussed further in the Appendix) were required to have first order terms with statistically significant and sensibly-signed parameter estimates. The other variables were also required to have statistically significant and sensibly-signed parameter estimates.

Examining the results in Table 2, it can be seen that all of the model parameter estimates are plausible as to sign and magnitude. At the sample mean, cost was found to be higher the higher were the values of all three scale-related variables. A 1% increase in the number of customers served was estimated to raise O&M expenses by 0.46%. A 1% hike in the generation volume was estimated to raise cost by 0.40%. A 1% increase in generation capacity is expected to raise cost by 0.05%. It follows that growth in the number of customers served has about the same cost impact as comparable growth in the two generation variables combined.

The parameter estimates for the additional business condition variables were also sensible.

- Cost was lower the greater was the percentage of capacity that wasn't nuclear.
- Cost was higher the greater was the percentage of capacity that was coal-fired.
- Cost was lower the greater was the percentage of capacity that wasn't scrubbed.
- Cost was lower the greater was the number of customers per transmission line mile.
- Cost was higher the greater was the extent of delivery system overheading.
- Cost was lower the lower was the apparent amount of DSM work undertaken.
- The estimate of the trend variable parameter suggests a slight 0.2% annual downward shift in cost over time for reasons other than the trends in the business condition variables.

The table also reports the adjusted R^2 statistic for the model. This is a widely used measure of the ability of the model to explain variation in the sampled costs of distributors. Its value was about 0.95, suggesting that the explanatory power of the model was high.

3.4 Business Conditions of Public Service

Public Service is a combined gas and electric utility with vertically integrated electric operations. Metropolitan Denver is the heart of its service territory. Service is also provided in corridors along the base of the northern Front Range, in the South Platte and San Luis Valleys, and in a swath of territory that runs across Colorado's midsection and includes Grand Junction.

The company generates a sizable percentage of the power that it sells but also buys substantial quantities. Most generation is coal-fired, but the company also operates a sizable fleet of gas-fired stations that includes combined cycle capacity. The Company owns and operates almost 4,300 miles of transmission line. There is no RTO in the region. The system makes sizable bulk power deliveries to other utilities.

The business conditions that drive the Company's O&M expenses will change substantially between 2008 and 2010. The Comanche 3 coal-fired generating station and two new gas-fired units at the Fort St. Vrain station will be fully operational. The share of coal fired capacity that has scrubbing facilities will increase markedly. DSM expenditures will also increase markedly, and these expenses will prospectively be expensed rather than amortized.

Table 3 compares the average values of the business conditions that Public Service forecasts for 2010 to the average values for the full sample in 2008. Values for Public Service are provided for 2008 as well as 2010. The last column of the table takes the ratio of the business conditions forecasted for Public Service in 2010 to the peer group norms.

It can be seen that the forecasted cost of Public Service in 2010 will be 1.19 times the sample mean in 2008. The number of customers served will, meanwhile, be 1.67 times the mean, while the net generation volume will be 1.04 times the mean and generation capacity was .84 times the mean.

Regarding input prices, the table shows that the O&M input prices faced by Public Service will be about 1.12 times the sample mean. This isn't surprising when it is considered that only a few of the companies in the sample have service concentrated in one of the nation's major metro areas. Turning next to the generation-related business conditions, Public Service has no nuclear capacity but the share of its capacity that is coal-fired capacity will be well above the sample norm. The percentage of generation capacity that is not scrubbed will be well below the sample norm.

As for the other business condition variables, the number of customers per transmission line mile will be about 1.57 times the sample mean. This suggests that the company can reap some transmission cost savings from the concentration of its customers in metro Denver. The forecasted extent of system overheading is only 0.51 times the norm, and this creates opportunities for distribution O&M economies. Provision of service to gas customers affords opportunities for scope economies. On the other hand, the DSM indicator variable suggests that 2010 O&M expenses reflect unusually high DSM expenses.

3.5 Benchmarking Results

3.5.1 Econometric Results

Table 4 presents the results of our econometric appraisal of Public Services's forecasted base rate O&M expenses for 2010. Excluding pensions, the Company's expenses were found to be more than 17% below the model's projection. A performance of this kind is ordinarily commensurate with a top quartile ranking in our research

3.5.2 Unit Cost Results

Table 5 benchmarks the proposed 2010 test year expenses using unit cost metrics. Comparisons are made to mean values for the full sample and the utilities in the Western Interconnection. Inspecting first the comparisons to the full sample, we see that Public Service's cost *per customer* is about 43% below the sample mean. Cost *per MWh generated* is 4% above the mean and cost *per MW of capacity* is about 23% above the mean. The disparity in these results is unsurprising given the fact that Public Service plans to continue purchasing large amounts of power in an effort to minimize the cost of power supply.

The unit cost index takes a weighted average of these results in order to produce a summary appraisal. We find that the proposed O&M expenses have a unit cost index value that is 16% below the full sample norm. The unit cost index for Public Services 2010 O&M expenses is 24% below the norm for the Western Interconnection.

3.6 Incentive Impact of Forward Test Years

In order to test the incentive impact of forward test years we considered the unit O&M expenses of the sampled utilities over the full 1995-2008 sample period. As in our benchmarking work, we considered three simple unit cost metrics, each of which involved a single dimension of operating scale. We also computed summary unit cost indexes that, effectively, take a weighted average of the trends for the simpler metrics. We considered how the unit cost trends differed for utilities operating under three kinds of test years: historical, partial, and forward. We defined a forward test year as one in which the last month of the test year was at least 12 months after the month of the rate case filing. We relied primarily on SNL for data on the filings.

Table 6 shows the kinds of test years used to regulate each of the utilities. It can be seen that 31 utilities operated under an historical test year, 3 operated under a partial test year, and 9 operated under forward test years. Some utilities could not be classified as operating under a particular test year regime.

Results of this exercise are reported in Table 7. It can be seen that using all three of the simple unit cost metrics and the unit cost index, the unit cost trends of the forward test year utilities were similar to --- and a little *slower* than --- those of the historic test year utilities and of the full utility sample. These results are consistent with the notion that there is no significant difference in the incentives to contain unit cost that are generated by historic and future test years.

APPENDIX

This section provides additional and more technical details of our empirical research.

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.

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

Here is an analogous cost model of double log form.

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

In the double log model the dependent variable and both business condition variables have been logged. This specification has the effect of making 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. Elasticity estimates are informative and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, the elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume.[13] This is restrictive, and may be inconsistent with the true form of the cost relationship that we are trying to model.

Here is an analogous model of translog form[14]

$$\begin{aligned}\ln C_{h,t} = a_0 + a_1 \cdot \ln YN_{h,t} + a_2 \cdot \ln WL_{h,t} + a_3 \cdot \ln YN_{h,t} \cdot \ln YN_{h,t} \\ + a_4 \cdot \ln WL_{h,t} \cdot \ln WL_{h,t} + a_5 \cdot \ln WL_{h,t} \cdot \ln YN_{h,t}\end{aligned} \qquad [A3]$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as $\ln YN_{h,t} \cdot \ln YN_{h,t}$ permit the elasticity of cost with respect to each business condition variable to differ at different values of the variable. The

[13] Cost elasticities are not constant in the linear model that is exemplified by equation [A1].

[14] 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.

elasticity of cost with respect to the output variable may, for example, be lower for a small utility than for a large utility that has exhausted its opportunities to realize incremental scale economies. Interaction terms like $\ln WL_{h,t} \cdot \ln YN_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in output may depend on the price of labor in the service territory.

The translog form is an example of "flexible" functional form. Flexible forms can accommodate a greater variety of possible relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms such as the double log. As the number of variables subject to the translog treatment increases, the precision of a model's cost prediction falls. It is therefore common to limit the number of variables in a cost model that are translogged. In this study, we have limited the translog treatment to the output variables of our model.

Estimation Procedure

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.

In order to achieve a more efficient estimator, we corrected for autocorrelation and heteroskedasticity in the error terms. These are common phenomena in statistical cost research. The estimation procedure was developed by PEG Research using the GAUSS statistical software program. Since we estimated these unknown disturbance matrices consistently, the estimators we eventually computed are equivalent to Maximum Likelihood Estimators (MLE).[15] Our estimates thus possess all the highly desirable properties of MLEs.

Note, finally, that the model specification was determined using the data for all sampled companies, including Public Service However, computation of model parameters and standard errors for the prediction required that the utility of interest be dropped from the sample when we estimated the coefficients in the predicting equation. This implies that the estimates used in developing the cost model will vary slightly from those in the model used for benchmarking.

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

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Table 1

SAMPLE OF UTILITIES USED FOR EMPIRICAL RESEARCH

Alabama Power
Appalachian Power
Arizona Public Service
Avista
Black Hills
Carolina Power & Light
Cleco Power
Columbus Southern Power
Dayton Power & Light
Duke Energy
El Paso Electric
Empire District Electric
Entergy Arkansas
Entergy Louisiana
Florida Power & Light
Florida Power
Georgia Power
Gulf Power
Idaho Power
Indianapolis Power & Light
Kansas City Power & Light
Kentucky Power
Kentucky Utilities
Louisville Gas & Electric
Minnesota Power
Mississippi Power
Montana Dakota Utilities
Nevada Power
Northern Indiana Public Service
Northern States Power (MN)
Ohio Power
Oklahoma Gas and Electric
Otter Tail Power
Portland General Electric
Public Service Company of Colorado
Public Service Company of New Mexico
Public Service Company of Oklahoma
Pacificorp
Puget Sound Energy
Sierra Pacific Power
South Carolina Electric & Gas
Southern Indiana Gas & Electric
Southwestern Electric Power
Southwestern Public Service
Tampa Electric
Tucson Electric Power
Virginia Electric & Power
Western Resources

48 sampled utilities

Boldface indicates Western Interconnect utilities

Table 2

Econometric Model of Non-Fuel O&M Expenses - Pensions Excluded

VARIABLE KEY

N = Number of Customers
VG = Net Generation Volume (MWh)
KG = Total Generation Capacity (MW)
NT = Customers per Transmission Line Mile
S = % of Generation Capacity that is Not Scrubbed
NUKE= % of Generation Capacity that is Not Nuclear
DSM= % of Distribution that is Not Customer Service and Sales
C = % of Generation Capacity that is Coal
OH = % of T&D Plant Overhead
NG = Number of Gas Customers
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
N	0.463 [1]	16.25	0.000
NN	0.238	4.57	0.000
NVG	-0.243	-6.20	0.000
VG	0.398 [1]	12.08	0.000
VGVG	0.259	7.48	0.000
KG	0.053 [1]	1.96	0.050
NT	-0.036	-2.85	0.005

[1] Elasticity estimate used to develop output indexes discussed in Table 5. The elasticity weight for customers is .463/.914 = .507. The elasticity weight for generation volume is .398/.914 = .435. The elasticity weight for generation capacity is .053/.914 =0.058. These weights sum up to 1.000.

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
S	-0.072	-3.94	0.000
NUKE	-1.024	-16.50	0.000
DSM	-0.409	-10.08	0.000
C	0.074	5.88	0.000
OH	0.106	3.05	0.002
NG	-0.005	-3.23	0.001
Trend	-0.002	-1.69	0.092
Constant	14.890	685.10	0.000
Rbar-Squared	0.950		
Sample Period	1995-2008		
Number of Observations	642		

Table 3

Comparison of Public Service's Business Conditions To Full Sample Norms

Business Condition	Units	PSCo Values, 2008 [A]	PSCo Values, 2010 [B]	Difference between PSCo Values 2008 & 2010 [B/A]	Sample Mean, 2008	PSCO 2010 / Sample Mean 2008
Non-Fuel O&M Cost	Dollars	396,599,998	513,066,110	1.294	430,656,335	1.19
Price Index of Labor and Materials	Index Number	145.80	149.26	1.024	133.1	1.12
Number of Retail Customers	Count	1,358,033	1,364,464	1.005	815,175	1.67
Net Generation Volume	MWh	21,862,160	25,223,285	1.154	24,351,109	1.04
Total Generation Capacity	MW	4,037	4,799	1.189	5,700	0.84
Customers per Transmission Line Mile	Ratio	409.8	330.3	0.806	210.65	1.57
% of Generation that is Not Scrubbed	Percent	55.3%	50.0%	0.904	0.764	0.65
% of Generation that is Not Nuclear	Percent	100.0%	100.0%	1.000	0.938	1.07
% of Distribution that is Not Customer Service and Sales	Percent	75.9%	59.2%	0.780	0.872	0.68
% of Generation Capacity that is Coal	Percent	67.4%	58.0%	0.860	0.513	1.13
% of Transmission and Distribution Plant Overhead	Percent	38.8%	36.6%	0.942	0.714	0.51
Number of Gas Customers	Count	1,287,556	1,297,205	1.007	94,182	13.77

Table 4

Econometric Comparison of Actual and Predicted O&M Cost for PSCo

Year	Difference (%)
2010	-17.2%

Table 5

How PSCo's 2010 Unit Cost Compares to Full Sample and Peer Group

	PSCo (2010)	Full Sample (2008)	Western Interconnection Utilities (2008)
Dollars per Customer	$ 376	$ 581	$ 521
Dollars per MWh Generated	$ 20.34	$ 19.48	$ 25.06
Dollars per MW Capacity	$ 106,911	$ 85,025	$ 107,678
Summary Unit Cost Index	**0.646**	**0.761**	**0.821**

How PSCO Compares[1]

	Full Sample (2008)	Western Interconnection Utilities (2008)
Dollars per Customer	-43.4%	-32.6%
Dollars per MWh Generated	4.3%	-20.9%
Dollars per MW Capacity	22.9%	-0.7%
Summary Unit Cost Index	**-16.4%**	**-24.0%**

1: Percent differences calculated logarithmically

Table 6

Test Years of Sampled Utilities

Forward

Utility Name
Florida Power & Light
Florida Power
Georgia Power
Gulf Power
Minnesota Power
Mississippi Power
Northern States Power (MN)
Portland General Electric
Tampa Electric

Partial

Utility Name
Columbus Southern Power
Dayton Power & Light
Ohio Power

Historic

Utility Name
Appalachian Power
Arizona Public Service
Avista
Black Hills
Carolina Power & Light
Cleco Power
Duke Energy
El Paso Electric
Empire District Electric
Entergy Arkansas
Entergy Louisiana
Indianapolis Power & Light
Kansas City Power & Light
Kentucky Power
Kentucky Utilities
Louisville Gas & Electric
Nevada Power
Northern Indiana Public Service
Oklahoma Gas and Electric
Otter Tail Power
Public Service Company of Colorado
Public Service Company of New Mexico
Public Service Company of Oklahoma
Puget Sound Energy
South Carolina Electric & Gas
Southern Indiana Gas & Electric
Southwestern Electric Power
Southwestern Public Service
Tucson Electric Power
Virginia Electric & Power
Western Resources

Excluded

Utility Name	Reason for Exclusion
Alabama Power	Test Year change during sample period
Idaho Power	Test Year change during sample period
Montana-Dakota Utilities	Varying test years amongst utility jurisdictions
Pacificorp	Varying test years amongst utility jurisdictions
Sierra Pacific Power	Varying test years amongst utility jurisdictions

Table 7

Unit Cost Trends by Test Year 1995-2008

	Test Year Type				
	Historic	Partial	Forward	All	Western Interconnection Utilities
Cost/Customer	2.2%	2.2%	1.9%	2.2%	1.9%
Cost/Generation Volume	2.4%	2.3%	1.4%	2.3%	2.3%
Cost/Generation Capacity	1.9%	3.2%	1.0%	1.9%	1.7%
Unit Cost Index	**2.2%**	**2.3%**	**1.6%**	**2.2%**	**2.1%**

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BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	Cause No. PUD 201100087
AUTHORIZING APPLICANT TO MODIFY ITS	)	
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

FILED
JUL 28 2011
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CORPORATION COMMISSION
OF OKLAHOMA

Direct Testimony

of

Mark Newton Lowry

on behalf of

Oklahoma Gas and Electric Company

July 28, 2011

Mark Newton Lowry
Direct Testimony

I. INTRODUCTION AND BACKGROUND

Q. **Please state your name, position, and business address.**

A. My name is Mark Newton Lowry. I am the President of Pacific Economics Group ("PEG") Research LLC. My business address is 22 E. Mifflin Street, Suite 302, Madison, WI 53705. I am testifying in this proceeding on behalf of Oklahoma Gas and Electric Company ("OG&E" or "the Company").

Q. **What are your responsibilities in your role as company president?**

A. PEG Research is a company in the Pacific Economics Group consortium which is active in the fields of utility performance research and regulation. Our practice, which has four PhD economists, is international in scope and has to date included projects in eleven countries. We work for a mix of utilities, regulators, consumer groups, and public agencies and this has given us a reputation for objectivity and dedication to regulatory science. For example, power distributors in the Canadian province of Ontario operate under multiyear rate plans with terms that are linked to a benchmarking study I directed for the Ontario Energy Board. My duties as President of PEG Research include the management of the company, supervision of cost-performance research, and the provision of expert witness testimony.

Q. **Please discuss your background and experience in the energy and utility industries.**

A. I have been an energy economist for twenty five years and have spent the last twenty years doing research and consulting on the utility industry. Before assuming my present position, I was a partner of Pacific Economics Group LLC for eight years and managed its Madison office. Prior to that, I worked at Christensen Associates in Madison, first as a Senior Economist and later as a Vice President. The primary focus of my consulting research has been the cost performance of gas and electric utilities. I have been a pioneer in the use of scientific cost research in energy utility regulation.

Before becoming a consultant I spent five years as an academic economist. I was an Assistant Professor of Mineral Economics at the Pennsylvania State University, where I taught energy economics. I also worked as a Visiting Professor at l'Ecole des Hautes Etudes Commerciales in Montreal. My academic research and teaching stressed the use of statistics in industry analysis.

I have served as a referee for several scholarly journals and have an extensive record of professional publications and public appearances. My publications include articles on benchmarking in the *Electricity Journal*, *Energy Policy*, and the *Energy Journal.* I hold a Ph.D. in applied economics from the University of Wisconsin, which is noted for its strength in economic statistics. My resume is provided as Exhibit MNL-1 to my testimony.

Q. **Please discuss your experience as an expert witness.**

A. I have testified many times on utility performance and other regulatory issues. Most of this testimony has involved cost research. In addition to Oklahoma, where I have previously testified on the cost performance of OG&E, I have testified in Alberta, British Columbia, California, Colorado, the District of Columbia, Georgia, Hawaii, Illinois, Kentucky, Maine, Massachusetts, Missouri, New York, Ontario, Quebec, Rhode Island,

and Vermont. Further details of my testimony can be found in my resume, which is attached as Exhibit MNL-1.

II. PURPOSE OF TESTIMONY

Q. **What is the purpose of your testimony?**

A. I have been asked by OG&E to analyze its non-fuel operation and maintenance ("O&M") expenses, particularly those expenses devoted to generation maintenance. To do so, I performed statistical benchmarking studies of these costs. This testimony provides a high level summary of these studies. The details of the studies are provided in the report which is attached hereto as Exhibit MNL-2.

Q. **How does your testimony relate to the testimony of other company witnesses?**

A. My testimony and the attached report provide a quantitative assessment of the Company's recent cost efficiency. The Company will be submitting additional testimony (by OG&E witness Donald R. Rowlett) which will address the specifics of how OG&E achieves its operating efficiency and remains a low-cost electric provider for customers.

III. SUMMARY OF STUDY

Q. **Why are benchmarking studies used in general rate cases?**

A. In a rate case, a utility's ability to effectively manage its cost is an important consideration for a commission in determining appropriate rate increases. Nonfuel O&M expenses are the largest component of base rate cost that a utility can attempt to control in the short run and are thus a natural focus for an efficiency inquiry. These expenses are also sufficiently large as to warrant rate increases when it can be demonstrated that the cost of an efficient utility is rising.

Benchmarking studies can address the issue of cost efficiency and are facilitated by the extensive operating data that utilities report to government agencies. However, performance appraisals are still difficult to make accurately. There are important differences between utilities in the scale of their operations, the facilities that they operate, and in other business conditions that influence their cost. It is often beyond the expertise of participants in the regulatory process to draw the right conclusions about efficiency from available data. Consultants with expertise in the field are thus occasionally retained by the various parties to regulation, including regulatory commissions, to prepare benchmarking studies.

Q. **What is statistical benchmarking and how is it useful in measuring utility performance?**

A. Statistical benchmarking is quite simply an approach to performance benchmarking that uses statistics. Any use of data on the operations of other utilities to create cost benchmarks is an exercise in statistics because the data are statistics. In addition, statistical methods such as econometrics are sometimes employed to identify the external business conditions that drive utility cost. This information can be used to develop benchmarks that properly reflect the impact that local business conditions will typically have on the cost of a particular utility such as OG&E.

Since statistical benchmarking can shed light on utility performance, it has become a widely used tool. Managers use benchmarking to gauge how well their companies are operating. Statistical benchmarking is also used increasingly in regulation, and regulatory benchmarking is encouraged in a recent report of the National Regulatory Research Institute.[1]

Q. **Please provide more details of your benchmarking studies for OG&E.**

A. The cost performance of OG&E was appraised using two well-established benchmarking methods: econometric modeling and unit cost indexing. Using both benchmarking methods, we measured the Company's cost performance in the three most recently completed years: 2008-2010. The data used to calculate the benchmarks were drawn entirely from respected public sources such as the Federal Energy Regulatory Commission ("FERC") Form 1. To calculate the costs of OG&E in 2010, we added to their reported FERC Form 1 expenses approximately $5.9 million to normalize the cost of a generation maintenance contract.

Q. **Please explain the econometric benchmarking method.**

A. Guided by cost theory, we developed econometric models of the impact that various quantifiable business conditions have on the non-fuel O&M and generation maintenance expenses of vertically integrated electric utilities ("VIEUs") like OG&E. Each business condition variable in the two cost models has a parameter that measures its cost impact. We estimated these parameters econometrically using large samples of historical data on the costs of U.S. VIEUs and the business conditions that they faced. This procedure identifies important drivers of utility cost and gauges their relative importance.

[1] Evgenia Shumilkina, *Utility Performance: How Can State Commissions Evaluate it Using Indexing, Econometrics, and Data Envelopment Analysis?* National Regulatory Research Institute 10-05, 2010.

The samples were more than adequate for the development of credible cost models. Numerous cost drivers were identified. Both models do a good job of explaining the sampled data. All parameter estimates are plausible and virtually all have high statistical significance.

We used each econometric benchmarking model to "predict" OG&E's corresponding cost during each year of the 2008-2010 period. The cost predictions are the benchmarks and reflect OG&E's local business conditions. As a final step, we compared OG&E's actual cost to the econometric benchmarks. Performance is good to the extent that OGE's actual costs are low compared to their respective benchmarks.

Q. **Please explain the unit cost method.**

A. For each cost category, we compared the Company's cost per unit of output to the average unit cost across a peer group using unit cost indexes. A unit cost index is the ratio of a cost index to an output index. It provides an automatic adjustment, prior to making a peer group comparison, for differences in the operating scale of utilities, thereby facilitating the inclusion of utilities of varying sizes in an OG&E peer group. There were different peer groups for generation maintenance and nonfuel O&M expenses. Most of the peers are current or former members of the Southwest Power Pool.

Q. **Why are there different peer groups for the two cost categories?**

A. The selection of the peer group plays a key role in the accuracy of benchmarking using a unit cost index. Economic theory and our econometric research reveal that both categories of cost depend on numerous business conditions in addition to operating scale.

The companies in the peer group should face cost pressures from these additional business conditions that are similar on balance to those faced by OG&E. It is sometimes difficult to find a large number of peers that face similar business conditions.

Our econometric work on generation maintenance expenses revealed that the mix of generation capacity is the most important consideration in the choice of a unit cost peer group. Most of the Company's capacity is fueled by clean-burning natural gas. OG&E also has some power plants that burn sub-bituminous western coal but does not scrub the exhaust from these plants because of the coal's low sulfur content. Since maintenance expenses for the fossil steam generation and other (chiefly gas-fired) power generation capacity that OG&E owns are itemized on the FERC Form 1, we can use these itemized data in our research and thereby choose peers, like Entergy Arkansas and Northern States Power, that have nuclear generation capacity provided that they match up particularly well to OG&E with respect to their fossil generation capacity mix.

In a study of *total* O&M expenses, which include expenses for nuclear generation, Entergy Arkansas and Northern States Power are inappropriate peers because they have nuclear operations, which typically involve high O&M. As replacements for these companies in the O&M peer group, we have chosen three utilities in the South Central region. Two of these—Cleco and Southwestern Electric Power—have a little more solid-fuel generating capacity than OG&E, do not exclusively burn western coal in this capacity, and scrub some of their emissions from solid-fuel combustion. The third utility—Entergy Mississippi—does burn western coal without scrubbing, but relies more on gas fired generation than OG&E does.

Q. **Please explain the output index that you use in your unit cost calculations.**

A. Because it is difficult to characterize the operating scale of utilities using only one output variable, the output indexes used in our two studies summarized multiple output comparisons between OG&E and the peer group by taking a weighted average of the comparisons. In the study of O&M expenses, for instance, we compared OG&E's scale to the averages for the peer group using generation volume, generation capacity, and the number of customers served. The weights for the output indexes (*e.g.* how much weight to place on the generation volume), like the selection of peer groups, were guided by our econometric research on utility cost drivers.

Q. **What are the results of your benchmarking work for non-fuel O&M expenses, as they relate to OG&E?**

A. The non-fuel O&M expenses of OG&E were found to be about 20% below the benchmarks produced by the econometric model on average from 2008 to 2010. This performance was in the top quartile and sixth best in a sample of 45 utilities. In other words, more than three quarters of the utilities in the econometric sample had costs that compared less favorably to their benchmarks during these years. In 2010, non-fuel O&M expenses were about 12% below the benchmark produced by the econometric model. This was also a top quartile performance. OG&E's ability to be a top cost performer year after year is, in my professional opinion, quite remarkable.

Using the unit cost indexes, we found that OG&E's unit O&M cost was a substantial 23% below the norm for the peer group on average from 2008 to 2010. The Company's unit cost was 19% below the peer group norm in 2010. The results that we obtained using the unit cost benchmarking method, which as I have explained involve sensible peer group comparisons, thus corroborate the results we obtained econometrically and support the finding that OG&E continues to be a superior cost performer.

Q. **What are the results of your benchmarking work for generation maintenance?**

A. The generation maintenance expenses of OG&E were found to be about 25% below the benchmarks generated by our econometric maintenance cost model on average from 2008 to 2010. This performance was in the top quartile. In 2010, generation maintenance expenses were about 4% below the benchmark produced by the econometric model. This was a second quartile performance.

Using the unit cost index, we found that OG&E's unit generation maintenance cost was a substantial 22% below the peer group norm on average from 2008 to 2010. The Company's unit cost was about 10% below the peer group norm in 2010. Using both benchmarking methods we therefore found that OG&E's generation maintenance expenses, while higher than in the past, were still quite reasonable in 2010.

Q. **Does this conclude your prepared direct testimony?**

A. Yes, it does.

Exhibit MNL-1

RESUME OF MARK NEWTON LOWRY

July 2011

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Education:
High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Agricultural and Resource Economics, University of Wisconsin -Madison, May 1984

Relevant Work Experience, Primary Positions:

Present Position **President, Pacific Economics Group Research LLC, Madison WI**

Chief executive of the research unit of the Pacific Economics Group consortium. Leads internationally recognized practice in alternative regulation ("Altreg") and utility statistical research. Other research specialties include: codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include senior management, supervision of research, and expert witness testimony.

October 1998-February 2009 **Partner, Pacific Economics Group LLC, Madison, WI**

Managed PEG's Madison office. Specific duties include project management and research, written reports, public presentations, expert witness testimony, personnel management, and marketing.

January 1993-October 1998 **Vice President**
January 1989-December 1992 **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on PBR and statistical benchmarking for energy utilities during these years.

Aug. 1984-Dec. 1988 **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Teaching and research specialty: analysis of markets for energy products and metals.

August 1983-July 1984 **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 — Research Assistant, Department of Agricultural and Resource Economics, University of Wisconsin-Madison

Dissertation research under Dr. Peter Helmberger on the role of speculative storage in markets for field crops. Work included the development of an econometric rational expectations model of the U.S. soybean market.

March 1981-March 1982 — Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States.
- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 — **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in non-competitive metal markets.

Major Consulting Projects:

1. Research on Gas Market Competition for a Western Electric Utility. 1981.
2. Research on the Natural Gas Policy Act for a Northeast Trade Association. 1981.
3. Interruptible Service Research for an Industry Research Institute. 1989.
4. Research on Load Relief from Interruptible Services for a Northeast Electric Utility. 1989.
5. Design of Time-of-Use Rates for a Midwest Electric Utility. 1989.
6. PBR Consultation for a Southeast Gas Transmission Company. 1989.
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8. Productivity Research for a Northeast Gas and Electric Utility. 1990-91.
9. Comprehensive Performance Indexes for a Northeast Gas and Electric Utility. 1990-1991.
10. PBR Consultation for a Southeast Electric Utility. 1991.
11. Research on Electric Revenue Adjustment Mechanisms for a Northeast Electric Utility. 1991.
12. Productivity Research for a Western Gas Distributor. 1991.
13. Cost Performance Indexes for a Northeast U.S. Gas and Electric Utility. 1991.
14. Gas Transmission Rate Design for a Western U.S. Electric Utility. 1991.
15. Gas Supply Cost Indexing for a Western U.S. Gas Distributor. 1992.
16. Gas Transmission Strategy for a Western Electric Utility. 1992.
17. Design and Negotiation of Comprehensive Benchmark Incentive Plans for a Northeast Gas and Electric Utility. 1992.
18. Gas Supply Cost Benchmarking and Testimony for a Northeast U.S. Gas Distributor, 1992.
19. Bundled Power Service Productivity Research for a Western Electric Utility. 1993-96.
20. Development of PBR Options for a Western Electric Utility. 1993.
21. Review of the Regional Gas Transmission Market for a Western Electric Utility. 1993.
22. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1993.

23. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1994.
24. Productivity Research for a Western Gas Distributor. 1994.
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26. Bundled Power Service Benchmarking for a Western Electric Utility. 1994.
27. White Paper on PBR for a U.S. Trade Association. 1995.
28. Productivity Research and PBR Plan Design for a Northeast Gas and Electric Company. 1995.
29. Regulatory Strategy for a Restructuring Canadian Electric Utility. 1995.
30. PBR Consultation for a Japanese Electric Utility. 1995.
31. Regulatory Strategy for a Restructuring Northeast Electric Utility. 1995.
32. Productivity Research and Plan Design Testimony for a Western Gas Distributor. 1995.
33. Productivity Testimony for a Northeast Gas Distributor. 1995.
34. Speech on PBR for a Western Electric Utility. 1995.
35. Development of a PBR Plan for a Midwest Gas Distributor. 1996.
36. Stranded Cost Recovery and Power Distribution PBR for a Northeast Electric Utility. 1996.
37. Benchmarking and Productivity Research and Testimony for a Northeast Gas Distributor. 1996.
38. Consultation on Gas Production, Transmission, and Distribution PBR for a Latin American Regulator. 1996.
39. Power Distribution Benchmarking for a Northeast Electric Utility. 1996.
40. Testimony on PBR for a Northeast Power Distributor. 1996.
41. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
42. Design of Gas Distributor Service Territories for a Latin American Regulator. 1996.
43. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
44. Service Quality PBR for a Canadian Gas Distributor. 1996.
45. Productivity and PBR Research and Testimony for a Canadian Gas Distributor. 1997.
46. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1997.
47. Design of a Price Cap Plan for a South American Regulator. 1997.
48. White Paper on Utility Brand Name Policy for a U.S. Trade Association. 1997.
49. Bundled Power Service Benchmarking and Testimony for a Western Electric Utility. 1997.
50. Review of a Power Purchase Contract Dispute for a Midwest City. 1997.
51. Research on Benchmarking and Stranded Cost Recovery for a U.S. Trade Association. 1997.
52. Research and Testimony on Productivity Trends for a Northeast Gas Distributor. 1997.
53. PBR Plan Design, Benchmarking, and Testimony for a Southeast Gas Distributor. 1997.
54. White Paper on Power Distribution PBR for a U.S. Trade Association. 1997-99.
55. White Paper and Public Appearances on PBR Options for Australian Power Distributors. 1997-98.
56. Gas and Power Distribution PBR Research and Testimony for a Western Energy Utility. 1997-98.
57. Research on the Cost Structure of Power Distribution for a U.S. Trade Association. 1998.
58. Research on Cross-Subsidization for a U.S. Trade Association. 1998.
64. Testimony on Brand Names for a U.S. Trade Association. 1998.
65. Research and Testimony on Economies of Scale in Power Supply for a Western Electric Utility. 1998.
66. PBR Plan Design and Testimony for a Western Electric Utility. 1998-99.
67. PBR and Bundled Power Service Testimony and Testimony for Two Southeast U.S. Electric Utilities. 1998-99.
68. Statistical Benchmarking for an Australian Power Distributor. 1998-9.
69. Testimony on Functional Separation of Power Generation and Delivery for a U.S. Trade Association. 1998.
70. Design of a Stranded Benefit Passthrough Mechanism for a Restructuring Electric Utility. 1998.
71. Consultation on PBR and Code of Conduct Issues for a Western Electric Utility. 1999.
72. PBR and Bundled Power Service Benchmarking Research and Testimony for a Southwest Electric Utility. 1999.
73. Power Transmission and Distribution Cost Benchmarking for a Western Electric Utility. 1999.
74. Cost Benchmarking for Three Australian Power Distributors. 1999.

75. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1999.
76. Benchmarking Research for an Australian Power Distributor. 2000.
77. Critique of a Commission-Sponsored Benchmarking Study for Three Australian Power Distributors. 2000.
78. Statistical Benchmarking for an Australian Power Transco. 2000.
79. PBR and Benchmarking Testimony for a Southwest Electric Utility. 2000.
80. PBR Workshop (for Regulators) for a Northeast Gas and Electric Utility. 2000.
81. Research on Economies of Scale and Scope for an Australian Electric Utility. 2000.
82. Research and Testimony on Economies of Scale in Power Delivery, Metering, and Billing for a Consortium of Northeast Electric Utilities. 2000.
83. Research and Testimony on Service Quality PBR for a Consortium of Northeast Energy Utilities. 2000.
84. Power and Natural Gas Procurement PBR for a Western Electric Utility. 2000.
85. PBR Plan Design for a Canadian Natural Gas Distributor. 2000.
86. TFP and Benchmarking Research for a Western Gas and Electric Utility. 2000.
87. E-Forum on PBR for Power Procurement for a U.S. Trade Association. 2001.
88. PBR Presentation to Florida's Energy 2000 Commission for a U.S. Trade Association. 2001.
89. Research on Power Market Competition for an Australian Electric Utility. 2001.
90. TFP and Other PBR Research and Testimony for a Northeast Power Distributor. 2000.
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Exhibit MNL-2

RECENT COST PERFORMANCE OF OKLAHOMA GAS & ELECTRIC

July 22, 2011

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Executive Summary

A central issue in utility regulation is the interpretation of operating data to ascertain whether the utility is operating efficiently. Regulators naturally want to know whether utility management is doing a good job. Statistical benchmarking using publicly available data on utility operations is a useful tool for appraising cost performance. A recent study by the National Regulatory Research Institute encouraged greater use of benchmarking in regulation.[1]

This paper reports on a statistical benchmarking study of the recent cost performance of Oklahoma Gas and Electric ("OG&E" or "the Company"). The focus of the study was generation maintenance expenses and a broader class of non-fuel O&M expenses that are amenable to accurate benchmarking. This report provides details of our studies.

Benchmarking Methods

OG&E, like other utilities, faces a unique set of local business conditions such as service infrastructure, demand characteristics, and geography. Many of these factors have a demonstrable impact on cost that is largely beyond the Company's control. To better estimate the cost performance of OG&E we used two well established statistical methods --- econometrics and unit cost indexing --- to develop benchmarks that account for external factors.

Guided by cost theory, we developed econometric models of the impact that various quantifiable business conditions have on the non-fuel O&M expenses and generation maintenance expenses of vertically integrated electric utilities ("VIEUs") like OG&E. Each business condition variable in the two models has a parameter that measures its impact on cost. These parameters were estimated statistically using historical data on utility operations drawn from respected public sources such as the Federal Energy Regulatory Commission ("FERC"). The samples of utility operating data were large and varied enough to permit development of credible cost models. Both models were found to have high explanatory

[1]Evgenia Shumilkina, "Utility Performance: How Can State Commissions Evaluate It Using Indexing, Econometrics, and Data Envelopment Analysis?", National Regulatory Research Institute 10-05, March 2010.

power. All estimates of model parameters were plausible and all but two had high statistical significance.

We used each model to predict OG&E's corresponding cost during the 2008-2010 period. The predicted cost values were the benchmarks and reflect OG&Es local business conditions. We then compared OG&E's actual cost to the econometric benchmarks. Good performance is reflected in utilities that have relatively low actual costs as compared to their respective benchmarks.

Our second method for ascertaining the performance of OG&E was to compare the Company's unit cost (cost per unit of output) to the average unit cost across a peer group using unit cost indexes. There were different peer groups for generation maintenance and non-fuel O&M expenses. Both unit cost indexes compared the operating scale of OG&E to that of the peer group using multiple output variables. The output weights for the indexes and the selection of peer groups was guided by our econometric work.

Research Results

Non-Fuel O&M Expenses

The non-fuel O&M expenses of OG&E were found to be about 20% below the benchmark generated by the econometric O&M cost model on average from 2008 to 2010. This performance, which was sixth best in the sample, was in the top quartile. In other words, more than three quarters of the sampled utilities had costs that compared less favorably to their econometric benchmarks. In 2010, non-fuel O&M expenses were about 12% below the benchmark produced by the econometric model. This was also a top quartile performance. OG&E's success in sustaining a high performance ranking in recent years has been remarkable.

OG&E's unit non-fuel O&M cost was about 23% below the norm for the sampled utilities on average from 2008 to 2010. The Company's unit cost was about 19% below the norm on average in 2010. The unit cost results corroborate the econometric results and support a finding that OG&E continues to be a superior cost manager.

Generation Maintenance Expenses

From 2008 to 2010, the generation maintenance expenses of OG&E were found to be on average about 25% below the benchmark generated by the econometric maintenance cost model. This performance was in the top quartile. In 2010, generation maintenance expenses were about 4% below the benchmark produced by the econometric model. This was a second quartile performance. OG&E's unit generation maintenance cost was about 22% below the norm for the peer group on average from 2008 to 2010. The Company's unit cost was 10% below the peer group norm on average in 2010. Using both benchmarking methods, we therefore find that while OG&E's generation maintenance expenses in 2010 were higher than in some recent years, they were still quite reasonable.

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1. Introduction

Statistical benchmarking has in recent years become a widely used tool in the assessment of utility performance. Managers use benchmarking to gauge how well their companies are operating. Benchmarking also plays a growing role in regulation. Benchmarking studies can, for instance, be used to assess the reasonableness of utility proposals to establish new rates or multi-year rate plans.

The benchmarking of utilities is facilitated by the extensive operating data which they report to government agencies. However, accurate performance appraisals also require statistical methods and an understanding of utility operations and data. There are important differences between utilities in the scale of their operations, the prices they pay for inputs, and in other business conditions that influence their cost.

Personnel of Pacific Economics Group ("PEG") Research LLC have been active for more than twenty years in the field of utility performance research. We pioneered the use of rigorous benchmarking methods in North American regulation. Senior author Mark Newton Lowry has testified on utility performance in numerous proceedings.

OG&E has retained PEG Research to prepare a study of its recent cost efficiency. The focus of the study is generation maintenance expenses and a broader class of non-fuel O&M expenses that is suitable for benchmarking. This report provides details of these studies. Section 2 of the report provides an introduction to benchmarking methods. Section 3 discusses our research for OG&E. More technical details of the research are presented in the Appendix.

2. Benchmarking Methodology

This section provides a non-technical discussion of some important benchmarking concepts and details the two benchmarking methods used in the study. More technical aspects of our methodology are discussed in the Appendix.

2.1 What is Benchmarking?

The word "benchmark" was originally a term of art used by surveyors. 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 to indicate something that can be used as a point of comparison in appraisals of performance.

Statistics are often used in such performance comparisons. For example, statistical benchmarking plays a major (if informal) role in player selection to the Pro Football Hall of Fame. Running backs, for example, are evaluated using statistics on their touchdowns, rushing yardage, and fumbles. The values achieved by Hall of Fame members like Barry Sanders are expected to be far better than those for an average player. Values that are markedly superior to the norm reflect a Hall of Fame performance standard.

Statistical performance benchmarking commonly involves one or more performance metrics, which are sometimes called key performance indicators ("KPIs"). The values of the KPIs achieved by an entity under scrutiny are compared to benchmark values that reflect performance standards. Statistical methods are used both to calculate benchmarks and to draw inferences about performance from benchmark comparisons. Statistical performance benchmarking of regulated utilities requires establishing KPIs and benchmarks that are relevant to utility performance. For example, given information on a utility's cost and a certain cost benchmark we might estimate cost performance by taking the ratio of the two values:

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

In this case, a smaller cost performance number indicates better efficiency. Cost performance values greater than 1 indicate that the utility's actual costs exceed the benchmark value, and values below 1 indicate that a utility has achieved costs below the benchmark. Cost performance comparisons for multiple utilities can be used to rank the relative cost efficiency of those utilities.

2.2 Importance of Cost Drivers

When trying to determine the relative performance of two sprinters, comparing their times in the 100-meter dash when one runner is running uphill and into a stiff wind while the other runs on a level track with a strong tailwind doesn't tell us much about what their relative performances would likely be in a head-to-head race. Similarly, in reviewing cost metrics and other types of business KPIs, it is widely recognized that differences in the values of the indicators that companies achieve depend significantly on the unique business conditions that each faces. In cost research, these unique conditions are sometimes called cost "drivers." Cost benchmarks can shed light on the performance of a utility's management if they reflect the typical impact of the cost drivers that the utility faces.

Economic theory is useful for identifying cost drivers so that their influence is considered in benchmarking studies. Under certain reasonable assumptions, cost "functions" exist that relate the minimum cost of a utility to the unique business conditions in its service territory. When the focus of benchmarking is a subset of total cost such as O&M expenses, cost theory reveals that the relevant business conditions include the prices of O&M inputs, the operating scale of the company, and the amounts of other, non-O&M inputs (*e.g.* capital) that the company uses.

The theoretical existence of "other input" variables in an O&M cost function means that a good appraisal of the efficiency of a utility in using O&M inputs should consider in some fashion the amounts of other inputs that it uses. This result is important for several reasons. Different production technologies may have different O&M requirements. Nuclear generation facilities, for instance, seem to require more O&M than a bank of combustion turbines with similar capacity. Opportunities often exist to substitute inputs in production. For example, a utility that generates its power from a new plant may spend less on maintenance than a utility that is struggling to keep an older plant in service. The owner of the new plant will bear higher capital depreciation expenses. Capital inputs have thus been substituted for O&M inputs.

Another reason that other inputs matter in an O&M cost study is that utilities use different methods to classify costs. Utilities may, for instance, differ in the way that they categorize certain expenditures between administrative and direct operating expenses, or between labor and non-labor inputs. As a general rule, therefore, benchmarking will tend to be simpler and more accurate to the extent that the scope of costs under consideration is comprehensive. For example, it will be easier to accurately benchmark *total* base rate O&M expenses than it will be to accurately benchmark *labor* expenses.

Regardless of the particular category of cost that a benchmarking study focuses on, economic theory allows for the existence of *multiple* output variables in the cost function. In other words, it is reasonable and often desirable to use multiple measures of operating scale. This is especially true for a vertically integrated electric utility like OG&E, which is in the business of providing diverse services that in other parts of the country are provided by separate and independent companies. The cost of a VIEU depends, for instance, on the number of customers it serves (as it provides "distribution service") as well as on its generation volume (as it provides "generation service"). It is also noteworthy that theory allows for numerous business conditions other than input prices, output quantities, and other inputs to affect the cost of service.

2.3 Benchmarking Methods

In this section we discuss the two benchmarking methods that we used in our study for OG&E: econometric modeling and unit cost indexing. We begin with the econometric method to establish a better context for the discussion of the indexing method.

2.3.1 Econometric Modeling

In Section 2.2, we noted that comparing the results of a 100-meter sprinter racing uphill into a stiff wind to a runner racing on a level course with a strong tailwind doesn't tell us much about the relative performance of the athletes and what their relative performances would be in a head-to-head race. We could, however, use statistics to infer information about their relative performances. For example, we could develop a theoretical model that related time in the 100-meter dash to track conditions like wind speed and direction and the incline of the track. We could then use a sample of 100-meter times turned in by runners under varying track conditions to estimate the effects of wind speed, incline and other conditions statistically. These estimated effects could then be used to compare the performances of the two sprinters given the track conditions that they faced. Computer models used to rank college football teams use statistics to estimate the impact on a team's winning percentage of the strength of its schedule and the percentage of its games played at home. Both exercises are analogous to the econometric modeling method used in this study: since the cost drivers faced by different utilities are unique, we statistically estimate the effects of these conditions, and control for them in our measurement of performance.

Basic Assumptions

The impact of external business conditions on the costs of utilities can be estimated using statistics. A branch of statistics called econometrics has developed procedures for estimating the impact of business conditions on economic variables using historical data.[2] First, the general form of the utility's cost function is specified. Econometric methods are then used to statistically quantify the impact of each cost driver in the model using historical data on the costs incurred by a group of utilities and the business conditions that they faced. The result is a model that adds up the impacts of each individual cost driver on the utility's cost.

For example, if cost were simply a function of the number of customers and the average utility wage rate (not generally true), we might develop the following cost model:

$$Cost = a_0 + a_1 * Customers + a_2 * Wage.$$

In this equation the terms a_1 and a_2 are the cost model "parameters". They measure the respective impact of customers and wages on utility costs. The values of the parameters are estimated econometrically. The sample used in parameter estimation can be a "time series" consisting of data over several years for a single company, a "cross section" consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies.

The results of econometric research are useful in identifying which business conditions drive utility cost. For example, econometric methods allow one to test the hypothesis that the

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

parameter for a candidate cost driver equals zero. A cost driver can be deemed statistically significant if this hypothesis is rejected at a high level of confidence. In a benchmarking study used in utility regulation it is sensible to exclude business condition variables that do not have statistically significant parameter estimates, as well as those with implausible parameter estimates.

Cost Predictions and Performance Appraisals

A cost function fitted with econometric parameter estimates may be called an econometric cost model. We can use such a model to "predict" a company's historical cost given local values for the cost-driver variables. These predictions are econometric benchmarks. Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year and company by the econometric model.

Suppose, for example, that we wish to benchmark the cost of a hypothetical electric utility called Southwest Power. We might then predict the cost of Southwest in period *t* using the following model.

$$\hat{C}_{Southwest,t} = \hat{a}_0 + \hat{a}_1 * N_{Southwest,t} + \hat{a}_2 * W_{Southwest,t}.$$

Here $\hat{C}_{Southwest,t}$ denotes the predicted cost of the Company, $N_{Southwest,t}$ is the number of customers it served, and $W_{Southwest,t}$ 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

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

Accuracy of Benchmarking Results

Statistical theory provides useful guidance regarding the accuracy of an econometric benchmark as a predictor of the benchmark that truly reflects the impact of local cost drivers. One important result is that a model can yield *biased* predictions of the true benchmark if relevant cost drivers are excluded from the model. It is therefore desirable to include in an econometric benchmarking model all cost drivers which are believed to be relevant, for which good data are available at reasonable cost, and which have plausible and statistically significant parameter estimates.

Even when an econometric model is unbiased it can be imprecise, yielding benchmarks that are too high for some companies and too low for others. Statistical theory suggests that the benchmark will be more precise to the extent that

- the model is successful in explaining the variation in cost in the historical data used in model development;
- the size of the sample used in model estimation is large;
- the number of cost driver variables included in the model is small relative to the sample size;
- the business conditions of sampled utilities are varied; and
- the business conditions of the subject utility are similar to those of the typical firm in the sample.

These results suggest that econometric benchmarking will be more accurate to the extent that it is based on a large sample of good operating data from companies with diverse operating conditions. There is no problem using in model estimation data from utilities with business conditions quite different from those of the subject utility so long as sample mean business conditions are fairly similar to the utility's on balance. When the sample is small, it will be difficult to identify all of the relevant cost drivers or to estimate their impacts accurately. It follows that it will generally be preferable to use panel data, encompassing information from multiple utilities over time, when these are available instead of a single cross section of data from several firms measured at a single point in time. Fortunately, large panels of good data on the operations of electric utilities are readily available in the United States.

2.3.2 Benchmarking Indexes

In their internal reviews of operating performance, utilities tend to employ the index approach to benchmarking in lieu of the econometric approach just described. Benchmarking indexes are also used sometimes in the regulatory arena. We begin our discussion with a review of index basics and then consider unit cost indexes.

Index Basics

An index is defined in one 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)".[3] In utility-performance benchmarking, indexing involves the calculation of ratios of the values of KPIs for a subject utility to the corresponding values for a sample of utilities. The companies that comprise the sample are sometimes called a peer group.

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 a "market basket" consisting of hundreds of goods and services. The weight for the inflation in the price of each product is its share of the value of all of the products in the basket. Thus if consumers typically spend $40 a week on beef and $5 on butter, beef might have a 2% weight in the index whereas butter might have only a 0.25% weight. A 5% increase in the price of steak would then have a much bigger impact on the inflation in the summary index than a 5% increase in the price of butter.

To better appreciate the advantages of multi-category indexes in benchmarking, recall from our discussion in Section 2.2 that the operating scale of a VIEU is often best measured using multiple output variables. These variables can have markedly different impacts even if all are worth considering. We can construct an output (quantity) index that takes a weighted average of output comparisons made using multiple variables.

In a cost-benchmarking application, it makes sense for the weights of an output index to reflect the relative importance of the individual output variables as cost drivers. The cost impact of an output variable is conventionally measured by its cost "elasticity". The elasticity of cost with respect to the number of customers served, for instance, is the percentage change in cost that results from a 1% change in the number. It is straightforward to estimate the required elasticities using econometric estimates of cost model parameters. We can then use as the weight

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

for each variable in an output index the share of its corresponding cost elasticity estimate in the sum of the estimated cost elasticities of the model's output variables.[4]

Unit Cost Indexes

A unit cost index is the ratio of a cost index to an output index. Each index compares the value for the subject utility to the average for a peer group. A unit cost index for Southwest Power, for instance, would have the general form

$$Unit\ Cost_t^{Southwest} = \frac{Cost_t^{Southwest} / Cost_t^{Peers}}{Output_t^{Southwest} / Output_t^{Peers}}.$$

In comparing the unit cost of a utility to the average for a peer group, we effectively introduce an automatic control for differences between the companies in operating scale, which as we have seen is an important cost driver. This permits us to include companies with more varied operating scales in the peer group. The output index can be multidimensional if it is desirable to measure operating scale using multiple output variables.

Unit cost indexes do not control for differences in the other cost drivers that are known to vary between utilities. Our discussion in Section 2.2 revealed that cost depends on input prices and miscellaneous other business conditions in addition 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 additional business conditions are similar on balance to those facing the subject utility. Thus, the choice of the peer group is an important step in a unit cost benchmarking exercise. Economic research on the drivers of utility cost is useful in peer group selection.

2.3.3 Averaging

Utilities manage their costs to reflect expected business conditions over a series of years and not the conditions specific to a single year. Cost in a single year may be sensitive to conditions, such as tornadoes and other severe weather events, which aren't considered in benchmarking because they are difficult to measure. Appraisals of cost efficiency are, therefore,

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

frequently made over a multi-year timeframe. We routinely assess efficiency over the most recent three years for which data have been gathered.

3. Empirical Research for OG&E

3.1 Data

As mentioned earlier, the energy utility industry is unusual in that detailed national operating data have been compiled by reliable sources for decades. Collection of many of these data is a legal mandate. The source of the cost and generation volume data used in this study was the Federal Energy Regulatory Commission ("FERC") Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations. Other data sources accessed in the research included the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor, the U.S. Energy Information Administration ("EIA"), Global Insight, and McGraw Hill.

Data were considered for inclusion in the O&M sample from all major U.S. investor-owned electric utilities that filed the Form 1 and had substantial involvement in power generation, transmission, and distribution throughout the sample period. Data were considered for inclusion in the generation maintenance sample from companies that had substantial involvement in fossil-fueled generation throughout the sample period. To be included in the study, the data were also required to be plausible and not unduly burdensome to process. Data from 45 companies were used to develop the econometric O&M benchmarking model. Data from 54 companies were used to develop the generation maintenance benchmarking model. The smaller data set for research on the O&M of VIEUs is due to the fact that several U.S. electric utilities that generate power have in recent years sold or spun off their transmission systems. The sampled companies are listed in Tables 1 and 2.

The sample period for the benchmarking studies was 1995-2010. The resultant O&M data set has 720 observations on each model variable. The generation maintenance data set had 864 observations on each model variable. Both samples are large and varied enough to permit recognition of numerous cost drivers.

Exhibit MNL-2

Table 1

ELECTRIC UTILITY DATA USED IN O&M COST RESEARCH

Alabama Power
Appalachian Power
Arizona Public Service
Avista
Black Hills Power
Carolina Power & Light
Cleco Power*
Columbus Southern Power
Dayton Power & Light
Duke Energy Carolinas
Duke Energy Indiana
Duke Energy Ohio
Empire District Electric
Entergy Arkansas
Entergy Mississippi*
Florida Power & Light
Florida Power
Georgia Power
Gulf Power
Idaho Power
Indianapolis Power & Light
Kansas City Power & Light
Kentucky Power
Kentucky Utilities
Louisville Gas & Electric
Montana-Dakota Utilities
MidAmerican Energy
Nevada Power
Northern Indiana Public Service
Northern States Power (MN)
Oklahoma Gas and Electric
Portland General Electric
Public Service Company of Colorado
Public Service Company of New Hampshire
Public Service Company of Oklahoma*
PacifiCorp
Puget Sound Energy
Sierra Pacific Power
South Carolina Electric & Gas
Southern Indiana Gas & Electric
Southwestern Electric Power*
Southwestern Public Service*
Tampa Electric
Virginia Electric & Power
Western Resources

* O&M peer group member

Number of companies in O&M sample: 45

Exhibit MNL-2

Table 2

ELECTRIC UTILITY DATA USED IN GENERATION MAINTENANCE COST RESEARCH

Alabama Power
Appalachian Power
Arizona Public Service
Avista
Black Hills Power
Carolina Power & Light
Cleco Power
Columbus Southern Power
Dayton Power & Light
Detroit Edison
Duke Energy Carolinas
Duke Energy Indiana
Duke Energy Ohio
El Paso Electric
Entergy Arkansas #
Florida Power & Light
Florida Power
Georgia Power
Gulf Power
Idaho Power
Indianapolis Power & Light
Kansas Gas and Electric
Kansas City Power & Light
Kentucky Power
Kentucky Utilities
Louisville Gas & Electric
Madison Gas and Electric
Montana-Dakota Utilities
MidAmerican Energy
Mississippi Power
Nevada Power
Northern Indiana Public Service
Northern States Power (MN) #
Ohio Power
Oklahoma Gas and Electric
Portland General Electric
Public Service Company of Colorado
Public Service Company of Oklahoma #
Public Service Company of New Hampshire
Public Service Company of New Mexico
PacifiCorp
Puget Sound Energy
Sierra Pacific Power
South Carolina Electric & Gas
Southern Indiana Gas & Electric
Southwestern Electric Power
Southwestern Public Service[1]#
Tampa Electric
Tucson Electric Power
Union Electric
Virginia Electric & Power
Western Resources
Wisconsin Electric Power
Wisconsin Power and Light
Wisconsin Public Service

Generation maintenance peer group member

Number of companies in generation maintenance econometric sample: 54

[1]Southwestern Public Service is a member of the unit cost peer group but was excluded from the econometric sample

3.2 Benchmarking OG&E's Non-Fuel O&M Expenses

3.2.1 Calculating O&M Expenses

The expenses addressed in the O&M benchmarking work were total electric O&M expenses less reported expenses in the FERC Form 1 categories for fuel, purchased power, customer service and information, employee pensions and benefits, franchise fees, and certain transmission activities.[5] We routinely exclude expenses for fuel, purchased power, and pensions and benefits from our O&M benchmarking studies on the grounds that they are large, volatile, and --- to a considerable degree --- beyond the control of utility management. Customer service and information expenses were excluded because these vary greatly with the extent of demand-side management programs and it is difficult to measure the scale of these programs. Franchise fees also vary greatly between utilities and are substantially beyond their control.

As for the excluded transmission expenses, the cost of transmission services purchased from other utilities varies widely and is fortunately itemized for easy removal. Some sampled utilities are members of regional transmission organizations ("RTOs") that undertake certain transmission services (*e.g.* dispatching and planning) for members and may also manage regional bulk power markets. This makes it undesirable to include these expense categories in a benchmarking study. Additionally, RTO member utilities provide RTOs with maintenance and other transmission services. The RTOs invoice member utilities large sums that include costs of the services that the utilities provide. These invoiced sums are sometimes reported by the utilities as O&M expenses. We have accordingly removed from the transmission expenses of all sampled companies the expenses for services that an RTO might provide, as well as the expense categories where RTO charges to the utility might be listed. The categories excluded comprise system control and load dispatching (FERC account 556), transmission load dispatching (FERC account 561), miscellaneous transmission expenses (FERC account 566), and regional market expenses (FERC account 575).

[5] In addition to Purchased Power expenses as reported on the FERC Form 1, we also exclude the Other Expenses category of Other Power Supply Expenses. We believe that large costs related to energy purchases are sometimes reported in this category.

3.2.2 Scale Variables

Two "classic" measures of utility output were utilized in our O&M benchmarking work: the annual average number of customers served and the total annual megawatt hours of net generation. Simply put, the greater the number of customers and generation output, the higher is the cost. The parameters of both of these variables are therefore expected to have a positive sign. An additional variable that varies with operating scale, generation capacity, is discussed further below.

3.2.3 Input Prices

The economic theory of production cost also suggests that the prices paid for production inputs are relevant business condition variables. We therefore included in the model an index of the prices that VIEUs pay for non-fuel O&M inputs. In estimating the model we divided cost by this input price index, a common practice in econometric cost research.

The O&M input price index was developed by PEG Research and is a weighted average of price indexes for labor and materials and services. The labor price index was constructed from BLS data. Occupational Employment Statistics ("OES") data for 2008 were used to construct average wage rates for each utility's service territory. These were calculated as a weighted average of the OES pay level for each job category using weights that correspond to the electric power generation, transmission, and distribution sector of the U.S. economy. Values for other years were calculated by adjusting the level in the focus year for the estimated change in the regional salaries and wages of utility workers. These estimates were constructed from BLS employment cost indexes.

Prices for material and service ("M&S") O&M inputs were assumed to have a 25% local labor content on average and therefore tend to be a little lower in regions with low labor prices. They are escalated by a summary M&S input price index constructed by PEG Research from detailed electric utility M&S price indexes that were calculated by Global Insight and published in its *Power Planner*. The O&M input price for each utility was constructed by combining the labor and non-labor prices using utility-specific cost-share weights.

3.2.4 Other Variables

Eight other variables were included in the O&M cost model. Six of these pertain to power generation. One of these is the total nameplate generation capacity that is owned by the company. This capacity, which is measured in megawatts, is an important supplemental cost driver because O&M of capacity is needed even when it is idle. Our capacity measures were processed from data on individual power plants obtained from Form EIA 860 and predecessor sources. Our research team aggregated the nameplate capacity of each sampled utility's operational power plants to arrive at a total capacity figure. We expect that O&M expenses will be higher the higher the amount of generation capacity. The parameter for this variable should therefore have a positive sign.

The model contains four variables that measure the *mix* of generation capacity that a utility owns. One such variable is the share of the capacity that is nuclear fueled. Another is the share of combustion turbines ("CTs") in the capacity. These turbines are conventionally fueled by clean-burning natural gas. A third variable is the share of other capacity that uses clean energy resources. This includes gas-fired steam turbine and combined cycle plants and wind turbines. A fourth capacity mix variable is the share of capacity that burns low-cost sub-bituminous coal. These variables are designed to capture any tendency for O&M expenses to vary with the kind of generating plant that companies own. We expect cost to be higher the higher is the share of generation capacity that is nuclear fueled and the lower is the share of CTs and other units that are powered by clean energy resources. The parameters for the percent nuclear variable should therefore be positive, whereas the parameters for the other two variables should be negative. We cannot predict the sign for the sub-bituminous coal variable because this coal is a solid fuel but has a low sulfur content.

The sixth generation-related variable in the model is the average age of generation plant. We expect older plant to involve higher O&M expenses. The parameter for this variable should therefore have a positive sign.

One additional model variable addresses conditions that affect the cost of providing power delivery services. That is the number of customers per transmission line mile.[6] The

[6] Due to data limitations the value of this variable is frozen at its 1999 value for all companies in the model's estimation.

source of our transmission line mile data is McGraw-Hill's *Directory of Electric Power Producers and Distributors*. This variable accounts for the extensiveness of the transmission system relative to the number of customers served. Other things being equal, we would expect that utilities with higher customer densities would have lower O&M expenses than utilities that need more extensive transmission facilities to serve the same number of customers. The parameter for this variable should therefore have a negative sign.

The O&M model also contains a trend variable. This permits predicted cost to change over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model.

3.2.5 Parameter Estimates

Estimation results for the O&M cost model are reported in Table 3. Due to the chosen form of the cost function, the parameter estimates for the output variables are the corresponding elasticities of cost with respect to these variables.[7] These are useful in the construction of the unit cost index.

Table 3 also reports the values of the t statistic and p value that correspond to each parameter estimate. These test statistics were also generated by the estimation program. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the test statistic. In this study, we employed critical values that are appropriate for a 90% confidence level given a large sample. The critical value of the t statistic corresponding to this confidence level was about 1.65. The critical value of the p value was 0.10. Any parameter estimate with a t-statistic greater than or equal to 1.65 in absolute value and a p-value less than or equal to 0.10 is statistically significant at our chosen confidence level. The test statistics were used in model specification. All cost driver variables other than trend variables were required to have statistically significant parameter estimates.

[7]The functional form issue is discussed further in the Appendix.

Table 3

ECONOMETRIC MODEL OF NON-FUEL O&M COST

Variable Key

N = Number of Retail Customers
V = Net Generation
CAP = Total Generation Capacity
NG = % Nuclear Generation Capacity
CT = % Combustion Turbine Capacity
OC = % Clean Capacity Other Than CT
SB = % Sub-bituminous Coal Capacity
AGE = Steam Generation Plant Age
NMT = Customers per Transmission Line Mile
Trend = Trend Variable

EXPLANATORY VARIABLE	ESTIMATED ELASTICITY	T-STATISTIC	P-VALUE
N	0.536	23.73	0.00
V	0.128	4.64	0.00
CAP	0.248	8.43	0.00
NG	0.061	13.81	0.00
CT	-0.032	-4.48	0.00
OC	-0.052	-7.23	0.00
SB	-0.036	-4.60	0.00
AGE	0.136	3.37	0.00
NMT	-0.043	-2.93	0.00
Trend	-0.000	-0.03	0.98
Constant	8.302	486.78	0.00
R-squared	0.966		
Number of Observations	720		
Sample Period	1995-2010		

Examining the results in Table 3, it can be seen that all of the O&M cost model parameter estimates were plausible as to sign and magnitude. Cost was found to be higher the higher were the two "classic" output variables. At the sample mean, a 1% rise in the number of customers was estimated to raise cost by about 0.54%; a 1% rise in the generation volume was estimated to raise cost by about 0.13%; and a 1% rise in generation capacity was estimated to raise cost by 0.25%.

The parameter estimates for the other cost drivers included in the model were also sensible and indicate the following:

- Cost was higher the greater was the share of capacity that was nuclear-fueled.
- Cost was lower the greater was the share of combustion turbines in the generation capacity.
- Cost was also lower the greater was the share of other capacity powered by clean energy resources.
- Cost was lower the greater was the share of generation capacity fueled by sub-bituminous coal.
- Cost was higher the higher was steam generation age.
- Cost was lower the greater was the number of customers per transmission line mile.
- The estimate of the trend variable parameter suggests there was essentially no shift in cost each year for reasons other than the trends in the business condition variables.

The table also reports the R squared statistic for the model. This statistic measures the ability of the model to explain variation in the sampled costs of distributors. Its value was about 0.97, suggesting that the explanatory power of the model was quite high.

3.2.6 OG&E's Business Environment

OG&E is a vertically integrated electric utility based in Oklahoma City. The heart of its service territory is the Oklahoma City metropolitan area, which has a population of more than 1.2 million people. The company also serves scattered areas to the north, south, and east of the metro area, including an area of western Arkansas which includes Fort Smith. In total, OG&E currently serves about 775,000 customers in a region of about 30,000 square miles.

The Company produces most of the power that it supplies to customers. This power is produced chiefly from comparatively clean energy resources such as natural gas. OG&E also has plants that burn low cost sub-bituminous Western coal. These plants do not currently require expensive sulfur removal facilities to comply with government emissions policies because of the low sulfur content of the coal. The gas-fired generating units, which are mostly combined cycle units and older steam turbines, involve lower capital cost than solid-fuel generation and are useful for meeting the pronounced demand surges that occur on the southern plains in the hot summer months.

The Company operates approximately 4,300 miles of transmission lines in Oklahoma and Arkansas. Operational authority over the transmission system has been transferred to the Southwest Power Pool ("SPP") RTO. The SPP provides dispatching, planning, and regional market services. It charges OG&E for network integrated transmission service, and these charges are reported by the Company as O&M expenses.

Table 4 compares OG&E's 2008-2010 average values for O&M cost and the identified cost drivers to the corresponding sample mean values. The cost for OG&E includes an upward adjustment of about $5.9 million to normalize the cost of a generation maintenance contract. It can be seen that the O&M expenses of OG&E were only 0.66 times the sample mean. In other words, cost was about 34% below the mean. The number of customers served was, meanwhile, 0.89 times the mean, while the generation volume was 1.02 times the sample mean and total generation capacity was 1.22 times the sample mean. Thus, cost was well below the mean despite measures of operating scale that were much closer to the mean and in one respect well above it. Turning next to input prices, Table 4 shows that the O&M input prices faced by OG&E were very close to the mean, and a little below.

Table 4

COMPARISON OF OG&E'S O&M BUSINESS CONDITIONS TO SAMPLE NORMS, 2008-2010

Business Condition	Units	Sample Mean	OG&E	OG&E / Sample Mean
Bundled Power Service O&M Cost	Dollars ($000)	438,532	288,467	0.66
Number of Retail Customers	Count	873,389	773,655	0.89
Total Net Generation	MWh	24,910,510	25,438,533	1.02
Total Generating Capacity	MW	6,256	7,633	1.22
O&M Input Price Index	Index Number	101.7	100.1	0.98
Share of Capacity Nuclear	Percent	4.8%	0.0%	0.00
Share of Capacity that is Combustion Turbines	Percent	17.1%	3.9%	0.23
Share of Capacity Other Clean	Percent	25.8%	58.7%	2.28
Share of Capacity Sub-bituminous Coal	Percent	18.6%	37.4%	2.01
Age of Plant	Years	33.7	32.9	0.98
Customers per Transmission Line Mile	Customers per Mile	220	163	0.74

As for the other cost driver variables, the shares of nuclear generation and combustion turbines in total capacity were well below the sample mean and the shares of generation capacity powered by other clean energy resources and of capacity that burned sub-bituminous coal were both well above the mean. The age of generation plant was very similar to the mean and a little below. The number of customers per transmission line mile was considerably below the mean, suggesting that the Company had an above average transmission workload.

3.2.7 Econometric Benchmarking Results

Using the econometric O&M benchmarking model, the Company's cost was on average about 20% below its predicted value over the 2008-2010 period. This was a top quartile score. In other words, more than three quarters of the sampled utilities had costs that compared less favorably to their econometric benchmarks. The Company's cost was found to be about 12% below its predicted value in 2010. This was also a top quartile score.

3.2.8 Unit Cost Results

Based on the econometric work, we have chosen the following five utilities for the O&M unit cost peer group:

Cleco
Entergy Mississippi
Public Service of Oklahoma
Southwestern Electric Power
Southwestern Public Service

These companies face several cost drivers that are similar to those of OG&E. For example, they tend to

- face labor prices below the sample average;
- have no nuclear capacity;
- use extensive amounts of natural gas and low-sulfur sub-bituminous coal in generation; and
- have transmission line miles that are large relative to the number of customers served due to a low to intermediate level of service territory urbanization.

Table 5 summarizes key results of our unit cost comparisons to the peer group for the years 2008-2010. There are results for the cost, output quantity, and unit cost indexes. Results are presented for each of the three most recent years for which data are available for all companies. An average of these three years is also displayed.

For the average of the 2008-2010 period, we find that OG&E's *unit* cost was therefore a substantial 23% below the mean. OG&E's cost was about 44% above the peer group norm, while its output index was about 86% above the peer group norm. Unit cost was about 19% below the peer group mean in 2010. These results corroborate the findings of our econometric benchmarking research and suggest that OG&E has been a superior O&M cost performer in recent years, including 2010.

3.3 Benchmarking OG&E's Generation Maintenance Expenses

3.3.1 Definition of Variables

Cost

The O&M expenses addressed in our second benchmarking exercise were the maintenance expenses for fossil steam generation and "other" power generation. These are reported in FERC accounts 510-514 and accounts 551-554, respectively. The great bulk of the expenses for other power generation that utilities report on FERC Form 1 are incurred in the maintenance of gas-fired power plants. However, small expenses for the maintenance of wind-powered and/or miscellaneous other (*e.g.* wood-burning) generation facilities are reported in this category for a few utilities, including OG&E.

Operating Scale

Three scale-related variables were utilized in our maintenance cost benchmarking work: the nameplate capacity of applicable (*i.e.* non-nuclear and non-hydro) generation [in megawatts ("MWs")] owned by the company and the volumes of fossil steam and other generation [both

Table 5

HOW THE O&M UNIT COST OF OG&E COMPARED TO PEER GROUP NORMS, 2008-2010

	Index*			
Year	**Cost**	**Output**	**Unit Cost Level**	**% Difference**
2008	1.407	1.873	0.751	-24.9%
2009	1.419	1.889	0.751	-24.9%
2010	1.490	1.827	0.815	-18.5%
Averages	**1.439**	**1.863**	**0.773**	**-22.7%**

Peer group consists of Cleco, Entergy Mississippi, Public Service Company of Oklahoma, Southwestern Electric Power, and Southwestern Public Service.

* Each index number is a bilateral comparison of the metric for OG&E to the mean for a peer group. The index number is the ratio of the OG&E value to the peer group mean.

measured in megawatt hours ("MWhs")].[8] The generation volumes were obtained from FERC Form 1. Data on capacity are discussed in Section 3.2.4 above. Cost is in theory higher the higher is a company's output. The parameters of all of these variables should therefore have a positive sign.

Input Prices

Pursuant to cost theory, we also included in the generation maintenance cost model a summary index of the prices of generation maintenance O&M inputs. The summary generation maintenance input price index was constructed using data and methods analogous to those described in Section 3.2.3 for O&M expenses. In estimating model parameters we once again divided cost by this input price index.

Other Variables

Five other variables were included in the generation maintenance cost model. Most are concerned with the mix of generation capacity owned. One capacity mix variable is the share of combustion turbines in the applicable generating capacity. CTs use clean-burning fuels such as natural gas. Another variable is the share of other capacity that uses clean energy resources. Coal- and resid-fired generating stations are more costly to maintain because they involve greater fouling and slagging of boilers, and require complicated facilities for fuel unloading, storage, handling, processing, and ash disposal.[10] We therefore expect the parameters of both of these variables to have a negative sign. Another capacity mix variable is the percentage of applicable capacity that is fueled by sub-bituminous coal. The sign of this parameter is difficult to predict because sub-bituminous coal is a solid fuel but has a lower sulfur content than most solid fuels.

A fourth additional cost-driver variable in the model is the percentage of fossil-fueled generating capacity that doesn't have sulfur dioxide ("SO_2") scrubbing facilities. This variable takes account of the fact that utilities vary in the extent to which they scrub their generation emissions. We expect that maintenance expenses will be lower the lower is the percentage of

[8] The metrics for capacity and other generation volume include some wind power for several sampled utilities, including OG&E.
[10] The higher cost of maintenance is typically more than offset by the lower cost of fuel.

generating capacity that does not have scrubbers. The parameter for this variable should therefore have a negative sign. The econometric model also contains a trend variable.

3.3.2 Parameter Estimates

Estimation results for the maintenance cost model are reported in Table 6. It shows that all of the cost model parameter estimates are plausible as to sign and magnitude. Maintenance cost was found to be higher the higher were all three scale-related variables. At the sample mean, a 1% rise in generation capacity was estimated to raise cost by about 0.66%. A 1% rise in the volume of steam generation was estimated to raise cost by about 0.15%, whereas a 1% rise in the other generation volume was estimated to raise cost by about 0.03%.

The parameter estimates for the other cost drivers included in the model were also sensible and indicate the following:

- Maintenance expenses were lower the higher were the shares of capacity that were CTs, other generation powered by clean resources, or were fueled by sub-bituminous coal.
- Cost was also lower the greater was the share of generation capacity that was unscrubbed.
- The estimate of the trend variable parameter suggests a 1.7% annual increase in cost for reasons other than the trends in the business condition variables.

Table 6 also reports the R squared statistic for the model. Its value was about 0.88, suggesting that the explanatory power of the model was high.

3.3.3 Business Conditions of OG&E

OG&E's large fleet of generating plants are of diverse character and include coal-fired steam turbines ("STs") (Muskogee units 4-6 and Sooner), gas-fired STs (Horseshoe Lake, Muskogee 3, Mustang, and Seminole), gas-fired combined cycle plants (*e.g.* McClain and Redbud), several gas-fired combustion turbines, and two wind farms. The coal-fired units were noted above to burn low-sulfur coal and do not have sulfur removal facilities.

Table 6

ECONOMETRIC MODEL OF GENERATION MAINTENANCE COST

Variable Key

SG = Net Fossil Steam Generation (MWh)
OG = Net Other Generation (MWh)
CAP = Total Fossil Steam and Other Generation Capacity (MW)
CT = % Capacity Combustion Turbines
OC = % Capacity Other Clean
SB = % Capacity Sub-bituminous Coal
NS = % of Generation Capacity Not Scrubbed
Trend = Trend Variable

EXPLANATORY VARIABLE	ESTIMATED ELASTICITY	T-STATISTIC	P-VALUE
SG	0.149	4.02	0.000
OG	0.025	12.69	0.000
CAP	0.664	17.81	0.000
CT	-0.185	-15.69	0.000
OC	-0.161	-11.61	0.000
SB	-0.020	-2.76	0.006
NS	-0.091	-4.76	0.000
Trend	0.017	10.89	0.000
Constant	6.718	245.10	0.000
R-squared	0.875		
Number of Observations	864		
Sample Period	1995-2010		

The youngest gas-fired ST is thirty-five years old, while the oldest is sixty years old. The coal fired units were built between 1977 and 1984. The youngest coal-fired unit is thus a little more than twenty-six years old, while the oldest is thirty-three years old. The Company is experiencing a significant aging of its generating fleet, in common with most VIEUs in the U.S. today. This should tend to put upward pressure on maintenance costs over time.

A classic text on power plant technology notes that the mature phase in the life of a power plant typically lasts between twenty-five and thirty years.

> Following this phase, the aging process becomes noticeable. Forced outages and maintenance costs increase, and availability declines. Component end of life usually causes the higher forced outage rate. Occasional operational error and the degradation of boiler components due to erosion, corrosion, creep, and fatigue lead to localized failures. The forced outage rate steadily increases during this phase unless major overhauls or component replacements are instituted.[11]

Table 7 compares the 2008-2010 average values of the generation maintenance cost model business conditions for OG&E to the sample mean values of these variables during the same years. The cost for OG&E includes the same $5.9 million upward adjustment that we applied to O&M expenses to normalize the cost of a generation maintenance contract. It can be seen that the maintenance cost of OG&E was about 0.92 times the sample mean. In other words, cost was about 8% below the mean. Applicable generation capacity was about 1.46 times the mean, whereas fossil steam generation volume was 1.25 times the mean and other power generation volume was 1.41 times the mean. Thus, OG&E's maintenance cost was modestly below the sample mean despite the fact that all three dimensions of operating scale were well above the mean. Turning next to input prices, the table shows that the generation maintenance input prices faced by OG&E were quite close to the mean, and a little below.

As for the other business condition variables, the share of combustion turbines in the applicable capacity was well below the mean, whereas the capacity shares of other generation powered by clean energy resources, and of generation fueled by sub-bituminous coal, were well above the mean. The share of capacity that was unscrubbed was well above the mean.

[11] S.C. Stultz and J.B. Kitto, eds. *Steam: Its Generation and Use* Fortieth Edition (Barberton, OH: Babcock and Wilcox, 1992).

Table 7

COMPARISON OF OG&E'S GENERATION MAINTENANCE BUSINESS CONDITIONS TO SAMPLE NORMS, 2008-2010

Business Condition	Units	Sample Mean	OG&E	OG&E / Sample Mean
Fossil Generation Maintenance Cost	Dollars ($000)	73,170	67,359	0.92
Generation Maintenance Input Price Index	Index	101.9	99.8	0.98
Applicable Generation Capacity	MW	5,225	7,633	1.46
Net Fossil Steam Generation	MWh	16,372,408	20,409,831	1.25
Net Other Generation	MWh	3,577,869	5,028,703	1.41
Share of Capacity Combustion Turbines	Percent	16.4%	3.9%	0.24
Share of Capacity Other Clean	Percent	24.9%	58.7%	2.35
Share of Capacity Sub-bituminous Coal	Percent	22.7%	37.4%	1.64
Share of Capacity Not Scrubbed	Percent	71.7%	100.0%	1.40

3.3.4 Econometric Benchmarking Results

Using the econometric generation maintenance cost model, OG&E's cost was found to be about 25% below the cost predicted by the model on average over the 2008-2010 period. This was a top quartile score. In 2010 the Company's cost was about 4% below the model's prediction. This was a second quartile score.

3.3.5 Unit Cost Results

In this study we used the econometric results to choose a generation maintenance cost peer group consisting of the following four utilities:

Entergy Arkansas
Northern States Power - Minnesota
Public Service of Oklahoma
Southwestern Public Service

These companies were chosen on the basis of the similarity of key generation-maintenance cost drivers to those facing OG&E. All companies relied primarily on sub-bituminous coal- and gas-fired generation during the 2008-2010 period and scrubbed a comparatively small share of their emissions for sulfur. Entergy Arkansas and Northern States Power ("NSP") were not used as peers in the O&M unit cost benchmarking because they have nuclear operations. This is not a concern in our generation maintenance benchmarking study because costs of nuclear (and hydroelectric) generation maintenance are itemized for easy removal. Our ability to use data for Entergy Arkansas and NSP make it unnecessary to use as peers three other utilities --- Cleco, Southwestern Electric Power, and Entergy Mississippi --- that were peers in the O&M work but have fossil generation mixes less similar to OG&E's.

The unit cost indexes used to benchmark generation-maintenance cost summarize comparisons for three scale measures: the applicable generation capacity and the volumes of fossil steam generation and other power generation. The weights are based on cost elasticity estimates for these variables that are drawn from the econometric cost model.

Table 8 summarizes key results of our unit cost comparisons to the peer group. There are results for the cost index, the output quantity index, and unit cost. Results are presented for 2008, 2009, and 2010. An average of the results for these three years is also displayed.

Table 8

HOW THE GENERATION MAINTENANCE UNIT COST OF OG&E COMPARED TO PEER GROUP NORMS, 2008-2010

	Index*			
Year	**Cost**	**Output**	**Unit Cost Level**	**% Difference**
2008	1.189	1.672	0.711	-28.9%
2009	1.263	1.706	0.740	-26.0%
2010	1.583	1.768	0.896	-10.4%
Averages	**1.34**	**1.72**	**0.78**	**-21.8%**

Peer group consists of Entergy Arkansas, Northern States Power-Minnesota, Public Service Company of Oklahoma, and Southwestern Public Service.

* Each index number is a bilateral comparison of the metric for OG&E to the mean for a peer group. The index number is the ratio of the OG&E value to the peer group mean.

We find that on average over the three years OG&E's *unit* cost was about 22% below the peer group mean on average. OG&E's generation maintenance cost was about 34% above the peer group norm over the three years while its output was about 72% above the norm. In 2010, OG&E's unit cost was about 10% below the peer group mean. Using both benchmarking methods, we therefore found that OG&E's 2010 generation maintenance expenses, while higher than in the previous two years, were still quite reasonable.

Appendix

This section provides additional and more technical details of our benchmarking work. We first address the form of the cost model and our econometric work. There follows a discussion of the unit cost indexes.

A.1 Econometric Research

A.1.1 Form of the Econometric Cost Models

Specific forms must be chosen for cost functions used in econometric research. The linear and the double-log forms are commonly employed. The cost model presented on p. 6 is an example of a linear cost model:

$$C = a_0 + a_1 * N + a_2 * W \qquad \text{[A1]}$$

Cost is a linear function of the number of customers served and the wage rate.

Here is an analogous cost model of double-log form:

$$\ln C = a_0 + a_1 * \ln N + a_2 * \ln W \qquad \text{[A2]}$$

In this form, the value of each cost driver has been converted to its natural logarithm. This specification has the effect of making 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 number of customers. When model data are mean-scaled for convenience, each parameter is the elasticity of cost with respect to the basic variable at sample-mean values of the business conditions.

One disadvantage of the double-log form is that variables cannot have zero values. Since several of the cost-driver variables in our study (*e.g.* the share of CTs in generation capacity) have zero values, we have elected to use a linear treatment for these variables and a logged treatment for the other variables, which include the output variables. The functional forms of the two models are therefore hybrids.

A.1.2 Estimation Procedure

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 error term in an econometric cost model is the difference between actual cost and the cost predicted by the model. It reflects imperfections in the development of the model. The imperfections may include any or all of the following: poor measurement 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. It is customary to assume that error terms are random variables with probability distributions that are determined by additional parameters, such as mean and variance, the values of which can be estimated. This opens the door to various kinds of statistical inference, such as hypothesis tests concerning the statistical significance of parameter estimates.

A variety of estimation procedures (aka "estimators") are used in econometric research. The appropriateness of each procedure depends on the assumptions 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, meaning that they vary across companies. Variances can, for example, be larger for companies with large operating scales. Estimation procedures that address several of the error term issues that are routinely encountered in utility cost benchmarking are not readily available in commercial econometric software packages. They instead require the development of customized estimation programs.

In our research for OG&E, we corrected for autocorrelation and heteroskedasticity in the error terms using a custom in-house estimation procedure developed with Gauss software. Since we estimated these unknown disturbance matrices consistently, our estimators are equivalent to Maximum Likelihood Estimators ("MLEs").[12] Our estimates thus possess all the highly desirable properties of MLEs.

Note, finally, that the model specification was determined using the data for all sampled companies, including OG&E. However, computation of model parameters and standard errors for the cost predictions required that the values for OG&E be dropped from the sample. The estimates used in developing the cost model will vary slightly from those in the model used for benchmarking.

A.2 Unit Cost Indexes

The unit cost indexes are designed to compare the unit cost of OG&E to the norm for a peer group. Each unit cost index is the ratio of a cost index to an output quantity index.

$$Unit\ Cost_{OG\&E,t} = \frac{Cost_{OG\&E,t}}{Output\ Quantity_{OG\&E,t}} \quad [A3]$$

The cost index for OG&E in each year t is defined by the formula

$$Cost\ Index_{OG\&E,t} = \frac{Cost_{OG\&E,t}}{\overline{Cost_t}} \quad [A4]$$

where $\overline{Cost_t}$ is the mean value of cost for the peer group in year t.

The output quantity index in each year t was defined by the formula

$$Output\ Quantity_{OG\&E,t} = \sum_i se_i * \frac{Y_{OG\&E,i,t}}{\overline{Y_{i,t}}}. \quad [A5]$$

Here,

$Y_{OG\&E,i,t}$ = Quantity of output variable i for OG&E

$\overline{Y_{i,t}}$ = Peer group mean of the quantity of output variable i.

se_i = Share of output variable i in the sum of the econometric estimates of the cost elasticities of the output quantities under sample mean values of the business conditions.

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

In the O&M model, the elasticities of cost with respect to the number of customers served, net generation, and generation capacity were estimated to be .536, .128, and .248, respectively. The corresponding elasticity-share weights for the output index were 58.8%, 14.0%, and 27.2% respectively. In the generation maintenance model, the elasticities of cost with respect to the volumes of fossil steam and other generation and generation capacity were estimated to be .149, .025, and .664 respectively. The corresponding elasticity-share weights for the output index were 17.8%, 3.0%, and 79.2%, respectively.

Equations [A3], [A4], and [A5] imply that

$$Unit\ Cost_{OG\&E,t} = \left(\frac{Cost_{OG\&E,t}}{\overline{Cost_t}}\right) \Big/ \left(\sum_i se_i * \frac{Y_{OG\&E,i,t}}{\overline{Y_{i,t}}}\right). \qquad [A6]$$

The percentage difference between the unit cost of OG&E and that of the peer group is then calculated using the formula $100*(Unit\ Cost_{OG\&E,t} - 1)$.

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Attachment 5
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EMPIRICAL RESEARCH IN SUPPORT OF INCENTIVE RATE SETTING IN ONTARIO:

REPORT TO THE ONTARIO ENERGY BOARD

May 2013

PEG

Pacific Economics Group Research, LLC

EMPIRICAL RESEARCH IN SUPPORT OF INCENTIVE RATE SETTING IN ONTARIO:

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Table of Contents

1. Introduction and Executive Summary

On October 18, 2012, the Ontario Energy Board (the Board) released a Report of the Board titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the RRFE Board Report). The RRFE Board Report sets out three rate-setting options: 4th Generation Incentive Rate-setting (4th Gen IR), which the Board considers suitable for most distributors; Custom Incentive Rate-setting (Custom IR) for distributors with large or highly variable capital requirements; and an Annual Incentive Rate-setting Index (Annual IR) for distributors with limited incremental capital requirements. The 4th Gen IR option will use rate adjustment formulas that are calibrated using estimates of Ontario-specific industry input price and total factor productivity (TFP) trends, as well as benchmark-based information on each distributor's relative efficiency. The 4th Gen IR builds on the 3rd Gen IR that has been in effect since 2008, but the existing IR regime is modified to better reflect input price and productivity trends in Ontario.[1]

In both 4th Gen IR and 3rd Gen IR, the allowed change in regulated rates for distribution services is based on the growth in an inflation factor minus an X-factor. The Board has concluded that the inflation factor for the 4th Gen IR will be a more industry-specific inflation factor designed to track inflation in the prices of inputs used by the Ontario electricity distribution sector.[2] The Board has found that any concerns regarding the volatility of an industry-specific inflation factor will be mitigated by the methodology it selects to measure inflation.

The basic architecture for the X-factor in the 4th Gen IR formula is intended to be similar to that developed in 3rd Gen IR. In its July 14, 2008 EB-2007-0673 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, the Board described the components of the 3rd Gen IR X-factor as follows:

[1] The First Generation IR was implemented in 2000. This mechanism had a three-year intended term but, before the plan could run its course, the Provincial Government imposed a freeze on overall retail electricity prices. This cap effectively eliminated any further formula-based distribution price adjustments for distribution services and thus ended the plan. The Board implemented a second generation incentive regulation mechanism (2nd Generation IRM) in December 2006. The 2nd Generation IR was essentially a transitional mechanism that applied until rates were "rebased" to reflect each distributor's cost of service in a test year.

[2] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012, p. 16.

> The productivity component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.
>
> The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that distributors are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by distributor and depend on the efficiency of a given distributor at the outset of the IR plan. Stretch factors are generally lower for distributors that are relatively more efficient.[3]

The Board indicated in the RRFE Board Report that it will retain this basic approach for 4th Gen IR but concluded that the productivity factor will be based on an estimate of industry Total Factor Productivity (TFP) growth in Ontario's electricity distribution sector. A single productivity factor will be set in advance and will apply to all distributors during the term of the 4th Gen IR. The Board used an index-based approach for estimating the industry TFP trend in 3rd Gen IR and intends to use the same approach for 4th Gen IR.[4]

The Board has stated that its basic approach for assigning stretch factors under the 3rd Gen IR will continue under 4th Gen IR, although it will be modified to reflect distributors' *total* cost performance.[5] Currently, each distributor is assigned to one of three efficiency cohorts based on two benchmarking evaluations of that distributor's operation, maintenance, and administrative (OM&A) costs.[6] Since 2008, these cohort assignments have been used to

[3] *EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008, p. 12.

[4] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 17.

[5] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 17-18.

[6] The Board's decision on how to establish the three efficiency cohorts is presented in EB-2007-0673 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008, pp. 20-23; the Board's decision on the empirical values for each of the three efficiency cohorts is presented in EB-2007-0673 *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, September 17, 2008, pp. 19-22. The first benchmarking evaluation compares a distributor's OM&A unit cost (i.e. OM&A cost divided by an index of the distributor's output) to the average OM&A cost for that distributor's designated peer group. The peer groups were based on PEG's analysis of the variables that drive OM&A costs across the Ontario electricity distribution industry.

The second benchmarking analysis is based on an econometric cost model. Using statistical methods, PEG developed an econometric model of each firm's OM&A cost. The parameters of the model were estimated using Ontario data. After these parameter estimates were obtained, data on the cost "driver" variables for each distributor were inserted into the model to develop an estimate of each firm's predicted (or expected) OM&A cost. Each year, the distributor's actual costs are compared to the predicted cost generated by the model plus or assign stretch factors. In 4th Gen IR, the Board will make these assignments using total cost benchmarking evaluations and determine the appropriate stretch factor values for the different efficiency cohorts in conjunction with its determination of the productivity factor.

The Board Staff retained Pacific Economics Group Research LLC (PEG) to advise on the development of 4th Gen IR. We worked closely with Board Staff to help organize and conduct a series of stakeholder Working Group discussions on Performance, Benchmarking and Ratemaking (PBR) topics for the 4th Gen IR.[7] Among other things, the PBR Working Group discussed options for measuring industry input price inflation, mitigating volatility in measured inflation, estimating TFP for the electricity distribution industry, and appropriate business conditions to consider when benchmarking Ontario distributors.

PEG was also asked to develop specific, quantitative recommendations for three elements of the 4th Gen IR rate adjustment formula: 1) the inflation factor; 2) the productivity factor that applies to the entire industry; and 3) stretch factors that apply to different cohorts of distributors in the industry. PEG endeavored to base our recommendations on all three elements using rigorous and objective empirical research that could be replicated, refined and extended in future IR applications. Some of our current benchmarking research may also inform the Board's review of custom IR applications. Our empirical analysis was also informed by, and consistent with, the suggestions and recommendations of the PBR Working Group as well as the principles for effective incentive regulation.

minus a confidence interval around the cost prediction. If actual cost is below predicted cost minus the lower bound of this interval, the difference between actual and predicted costs is statistically significant and the distributor is deemed to be a superior cost performer. On the other hand, if actual cost is above predicted cost plus the upper bound of the confidence interval, the difference between actual and predicted costs is statistically significant and the distributor is deemed to be an inferior cost performer. If the difference between actual and predicted cost is within the confidence interval, the distributor is deemed to be an average cost performer.

The efficiency cohorts in 3rd Gen IR are determined using both benchmarking evaluations. If a distributor is a superior cost performer and in the top quartile of the industry on the unit cost benchmark, it is in efficiency cohort I and assigned a stretch factor of 0.2 per cent. If a distributor is an inferior cost performer and in the bottom quartile of the industry on the unit cost benchmark, it is in efficiency cohort III and assigned a stretch factor of 0.6 per cent. All other distributors are in efficiency cohort II and assigned a stretch factor of 0.4 per cent. Larger stretch factors are assigned for relatively less efficient firms since they are deemed to have greater potential to achieve incremental productivity gains.

[7] The PBR Working Group held nine meetings between January 11, 2013 and March 1, 2013. In addition to Board Staff and Dr. Kaufmann, the PBR Working Group had representatives from Hydro One Networks, Waterloo North Hydro, Canadian Niagara Power, Cornerstone Hydro Electric Concepts, the Association of Major Power Consumers in Ontario, the Consumers Council of Canada, the Vulnerable Energy Consumers Coalition, the Power Workers' Union, Toronto Hydro, Hydro Ottawa, the School Energy Coalition, and the Electricity Distributors' Asssociation.

Our recommendations can be briefly summarized. PEG recommends that the inflation factor be constructed as a weighted average of inflation in three separate indices: 1) a capital service price that PEG has constructed using publicly available information; 2) average weekly earnings for workers in Ontario; and 3) the GDP-IPI. The weights that apply to each index are equal to the estimated shares of capital, labor, and non-labor OM&A expenses, respectively, in total distribution cost for the Ontario electricity distribution industry. This inflation factor can be updated and computed each year using publicly-available information on inflation in the selected indices and, when relevant, changes in the Board's approved rates of return.

We also recommend that, in each year, the inflation factor be measured as the average value of inflation in our recommended input price index (IPI) over the three most recent years. Measuring inflation as the three-year moving average in our recommended IPI substantially reduces the volatility of the inflation factor. Evidence over the 2002-2011 period suggests that the volatility of PEG's recommended IPI will be similar to the volatility of the inflation factor that is currently used in 3rd Gen IR.

PEG produced two estimates for TFP growth for Ontario electricity distributors over the 2002-2011 period. Both estimates excluded Toronto Hydro and Hydro One because of evidence showing that these firms directly and materially impact the industry's estimated TFP growth, and the measured TFP growth trend in an IR plan should be "external" to the utilities in the industry that are potentially subject to that plan. Using index-based methods, PEG estimated that TFP for the Ontario electricity distribution sector grew at an average annual rate of 0.1% per annum. PEG also used an econometric cost model to backcast TFP growth for the industry between 2002 and 2011. The backcast analysis predicted average TFP growth of 0.07% over the sample period.

Given that the index-based and econometric-based TFP estimates are both close to 0.1%, PEG recommends that the productivity factor for 4th Gen IR be set equal to 0.1%. In addition to being consistent with the two empirical estimates, PEG believes a productivity factor of 0.1% is reasonable for several reasons. First, PEG's analysis shows that the industry's slower TFP growth stems primarily from a slowdown in output growth rather than an acceleration in distributors' spending. The slower output growth has been particularly pronounced since the introduction of CDM programs in 2006. PEG believes the continued emphasis on CDM policies in Ontario will continue to limit the potential for output quantity and TFP gains for the industry.

Second, we find the available evidence does not support a negative productivity factor. While TFP growth for the Ontario electricity distribution industry has been negative since 2007, much of this decline is attributable to the severe recession in 2008-09. This was a one-time event and is not anticipated to recur during the term of 4th Gen IR. PEG also concludes that the experience since 2007 is not long enough to be the basis for a productivity factor; TFP trends should be calculated over at least a nine-year period. We also do not favor treating sub-periods within a sample period differently (*e.g.* by placing more weight on one sub-period rather than another), since such an approach can give rise to "cherry picking" and artificial manipulation of the available data. The nine-year industry TFP trend is more consistent with a productivity factor of 0.1% than a substantially negative productivity factor.

Third, an IPI inflation factor combined with a productivity factor of 0.1% would mean electricity distributor prices grow at nearly the same rate as the industry's input price inflation, if all else is held equal. PEG's research shows that input price inflation for the electricity distribution industry has been slightly below GDP-IPI inflation. It is not unusual for price inflation in a particular sector (such as electricity distribution) to be similar to average price inflation in the economy. If the productivity factor was the only component of the X factor, a productivity factor equal to 0.1% would likely mean that electricity distribution prices grow at rates similar to the prices of other goods and services in the economy. Price inflation in a particular sector that is similar to aggregate, economy-wide inflation is not necessarily a sign of sub-par productivity performance in that sector.

However, the productivity factor is *not* the only component of the X factor, nor is it the component of the X factor that is designed to ensure that consumers benefit from incentive rate setting. Stretch factors are intended to reflect distributors' incremental efficiency gains under incentive ratemaking. Adding a stretch factor to the productivity factor allows customers to share in these anticipated efficiency gains. PEG has recommended positive stretch factors for most distributors, which means that electricity distributor prices are expected to fall in "real," inflation-adjusted terms under the index-based rate adjustments allowed in 4th Gen IR. A productivity factor of 0.1% is therefore not incompatible with the

Board's incentive rate-setting objectives of encouraging cost efficiency and ensuring that customers share in these efficiency gains.

PEG used econometric and unit cost/peer group models that we developed to benchmark distributors' total cost performance and inform stretch factor assignments. As in 3rd Gen IR, both benchmarking methods were used to identify efficiency cohorts in the industry, but we recommend expanding the number of these cohorts from three (in 3rd Gen IR) to five. This recommendation is designed to facilitate the movement of distributors into higher cohorts. Since distributors in higher cohorts are subject to lower recommended stretch factors, a larger number of cohorts strengthens distributors' incentives to pursue efficiency.

PEG recommends that distributors be assigned to efficiency cohort I if they are significantly superior cost performers at a 90% confidence level and if they are in the top quintile of distributors on the peer group/unit cost benchmarking analysis. Eight distributors satisfy these criteria, and we recommend that the eight distributors in cohort I be assigned a stretch factor of 0. Distributors will be assigned to efficiency cohort II if they are significantly superior cost performers at a 90% confidence level and if they are in the second quintile of distributors on the peer group/unit cost benchmarking analysis. Four distributors satisfy these criteria, and we recommend that the four distributors in cohort II be assigned a stretch factor of 0.15%.

Conversely, PEG recommends that distributors be assigned to efficiency cohort V if they are significantly inferior cost performers at a 90% confidence level and if they are in the bottom quintile of distributors on the peer group/unit cost benchmarking analysis. Thirteen distributors satisfy these criteria, and we recommend that the 13 distributors in cohort V be assigned a stretch factor of 0.6%. Distributors will be assigned to efficiency cohort IV if they are significantly inferior cost performers at a 90% confidence level and if they are in the fourth quintile of distributors on the peer group/unit cost benchmarking analysis. Four distributors satisfy these criteria, and we recommend that the four distributors in cohort IV be assigned a stretch factor of 0.45%. The remaining 44 distributors are in cohort III and will be assigned a stretch factor of 0.3%.

By increasing the number of cohorts from three to five, this approach for assigning stretch factors makes it easier for distributors to migrate into higher cohorts by controlling costs. The recommended maximum stretch factor remains 0.6%, but PEG recommends that the minimum stretch factor be reduced to zero to encourage and reward efforts to reduce unit cost. PEG also recommends that the stretch factor for the largest group of distributors be reduced from 0.4% to 0.3% to reflect the expectation that, on average, incremental efficiency gains become more difficult to achieve over time.

PEG believes that the empirical research used to develop these recommendations for 4th Gen IR can provide a solid foundation for future incentive rate-setting in Ontario. PEG has estimated TFP trends and benchmarked the total costs of electricity distributors in Ontario. Our TFP and benchmarking studies can be updated and refined over time to accommodate new data from the industry or consider different business condition variables, including measures of service reliability such as SAIDI and SAIFI. Overall, PEG believes the methodologies used to determine the X factors in the 4th Generation IR strike a reasonable balance between rigor, objectivity and feasibility (given the data constraints), while simultaneously developing empirical techniques that can provide a foundation for effective IR applications for Ontario in the future.

Our report is structured as follows. After this introduction, Chapter Two details the basic indexing logic that underpins the calibration of X factors. Chapter Three presents our recommended inflation factor. Chapter Four discusses data sources and issues associated with available data. Chapter Five presents our econometric research on the cost performance of Ontario electricity distributors. Chapter Six estimates historical TFP growth for the Ontario electricity distribution industry and uses the econometric cost model to “backcast” the industry’s TFP growth for the 2002-2011 period. Chapter Seven presents information on unit cost and “cost driver” variables, identifies six peer groups of Ontario electricity distributors, develops unit cost comparisons for the peer groups, and makes recommendations for efficiency cohorts and stretch factors. Chapter Eight presents final recommendations and concluding remarks.

There are also three appendices. Appendix One presents a mathematical decomposition of TFP growth into its various components. Appendix Two presents some technical details of PEG’s econometric modeling. Appendix Three presents technical details on some of the statistical tests undertaken in Chapter Five.

2. Inflation and X Factors

This chapter will provide some background on developing appropriate inflation and X factors in index-based incentive regulation plans. We begin by presenting the indexing logic that illustrates the relationship between the parameters of indexing formulas and just and reasonable rate adjustments. We turn next to specific choices for inflation factors. We then discuss the X factor.

2.1 Indexing Logic

The 4th Gen IR will use a price cap index (PCI) formula to restrict the change in electricity distribution prices. While PCIs vary from plan to plan, the PCI growth rate $(growthPCI)$ is typically given by the growth in an inflation factor (*P*) minus an X-factor (*X*) plus or minus a Z-factor (*Z*), as in the formula below:

$$growth\ PCI = P - X \pm Z. \qquad [1]$$

In North American regulation, the terms of the PCI are set so that the change in regulated prices mimics how prices change, in the long run, in competitive markets. This is a reasonable basis for calibrating utility prices since rate regulation is often viewed as a surrogate for the competitive pressures that would otherwise lead to “just and reasonable” rates. Economic theory has also established that competitive markets often create the maximum amount of benefits for society.[8] It follows that effective utility regulation should replicate, to the greatest extent possible, the operation and outcomes of competitive markets. A “competitive market paradigm” is therefore useful for establishing effective regulatory arrangements, and several features of competitive markets have implications for how to calibrate PCI formulas.

One important aspect of competitive markets is that prices are “external” to the costs or returns of any individual firm. By definition, firms in competitive markets are not able to affect the market price through their own actions. Rather, in the long run, the prices facing

[8] This is sometimes known as the “First Fundamental Welfare Theorem” of economics, but it should be noted that the theoretical finding that competition leads to efficient outcomes does not apply under all conditions (*e.g.* if there are externalities whose costs or benefits are not reflected in competitive market prices).

any competitive market firm will change at the same rate as the growth in the industry's unit cost.

Competitive market prices also depend on the *average* performance in the industry. Competitive markets are continually in a state of flux, with some firms earning more and others less than the "normal" rate of return on invested capital. Over time, the average performance exhibited in the industry is reflected in the market price.[9]

Taken together, these features have the important implication that in competitive markets, returns are commensurate with performance. A firm can improve its returns relative to its rivals by becoming more efficient than those firms. Companies are not disincented from improving efficiency by the prospect that such actions will be translated into lower prices because the prices facing any individual firm are external to its performance. Firms that attain average performance levels, as reflected in industry prices, would earn a normal return on their invested capital. Firms that are superior performers earn above average returns, while firms with inferior performance earn below average returns. Regulation that is designed to mimic the operation and outcomes of competitive markets should allow for this important result.

Another implication of the competitive market paradigm bears a direct relationship to the calibration of PCI formulas. As noted above, in the long run, competitive market prices grow at the same rate as the industry trend in unit cost. Industry unit cost trends can be decomposed into the trend in the industry's input prices minus the trend in industry total factor productivity (TFP). Thus if the selected inflation measure is approximately equal to the growth in the industry's input prices, the first step in implementing the competitive market paradigm is to calibrate the X factor using the industry's long-run TFP trend.

The mathematical logic underlying this result merits explanation. We begin by noting that if an industry earns a competitive rate of return in the long run, the growth in an index of the prices it charges (its output prices) will equal its growth in unit cost.

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[9] This point has also been made in the seminal 1986 article in the Yale Journal of Regulation, *Incentive Regulation for Electric Utilities* by P. Joskow and R. Schmalensee. They write "at any instant, some firms (in competitive markets) will earn more a competitive return, and others will earn less. An efficient competitive firm will expect on average to earn a normal return on its investments when they are made, and in the long run the average firm will earn a competitive rate of return"; *op cit*, p. 11.

$$trend\ Output\ Prices^{Industry} = trend\ Unit\ Cost^{Industry}. \qquad [2]$$

As stated above, the trend in an industry's unit cost is the difference between trends in its input price index and its TFP index. The full logic behind this result is presented below:

$$\begin{aligned}
\text{trend Unit Cost}^{\text{Industry}} &= \text{trend Cost}^{\text{Industry}} - \text{trendOutput Quantities}^{\text{Industry}} \\
&= \left(\textit{trend}\text{ Input Prices}^{\text{Industry}} + \textit{trend}\text{ Input Quantities}^{\text{Industry}}\right) \\
&\quad - \textit{trend}\text{ Output Quantities}^{\text{Industry}} \\
&= \textit{trend}\text{ Input Prices}^{\text{Industry}} \\
&\quad - \left(\text{trend Output Quantities}^{\text{Industry}} - \textit{trend}\text{ Input Quantities}^{\text{Industry}}\right) \\
&= \text{trend Input Prices}^{\text{Industry}} - \textit{trend}\text{ TFP}^{\text{Industry}}.
\end{aligned} \qquad [3]$$

Substituting [3] into [2] we obtain

$$trend\ Output\ Prices^{Industry} = trend\ Input\ Prices^{Industry} - trend\ TFP^{Industry} \qquad [4]$$

Equation [4] demonstrates the relationship between the X factor and the industry TFP trend. If the selected inflation measure (*P* in equation [1]) is a good proxy for the industry's trend in input prices, then choosing an X factor equal to the industry's TFP trend causes output prices to grow at the rate that would be expected in a competitive industry in the long run. This is the fundamental rationale for using information on TFP trends to calibrate the X factor in index-based PBR plans.

It should be emphasized that both the input price and TFP indexes above correspond to those for the relevant utility *industry*. This is necessary for the allowed change in prices to conform with the competitive market paradigm. In competitive markets, prices change at the same rate as the industry's trend in unit costs and are not sensitive to the unit cost trend of any individual firm. This is equivalent to saying that competitive market prices are external to the performance of any given firm in the industry.

There are two main options for selecting inflation factors in index-based PBR plans. One general approach is to use a measure of economy-wide inflation such as those prepared by government agencies. Examples include the Gross Domestic Product Implicit Price Index (GDP-IPI) or the US Price Index for Gross Domestic Product (GDP-PI). An established alternative is to construct an index of external price trends for the inputs used to provide utility services. This approach is explicitly designed to measure input price inflation of the regulated industry.[10] The Board has found that the inflation factor in 4th Gen IR will be a measure of industry input price inflation, so the indexing logic presented in equations [1] through [4] is valid for 4th Gen IR.

While industry TFP and input price measures are used to calibrate X factors, in most index-based incentive regulation plans the X factor is greater than what is reflected in the utility industry's long-run TFP trend. This is because industry TFP trends are usually measured using historical data from utility companies. Utilities have historically not operated under the competitive market pressures that naturally create incentives to operate efficiently, and it is also widely believed that traditional, cost of service regulation does not promote efficient utility behavior.

Incentive regulation is designed to strengthen performance incentives, which should in turn encourage utilities to increase their efficiency and register more rapid TFP growth relative to historical norms. It is also reasonable for these performance gains to be shared with customers since incentive rate-setting is designed to produce "win-win" outcomes for customers and shareholders. For this reason, nearly all North American incentive regulation plans have also included what are called "consumer dividends" or productivity "stretch factors" as a component of the X factor. The stretch factor reflects the expected acceleration in TFP relative to historical TFP trends.[11]

2.2 X Factors and Productivity Measurement

2.2.1 TFP Basics

As discussed, the most common approach for setting X factors in North America is to calibrate productivity factors using measures of industry rather than individual company TFP growth. Since productivity plays an important role in North American incentive regulation, it is valuable to review some basics on TFP measurement. We will also briefly consider the relationship between TFP growth and the various factors that can "drive" changes in productivity over the term of an incentive regulation plan.

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[10] A less common approach is to set inflation measures using changes in *output* prices charged by peer utilities. It is important for any such peer-price inflation measure to be constructed carefully so that it reflects the circumstances of companies that are very similar to the utility subject to the incentive regulation plan.

[11] More precisely, the stretch factor is that portion of the expected acceleration of TFP growth that it passed through to the change in customer rates as a form of benefit-sharing under the plan.

A TFP index is the ratio of an output quantity index to an input quantity index.

$$TFP = \frac{Output\ Quantities}{Input\ Quantities}. \qquad [5]$$

TFP therefore represents a comprehensive measure of the extent to which firms convert inputs into outputs. Comparisons can be made between firms at a point in time or for the same firm (or group of firms) at different points in time.

The growth trend in a TFP trend index is the difference between the trends in the component output quantity and input quantity indexes.

$$trend\ TFP = trend\ Output\ Quantities - trend\ Input\ Quantities\ . \qquad [6]$$

The trend in output quantity of an industry summarizes trends in the workload that it performs. If output is multidimensional, the growth in each output quantity dimension considered is measured by a subindex. The growth in the output quantity index depends on the growth in the quantity subindexes.

The trend in input quantity of an industry summarizes trends in the amounts of production inputs used. TFP grows when the output quantity index rises more rapidly (or falls less rapidly) than the input quantity index. TFP can rise or fall in a given year but in most industries typically trends upward over time.

As equation [3] shows, a TFP index will capture the effect of all developments that cause the unit cost of an industry to grow more slowly than its input prices. The sources of TFP growth are diverse. Appendix One of this report presents a technical, algebraic decomposition of TFP growth into its various components. This section provides a non-technical discussion of the sources of TFP growth.

One component is technical change. New technologies permit an industry to produce a given amount of output with fewer inputs. Economies of scale are a second source of TFP growth. Scale economies are realized when cost grows less rapidly than output. A third important source of TFP growth is the elimination of “X inefficiencies”, or inefficiencies that arise when companies fail to operate at the maximum efficiency that technology allows. TFP will grow (decline) to the extent that X inefficiency diminishes (increases).

In most regulatory proceedings where TFP trends have been estimated using indexing methods, long-run TFP trends have been estimated using 10 or more years worth of historical data. A 10 year period is generally considered to be sufficient for smoothing out short-term fluctuations in TFP that can arise because of changes in output (*e.g.* kWh deliveries that are sensitive to changes in weather and economic activity) and the timing of different types of expenditures. This long-run historical TFP trend is then assumed (either implicitly or explicitly) to be a reasonable proxy for the TFP growth that is expected over the term of the indexing plan.

This is not always an appropriate assumption. For example, it is often not warranted to assume that TFP growth measured for short historical periods will be a good proxy for future trends. Shorter sample periods are more likely to be distorted by factors such as the timing of expenditures or unusual output growth. There is accordingly less confidence that past TFP trends are a good proxy for the future trend if the available data only allows TFP to be calculated for a relatively short period. As discussed, a general rule of thumb in regulatory proceedings is that a minimum of 10 years of data are needed to calculate a generally reliable estimate of the industry's long-run TFP trend.

2.2.2 Econometric Estimation of TFP Trends

In addition to estimating historical TFP trends using indexing methods, econometric methods can be used to estimate TFP growth. The econometric approach essentially uses statistical methods to estimate the underlying "drivers" of TFP growth, such as technological change and the realization of scale economies. Statistical techniques can estimate the impact of each of these sources of TFP growth by using data from electricity distributors operating under a wide variety of business conditions. Once those underlying TFP "drivers" are estimated, they can be combined with data on the changes in the business condition variables that apply for either individual electricity distributors or for groups of distributors. This information can then be brought together using a methodological framework that draws on the decomposition of TFP outlined in Appendix One of this report.

The econometric approach to estimating TFP growth has a number of potential advantages. One is that it is rigorous and has a strong foundation in statistical methods and the economics literature. This approach can also be tailored to reflect the specific business conditions, and "TFP drivers," of the Ontario power distribution industry.

The main disadvantage of the econometric approach is its complexity. Econometrics often involves technically complex statistical methods. The TFP estimates that result from econometric modeling therefore tend to be less transparent and not as easy to understand as those resulting from indexing methods. While unnecessary complexity should be avoided in regulatory proceedings, it is not always practical or desirable to rely on simpler, index-based TFP estimates when calibrating the terms of PCI formulas. This would be the case, for example, if the available time series data was either too short, or distorted by transitory factors, and therefore did not yield reliable estimates of long-term TFP trends.

2.2.3 Stretch Factors

The final component of the X factor is the productivity "stretch factor" or consumer dividend. The stretch factor is designed to reflect incremental efficiency gains utilities are expected to achieve under incentive regulation. Adding a stretch factor to the productivity factor allows a share of these anticipated efficiency gains to be reflected in price adjustments under the incentive regulation plan. Because a positive stretch factor leads prices to grow less rapidly under an incentive regulation plan, stretch factors allow customers to share in the expected benefits of incentive regulation while the plan is in effect.

In practice, North American regulators have chosen the values for stretch factor almost entirely on the basis of judgment. This judgment has led to approved stretch factors in a relatively narrow range, between 0.25% and 1%, with an average value of approximately 0.5%. PEG presented evidence on these approved consumer dividends, and on approved X factors more generally, in our report for 2nd Generation IRM.[12]

[12] See M.N. Lowry *et al*, *Second Generation Incentive Regulation for Ontario Power Distributors*, June 13, 2006, Table 1 on p. 55. The average stretch factor in the 11 plans on this table for which there were acknowledged stretch factors was 0.54%.

3. The Inflation Factor

The inflation factor in the current 3rd Gen IR is the Gross Domestic Product Implicit Price Index for final domestic demand (GDP-IPI). The Board has concluded that a more industry-specific measure of input price inflation will be used as the inflation factor in 4th Gen IR.[13] In 3rd Gen IR, the Board considered using an industry input price index (IPI) for the inflation factor but decided against doing so because of the potential volatility of such an index. The Board has concluded that concerns regarding volatility in the IPI will be mitigated by the methodology it selects to measure inflation.

Electricity distributors procure three broad classes of inputs: 1) capital; 2) labor; and 3) non-labor, OM&A expenses. The main challenge in developing an IPI is identifying the best available subindices for measuring inflation in the prices of electricity distributors' capital, labor, and non-labor OM&A inputs, respectively. Once these are identified, overall inflation is easily computed as the weighted average of the inflation rates in each subindex, where the weights are equal to each input's associated share of the industry's total cost. The details of calculating industry total cost will be discussed in Chapter Four of this report.

The Board has said that it will be guided by the following criteria when deciding on appropriate input price subindices and an appropriate inflation factor:[14]

- the inflation factor must be constructed and updated using data that are readily available from public and objective sources such as Statistics Canada, the Bank of Canada, and Human Resources and Social Development Canada;
- to the extent practicable, the component of the inflation factor designed to adjust for inflation in non-labor prices should be indexed by Ontario distribution industry-specific indices; and

[13] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 16.
[14] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 16.

- the component of the inflation factor designed to adjust for inflation in labor prices will be indexed by an appropriate generic and off-the-shelf labor price index (i.e., the labor price index will not be distribution industry-specific).

PEG has developed two alternative, inflation factors that we believe comply with the Board's criteria. The first is a "two-factor" IPI, where industry input price inflation is measured using separate input price subindices for capital and OM&A inputs. The second option is a "three-factor" IPI, where inflation is measured using separate input price subindices for capital, labor, and non-labor OM&A inputs, respectively.

This Chapter will summarize PEG's research on the inflation factor. We begin by discussing the choices for inflation subindices. We then discuss the issue of inflation volatility and options for mitigating volatility. Next we present our estimates of historical input price inflation for Ontario electricity distributors using the two-factor and three-factor IPI options. Finally, PEG presents its recommended inflation factor for 4th Gen IR.

3.1 Inflation Subindices

3.1.1 Subindex Weights

Industry-wide input price inflation is computed as the weighted average of inflation in price subindices for different inputs, where the weights are equal to each input's share of the industry's total cost. A single inflation factor will apply to all distributors in the industry under 4th Gen IR, so it is appropriate for the weights in the IPI to be calculated using average cost shares for the industry as a whole. Developing an IPI with separate indices for capital, labor, and non-labor OM&A input prices therefore requires information on the share of each of these input categories in the total cost of the Ontario electricity distribution industry.

Industry total cost was computed as the sum of capital cost and distribution OM&A expenses. The weight that applies to the capital input price index (described below) was electricity distributors' capital cost divided by the total cost measure used in the TFP analysis. It is appropriate to use the cost measure used in the TFP analysis since the input price index plays a role in the computation of TFP growth *(e.g.* the change in OM&A inputs is calculated as the growth in OM&A expenses minus the growth in OM&A input prices). The input price index that PEG recommends as an inflation factor will therefore also be a component of the TFP analysis and therefore should be consistent with the cost measure used in this analysis.

Developing separate weights for labor and non-labor OM&A input prices requires information on labor's share of OM&A expenses. These data are confidential for specific distributors in Ontario. However, in its 3rd Gen IR inflation factor proposal, Staff estimated that labor expenses accounted for 70% of distributors' OM&A expenses.[15] PEG used this industry-wide, estimated ratio to obtain estimates of the industry's labor cost and non-labor OM&A costs. Cost shares for labor and non-labor OM&A inputs were then obtained by dividing these respective costs by the total cost of the electricity distribution industry.

3.1.2 Labor Prices

The RRFE Board Report finds that labor prices should be indexed by generic and off-the-shelf labor price indices (i.e. indices that are not distribution industry-specific). PEG believes the best generic and off-the-shelf labor price index to use in the 4th Gen IR inflation factor is average weekly earnings (AWE) for all workers in Ontario.[16] This index reflects labor price trends for both salaried and hourly workers. It also captures Province-wide labor price pressures, not specific developments or labor settlements for Ontario's electricity distribution sector. PEG therefore recommends that the AWE for all Ontario workers be used to measure labor price inflation in the inflation factor used in 4th Gen IR.

3.1.3 Capital Input Prices

Unlike labor prices, the Board has found that non-labor prices should to the extent practicable be indexed by Ontario distribution industry-specific indices. There are two classes of non-labor inputs: capital and non-labor OM&A expenses. We deal with each of these non-labor input categories in turn.

PEG has used a capital service price to measure capital input prices. In this report, we will use these terms synonymously. The formula for the capital service price index is:

$$WKS_t = d \cdot WKA_t + WKA_{t-1} \cdot r_t \qquad [7]$$

The two terms of the service price formula reflect the "return of" and the "return on" capital, respectively. The first term corresponds to depreciation, where *d* is the economic rate

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15 *Staff Discussion Paper on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors,* February 28, 2008, pp. 52.

16 Techncially, this is the Average Weekly Earnings for the industrial aggregate in Ontario, and the series providing these data on annual basis is series number 281-0027. It should be recognized, however, that the "industrial aggregate" in Ontario includes goods-making and non-goods making industries.

of depreciation on the capital stock. The second term corresponds to the rate of return on capital, where r_t is the opportunity cost of plant ownership per dollar of plant value. WKA_t is an element of both the first and second terms. It corresponds to a price index that reflects the cost of purchasing and installing distribution assets. Implementing this formula requires measures for the rate of depreciation d, the rate of return r, and the asset price index WKA.

In this study, PEG uses a "geometric" depreciation rate where capital decays at a constant rate each year. Academic studies that examine the prices paid for used capital assets in secondary markets lend support for this pattern of depreciation.[17] PEG also consulted on this issue with the PBR Working Group, and it supported a geometric depreciation rate. The geometric rate of depreciation r was estimated to be 4.59%.[18]

The rate of return r_t was computed as the weighted average cost of capital (WACC) for Ontario distributors. This is appropriate since the rate of return in equation [7] is designed to reflect a distributor's opportunity cost of capital, not its actual returns. The WACC was calculated using Board-approved values for long-term debt rates, short-term debt rates, and return on equity since 2002. Before May 2008, the Board approved different long-term debt and equity rates for different size categories of distributors. PEG used the Board-approved values for medium-small companies in the years before 2008 (*i.e.* from 2002 through 2007) because this size category accounts for the largest number of distributors in the Province. In all years, we applied the Board's current, deemed capital structure when computing the WACC. The current capital structure assumes 40% equity, 56% long-term debt, and 4% short-term debt. PEG consulted on this issue with the PBR Working Group, and the Working Group supported PEG's recommended approach of using the Board-approved WACC and the capital structure to calculate the rate of return r_t.

Our measure of the asset-price index WKA_t was the Electric Utility Construction Price Index (EUCPI) for distribution assets. This index includes the costs of purchasing and installing distribution assets and therefore reflects the costs of construction labor. The EUCPI is calculated by Statistics Canada for distribution systems throughout Canada. Statistics Canada does not publish data on the EUCPI specifically for Ontario.

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[17] Hulten and Wykoff (1981)

[18] This was equal to a weighted average of the declining balance rates estimated by Hulten and Wykoff *op cit* for equipment and structures, divided by the estimated lifetimes for different assets. Because depreciation factors more directly into our cost estimates, details of this calculation are provided in Chapter 4 of this report.

We believe a capital service price estimated using these data satisfies the Board's criteria for measuring non-labor prices in the inflation factor. The capital service price can be updated in a straightforward manner each year using two pieces of information: changes in the Board's approved WACC, and changes in the EUCPI. Both sets of data come from public and objective sources. The EUCPI series is updated in early April of each year. The Board-approved WACC is obviously specific to the Ontario electricity distribution industry. The EUCPI reflects trends in electricity distribution asset prices in Canada, rather than Ontario specifically. Nevertheless, this is the most practical, publicly-available index of electricity distribution asset prices for Ontario distributors since Stats Canada does not publish any comparable series that are specific to Ontario.

Table One presents information on this capital service price for Ontario distributors over the 2002-2011 period. This is the same sample period that will be used in this report's TFP analysis. The table presents information on annual inflation in each of the three components of the capital service price, although with a geometric rate of depreciation the depreciation rate is by definition constant in all sample years. We also compute annual changes in the overall capital service price index in the second to last column from the right (*i.e.* the "Capital Price Inflation" column), as well as a three-year moving average of capital service price inflation in the last column on the right.

It can be seen that capital service prices grew at an average annual rate of 1.00% per annum over the sample period. When measured on a three-year moving average basis, the capital service price grew somewhat more rapidly at 1.13% per annum. The EUCPI grew at an average rate of 2.27% per annum between 2002 and 2011, and the Board-approved WACC declined at an average rate of 1.77% over this period.

PEG's recommended capital service price is somewhat volatile, with annual inflation in the index ranging from -0.7% in 2006 to 2.4% in 2007 and 2008. The standard deviation in the annual capital service price index is 1.11%. However, when measured on a three-year moving average basis, the capital service price varies over a smaller range (from a high of 2.0% in 2009 to a low of 0.1% in 2006) and the standard deviation is reduced by about 40% to 0.69%. This analysis suggests that volatility in capital service prices can be mitigated by measuring their inflation as a three-year moving average rather than through annual changes in index values.

Table 1

Calculation of Capital Service Price Index

Year	EUCPI	Annual Growth	WACC	Annual Growth	Depreciation Rate	Capital Price Index	Capital Price Inflation	Three Year Moving Average
2002	130.5		8.30%		4.59%	16.74		
2003	130.6	0.1%	8.30%	0.00%	4.59%	16.82	0.5%	
2004	131.1	0.4%	8.30%	0.00%	4.59%	16.85	0.2%	
2005	133.6	1.9%	8.30%	0.00%	4.59%	17.01	0.9%	0.5%
2006	142.4	6.4%	7.74%	-6.88%	4.59%	16.88	-0.7%	0.1%
2007	148.8	4.4%	7.35%	-5.22%	4.59%	17.30	2.4%	0.9%
2008	150.3	1.0%	7.27%	-1.11%	4.59%	17.72	2.4%	1.4%
2009	151.1	0.5%	7.32%	0.63%	4.59%	17.93	1.2%	2.0%
2010	155.1	2.6%	7.40%	1.14%	4.59%	18.30	2.0%	1.9%
2011	160.1	3.2%	7.08%	-4.46%	4.59%	18.32	0.1%	1.1%
Average		**2.27%**		**-1.77%**			**1.00%**	**1.13%**
Standard Deviation		**2.11%**		**2.95%**		`	**1.11%**	**0.69%**
Standard Deviation/ Average		**92.7%**		**-166.7%**			**110.4%**	**61.0%**

Notes: The weighted average cost of capital is computed using 40% equity, 56% long term debt and 4% short term debt and Board-approved allowed rates of return.

3.1.4 Non-Labor OM&A Input Prices

The other non-labor input for electricity distributors is non-labor OM&A expenditures. The Board has found that non-labor input inflation indices should be drawn from public and objective sources and be as specific as practicable to the Ontario electricity distribution industry. However, while private vendors like DRI have developed indices that specifically measure inflation in utilities' non-labor OM&A input prices, PEG is not aware of similar indices that are available from objective, public sources.

One difficulty is that "non-labor OM&A" covers a wide and diverse set of expenditures. These inputs include insurance, fuel, office supplies, and some IT software. No single, publicly-available price index focuses solely on these inputs. Constructing such an index using highly disaggregated price subindices for the relevant input categories, and their associated shares of distributors' non-labor OM&A cost, would be laborious and non-transparent. Even if it was feasible to construct such an index using publicly available data, it would not be easy to update it annually during the term of the 4th Gen IR.

Another complication is that at least some inflation in non-labor OM&A input prices will actually include inflation in *labor* prices. The reason is that distributors' contracts for outsourced, operational services are reported as non-labor OM&A expenses.[19] Labor is an important cost component of many outsourcing contracts. Consequently, factors impacting labor prices will be reflected, to some extent, in the amounts reported by distributors as non-labor, OM&A expenses.

The practical difficulties of isolating such labor expenses, and in identifying publicly available indices that reflect the breadth of non-labor OM&A input prices, requires decisions on how best to satisfy the Board's criteria for establishing an inflation factor. One issue is what inflation subindex is the best practical choice for capturing the diverse array of inputs that will be reflected in distributors' non-labor, OM&A expenditures. A second issue is to what extent the best practical option for a non-labor, OM&A input price index should stress labor price pressures reflected in outsourcing contracts and recorded as non-labor OM&A expenditures. Selecting a broad-based price index that emphasizes the diversity of the input

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[19] The cost of these outsourcing contracts is not separately categorized in the RRRs.

mix would necessarily rule out an index stressing labor price pressures, and there is no practical way to construct a non-labor OM&A input price measure that includes both since data are not available on the share of outsourced contract labor in OM&A expenses.

Because of these practical challenges, PEG's analysis considers two options for the price subindex for non-labor OM&A inputs. The first is AWE for all Ontario workers. This option obviously emphasizes the portion of labor cost implicit in non-labor OM&A expenses. Since the AWE is also used to measure labor input prices, having this index apply to non-labor OM&A inputs as well would effectively mean that two price subindices are used to measure inflation in the three input categories. We call this option the "two-factor" IPI.

The second option is to use the GDP-IPI to measure non-labor OM&A input prices. This option emphasizes the breadth and diversity of non-labor OM&A inputs. The GDP-IPI is a good index for reflecting the broad scope of these inputs, since it applies to all final domestic demand in Canada. In addition to being very broad, this index is currently used in 3rd Gen IR and therefore familiar to the Board, Staff, and stakeholders. The second option uses distinct input price subindices for each of the three input categories, and PEG accordingly calls this the "three-factor" IPI.

Table Two provides information on inflation in the AWE-All Employees and the GDP-IPI indices over the 2002-2011 period. It can be seen that average AWE inflation of 2.56% per annum has exceeded the 1.69% average annual growth in the GDP-IPI. The gap widens somewhat (2.61% vs. 1.69%) if the two indices are measured on a three-year moving average basis. The AWE is also more volatile, with a standard deviation of 1.01% (or about 39% of annual AWE inflation) compared with a standard deviation of 0.35% (or about 21% of annual inflation) for the GDP-IPI. In general, these data show that if the AWE rather than the GDP-IPI was used as the non-labor OM&A input price subindex, it would tend to lead to more rapid and more volatile changes in the inflation factor.

3.2 Mitigating Inflation Volatility

An important consideration in constructing the inflation factor for 4th Gen IR is volatility. Tables One and Two show PEG's capital service is the most volatile of our recommended input price subindices. These tables also show that measuring inflation on the basis of a three-year moving average substantially reduces volatility. Using standard

Table 2

Alternate Measures of Non-Labor OM&A Input Price Inflation

	AWE- All Employees			GDPIPI		
Year	Ontario	Annual Growth	Three Year Moving Average	Ontario	Annual Growth	Three Year Moving Average
2002	710.73			92.25		
2003	728.23	2.43%		93.54	1.39%	
2004	748.78	2.78%		95.11	1.66%	
2005	776.19	3.60%	2.94%	96.96	1.92%	1.66%
2006	788.62	1.59%	2.66%	98.43	1.51%	1.70%
2007	818.93	3.77%	2.99%	100.00	1.58%	1.67%
2008	838.14	2.32%	2.56%	102.30	2.27%	1.79%
2009	849.15	1.31%	2.47%	103.60	1.26%	1.71%
2010	882.21	3.82%	2.48%	105.10	1.44%	1.66%
2011	894.71	1.41%	2.18%	107.40	2.16%	1.62%
Average		**2.56%**	**2.61%**		**1.69%**	**1.69%**
Standard Deviation		**1.01%**	**0.28%**		**0.35%**	**0.05%**
Standard Deviation/Average		**39.33%**	**10.81%**		**20.94%**	**3.15%**

deviation as the volatility metric, relative volatility of the capital service price declines by 38% when inflation is measured as average inflation over the last three years rather than by the average annual change in the index. The comparable figures for the AWE and the GDP-IPI are 72% and 86%, respectively.[20]

These data suggest that a three-year moving average is an effective way to mitigate inflation volatility. We also consulted on this approach with the PBR Working Group, and it supported using a three-year moving average to mitigate inflation volatility. PEG therefore recommends that a three-year moving average be used to damp volatility of both the two-factor IPI and the three-factor IPI. This three-year moving average is calculated simply by computing annual inflation in the IPI for each of the three most recent years and then calculating the average of these inflation rates.

3.3 Historical Results on Industry Input Price Inflation

Overall input price indexes were constructed as a weighted average of the selected input price subindices. The weights were based on the share of the total cost measure used in the TFP analysis that is associated with the respective input. These cost shares were 62.4% for capital, 26.3% for labor, and 11.3% for non-labor OM&A expenses.

Table Three presents data on inflation in the two-factor IPI for the 2002-2011 period. Table Four presents data on inflation in the three-factor IPI for the same period. Table Five compares the inflation rates of the two IPIs.

In Table 3, it can be seen that the two-factor IPI grew at an average annual rate of 1.59% over the sample period. This average inflation rate rises somewhat to 1.68% if it is measured on a three-year moving average basis. The standard deviation of the two-factor IPI is 0.95% if inflation is measured annually but falls to 0.39% if inflation is measured as a three-year moving average. A three-year moving average therefore reduces volatility in this index by about 59% (*i.e.* ((0.95%-0.39%)/0.95% = 59%).

Table 4 shows that the three-factor IPI grew at an average annual rate of 1.49% between 2002 and 2011. This average inflation rate rises somewhat to 1.58% if it is

[20] For the capital service price, the standard deviations associated with annual and three year moving average inflation are 1.11% and 0.69%; the percentage decline in standard deviation, relative to value when inflation is measured annually, is ((1.11% - 0.19%)/1.11%)= 38%. The comparable calculations for the AWE and GDP-IPI are ((1.01%-0.28%)/1.01%) = 72%, and ((0.35%-0.05%)/0.36%) = 86%.

Table 3

Two-Factor Inflation Measure

	OM&A Input Price			Capital Service Price			Inflation Measure		
Year	AWE-All Employees-	Annual Growth	Weight	Index	Annual Growth	Weight	Index	Annual Growth	Three Year Moving Average
2002	710.73			16.74			100.00		
2003	728.23	2.43%	37.6%	16.82	0.47%	62.4%	101.22	1.21%	
2004	748.78	2.78%	37.6%	16.85	0.19%	62.4%	102.40	1.16%	
2005	776.19	3.60%	37.6%	17.01	0.92%	62.4%	104.39	1.93%	1.43%
2006	788.62	1.59%	37.6%	16.88	-0.74%	62.4%	104.53	0.13%	1.07%
2007	818.93	3.77%	37.6%	17.30	2.42%	62.4%	107.64	2.93%	1.66%
2008	838.14	2.32%	37.6%	17.72	2.39%	62.4%	110.22	2.37%	1.81%
2009	849.15	1.31%	37.6%	17.93	1.21%	62.4%	111.60	1.24%	2.18%
2010	882.21	3.82%	37.6%	18.30	2.04%	62.4%	114.66	2.71%	2.11%
2011	894.71	1.41%	37.6%	18.32	0.13%	62.4%	115.36	0.61%	1.52%
Average		**2.56%**			**1.00%**			**1.59%**	**1.68%**
Standard Deviation		**1.01%**			**1.11%**			**0.95%**	**0.39%**
Standard Deviation/ Average		**39.3%**			**110.4%**			**60.1%**	**23.0%**

Table 4

Three Factor Inflation Measure

	OM&A Input Price						Capital Service Price			Inflation Measure		
Year	GDPIPI-Ontario	Annual Growth	Weight	AWE- All Employees-Ontario	Annual Growth	Weight	Index	Annual Growth	Weight	Index	Annual Growth	Three Year Moving Average
2002	92.25			710.73			16.74			100.00		
2003	93.54	1.39%	11.3%	728.23	2.43%	26.3%	16.82	0.47%	62.4%	101.10	1.09%	
2004	95.11	1.66%	11.3%	748.78	2.78%	26.3%	16.85	0.19%	62.4%	102.15	1.04%	
2005	96.96	1.92%	11.3%	776.19	3.60%	26.3%	17.01	0.92%	62.4%	103.94	1.74%	1.29%
2006	98.43	1.51%	11.3%	788.62	1.59%	26.3%	16.88	-0.74%	62.4%	104.07	0.12%	0.97%
2007	100.00	1.58%	11.3%	818.93	3.77%	26.3%	17.30	2.42%	62.4%	106.90	2.68%	1.52%
2008	102.30	2.27%	11.3%	838.14	2.32%	26.3%	17.72	2.39%	62.4%	109.45	2.36%	1.72%
2009	103.60	1.26%	11.3%	849.15	1.31%	26.3%	17.93	1.21%	62.4%	110.82	1.24%	2.09%
2010	105.10	1.44%	11.3%	882.21	3.82%	26.3%	18.30	2.04%	62.4%	113.55	2.44%	2.01%
2011	107.40	2.16%	11.3%	894.71	1.41%	26.3%	18.32	0.13%	62.4%	114.35	0.70%	1.46%
Average		**1.69%**			**2.56%**			**1.00%**			**1.49%**	**1.58%**
Standard Deviation		**0.35%**			**1.01%**			**1.11%**			**0.87%**	**0.40%**
Standard Deviation/ Average		**20.9%**			**39.3%**			**110.4%**			**58.4%**	**25.2%**

Table 5

Inflation Measure Summary

	Option One: Two Factor Inflation Measure			Option Two: Three Factor Inflation Measure		
Year	Index	Annual Growth	Three Year Moving Average	Index	Annual Growth	Three Year Moving Average
2002	100.00			100.00		
2003	101.22	1.21%		101.10	1.09%	
2004	102.40	1.16%		102.15	1.04%	
2005	104.39	1.93%	1.43%	103.94	1.74%	1.29%
2006	104.53	0.13%	1.07%	104.07	0.12%	0.97%
2007	107.64	2.93%	1.66%	106.90	2.68%	1.52%
2008	110.22	2.37%	1.81%	109.45	2.36%	1.72%
2009	111.60	1.24%	2.18%	110.82	1.24%	2.09%
2010	114.66	2.71%	2.11%	113.55	2.44%	2.01%
2011	115.36	0.61%	1.52%	114.35	0.70%	1.46%
Average		**1.59%**	**1.68%**		**1.49%**	**1.58%**
Standard Deviation		**0.95%**	**0.39%**		**0.87%**	**0.40%**
Standard Deviation/ Average		**60.1%**	**23.0%**		**58.4%**	**25.2%**

measured on a three-year moving average basis. The standard deviation of the three-factor IPI is 0.87% if inflation is measured annually but falls to 0.40% if inflation is measured as a three-year moving average. A three-year moving average therefore reduces volatility of this IPI by about 54% (*i.e.* ((0.87%-0.40%)/0.87% = 54%). The two-factor and the three-factor IPIs therefore have nearly identical standard deviations when measured on a three-year moving average basis (*i.e.* 0.39% and 0.40%, respectively). This implies that a three-year moving average application of either IPI option can be expected to mitigate volatility in the inflation factor by similar amounts.

Table Four also shows that a three-year moving average application of either IPI is likely to generate volatility in measured inflation that is similar to what has been experienced under 3rd Gen IR. Currently, inflation in 3rd Gen IR is measured by annual changes in the GDP-IPI. Table Four shows that the standard deviation of the GDP-IPI, when measured by annual changes in the index, is 0.35%. As discussed, the standard deviations for the two-factor and three-factor IPIs, when measured on a three-year moving average basis, are 0.39% and 0.40%, respectively. Past experience therefore suggests that the volatility of either the two- or three-factor IPI would be expected to be similar to the inflation volatility that customers have experienced under 3rd Gen IR. PEG therefore concludes that a three-year moving average of either IPI would effectively mitigate volatility in the inflation factor.

3.4 Recommended Inflation Factor

The empirical results for the two-factor IPI and three-factor IPI are similar. The options are nearly indistinguishable in terms of volatility. The three-factor IPI will likely lead to lower inflation than the two-factor IPI because GDP-IPI inflation is almost always below inflation in the AWE. Our historical data show that three-factor IPI leads to roughly 0.1% less inflation each year compared with the two-factor IPI.

Notwithstanding these similarities, PEG believes the three-factor IPI better satisfies the Board’s criteria for an inflation factor in 4th Gen IR. The Board has established separate criteria for the labor- and non-labor input price subindices to be used in the inflation factor. The subindex designed to adjust for inflation in non-labor prices should be Ontario distribution industry-specific, while the subindex designed to adjust for inflation in labor prices should be a generic and off-the-shelf labor price index and therefore not distribution industry-specific. Since the Board has established different criteria for labor and non-labor input price subindices, it would be more difficult to satisfy these distinct criteria if the generic, off the shelf index used to measure labor price inflation was also used to measure a portion of non-labor input price inflation. However, that is what the two-factor IPI does, since it uses the AWE to measure both labor price inflation and non-labor OM&A input price inflation. The two-factor IPI option therefore blurs the criteria that the Board has established for selecting separate labor and non-labor price indices for the inflation factor.

The three-factor IPI will also be a more accurate measure of the underlying input price pressures that electricity distributors face. The two-factor IPI measures inflation in capital and labor prices only and makes no allowance for the miscellaneous other inputs that electricity distributors procure. The three-factor IPI is more disaggregated and includes what is likely to be a more precise measure of non-labor OM&A input price inflation.

Because both options are similar in terms of mitigating volatility and the three-factor IPI is superior to the two-factor IPI with respect to satisfying the Board's criteria and on conceptual grounds, PEG recommends that the three-factor IPI be used as the inflation factor in 4th Gen IR. Moreover, we recommend that this inflation factor be calculated each year as a three-year moving average of the three-factor IPI. This is equivalent to setting updated values for the inflation factor that are equal to the average inflation rate of the three-factor IPI over the three, most recent years preceding the year of the update.

4. Data for Total Factor Productivity and Total Cost Analysis

In 4th Gen IR, the Board has found that the productivity factor will be based on the estimated TFP trend for the Ontario electricity distribution industry and stretch factors will be based on benchmarking analyses of distributors' total costs. PEG was asked to provide recommendations for the productivity factor and stretch factors, so our work required estimates of industry TFP growth and benchmarking comparisons of Ontario distributors' total cost. These analyses require estimates of Ontario distributors' capital stocks, since capital typically accounts for more than half the costs of electricity distribution services. PEG developed these capital measures using data from several sources. In some instances, PEG needed to supplement the publicly available data with Board requests for additional information.

This chapter discusses data issues, with an emphasis on capital measurement. We begin by discussing the primary data sources. We then discuss the calculation of capital additions, capital stocks and the Board's supplemental data request. Next we discuss the calculation of capital cost. Finally, we discuss the computation of total cost measures for our TFP and benchmarking work. It should be noted that all data used in PEG's analysis is posted on the Board's website.

4.1 Primary Data Sources

Extensive data are available on the operations of Ontario power distributors. 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 trial balances include highly itemized data on gross plant value. The accumulated "amortization" (*i.e.* depreciation) on electric utility property plant and equipment is also reported, as well as the accumulated amortization on tangible and intangible plant.

An 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. The PBR data provide data on plant value as well as plant additions, which are not reported in the trial balances.[21] 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 currently available for nine customer classes: residential, general service < 50 kW, general service > 50 kW, large users, subtransmission customers, embedded distributors, street lighting, sentinel lighting, and unmetered scattered load.

The available RRR data have a number of strengths that support their use in TFP and total cost benchmarking research. The trial balance cost data are highly detailed. The PBR data also include detailed information on revenues and outputs, including data on peak distribution loads.

RRR data also have some limitations. The most serious problem for TFP and total cost estimation is the number of years of available information. An extensive time series of capital data is particularly valuable for developing capital cost measures, as we explain below.

4.2 Data on Capital and Capital Additions

Accurate and standardized capital cost measures require years of consistent, detailed plant additions data. RRR data on plant additions are, at best, only available since 2002.[22] The lack of extensive time series data on capital additions limits the reliability of the capital measures that can be computed using RRR data.

In practical terms, measuring the quantity of capital typically begins with a *benchmark* capital stock, or (price deflated) value of net plant value in some base year. The base year for the capital quantity should be as distant from the present day as is practical. As the base year becomes more remote, all else equal the value of capital depends more on observed values for capital additions that are added to this benchmark value rather than the value of benchmark capital stock itself.

Capital measures typically become more accurate as measured capital values depend on cumulative capital additions rather than the benchmark capital value. Capital additions

[21] Some capital spending data are also provided on distributors' audited financial statements.

[22] Direct data on plant additions are available from 2002 through Section 2.1.5 of the RRRs; indirect measures of plant additions, using Trial Balance data on changes in gross asset values and asset retirements, would only be available from 2003.

between any two periods are measured more accurately when they are appropriately "deflated" by contemporaneous changes in capital asset prices. This, in turn, is equivalent to separating capital expenditures into a change in (gross) capital input quantities and a change in the prices paid for capital inputs. Since TFP growth is defined as the change in total output quantity minus the change in total input quantity, only the change in real capital inputs is used directly to measure TFP growth. Building up capital measures from the longest, practical time series of deflated capital additions therefore enables TFP measures to place greater emphasis on direct changes in capital input quantities. This leads to more accurate measures of capital input than relying on benchmark capital values, where there is more uncertainty about how to deflate reported net plant in a given, benchmark year.[23]

In order to make our capital benchmark year as remote from the present day as possible, PEG supplemented the RRR data on utility plant with plant values from the Municipal Utility Databank (MUDBANK). MUDBANK was a dataset on municipal utilities that was compiled by Ontario Hydro under the previous electric utility industry structure. The MUDBANK data allowed PEG to use 1989 as the capital benchmark year in our TFP analysis.

However, the 1989 capital benchmark did not prove to be feasible for six distributors. One was Hydro One, which was part of the previous Ontario Hydro. MUDBANK contains data on the municipal utilities for which Ontario Hydro performed a regulatory-type function, but not on Ontario Hydro itself, so Hydro One data before 2002 are not available. Similarly, MUDBANK data are not available in all necessary years for Algoma Power, PUC Distribution, Canadian Niagara Power, Greater Sudbury Hydro, and Innisfil Hydro. For these companies and for Hydro One, we therefore used a 2002 benchmark capital stock value

MUDBANK data are available for all municipal utilities through 1997 and for some municipal utilities through 1998. RRR data are available from 2002 to the present for all distributors. Because there was a data "gap" between these data sources between 1997 and 2002, PEG had to interpolate capital additions data between 1997 and 2002.

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[23] If a full series of capital stock additions was available for each distributor in the industry since its inception, it would not be necessary to start with a benchmark capital stock, for actual data on capital additions could then be used to develop estimates of capital quantity in any given year. In practice, however, it is almost never possible to obtain the full historical series of capital stock changes for any distributor, so capital quantity measurement must begin with a benchmark value in a base year.

In most cases, PEG was able to infer capital additions over this period using the differences in existing gross asset values between those years. This was done simply by calculating the difference between gross capital assets in 2002 and gross capital assets in 1997, dividing this difference by five, and adding in a measure of estimated capital retirements in these years. Based on RRR data for the distributors, we estimated annual retirements to be 0.5% of gross capital values.

In some cases, however, PEG noticed precipitous drops in gross assets between 1997 and 2002. These drops did not appear to be plausible. Discussions with the PBR Working Group revealed that, in some mergers over the 1997-2002 period, the gross capital stocks reported in 2002 for the merged company were in fact equal to *net* asset values in those years. The actual gross stocks were accordingly higher than what was reported by these distributors in 2002.

In light of this fact, for those distributors with precipitous drops in gross capital values between 1997 and 2002, PEG inferred capital additions between these years in the following way:

1. First, we assumed that what was reported as gross plant in 2002 was actually *net* plant in 2002.

2. PEG estimated each distributor's (Accumulated Depreciation/Gross Asset) (i.e. (AD/G)) ratio for 1997 using the MUDBANK data; we assumed that this estimate was accurate and that this ratio did not change between 1997 and 2002.

3. Given those two pieces of information, we inferred a measure of gross plant for each of the necessary companies in 2002 by recognizing that:

    a. Net plant = Gross plant (G) – Accumulated Depreciation (AD), which implies:
    b. Net plant/Gross plant = 1 – AD/G, and therefore:
    c. Gross plant = Net plant/(1-AD/G)

4. PEG inserted net plant for 2002 (as assumed in Step 1) and the estimate AD/G (computed in step 2) into the equation in Step 3c to derive an estimate of Gross plant in 2002. PEG obtained estimates of 2002 gross plant in this way for each of the distributors with precipitous drops in gross plant between 1997 and 2002.

5. Given the estimate for 2002 gross plant from Step 4, capital additions for the relevant group of distributors was estimated in each year between 1997 and 2002 as (Gross plant 2002 – Gross plant 1997)/5, plus the estimate of capital retirements in each year.

PEG also used the MUDBANK and RRR data to estimate capital additions in other years after the 1989 benchmark year. We used differences in MUDBANK gross capital values between 1989 and 1997 (and, where the data were available, 1998) to estimate gross capital additions over this period. We also used differences in gross capital from the Trial Balance data to estimate gross capital additions between 2002 and 2011. Although capital additions data were available directly from the PBR Section of the RRRs, the Working Group advised against relying on the PBR data and instead recommended that PEG use the Trial Balance data.[24]

Finally, PEG included distributor capital additions for smart meters in the 2006-2011 period in our measured capital additions. Many distributors booked these additions to a deferral account while the smart meter rollout was in progress and analog meters were still on distributors' books. A full series of annual changes in smart meter capital additions was accordingly not available from RRR data sources.

PEG obtained data on annual capital additions for smart meters through a supplementary data request from the Board. In addition, the Board's supplemental data request asked distributors to provide additional information on two sources of costs for the 2002-2011 period: 1) ownership of high-voltage (HV) transmission substations, and whether account 1815 of the RRRs included amounts that were not related to ownership of HV equipment or capital contributions related to HV equipment; and 2) charges for low voltage (LV) services provided by "host" distributors to other distributors embedded within their systems. Both of these cost components were important for developing appropriate cost measures for the purposes of total cost benchmarking, as we explain in Section 4.4.

4.3 Computing Capital Cost

PEG estimated the cost of utility plant in a given year t (CK_t) as the product of a capital service price index (WKS_t) discussed in Chapter Three and an index of the capital quantity at the end of the prior year (XK_{t-1}).

[24] It should also be noted that data were available from various sources in 2000 and 2001, although not for all distributors. Many stakeholders who took part in the PBR Working Group discussions had concerns with the accuracy of the data that were available. The Working Group therefore recommended that the available 2000-01 data not be used in PEG's TFP or benchmarking analyses.

$$CK_t = WKS_t \cdot XK_{t-1}. \qquad [7]$$

The formula for the capital service price index is

$$WKS_t = d \cdot WKA_t + WKA_{t-1} \cdot r_t \qquad [8]$$

This is identical to the capital service price used in Chapter Three. The first term in the expression corresponds to the cost of depreciation. The second term corresponds to the rate of return on capital. The values for WKA_t and r_t are identical to those described and used in Chapter Three.

PEG calculated the value of the economic, "geometric" depreciation rate for the Ontario electricity distribution industry to be 4.59% based on: 1) the estimated declining balance parameters for structures and equipment (0.91 and 1.65 respectively) in Hulten and Wykoff's seminal depreciation study; 2) OEB data on average asset lives in Ontario for different categories of assets, as estimated by Kinetrics Inc. in its July 8, 2010 report *Asset Depreciation Study for the Ontario Energy Board*; and 3) the share of each asset category in the Ontario electricity distribution industry's total gross capital stock in 2011, as calculated from RRR data. Table Six shows the details of this calculation.

It should be noted that PEG's capital cost and capital service price measures do not include tax costs. This decision reflected the institutional and policy environment in Ontario. It was recognized that tax rates for electricity distributors fell over the 2002-2011 period, and this development is unlikely to persist. Including tax changes over 2002-2011 could provide a misleading estimate of the TFP and input price trends that could be expected over the next five years, so we did not include tax costs in our analysis. The decision to exclude taxes from PEG's measures of total cost was supported by the Working Group.

Regarding capital stocks, as previously discussed, measuring the quantity of capital begins with a benchmark capital stock, or price-deflated value of capital in some base year. The benchmark year for the capital stock in PEG's study is 1989 (except for the six previously noted distributors). We deflated the benchmark capital stocks by a "triangularized weighted average" of capital asset prices over a multi-year period preceding the 1989 benchmark capital value.[25]

[25] See Stevenson (1980) for a discussion of this approach.

Table 6

CALCULATION OF THE ECONOMIC DEPRECIATION RATE

	Distribution Substations	Poles and Wires	Line Transformers	Services and Meters	General Plant	Equipment	Information Technology	Total Plant
Industry Total (2011)	$ 1,106,968,267	$ 12,984,407,954	$ 3,852,700,174	$ 1,816,079,550	$ 530,943,619	$ 998,075,226	$ 818,062,952	$ 22,107,237,742
Percent of Total	5.0%	58.7%	17.4%	8.2%	2.4%	4.5%	3.7%	100.0%
Hulten-Wykoff Parameter [A]	1.65	0.91	1.65	1.65	0.91	1.65	1.65	
Life [B]	45	50	45	35	50	10	4	
Rate [A/B]	3.67%	1.82%	3.67%	4.71%	1.82%	16.50%	41.25%	4.59%

The following perpetual inventory equation is used to compute subsequent values of the capital quantity index *XK* (*i.e.* the capital stock) after the benchmark year:

$$XK_t = (1-d) \cdot XK_{t-1} + \frac{VI_t}{WKA_t}. \qquad [9]$$

Here, the parameter d is the economic depreciation rate, VI_t is the value of gross additions to the distributor's plant, and WKA_t is an index of distributor plant asset prices. The value of *WKA* is the electric utility construction price index and is identical to what is used in equation [8] and in the construction of the inflation factor. The depreciation rate is identical to what is derived on Table Six. PEG's estimates of gross capital additions VI_t were described in Section 4.2.

4.4 Total Cost Measures for TFP and Benchmarking Analysis

The TFP and the benchmarking analyses both require estimates of total cost. For TFP, an estimate of industry total cost is necessary to derive the shares of capital and OM&A expenses in total costs. These cost share weights are then used to weight the growth in capital and OM&A inputs, respectively, when computing the overall growth in input quantity. PEG computed total costs for the industry over 2002-2011 as the sum of distribution OM&A expenses from the RRRs and the industry's total capital costs, as discussed in Section 4.2 and 4.3.

Capital costs for the TFP analysis were computed using equations [7] and [8] and gross capital additions net of capital contributions in aid of construction (CIAC). CIAC payments were excluded from the TFP cost measure because CIAC should not be included in PEG's estimate of TFP growth. The reason is that estimated TFP growth will be part of the PCI formula used to adjust regulated distribution rates. CIAC payments are not part of distributors' rate base and therefore not subject to this rate adjustment formula. Including CIAC in our TFP analysis would therefore create a mismatch between the costs used as inputs for IR-based rate adjustments and the costs that are actually subject to that IR mechanism.

PEG's benchmarking analysis requires total cost measures for every Ontario distributor. The starting point for the benchmarking cost measure was the total cost used in our TFP analysis. However, the Working Group undertook extensive discussions on whether, and how, total cost should be adjusted in order to make "apples to apples" benchmarking comparisons across distributors.[26] The Working Group supported three cost adjustments.

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

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

PEG also added in two cost items to make costs more comparable across distributors. First, we included charges for low voltage (LV) services that were paid by distributors to their "host" distributors. These charges are regulated separately by the OEB but not included in the RRRs. We obtained these data through the Board's supplementary data request described in Section 4.2. PEG excluded the costs of regulatory asset recovery from the Hydro One LV charges because they include more than payment for LV services.

PEG also included contributions in aid of construction (CIAC) in the capital cost measure. While CIAC payments are outside of the Board's IR rate adjustment formula, they are part of the capital stock that distributors use to provide service to their customers. If these CIAC were not included in distributors' cost measures used for benchmarking, these costs

[26] These adjustments make the capital and OM&A cost shares for benchmarking somewhat different than the cost shares used in our TFP and input price analysis. The cost shares described in Chapter Three are derived from the cost measure used in PEG's TFP work and are the appropriate ones to use in those analyses.

would differ across distributors simply because of differences in the relative amounts of capital financed by CIAC.

Table Seven summarizes the differences between the cost measures that PEG used to estimate TFP and to benchmark distributors' total costs. Again, the three adjustments to our TFP cost measure were necessary to promote apples-to-apples cost comparisons across Ontario's electricity distributors. However, if these cost adjustments were made to the TFP cost measure, they would have either eliminated cost items (*e.g.* HV assets that are deemed to be distribution assets for some distributors) that will be subject to the PCI adjustment, or added in cost items (*e.g.* CIAC and LV charges to embedded distributors) that will not be subject to the PCI adjustment. Because our TFP study is to designed to inform the Board's decision on an appropriate productivity factor that will be an element of the PCI, the cost measure used in out TFP study was appropriate for that purpose.

PEG developed total cost measures for 73 distributors in Ontario. These distributors are listed in Table Eight.[27] PEG relied on RRR data reported by the distributors for our TFP and benchmarking research. PEG did not adjust these reported RRR data, except for a few instances where there appeared to be clear data recording errors. A complete list of these data adjustments is provided in Table Nine.

[27] Two distributors were excluded from our analysis: Five Nations Energy and Hydro One Remote Communities.

Table 7

Cost Measures for Empirical Analysis

Industry TFP Growth	Included in Study?	Distribution Cost Benchmarking	Included in Study?
Candidate Capital Costs:		**Candidate Capital Costs:**	
Capital Benchmark Year: 1989*		Capital Benchmark Year: 1989*	
Transmission Substations > 50 KV Assets**	Yes	Transmission Substations > 50 KV Assets**	No
Gross Capital Expenditures	Yes	Gross Capital Expenditures	Yes
CIAC	No	CIAC	Yes
Smart Meter Expenditures	Yes	Smart Meter Expenditures	Yes
Candidate OM&A Costs:		**Candidate OM&A Costs:**	
Distribution OM&A	Yes	Distribution OM&A	Yes
High Voltage OM&A***	Yes	High Voltage OM&A***	No
Low Voltage Charges to Embedded Distributors****	No	LV Charges to Embedded Distributors****	Yes

Notes:

* Exceptions are Hydro One, Algoma Power, Canadian Niagara Power, Greater Sudbury Power, Innisfill Hydro and PUC Distribution, where data before 2002 were not available.

** Account Number 1815

*** Proxy High Voltage OM&A costs were calculated as the sum of OM&A in accounts 5014, 5015, and 5112

**** Excludes Regulatory Asset Recovery Charges

Table 8

SAMPLED POWER DISTRIBUTORS
(2011 Utility Names)

Algoma Power Inc.
Atikokan Hydro Inc.
Bluewater Power Distribution Corporation
Brant County Power Inc.
Brantford Power Inc.
Burlington Hydro Inc.
Cambridge and North Dumfries Hydro Inc.
Canadian Niagara Power inc.
Centre Wellington Hydro Ltd.
Chapleau Public Utilities Corporation
COLLUS Power Corporation
Cooperative Hydro Embrun Inc.
E.L.K. Energy Inc.
Enersource Hydro Mississauga Inc.
Entegrus Powerlines
EnWin Utilities Ltd.
Erie Thames Powerlines Corporation
Espanola Regional Hydro Distribution Corporation
Essex Powerlines Corporation
Festival Hydro Inc.
Fort Frances Power Corporation
Greater Sudbury Hydro Inc.
Grimsby Power Incorporated
Guelph Hydro Electric Systems Inc.
Haldimand County Hydro Inc.
Halton Hills Hydro Inc.
Hearst Power Distribution Company Limited
Horizon Utilities Corporation
Hydro 2000 Inc.
Hydro Hawkesbury Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc.
Hydro Ottawa Limited
Innisfil Hydro Distribution Systems Limited
Kenora Hydro Electric Corporation Ltd.
Kingston Hydro Corporation
Kitchener-Wilmot Hydro Inc.
Lakefront Utilities Inc.
Lakeland Power Distribution Ltd.
London Hydro Inc.
Midland Power Utility Corporation
Milton Hydro Distribution Inc.
Newmarket - Tay Power Distribution Ltd.
Niagara Peninsula Energy Inc.
Niagara-on-the-Lake Hydro Inc.
Norfolk Power Distribution Inc.
North Bay Hydro Distribution Limited
Northern Ontario Wires Inc.
Oakville Hydro Electricity Distribution Inc.
Orangeville Hydro Limited
Orillia Power Distribution Corporation
Oshawa PUC Networks Inc.
Ottawa River Power Corporation
Parry Sound Power Corporation
Peterborough Distribution Incorporated
PowerStream Inc.
PUC Distribution Inc.
Renfrew Hydro Inc.
Rideau St. Lawrence Distribution Inc.
Sioux Lookout Hydro Inc.
St. Thomas Energy Inc.
Thunder Bay Hydro Electricity Distribution Inc.
Tillsonburg Hydro Inc.
Toronto Hydro-Electric System Limited
Veridian Connections Inc.
Wasaga Distribution Inc.
Waterloo North Hydro Inc.
Welland Hydro-Electric System Corp.
Wellington North Power Inc.
West Coast Huron Energy Inc.
Westario Power Inc.
Whitby Hydro Electric Corporation
Woodstock Hydro Services Inc.

Total Companies: 73

Table 9

SUMMARY OF DATA ADJUSTMENTS

Company Name	Year	Data Changed by PEG
ALGOMA POWER INC.	2005	kW and kWh data are transposed for non-residential. They were reversed and totals recalculated
ATIKOKAN HYDRO INC.	2006	KWh are shifted from 2006 to 2007. Average values by customer class for 2006-2007 were substituted. Residential inferred from total and other categories.
ATIKOKAN HYDRO INC.	2007	KWh are shifted from 2006 to 2007. Average values by customer class for 2006-2007 were substituted. Residential inferred from total and other categories.
BLUEWATER POWER DISTRIBUTION CORPORATION	2005	75% drop in System Peak; estimated using previous and subsequent years
CANADIAN NIAGARA POWER INC.	2002	Reversal of OH and UG reporting for Fort Erie; Switched such that OH is dominant
CANADIAN NIAGARA POWER INC.	2003	Reversal of OH and UG reporting for Fort Erie; Switched such that OH is dominant
CANADIAN NIAGARA POWER INC.	2004	Reversal of OH and UG reporting for Fort Erie; Switched such that OH is dominant
E.L.K. ENERGY INC.	2002	System peak units problem, multiply reported data by 1000
E.L.K. ENERGY INC.	2003	System peak units problem, multiply reported data by 1000
ENWIN UTILITIES LTD.	2002	System peak units problem, multiply reported data by 1000
ENWIN UTILITIES LTD.	2003	System peak units problem, multiply reported data by 1000
ENWIN UTILITIES LTD.	2004	System peak units problem, multiply reported data by 1000
FORT FRANCES POWER CORPORATION	2005	kWh data were transposed for non-residential. They were reversed and totals recalculated
HALTON HILLS HYDRO INC.	2005	Missing system peak values; estimate based on 2004 and 2007 values
HALTON HILLS HYDRO INC.	2006	Missing system peak values; estimate based on 2004 and 2007 values
HYDRO ONE BRAMPTON NETWORKS INC.	2008	System peak units problem, multiply reported data by 1000
HYDRO ONE NETWORKS INC.	2003	99% drop in system peak, impute using 2002 and 2005 data
HYDRO ONE NETWORKS INC.	2004	99% drop in system peak, impute using 2002 and 2005 data
PARRY SOUND POWER CORPORATION	2005	System peak units problem, multiply reported data by 1000
PUC DISTRIBUTION INC.	2002	System peak units problem, multiply reported data by 1000
PUC DISTRIBUTION INC.	2003	System peak units problem, multiply reported data by 1000
PUC DISTRIBUTION INC.	2004	System peak units problem, multiply reported data by 1000
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	2002	Units problem; multiply km of line by 10
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	2005	System peak units problem, multiply reported data by 1000
WEST COAST HURON ENERGY INC.	2002	System peak units problem, multiply reported data by 1000
WEST COAST HURON ENERGY INC.	2003	System peak units problem, multiply reported data by 1000
WEST COAST HURON ENERGY INC.	2004	System peak units problem, multiply reported data by 1000
WEST COAST HURON ENERGY INC.	2005	System peak units problem, multiply reported data by 1000
WEST COAST HURON ENERGY INC.	2006	System peak units problem, multiply reported data by 1000
WESTARIO POWER INC.	2002	Missing system peak values; impute based on corrected 2003 values
WESTARIO POWER INC.	2003	Units problem for summer and winter peak, divide by reported values by 10, 100

5. Econometric Research on Cost Performance

PEG was asked to benchmark the total cost of Ontario's electricity distributors. We did this using two benchmarking methods: 1) a total cost econometric model; and 2) total unit cost comparisons across selected peer groups of distributors. This Chapter discusses our econometric work, while Chapter Seven will discuss the unit cost benchmarking.

5.1 Total Cost Econometric Model

An econometric cost function is a mathematical relationship between the cost of service and business conditions. Business conditions are aspects of a company's operating environment that may influence its costs but are largely beyond management control. Economic theory can guide the selection of business condition variables in cost function models.

According to theory, the total cost of an enterprise depends on the amount of work it performs - the scale of its output - and the prices it pays for capital goods, labor services, and other inputs to its production process.[28] Theory also provides some guidance regarding the nature of the relationship between outputs, input prices, and cost. For example, cost is likely to rise if there is inflation in input prices or more work is performed.

For electricity distribution, total customers served and total kWh delivered are commonly used for output variables. Peak demand is another potential output variable. Peak demand is a billing determinant for some customers, but peak demand will also be an important cost driver for smaller customers whose peak demands are not metered. The reason is that delivery systems must be sized to accommodate peak demands, so there is a direct relationship between customers' peak demands and the costs of the necessary power delivery infrastructure.

In addition to output quantities and input prices, electricity distributors confront other operating conditions due to their special circumstances. Unlike firms in competitive industries, electricity distributors are obligated to provide service to customers within a given

[28] Labor prices are usually determined in local markets, while prices for capital goods and materials are often determined in national or even international markets.

service territory. Distribution services are delivered directly into the homes, offices and businesses of end-users in this territory. Distributor cost is therefore sensitive to the circumstances of the territories in which they provide delivery service.

One important factor affecting cost is customer location. This follows from the fact that distribution services are delivered over networks that are linked directly to customers. The location of customers throughout the territory directly affects the assets that utilities must put in place to provide service. The spatial distribution of customers will therefore have implications for network cost.

The spatial distribution of customers is sometimes proxied by the total circuit km of distribution line, or the total square km of territory served. Provided customer numbers is also used as a cost measure, these variables will together reflect the impact of different levels of customer density within a territory on electricity distribution costs.

Cost can also be sensitive to the mix of customers served. The assets needed to provide delivery service will differ somewhat for residential, commercial, and industrial customers. Different types of customers also have different levels and temporal patterns of demand and different load factors.

In addition to customer characteristics, cost can be sensitive to the physical environment of the service territory. The cost of constructing, operating and maintaining a network will depend on the terrain over which the network extends. These costs will also be influenced by weather and related factors. For example, costs will likely be higher in areas with a propensity for ice storms or other severe weather that can damage equipment and disrupt service. Operating costs will also be influenced by the type and density of vegetation in the territory, which will be at least partly correlated with precipitation and other weather variables.

Econometric cost functions require that a functional form be specified that relates cost to outputs, input prices, and other business conditions. The parameter associated with a given variable reflects its impact on the dependent cost variable. Econometric methods are used to estimate the parameters of cost function models. Econometric estimates of cost function parameters are obtained using historical data on the costs incurred by distributors and measurable business condition variables that are included in the cost model.

5.2 Econometric Research on Electricity Distribution Cost

Economic theory says that the cost of an enterprise depends on input prices and the scale of output. PEG's cost function included input prices, as defined and measured in Chapter Three of this report. PEG investigated a number of different choices for output variables, including customer numbers, kWh deliveries, different measures of peak demand, and total km of line. We also investigated the impact of other business condition variables that are largely beyond management control but can still impact distribution cost. Data on both the output and business condition variables were drawn from Section 2.1.5 of the RRRs.

PEG consulted extensively on the choices for outputs and business condition variables in our econometric work. This included discussions with the PBR Working Group, as well as a March 1, 2013 webinar on the topic in which the entire industry and other stakeholders were allowed to participate. This webinar generated substantial comment on the merits of a variety of "cost driver" variables that PEG considered during its econometric work. In addition to outputs, the business condition variables we explored could be categorized as belonging to one of five sets of cost drivers:

1) The mix of customers served *e.g.* serving a more industrialized customer base, load factor
2) Variables correlated with urbanization and urban density, such as municipal population per square km of urban territory, the percent of urban territory in total territory, or the share of lines that are underground
3) Geography, such as total area served, the share of territory that is on the Canadian shield, and whether a distributor's territory is in Northern Ontario
4) The age of assets, as proxied by accumulated depreciation relative to gross plant value or the share of total customers that were added in the last 10 years
5) High-voltage intensiveness, such as the share of transmission substation assets (greater than 50 kV) in total distribution plant. This variable was designed to reflect costs associated with high voltage assets that could not be specifically identified and eliminated from our cost measure.

The model also contains a trend variable. This variable captures systematic changes in costs over time that are not explained by the specified business conditions. It may also reflect the failure of the included business condition variables to measure the trends in relevant cost drivers properly. The model may, for instance, exclude an important cost driver or measure such a cost driver imperfectly. The trend variable might then capture the impact on cost of the trend in the driver variable.

5.3 Estimation Results and Econometric Benchmarking

5.3.1 Full Sample Econometric Results

Estimation results for our electricity distribution cost model are reported in Table 10. The estimated coefficients for the business conditions and the "first order" terms of the output variables are elasticities of cost for the sample mean firm with respect to the variable. The first order terms do not involve squared values of business condition variables or interactions between different variables. The table shades results for these terms for reader convenience.

Table 10 also reports the t values generated by the estimation program. The t values were used to assess the statistical significance of the estimated cost function parameters. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected at a 5% significance level (*i.e.* a 95% confidence level). Each statistically significant parameter estimate is identified with an asterisk.

Examining the results in Table 10, it can be seen that there are three statistically significant output variables: customer numbers; kWh deliveries; and system capacity peak demand. Our measure of customer numbers is equal to total customers minus street lighting, sentinel lighting, and scattered unmetered customers. The kWh deliveries measure is billed kWh deliveries (before loss adjustment) to all customers.

The system capacity peak demand measure was equal to the highest annual peak demand measure for a distributor up to the year in question. For example, in 2002 (the first sample year), the system capacity measure for each distributor was its annual peak demand for 2002. In 2003, if the distributor's reported annual peak exceeded its 2002 peak, the system capacity peak was equal to the annual peak demand in 2003. If the annual peak in 2003 was below the annual peak in 2002, the annual peak in 2002 was the highest peak demand measure reported by the distributor, and this value is therefore also recorded as the

Table 10

Econometric Coefficients: Full Sample

VARIABLE KEY

Input Price:	WK = Capital Price Index
Outputs:	N = Number of Customers
	C = System Capacity Peak Demand
	D = Retail Deliveries
Other Business Conditions:	A = 2011 Service Territory
	L = Average Line Length (km)
	NG = % of 2011 Customers added in the last 10 years
	Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.624	88.183
N*	0.398	7.094
C*	0.220	4.346
D*	0.102	3.314
WKxWK	0.060	1.392
NxN	-0.480	-1.777
CxC	0.142	0.572
DxD*	0.189	2.558
WKxN*	0.026	1.372
WKxC	0.028	1.582
WKxD	0.000	-0.009
NxC	0.227	0.929
NxD	0.054	0.527
CxD*	-0.210	-2.335
A	0.018	1.552
L*	0.246	8.651
NG*	0.022	3.143
Trend*	0.012	8.578
Constant*	12.818	353.823
System Rbar-Squared	0.983	
Sample Period	2002-2011	
Number of Observations	729	

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

system capacity peak for 2003. Values in subsequent years were calculated in the same manner. The system capacity variable is intended to reflect distribution infrastructure sized to meet peak demands. Even if those demands fall over time, the distributor's infrastructure and its associated costs will (in nearly all cases) remain. The system capacity peak variable was suggested in the PBR Working Group discussions and largely supported by the Group.

The output parameter estimates, as well as the parameter estimate for capital input prices, were plausible as to sign and magnitude. Cost was found to increase for higher values of capital service prices and output quantities. At the sample mean, a 1% increase in the number of customers raised cost by .40%. A 1% hike in kWh deliveries raised cost by about .10%. A 1% increase in system capacity increased distribution cost by 0.22%. Customer numbers was therefore the dominant output-related cost driver, followed by peak demand, followed by kWh deliveries.

Two other business condition variables are also identified as statistically significant cost drivers on Table 10. One is a distributor's average circuit km of line over the 2002-2011 period. It can be seen that a 1% increase in average circuit km raised distribution cost by 0.25%. PEG used average km over the sample period, rather than each distributor's reported time series of km, because of anomalous trends in circuit km data for some distributors. The circuit km coefficient therefore reflects the cost impact of cross-sectional differences in circuit km across distributors, but not the impact of *changes* in km of line (all else equal) over the 2002-2011 period, on distribution cost.

The circuit km variable clearly has an output-related dimension, because it reflects customers' location in space and distributors' concomitant need to construct delivery systems that transport electrons directly to the premises of end-users. The average circuit km variable can be considered a legitimate output when examining cross-sectional differences in costs across Ontario distributors. Circuit km could, for example, play an important role in identifying appropriate peer groups for unit cost comparisons, since this benchmarking exercise compares unit costs across Ontario distributors at a given point in time. However, it would not be appropriate for the average circuit km variable to be used as an output variable in the current TFP study. This study is designed to estimate *trends* in TFP for the Ontario electricity distribution industry, but the current average km variable only reflects cross sectional, and not trend, impacts on distribution cost.

One other business condition variable in Table 10 is statistically significant. It is the share of a distributor's customers that was added over the last 10 years. This variable is designed to proxy recent growth and the age of distribution systems. All else equal, serving a relatively fast-growing territory requires a greater amount of more current capital additions. These investment pressures could put upward pressure on costs. Our model shows that a 1% increase in this variable increases distribution costs by 0.022%.

A surprising finding of our cost model was the coefficient on the trend variable. This coefficient was estimated to be 0.0124%. This implies that, even when input prices, outputs, and other business condition variables remain unchanged, costs for the Ontario electricity distribution industry still increased by an average of 1.2% per annum between 2002 and 2011. This is counter to the usual finding in cost research, where the coefficient on the trend variable is negative. One factor that could be contributing to these upward cost pressures is government policy implemented over the sample period. Another possibility is that there are cost pressures for a sizeable portion of the industry due to company-specific factors, rather than industry-wide policies, but it is difficult to capture these company-specific cost pressures in measurable business condition variables.

PEG did examine a wide range of other business condition variables in our cost research. These other variables were either not statistically significant or did not have sensible signs. These variables included:

- The percent of distribution territory on the Canadian shield
- A dummy variable for whether or not a distributor was located in Northern Ontario
- The share of transmission substation plant (greater than 50 kV) in total gross plant
- The share of deliveries to residential customers
- Load factor
- The share of service territory that is urban
- Municipal population divided by km^2 of urban territory
- The percentage of circuit km that are underground

5.3.2 Full Sample Econometric Benchmarking

PEG used the cost model presented in Table 10 to generate econometric evaluations of the cost performance of Ontario electricity distributors. This was done by inserting values for each distributor's output and business condition variables into a cost model that is "fitted" with the coefficients presented in Table 10. This process yields a value for the predicted (or expected) costs for each distributor in the sample given the exact business condition variables faced by that distributor. The model also generated confidence intervals around that cost prediction.

PEG then compared each distributor's actual total cost to the model's cost prediction plus or minus the confidence intervals. This comparison was made for each distributor's average value of cost in 2009-2011. These are the three most recent years of the sample period, as well as being the three years that 3rd Gen IR has been in effect. By focusing the cost evaluations on these years, the analysis assesses distributors' relative cost performance under the current, incentive-based regulatory regime rather than their performance under previous regulatory arrangements that are no longer in effect.

A distributor is deemed to be a significantly superior cost performer if its costs are below the model's prediction minus the confidence interval. A distributor is deemed to be a significantly inferior cost performer if its costs are above the model's prediction plus the confidence interval. A distributor is considered an average cost performer if is costs are within the confidence intervals.

Table 11 presents these cost evaluations for both 95% and 90% levels of confidence. The first column presents the difference between each distributor's actual and predicted cost in percentage terms. Distributor names have been suppressed in this table (as well as in Tables 13 and 26 that follow) and replaced with a number that is used consistently throughout the report. The second column reflects the "p value," or level of statistical significance associated with the hypothesis that this difference between actual and predicted costs is equal to zero.

Table 11

Difference Between Actual and Predicted Cost: Full Sample

	Actual minus Predicted Cost	P-Value	
Distributor Number 73	-56.4%	0.000	
Distributor Number 5	-44.1%	0.002	
Distributor Number 15	-37.7%	0.000	95% Confidence
Distributor Number 24	-27.8%	0.010	
Distributor Number 69	-22.9%	0.022	
Distributor Number 35	-22.1%	0.024	
Distributor Number 44	-19.1%	0.047	
Distributor Number 14	-19.0%	0.043	
Distributor Number 25	-18.9%	0.064	
Distributor Number 11	-16.6%	0.069	
Distributor Number 10	-16.3%	0.073	90% Confidence
Distributor Number 54	-15.4%	0.083	
Distributor Number 38	-15.1%	0.086	
Distributor Number 21	-13.0%	0.124	
Distributor Number 2	-9.4%	0.200	
Distributor Number 57	-8.5%	0.225	
Distributor Number 43	-8.3%	0.230	
Distributor Number 17	-8.0%	0.247	
Distributor Number 65	-7.8%	0.243	
Distributor Number 27	-6.7%	0.345	
Distributor Number 39	-6.6%	0.281	
Distributor Number 19	-6.4%	0.286	
Distributor Number 59	-5.5%	0.311	
Distributor Number 23	-5.3%	0.317	
Distributor Number 58	-5.0%	0.330	
Distributor Number 31	-4.9%	0.333	
Distributor Number 4	-4.7%	0.338	
Distributor Number 63	-4.7%	0.346	
Distributor Number 52	-3.1%	0.396	
Distributor Number 29	-2.6%	0.410	
Distributor Number 62	-2.5%	0.412	
Distributor Number 7	-2.4%	0.415	
Distributor Number 28	-2.0%	0.432	
Distributor Number 60	-1.8%	0.435	
Distributor Number 22	-0.2%	0.494	

Table 11 (continued)

Difference Between Actual and Predicted Cost: Full Sample

	Actual minus Predicted Cost	P-Value	
Distributor Number 67	0.7%	0.474	
Distributor Number 50	1.1%	0.462	
Distributor Number 41	1.3%	0.453	
Distributor Number 56	3.1%	0.392	
Distributor Number 12	4.0%	0.361	
Distributor Number 8	4.0%	0.360	
Distributor Number 6	4.2%	0.354	
Distributor Number 30	4.6%	0.339	
Distributor Number 32	5.7%	0.309	
Distributor Number 20	7.7%	0.245	
Distributor Number 64	8.1%	0.236	
Distributor Number 71	8.6%	0.221	
Distributor Number 16	8.6%	0.222	
Distributor Number 33	8.8%	0.215	
Distributor Number 1	9.2%	0.211	
Distributor Number 18	10.6%	0.197	
Distributor Number 37	12.0%	0.164	
Distributor Number 13	12.1%	0.137	
Distributor Number 70	13.3%	0.116	
Distributor Number 40	13.6%	0.114	
Distributor Number 51	14.2%	0.098	
Distributor Number 46	14.4%	0.102	
Distributor Number 53	14.5%	0.104	
Distributor Number 3	14.9%	0.096	
Distributor Number 42	16.9%	0.067	90% Confidence
Distributor Number 72	17.8%	0.055	
Distributor Number 55	19.4%	0.041	
Distributor Number 45	19.6%	0.062	
Distributor Number 34	20.0%	0.042	
Distributor Number 47	20.5%	0.044	
Distributor Number 66	21.2%	0.028	
Distributor Number 61	21.7%	0.030	
Distributor Number 36	22.2%	0.024	95% Confidence
Distributor Number 48	25.8%	0.012	
Distributor Number 9	38.3%	0.000	
Distributor Number 68	48.6%	0.000	
Distributor Number 49	65.9%	0.000	
Distributor Number 26	73.1%	0.000	

Note: Light shading implies result is within 95% confidence interval. Darker shading implies result is within 90% confidence interval.

It can be seen that eight distributors are identified as superior cost performers at the 95% level, and five additional distributors are superior cost performers at the 90% confidence level. The bulk of the industry – 44 distributors –is identified as being average cost performers. Sixteen distributors are seen to be inferior cost performers at the 90% level, and 11 of these distributors are also inferior cost performers at the 95% level.

Although they are not specifically identified on Table 11, the Hydro One and Toronto Hydro econometric results raise concerns regarding the productivity factor that applies to the entire industry. Hydro One and Toronto Hydro are the two largest electricity distributors in the Province and could be exerting a disproportionate impact on econometric estimates for the industry. There are at least two ways that Hydro One and Toronto Hydro could be distorting the industry's measured TFP trend.

First, the estimated cost elasticities for the output variables are used to construct the industry's output quantity index. If Hydro One and Toronto Hydro's presence in the econometric sample leads to a statistically significant change in these cost elasticities, this will be translated directly into a change in the cost elasticities that are used to weight the growth in output quantity subindexes. Unless all output quantity subindexes are growing at the same rate, this will in turn change the industry's measured growth in output quantity and therefore its measured TFP growth.

Second, Hydro One and Toronto Hydro could be having a disproportionate impact on the estimated trend coefficient in the econometric model. Systematic, upward cost pressures that are specific to these distributors, but not reflected in the model's business condition variables, could contribute to the positive trend coefficient. All else equal, a positive upward trend in cost is also reflected in lower, measured TFP growth.

If Hydro One and Toronto Hydro are materially impacting TFP growth for the Ontario electricity distribution industry, there is a strong case for excluding them when estimating the industry's TFP trend. Recall from Chapter Two that North American incentive regulation uses "a competitive market paradigm" to set the terms of rate indexing formulas. Chapter Two also emphasizes (p. 8) that "one important aspect of competitive markets is that prices are external to the costs or returns of any individual firm." The TFP trends used in rate indexing formulas should therefore be "external" to regulated utilities and reflect the average trend of the entire industry, not be unduly influenced by a small number of companies. This is central to the conceptual foundation for incentive regulation. If Toronto Hydro and Hydro One exert a disproportionate impact on the industry's measured TFP trend (by either directly impacting measured cost elasticities for outputs or indirectly impacting cost trends), then one of the foundational principles of incentive regulation is violated. In this instance, PEG would advise the Board to remove Toronto Hydro and Hydro One from the sample used to estimate TFP in order to obtain a TFP trend that is "external" for the entire industry.[29]

5.3.3 Restricted Sample Econometric Results

To explore the potential impact of Hydro One and Toronto Hydro on the econometric and TFP results, PEG re-estimated the econometric model presented in Table 10 for a sample that excluded Hydro One and Toronto Hydro. Other than eliminating these distributors from the sample, the econometric model is identical to what was previously presented. Results for this model are presented in Table 12.

In general terms, the results are similar, although there are notable differences. The cost elasticities for customer numbers, system peak capacity, and kWh deliveries are now 0.444, 0.215, and 0.050, respectively. This compares with previous estimates of 0.400, 0.220. and 0.102 for these variables. By reducing the coefficient on kWh but correspondingly increasing the cost elasticity for customer numbers, the updated cost model strengthens the finding that the main output-based drivers of power distribution cost are customer numbers and peak demand, with kWh having less quantitative impact.

The coefficient on circuit km of line is also reduced somewhat, from a previous estimate of 0.246 to a current estimate of 0.241. The coefficient on the trend variable is also lower. In the updated model, the estimated cost trend (independent of all other cost drivers) is 1.18% per annum, compared with 1.24% in the previous model. All else equal, this lower cost trend implies a 0.06% increase in the industry's TFP trend.

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[29] Clearly, a sample that excludes Toronto Hydro and Hydro One would remain external to those companies; an estimated TFP trend cannot be dominated by a company that has been excluded from the sample. A sample excluding Hydro One and Toronto Hydro would also almost certainly remain external to the 71 Ontario distributors that are still in the sample since each of those companies would be relatively small compared with the industry aggregate.

Table 12

Econometric Coefficients: Restricted Sample

VARIABLE KEY

Outputs:	N =	Number of Customers
	C =	System Capacity
	D =	Retail Deliveries
Other Business Conditions:	A =	2011 Service Territory
	U =	% of Lines Underground
	L =	Average Line Length (km)
	NG =	% of 2011 Customers added in the last 10 years
Input Price:	WK =	Capital Price Index
	Trend =	Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.602	90.121
N*	0.444	8.338
C*	0.215	4.175
D*	0.050	1.822
WKxWK	0.058	1.322
NxN*	-0.490	-1.739
C*C	0.324	1.245
DxD*	0.123	1.723
WKxN*	0.033	1.690
WKxC	0.029	1.610
WKxD	0.000	-0.019
NxC	0.111	0.435
NxD	0.152	1.434
CxD*	-0.256	-2.829
A	0.019	1.624
U	0.014	0.869
L*	0.241	8.662
NG*	0.021	2.897
Trend*	0.012	8.311
Constant*	12.141	546.199
System Rbar-Squared	0.980	
Sample Period	2002-2011	
Number of Observations	709	

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

The difference between the coefficients in Tables 10 and 12 are suggestive, and PEG undertook several statistical tests on whether Hydro One and Toronto Hydro have a statistically significant impact on the four parameter estimates that, directly or indirectly, can be manifested in the industry's TFP trend. These are the estimates on the number of customers, peak demand, kWh, and trend parameters. These statistical tests are presented in Appendix Three of this report.

These tests show that the hypothesis that Hydro One Networks and Toronto Hydro do not have a statistically significant impact on these four parameter estimates can be rejected with 99% confidence. PEG therefore concludes that Toronto Hydro and Hydro One are likely to have a significant impact on the estimated TFP trend for the Ontario electricity distribution industry. Sound incentive regulation should utilize external measures of industry TFP trends, not estimates that may be impacted by one or two dominant firms in an industry. We have accordingly removed Toronto Hydro and Hydro One from both the econometric model as well as the sample used to estimate TFP growth for the Ontario electricity distribution industry. If both distributors were not removed from the econometric sample, they would impact the cost elasticities used to weight outputs and therefore directly impact estimated TFP growth for the industry.

5.3.4 Restricted Sample Econometric Benchmarking

Given the decision to remove Toronto Hydro and Hydro One from the cost model, PEG used the cost model presented in Table 12 to generate econometric evaluations of the cost performance of Ontario electricity distributors. The process for generating these cost evaluations was identical to that discussed for the full sample. Table 13 presents these cost evaluations for both 95% and 90% levels of confidence.

Table 13

Difference Between Actual and Predicted Cost: Restricted Sample

Distibutor Number	Actual minus Predicted Cost	P-Value	
Distributors Number 73	-56.1%	0.000	
Distributors Number 5	-45.6%	0.001	
Distributors Number 15	-38.1%	0.000	
Distributors Number 24	-30.0%	0.005	95% Confidence
Distributors Number 35	-24.4%	0.011	
Distributors Number 25	-22.6%	0.030	
Distributors Number 69	-22.0%	0.021	
Distributors Number 44	-21.1%	0.026	
Distributors Number 11	-20.1%	0.030	
Distributors Number 54	-16.7%	0.057	
Distributors Number 14	-16.6%	0.060	
Distributors Number 10	-16.3%	0.064	90% Confidence
Distributors Number 21	-15.0%	0.082	
Distributors Number 38	-14.2%	0.091	
Distributors Number 27	-12.5%	0.225	
Distributors Number 65	-11.0%	0.154	
Distributors Number 2	-9.7%	0.182	
Distributors Number 57	-8.3%	0.217	
Distributors Number 39	-7.9%	0.233	
Distributors Number 4	-7.1%	0.254	
Distributors Number 59	-6.9%	0.258	
Distributors Number 29	-6.7%	0.269	
Distributors Number 17	-6.1%	0.294	
Distributors Number 31	-6.1%	0.284	
Distributors Number 58	-5.3%	0.310	
Distributors Number 23	-5.1%	0.317	
Distributors Number 62	-4.8%	0.325	
Distributors Number 28	-4.5%	0.338	
Distributors Number 43	-3.9%	0.357	
Distributors Number 41	-1.8%	0.433	
Distributors Number 67	-1.4%	0.446	
Distributors Number 63	-1.0%	0.465	
Distributors Number 19	-1.0%	0.464	
Distributors Number 22	-0.8%	0.471	

Note: Light shading implies result is within 95% confidence interval. Darker shading implies result is within 90% confidence interval.

Table 13 (continued)

Difference Between Actual and Predicted Cost: Restricted Sample

	Actual minus Predicted Cost	P-Value	
Distributor Number 7	0.2%	0.494	
Distributor Number 50	2.0%	0.427	
Distributor Number 8	2.1%	0.422	
Distributor Number 60	2.6%	0.404	
Distributor Number 56	2.6%	0.403	
Distributor Number 12	2.9%	0.393	
Distributor Number 6	3.2%	0.381	
Distributor Number 30	3.7%	0.363	
Distributor Number 16	6.3%	0.278	
Distributor Number 52	7.0%	0.269	
Distributor Number 20	7.0%	0.254	
Distributor Number 33	7.3%	0.247	
Distributor Number 71	7.6%	0.237	
Distributor Number 64	9.5%	0.186	
Distributor Number 18	9.9%	0.206	
Distributor Number 3	10.7%	0.162	
Distributor Number 13	11.3%	0.145	
Distributor Number 1	11.4%	0.151	
Distributor Number 46	13.4%	0.107	
Distributor Number 40	14.0%	0.098	
Distributor Number 51	14.2%	0.088	
Distributor Number 70	14.5%	0.085	
Distributor Number 53	14.5%	0.093	
Distributor Number 45	16.0%	0.096	90% Confidence
Distributor Number 37	16.6%	0.081	
Distributor Number 55	17.2%	0.054	
Distributor Number 72	17.2%	0.054	
Distributor Number 32	17.3%	0.060	
Distributor Number 42	18.1%	0.046	
Distributor Number 66	18.9%	0.038	
Distributor Number 61	19.8%	0.038	
Distributor Number 36	20.7%	0.028	95% Confidence
Distributor Number 34	20.7%	0.030	
Distributor Number 47	24.9%	0.014	
Distributor Number 48	25.4%	0.009	
Distributor Number 9	35.9%	0.000	
Distributor Number 49	66.6%	0.000	

Note: Light shading implies result is within 95% confidence interval. Darker shading implies result is within 90% confidence interval.

It can be seen that nine distributors are identified as superior cost performers at the 95% level, and five additional distributors are superior cost performers at the 90% confidence level. Forty one distributors are average cost performers. A total of 18 distributors are seen to be inferior cost performers at the 90% level, and nine of these distributors are also inferior cost performers at the 95% level.

5.4 Implications for TFP and Unit Cost Analysis

PEG's econometric results have implications for the analysis that underpins our productivity factor and stretch factor recommendations. Most importantly, the econometric results show that Hydro One and Toronto Hydro should be eliminated from the industry aggregate that is used to estimate industry TFP trends for 4th Gen IR. Including Hydro One and Toronto Hydro will likely produce an estimate of industry TFP growth in which the experience of these distributors has a disproportionate impact on the industry's estimated TFP trend. Such a TFP trend would not be an industry-wide TFP trend that is appropriate to use in the PCI. In the following Chapter, PEG's TFP analysis will therefore exclude Hydro One and Toronto Hydro from our industry sample.

The econometric results also have implications for our unit cost/peer group benchmarking. The econometric cost model identified five statistically significant drivers of electricity distribution cost in Ontario: 1) customer numbers; 2) kWh deliveries; 3) system capacity peak demand; 4) average circuit km of lines; and 5) share of customers added in the last 10 years.. In Chapter Seven, PEG will use these cost driver variables directly to select the peer groups that are used to benchmark unit costs.

6. Estimating Total Factor Productivity Growth

This Chapter presents PEG's estimates of TFP growth for the Ontario electricity distribution industry over the 2002-2011 period. We begin by briefly discussing our index-based methods of estimating TFP. The following two sections discuss the Ontario distributors' output quantity and input quantity indexes, respectively. We then present our index-based estimates of industry output quantity, input quantity, and TFP growth. Finally, we use the cost model developed in Chapter Five to develop a "backcast" of TFP growth over the 2002-2011 period.

6.1 Indexing Methods

PEG calculated TFP indexes in Ontario using the Törnqvist index form. With this index, the annual growth rate of the input quantity index is determined by the formula:

$$\ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(S_{j,t} + S_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \qquad [10]$$

Here in each year t,

$Input\ Quantities_t$ = Input quantity index

$X_{j,t}$ = Input quantity subindex for input category j

$S_{j,t}$ = Share of input category j in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of the quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. For the input quantity indexes, weights are equal to the average shares of each input in the total distribution cost. With the Tornqvist form, the annual growth rate of the output quantity index is determined by the formula:

$$\ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(S_{k,t} + S_{k,t-1} \right) \cdot \ln\left(\frac{Y_{k,t}}{Y_{k,t-1}} \right). \qquad [11]$$

Here in each year t,

$Output\ Quantities_t$ = Output quantity index

$Y_{k,t}$ = Output quantity subindex for output category k

$S_{k,t}$ = Cost elasticity share for output category k.

Again the growth rate of the index is a weighted average of the growth rates of the quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. For the output quantity index, weights are cost elasticity shares *i.e.* the cost elasticity for each quantity subindex divided by the sum of the cost elasticities for all outputs. Cost elasticity shares were estimated using the total cost function and econometric research presented in Section 5.3.3.

The annual growth rate in the TFP index is given by the formula

$$\ln\left(TFP_t / TFP_{t-} \right) = \ln\left(Output\ Quantities_{\ t} / Output\ Quantities_{\ t-1} \right) - \ln\left(Input\ Quantities_{\ t} / Input\ Quantities_{\ t-1} \right). \qquad [12]$$

We estimated TFP trends for the Ontario electricity distribution industry for the 2002-2011 period. The trend in this TFP index was computed using the formula:

$$trend\ TFP_t = \frac{\sum_t {}_{2002}^{2011} \ln\left(TFP_t / TFP_{t-1} \right)}{9} = \frac{\ln\left(TFP_{2011} / TFP_{2002} \right)}{9} \qquad [13]$$

The trend is the average annual growth rate during the years of the sample period. The reported trends in other indexes and subindexes that appear in this report are computed analogously.

6.2 Output Quantity Variables

As discussed in Chapter Five, the output quantity subindexes are customer numbers (other than street lighting, sentinel lighting, and scattered unmetered customers), total kWh deliveries, and system capacity peak demand. Output quantity growth is a weighted average of the growth in these subindexes, with weights equal to each output's cost elasticity share. These cost elasticities are equal to the coefficients on the first order terms of associated outputs in the cost model presented in Table 12. These cost elasticities were 0.444 for customer numbers, 0.050 for kWh, and 0.215 for system capacity. The associated cost elasticity shares, which must necessarily sum to one, are 0.636, 0.071, and 0.303 for customer numbers, kWh, and system capacity peak demand, respectively.

6.3 Input Prices and Quantities

PEG developed measures of input quantities for two input quantity subindexes: capital and OM&A inputs. The growth in the overall input quantity index was a weighted average of the growth in these two input quantity subindexes. The weight that applied to each subindex was its share of electricity distribution cost.

Our measures of capital inputs and capital costs used for TFP research were discussed extensively in Chapter Four. The quantity subindex for OM&A was estimated as the ratio of distribution OM&A expenses to an index of OM&A prices. The OM&A price index was identical to the labor and non-labor OM&A component of the three-factor IPI that was constructed in Chapter Three. We estimated the change in OM&A inputs using the theoretical result that the growth rate in the cost of any class of input *j* is the sum of the growth rates in appropriate input price and quantity indexes for that input class. This implies that

$$growth\ Input\ Quantities_j = growth\ Cost_j - growth\ Input\ Prices_j . \qquad [14]$$

6.4 Index-Based Results

PEG's index-based TFP results for the Ontario electricity distribution industry excluding Toronto Hydro and Hydro One are presented in Tables 14 through 18. Table 14 presents details on the output quantity index. Table 15 presents the calculation of capital costs and capital input quantity. Table 16 shows the computation of OM&A input quantity. Table 17 brings the results of Tables 15 and 16 together and shows the growth in total input quantity. Finally, Table 18 displays the calculation of the TFP indexes. For all tables, the sample period was 2002-2011.

Table 14

Output Quantity Trends for Ontario Power Distributors, 2002-2011

Year	Total Customers		Peak Demand (KW)		Delivery Volume (KWh)		Output Quantity Index	
	Level	Growth	Level	Growth	Level	Growth	Index	Growth
2002	2,525,210		14,953,754		65,523,878,635		100.00	
2003	2,590,817	2.6%	15,124,270	1.1%	67,480,321,397	2.9%	102.18	2.2%
2004	2,647,118	2.1%	15,282,376	1.0%	68,588,997,365	1.6%	104.01	1.8%
2005	2,703,821	2.1%	15,710,004	2.8%	72,989,180,570	6.2%	106.76	2.6%
2006	2,748,114	1.6%	16,004,095	1.9%	71,323,881,577	-2.3%	108.28	1.4%
2007	2,781,589	1.2%	16,030,411	0.2%	75,581,326,413	5.8%	109.61	1.2%
2008	2,823,654	1.5%	16,040,362	0.1%	74,626,460,193	-1.3%	110.56	0.9%
2009	2,864,567	1.4%	16,095,983	0.3%	71,454,871,565	-4.3%	111.34	0.7%
2010	2,885,251	0.7%	16,172,034	0.5%	71,603,206,532	0.2%	112.02	0.6%
2011	2,919,186	1.2%	16,287,524	0.7%	71,223,956,582	-0.5%	113.04	0.9%
Average Annual Growth Rate 2002-2011		**1.61%**		**0.95%**		**0.93%**		**1.36%**

Table 15

Capital Quantity and Cost Trends for Ontario Power Distributors, 2002-2011

	Capital Cost		Capital Price Index		Capital Quantity	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	101.44	1.4%	100.47	0.5%	100.97	1.0%
2004	103.28	1.8%	100.66	0.2%	102.60	1.6%
2005	105.91	2.5%	101.59	0.9%	104.25	1.6%
2006	105.93	0.0%	100.84	-0.7%	105.05	0.8%
2007	111.44	5.1%	103.31	2.4%	107.87	2.6%
2008	115.69	3.7%	105.82	2.4%	109.33	1.3%
2009	117.22	1.3%	107.10	1.2%	109.45	0.1%
2010	121.02	3.2%	109.31	2.0%	110.71	1.2%
2011	123.06	1.7%	109.45	0.1%	112.41	1.5%
Average Annual Growth Rate 2002-2011		**2.31%**		**1.00%**		**1.30%**

Table 16

OM&A Quantity Trends for Ontario Electric Distributors, 2002-2011

	OM&A Cost		OM&A Price Index		OM&A Quantity	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.000		100.000		100.000	
2003	104.040	4.0%	102.142	2.1%	101.858	1.8%
2004	105.063	1.0%	104.672	2.4%	100.373	-1.5%
2005	107.207	2.0%	107.961	3.1%	99.302	-1.1%
2006	110.827	3.3%	109.664	1.6%	101.061	1.8%
2007	119.077	7.2%	113.133	3.1%	105.254	4.1%
2008	123.993	4.0%	115.771	2.3%	107.102	1.7%
2009	126.377	1.9%	117.277	1.3%	107.759	0.6%
2010	127.286	0.7%	120.975	3.1%	105.217	-2.4%
2011	136.679	7.1%	122.969	1.6%	111.150	5.5%
Average Annual Growth Rate 2002-2011		**3.47%**		**2.30%**		**1.17%**

Table 17

Input Quantity Trends for Ontario Electric Distributors, 2002-2011

	Input Quantity Index		Capital Quantity		O&M Quantity	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	101.29	1.3%	100.97	1.0%	101.86	1.8%
2004	101.77	0.5%	102.60	1.6%	100.37	-1.5%
2005	102.39	0.6%	104.25	1.6%	99.30	-1.1%
2006	103.56	1.1%	105.05	0.8%	101.06	1.8%
2007	106.91	3.2%	107.87	2.6%	105.25	4.1%
2008	108.52	1.5%	109.33	1.3%	107.10	1.7%
2009	108.85	0.3%	109.45	0.1%	107.76	0.6%
2010	108.64	-0.2%	110.71	1.2%	105.22	-2.4%
2011	111.99	3.0%	112.41	1.5%	111.15	5.5%
Average Annual Growth Rate 2002-2011		**1.26%**		**1.30%**		**1.17%**

Table 18

TFP Index Calculation for Ontario Power Distributors, 2002-2011

	Output Quantity Index		Input Quantity Index		TFP Index	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	102.18	2.2%	101.29	1.3%	100.88	0.87%
2004	104.01	1.8%	101.77	0.5%	102.20	1.31%
2005	106.76	2.6%	102.39	0.6%	104.26	1.99%
2006	108.28	1.4%	103.56	1.1%	104.56	0.28%
2007	109.61	1.2%	106.91	3.2%	102.52	-1.96%
2008	110.56	0.9%	108.52	1.5%	101.88	-0.63%
2009	111.34	0.7%	108.85	0.3%	102.29	0.40%
2010	112.02	0.6%	108.64	-0.2%	103.11	0.80%
2011	113.04	0.9%	111.99	3.0%	100.94	-2.13%
Average Annual Growth Rate 2002-2011		**1.36%**		**1.26%**		**0.10%**

Turning first to the output quantity results, it can be seen that overall output quantity grew at a modest annual rate of 1.36% per annum. Customers grew by an average of 1.61% annually. In contrast, kWh deliveries and system capacity demand grew more slowly, at 0.93% and 0.95% per annum, respectively. The fact that customers grew more rapidly than either deliveries or peak demand means that volumes per customer and peak demands per customer have declined, on average, over the sample period. Some of these declines clearly result from the severe recession that took place in 2008-09; for example, kWh deliveries fell by 1.3% and 4.3% in these respective years. However, some of the decline in volumes and demand per customer can likely be attributed to energy conservation policies that have been pursued in Ontario over the sample period. Output declines appear to be especially pronounced after the introduction of CDM programs in 2006.

Table 15 shows that capital input quantity grew at an average rate of 1.3% between 2002 and 2011. There is no evidence that capital investment has been accelerating over this period. In fact, capital input grew at an average rate of 1% in the approximately second half of the sample (*i.e.* from 2007 through 2011), compared with average growth of 1.5% per annum in the first half of the period (*i.e.* from 2002 through 2007).

In Table 16, it can be seen that OM&A inputs grew at an average rate of 1.17% over the sample period. This is somewhat slower than the growth in capital input, although OM&A is more variable from year-to-year than capital. For example, OM&A inputs fell by 2.4% in 2010, but then rose by 5.5% in 2011. OM&A input growth has accelerated slightly between the first and second halves of the sample period. OM&A inputs grew at an average annual rate of 1.03% between 2002 and 2007, and at an average rate of 1.36% between 2007 and 2011.

Table 17 shows the change in overall input quantity. Overall inputs grew at an average rate of 1.26% between 2002 and 2011. Input growth has decelerated slightly to 1.16% per annum over the 2007-2011 period compared with average annual growth of 1.34% between 2002 and 2007. The year-to-year volatility in total input quantity mirrors the volatility in OM&A input.

Table 18 shows that Ontario distributors' TFP has been generally flat over the 2002-2011 period, growing at only a 0.1% average rate. TFP trends have also diverged markedly between the first half (0.50% average TFP growth) and second half (-0.39% average TFP growth) of this period. This decline in the industry's TFP trend is due entirely to slowing output quantity growth in more recent years. Output quantity grew at an average rate of 1.83% per annum between 2002 and 2007. For the 2007-2011 period, output quantity grew by only 0.77% per annum. This 1.06% slowdown in output growth was only partially offset by the 0.18% decline in input quantity growth between the first and second halves of the sample period.

As discussed, Tables 14 and 18 exclude Hydro One and Toronto Hydro because we believe that including these companies would lead to a distorted estimate of the industry TFP trend for 4th Gen IR. If these companies had been included, however, average TFP growth for the industry over the 2002-2011 period would have been -1.10%. Because of the importance of using remote "benchmark" capital values in TFP studies, it could also be argued that the distributors for which it was necessary to use a 2002 capital benchmark year, rather than a 1989 benchmark year, should also be excluded from the industry's estimated TFP trend. If these five additional companies (Algoma Power, Canadian Niagara Power, Greater Sudbury Hydro, Innisfil Hydro, and PUC Distribution) are also excluded from the sample, the industry's average TFP growth rate rises slightly from 0.10% to 0.21%.

6.5 Econometric "Backcast" of Industry TFP Growth

A "backcast" is analogous to a forecast except that it generates counterfactual scenarios for the past rather than hypothetical scenarios for the future. In this instance, our objective was to use our cost model to predict what the TFP growth the Ontario electricity distribution industry, excluding Hydro One and Toronto Hydro, would have been over the 2002-2011 period. This provides another piece of evidence on TFP growth for the Ontario industry that may inform the Board's choice for a productivity factor.

PEG generated backcast TFP predictions for the Ontario electricity distribution industry in the following way. First, we used our estimated econometric model of electricity distribution cost for the Ontario electricity distribution industry (excluding Hydro One and Toronto Hydro) to estimate the various drivers of electricity distribution cost. The coefficients for this model are presented in Table 12 in Chapter Five. Next, we inserted the industry's values (excluding Hydro One and Toronto Hydro) for the relevant cost driver variables into the fitted econometric model, for each of the 2002-2011 years. This generated a series of predictions for the industry's predicted costs of electricity distribution services for 2002-2011.

The first step in turning these predictions into a series of TFP growth rates for the 2002-2011 period was to transform the industry's 2002-2011 predicted costs into a cost index with a base year of 2002. We then divided each value of these cost indices by the respective (three input) industry input price index for the year, as presented in Chapter Three of this report. Using the indexing logic presented in Chapter Two, a cost index divided by an input price index is equal to an input quantity index. This process therefore yielded a notional input quantity index for the industry in 2002-2011. We computed the annual changes in this notional input quantity index and subtracted these input quantity growth rates from the respective industry's actual growth in output quantity in that year, as presented in Table 14.

This process yields a TFP growth measure that is identical in every respect but one to what PEG previously developed and presented in Table 18 using indexing methods. The one difference is that we substituted an econometric projection of the industry's electricity distribution costs, in each sample year, for the industry's actual, measured costs in that year. The resulting "backcast" TFP growth estimate therefore represents a benchmark level of TFP growth for the industry.

The TFP backcast calculations are presented in Tables 19 and 20. Table 19 shows the projected change in total cost over the 2002-2011 period, using PEG's econometric model (for the sample excluding Hydro One and Toronto Hydro) and values for average changes in the cost driver variables over this period. It can be seen that PEG's model predicts total cost growth for the Ontario electricity distribution industry of 2.78% per annum over the sample period.

Table 20 combines this change in predicted cost with other, observed information over 2002-2011 to generate a TFP prediction for the Ontario electricity distribution industry. It can be seen that the econometric backcast of TFP growth for Ontario distributors over the 2002-2011 period was 0.07% per annum. This is quite similar to the 0.1% TFP trend that PEG estimated using index-based methods.

Table 19

COST GROWTH BACKCAST FROM ECONOMETRIC RESEARCH

Sample Years	**Industry Average 2002-2011**
Econometric Coefficient Estimates	
Customers [A]	0.44
System Capacity [B]	0.22
Total Deliveries [C]	0.05
Service Territory Size [D]	0.02
Percentage of Lines Underground [E]	0.01
Average Line Length [F]	0.24
Customer Additions in Previous 10 years [G]	0.02
Capital Input Price [H]	0.60
Sum of Output Elasticities [I=A+B+C+F]	0.950
Output Index Weights	
Customers [J=A/I]	46.74%
System Capacity [K=B/I]	22.64%
Total Deliveries [L=C/I]	5.29%
Average Line Length [M=F/I]	25.33%
Subindex Growth	
Customers [N]	1.61%
System Capacity [O]	0.95%
Total Deliveries [P]	0.93%
Service Territory Size [Q]	0.00%
Percentage of Lines Undergrounded [R]	1.93%
Average Line Length [S]	0.00%
Customer Additions in Previous 10 years [T]	0.00%
Capital Input Price [U]	1.01%
Subindex Growth * Econometric Coefficients	
Customers [V=A*N]	0.72%
System Capacity [W=B*O]	0.20%
Total Deliveries [X=C*P]	0.05%
Service Territory Area [Y=D*Q]	0.00%
Percentage of Lines Undergrounded [Z=E*R]	0.03%
Average Line Length [AA=F*S]	0.00%
Customer Additions in Previous 10 years [BB=G*T]	0.00%
Capital Input Price [CC=H*U]	0.61%
Trend [DD]	**1.18%**
Change in Projected Cost [V+W+X+Y+Z+AA+BB+CC+DD]	**2.78%**

Table 20

TFP Backcasts for the Ontario Electricity Distribution Industry, 2002-2011

Change in Predicted Cost [A]	2.78%
Change in Input Price Index [B]	1.49%
Change in Predicted Input Quantity Index [C] = [A] - [B]	1.29%
Change in Output Quantity Index [D]	1.36%
Change in Predicted TFP [E] = [D] - [C]	0.07%

6.6 Recommended Productivity Factor

Given that the index-based and econometric-based TFP estimates are both close to 0.1%, PEG recommends that the productivity factor for 4th Gen IR be set equal to0.1%. In addition to being consistent with the two empirical estimates, PEG believes a productivity factor of 0.1% is reasonable for several reasons. First, PEG's analysis shows that the industry's slower TFP growth stems primarily from a slowdown in output growth rather than an acceleration in distributors' spending. The slower output growth has been particularly pronounced since the introduction of CDM programs in 2006. PEG believes the continued emphasis on CDM policies in Ontario will continue to limit the potential for output quantity and TFP gains for the industry.

Second, we find the available evidence does not support a negative productivity factor. While TFP growth for the Ontario electricity distribution industry has been negative since 2007, much of this decline is attributable to the severe recession in 2008-09. This was a one-time event and is not anticipated to recur during the term of 4th Gen IR. PEG also concludes that the experience since 2007 is not long enough to be the basis for a productivity factor; TFP trends should be calculated over at least a nine-year period. We also do not favor treating sub-periods within a sample period differently (*e.g.* by placing more weight on one sub-period rather than another), since such an approach can give rise to "cherry picking" and artificial manipulation of the available data. The nine-year industry TFP trend is more consistent with a productivity factor of 0.1% than a substantially negative productivity factor.

Third, an IPI inflation factor combined with a productivity factor of 0.1% would mean electricity distributor prices grow at nearly the same rate as the industry's input price inflation, if all else is held equal. PEG's research shows that input price inflation for the electricity distribution industry has been slightly below GDP-IPI inflation. It is not unusual for price inflation in a particular sector (such as electricity distribution) to be similar to average price inflation in the economy. If the productivity factor was the only component of the X factor, a productivity factor equal to 0.1% would likely mean that electricity distribution prices grow at rates similar to the prices of other goods and services in the economy. Price inflation in a particular sector that is similar to aggregate, economy-wide inflation is not necessarily a sign of sub-par productivity performance in that sector.

However, the productivity factor is *not* the only component of the X factor, nor is it the component of the X factor that is designed to ensure that consumers benefit from incentive rate setting. Stretch factors are intended to reflect distributors' incremental efficiency gains under incentive ratemaking. Adding a stretch factor to the productivity factor would allow customers to share in these anticipated efficiency gains. A productivity factor of 0.1% is therefore not incompatible with the Board's incentive rate-setting objectives of encouraging cost efficiency and ensuring that customers share in these efficiency gains.[32]

[32] Although PEG's recommended productivity factor is based on an analysis of the evidence and circumstances in the Ontario electricity distribution industry, it may also be instructive to consider recent precedents on X factors and productivity factors that are based explicitly on productivity evidence. PEG is aware of eight such plans (or in some cases, sets of plans) that are currently in effect outside of Ontario: for Central Maine Power (in ME, USA); Central Vermont Public Service and Green Mountain Power (both in VT, USA); ENMAX in Alberta; the other electricity distributors in Alberta; the gas distributors in Alberta; the electricity distributors in New Zealand; and the gas distributors in New Zealand. In the six electricity distribution plans, the approved X factors, industry produtivity factors (PF) and stretch factors (SFs) (where there were explicit findings on these distinct elements) are:

Company	PF	SF	X Factor
Central Maine Power	NA	NA	1.0%
Central Vermont Public Service	NA	NA	1.0%
Green Mountain Power	NA	NA	1.0%
ENMAX	0.8%	0.4%	1.2%
Other Alberta LDCs	0.96%	0.2%	1.16%
New Zealand LDCs	1.10%	NA	0

For the two gas distribution plans, the analogous factors are:

Company	PF	SF	X Factor
Other Alberta LDCs	0.96%	0.2%	1.16%
New Zealand LDCs	NA	NA	0

It should be noted that the same empirical evidence was used to establish all elements of the X factors for gas and electricity distributors in Alberta, but separate TFP studies were performed for gas and electricity distributors in New Zealand. The reason there was a positive productivity factor for the New Zealand electricity distribution industry but a zero X factor is the formula for the X factor in New Zealand includes the difference between industry and economy-wide TFP growth, not just industry TFP growth.

It can be seen that the average value of the X factor in the electricity distribution plans is about 0.90%, and approved productivity factors (where there have been explicit findings on industry TFP growth) have been between 0.8% and 1.16%. Although PEG is not recommending a zero X factor, a zero X factor would not be unprecedented among current plans. However, no index-based plans that are currently in effect have approved a negative productivity factor.

7. Unit Cost Benchmarking and Stretch Factors

7.1 Methodological Approach

PEG was asked to benchmark distributors' total unit costs for 4th Gen IR. This task builds on PEG's OM&A unit cost benchmarking work in 2007-08, which was applied in 3rd Gen IR. Our unit cost metric is calculated by dividing each distributor's total distribution cost (rather than OM&A cost, as in 3rd Gen IR) by a comprehensive index of its output. As discussed in Chapter Four, the relevant unit cost measure for benchmarking excludes the capital and O&M costs of HV transformation but includes CIAC as well as LV charges paid by embedded distributors to host distributors.

Each distributor's unit cost was benchmarked relative to the unit cost of a designated "peer group" of Ontario distributors. These peer groups were determined directly on the basis of PEG's cost function research discussed in Chapter Five. As with the econometric benchmarking, unit cost comparisons were undertaken for the last three years, 2009-2011, since these years generally coincided with distributors' performance under the current regulatory regime. This was done by averaging each distributor's unit cost over these years, and using these average unit cost measures as the basis for benchmark comparisons.

This Chapter discusses PEG's unit cost benchmarking. We begin by describing how the peer groups were determined. Next, we present the unit cost calculations for each distributor and the unit cost comparisons. Finally, using both the econometric and unit cost benchmarking evidence, PEG makes recommendations for efficiency cohorts and stretch factors for the Ontario electricity distribution industry.

7.2 Cost Drivers and Determining Peer Groups

In addition to capital input prices and the trend variable, Table 12 identified five different drivers of distribution cost in Ontario: 1) customer numbers; 2) system peak capacity; 3) kWh deliveries; 4) circuit km of distribution line; and 5) share of customers added in last 10 years. PEG used direct information on these cost drivers, as well as total service territory and share of lines that are underground (which were previously found to be significant cost drivers)to determine each distributor's "peers." Using similarities in cost drivers is clearly sensible for determining peer groups, because "apples to apples" cost comparisons are more likely when a distributor is compared to other distributors facing similar business conditions. PEG has endeavored to make the process of selecting peer groups based on similarities in cost drivers as transparent as possible.

We began by noting that four of the cost driver variables were related to distribution output: customer numbers; system peak demand; kWh deliveries; and circuit km of line. For each distributor, these four output variables can be aggregated into a comprehensive output quantity index using the cost elasticity shares presented in Table 12. This approach weights each of the four outputs by its respective, estimated impact on distribution cost. Each distributor's weighted outputs are then summed and expressed relative to the average aggregate output for the Ontario electricity distribution industry. This is known as a bilateral output index. Distributors with above average output will have a bilateral output index value that is above one, while distributors with below average output will have a bilateral output index that is less than one. The calculated, bilateral index values for every Ontario distributor are presented in Table 21.

The three remaining variables are total service territory area, percent of lines that are underground, and customer growth. For the purpose of identifying distributors with similar levels of business conditions, PEG began by examining a two dimensional graph where the bilateral output index for each distributor (vertical axis) was plotted against its service territory (horizontal axis). We then divided this chart up into four different quadrants, depending on whether the bilateral output index was above or below its mean value and the service area was above or below its median level.[33]

This graph is presented in Chart One for all distributors except Algoma Power, Hydro One and Toronto Hydro. These distributors are not included because their service territories and output are so large compared with other distributors that including them would compress every other sample observation into a very small space, making it impossible to distinguish different output-service territory combinations within the Ontario electricity distribution sector. The horizontal line in Chart One reflects the mean value for output; all distributors

[33] We used the "median" rather than "mean" values to distinguish firms based on service territory because the territories for two distributors – Algoma Power and Hydro One Networks – were so much larger than every other Ontario distributor that they produce a distorted measure of "average" service territory in the Province. In fact, when the sample mean service territory is calculated, every firm but Hydro One and Algoma Power would have territories below the mean.

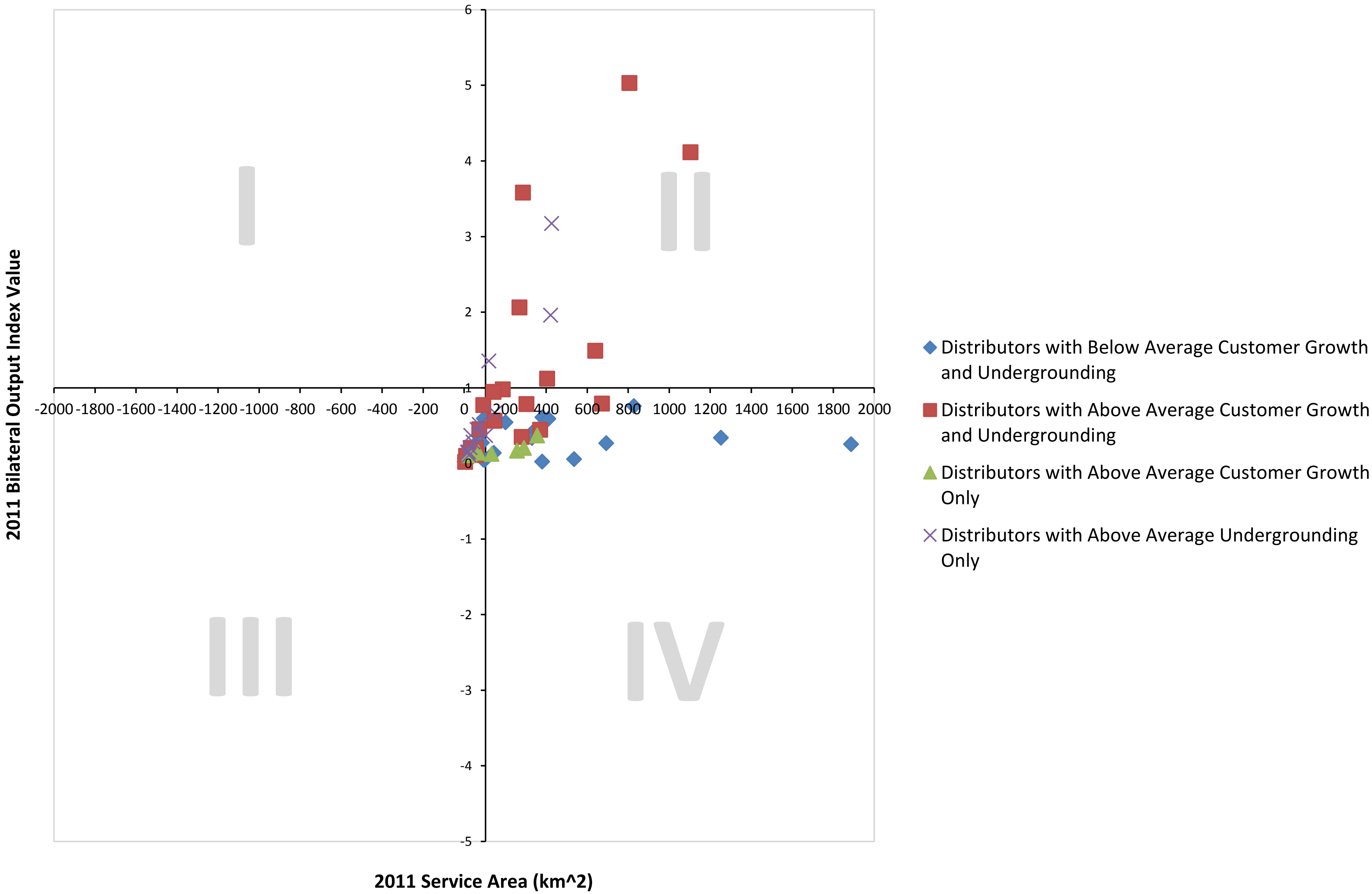
Table 21

2009-2011 Bilateral Output Index

Company Name	2009 Bilateral Output Index	2010 Bilateral Output Index	2011 Bilateral Output Index	2009-2011 Bilateral Output Index Average
ALGOMA POWER INC.	0.231	0.229	0.228	0.229
ATIKOKAN HYDRO INC.	0.027	0.026	0.026	0.026
BLUEWATER POWER DISTRIBUTION CORPORATION	0.479	0.478	0.480	0.479
BRANT COUNTY POWER INC.	0.151	0.151	0.152	0.151
BRANTFORD POWER INC.	0.440	0.430	0.458	0.443
BURLINGTON HYDRO INC.	0.900	0.902	0.897	0.900
CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.	0.685	0.687	0.691	0.688
CANADIAN NIAGARA POWER INC.	0.389	0.388	0.388	0.388
CENTRE WELLINGTON HYDRO LTD.	0.087	0.087	0.089	0.088
CHAPLEAU PUBLIC UTILITIES CORPORATION	0.018	0.017	0.017	0.018
COLLUS POWER CORPORATION	0.189	0.193	0.192	0.192
COOPERATIVE HYDRO EMBRUN INC.	0.020	0.020	0.020	0.020
E.L.K. ENERGY INC.	0.128	0.128	0.130	0.129
ENERSOURCE HYDRO MISSISSAUGA INC.	3.006	2.991	2.998	2.998
ENTEGRUS POWERLINES	0.541	0.548	0.540	0.543
ENWIN UTILITIES LTD.	1.065	1.074	1.070	1.070
ERIE THAMES POWERLINES CORPORATION	0.225	0.225	0.224	0.225
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	0.049	0.048	0.048	0.049
ESSEX POWERLINES CORPORATION	0.333	0.336	0.331	0.333
FESTIVAL HYDRO INC.	0.233	0.233	0.234	0.234
FORT FRANCES POWER CORPORATION	0.048	0.048	0.046	0.048
GREATER SUDBURY HYDRO INC.	0.566	0.563	0.564	0.565
GRIMSBY POWER INCORPORATED	0.121	0.134	0.134	0.130
GUELPH HYDRO ELECTRIC SYSTEMS INC.	0.660	0.666	0.678	0.668
HALDIMAND COUNTY HYDRO INC.	0.376	0.374	0.379	0.376
HALTON HILLS HYDRO INC.	0.369	0.367	0.373	0.369
HEARST POWER DISTRIBUTION COMPANY LIMITED	0.041	0.041	0.041	0.041
HORIZON UTILITIES CORPORATION	2.771	2.752	2.743	2.755
HYDRO 2000 INC.	0.015	0.015	0.015	0.015
HYDRO HAWKESBURY INC.	0.067	0.066	0.066	0.066
HYDRO ONE BRAMPTON NETWORKS INC.	1.755	1.780	1.821	1.785
HYDRO ONE NETWORKS INC.	20.781	20.742	20.677	20.733
HYDRO OTTAWA LIMITED	3.666	3.672	3.721	3.686
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	0.223	0.224	0.224	0.223
KENORA HYDRO ELECTRIC CORPORATION LTD.	0.064	0.064	0.064	0.064
KINGSTON HYDRO CORPORATION	0.314	0.312	0.311	0.312
KITCHENER-WILMOT HYDRO INC.	1.068	1.068	1.073	1.070
LAKEFRONT UTILITIES INC.	0.108	0.107	0.108	0.108
LAKELAND POWER DISTRIBUTION LTD.	0.139	0.139	0.137	0.138
LONDON HYDRO INC.	1.787	1.795	1.803	1.795
MIDLAND POWER UTILITY CORPORATION	0.087	0.092	0.107	0.095
MILTON HYDRO DISTRIBUTION INC.	0.386	0.412	0.431	0.410
NEWMARKET-TAY POWER DISTRIBUTION LTD.	0.461	0.461	0.433	0.452
NIAGARA PENINSULA ENERGY INC.	0.760	0.758	0.759	0.759
NIAGARA-ON-THE-LAKE HYDRO INC.	0.123	0.123	0.125	0.124
NORFOLK POWER DISTRIBUTION INC.	0.279	0.278	0.278	0.278
NORTH BAY HYDRO DISTRIBUTION LIMITED	0.320	0.318	0.318	0.319
NORTHERN ONTARIO WIRES INC.	0.097	0.096	0.096	0.097
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	0.844	0.841	0.853	0.846
ORANGEVILLE HYDRO LIMITED	0.129	0.130	0.130	0.130
ORILLIA POWER DISTRIBUTION CORPORATION	0.175	0.175	0.175	0.175
OSHAWA PUC NETWORKS INC.	0.622	0.620	0.626	0.623
OTTAWA RIVER POWER CORPORATION	0.113	0.113	0.113	0.113
PARRY SOUND POWER CORPORATION	0.052	0.052	0.052	0.052
PETERBOROUGH DISTRIBUTION INCORPORATED	0.405	0.403	0.404	0.404
POWERSTREAM INC.	4.472	4.433	4.476	4.460
PUC DISTRIBUTION INC.	0.417	0.414	0.414	0.415
RENFREW HYDRO INC.	0.047	0.046	0.046	0.046
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	0.073	0.073	0.073	0.073
SIOUX LOOKOUT HYDRO INC.	0.055	0.054	0.058	0.056
ST. THOMAS ENERGY INC.	0.185	0.185	0.185	0.185
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	0.615	0.607	0.608	0.610
TILLSONBURG HYDRO INC.	0.096	0.095	0.095	0.096
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	8.831	8.886	8.929	8.882
VERIDIAN CONNECTIONS INC.	1.363	1.377	1.406	1.382
WASAGA DISTRIBUTION INC.	0.117	0.120	0.123	0.120
WATERLOO NORTH HYDRO INC.	0.723	0.736	0.745	0.735
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	0.269	0.265	0.242	0.259
WELLINGTON NORTH POWER INC.	0.045	0.046	0.045	0.045
WEST COAST HURON ENERGY INC.	0.051	0.050	0.051	0.050
WESTARIO POWER INC.	0.264	0.275	0.274	0.271
WHITBY HYDRO ELECTRIC CORPORATION	0.525	0.525	0.539	0.530
WOODSTOCK HYDRO SERVICES INC.	0.181	0.183	0.183	0.182

Chart 1

Cost Drivers and Ontario Peer Groups



plotted above this line have overall output levels that exceed the industry average, and all distributors plotted below this line have output levels below the industry average. The vertical line in Chart One shows the median level of service territory in the Province. All distributors to the right of this vertical line have above median service territories, while all distributors plotted to the left of the vertical line have below median service territories.

The vertical and horizontal lines on Chart One divide the Ontario electricity distribution industry into four quadrants. These quadrants are distinguished by relative differences in overall output and service territories among distributors in the Province. Quadrant I contains distributors with above average output but below median service territories; quadrant II has distributors with above average output and above-median service territories; quadrant III has distributors with below average output and below median service territories; and quadrant IV has distributors with below average output but above median service territories. It can be seen that quadrant I is empty, which means that no distributors in Ontario have higher than average output levels but a service territory of below median size. We can therefore confine our attention to quadrants II, III, and IV.

The two remaining variables that are not reflected on the vertical or horizontal axes of Chart One are customer growth and percent of lines that are underground. Within each quadrant, however, distributors can be categorized according to their similarity on these cost drivers by considering whether each distributor registers above or below average values for the variable in question. There are four possibilities for how distributors compare on these two variables within each quadrant:

1. A distributor has above average customer growth, but below average undergrounding
2. A distributor has above average undergrounding, but below average customer growth
3. A distributor has above average customer growth and above average undergrounding
4. A distributor has *below* average customer growth and *below* average undergrounding

These four possibilities are depicted on Chart One using four different symbols. Distributors with above average undergrounding only are graphed using an “X” symbol. Distributors with above average customer growth only are graphed with a triangle. Distributors with above average customer growth and undergrounding are graphed with a square. Distributors with *below* average customer growth and undergrounding are graphed with a diamond.

In summary, Chart One presents a visual depiction of Ontario electricity distributors based on similarities in values of the seven statistically significant drivers of electricity distribution cost. Distributors are placed into one of the three quadrants based on similarities in overall output (an aggregation of four output variables) and service territory. Within each quadrant, firms are further categorized based on similarities in their customer growth and undergrounding.

Because there are four different categories of firms within each of the three quadrants, a total of 12 potential peer groups can be identified based on similarities in the seven cost drivers. These potential peer groups are:

1. Above average output, above median area, above average undergrounding
2. Above average output, above median area, above average customer growth
3. Above average output, above median area, above average undergrounding and customer growth
4. Above average output, above median area, *below* average undergrounding and customer growth
5. Below average output, above median area, above average undergrounding
6. Below average output, above median area, above average customer growth
7. Below average output, above median area, above average undergrounding and customer growth
8. Below average output, above median area, *below* average undergrounding and customer growth
9. Below average output, below median area, above average undergrounding
10. Below average output, below median area, above average customer growth
11. Below average output, below median area, above average undergrounding and customer growth

12. Below average output, below median area, *below* average undergrounding and customer growth

These potential peer groups, and the distributors in each of them, are presented in Table 22. It can be seen that one of these potential peer groups – number 2 (above average output, above median area, above average customer growth only) – is empty. Two other potential peer groups – number 4 (above average output, above median area, below average undergrounding and customer growth) and number 5 (below average output, above median area, above average undergrounding only) – have only one distributor in the group. Because it is impossible to have "peer" comparisons with only a single firm in a group, the distributors in these two other groups need to be moved to one of the other potential peer groups if they are to be part of the peer group benchmarking exercise. Eliminating the one empty peer group and re-assigning these two distributors (Hydro One and Oshawa PUC) would therefore reduce the number of potential peer groups from 12 to nine.

Three of the remaining potential peer groups have four or fewer distributors in the group. These are group number 1 (above average output, above median area, above average undergrounding only), group number 6 (below average output, above median area, above average customer growth only), and group number 10 (below average output, below median area, above average customer growth only). One of the criticisms of the benchmarking study used in 3rd Gen IR is that some peer group benchmarking assessments relied on too small a number of peers. It was argued that, if there are too few peers in a group, comparing unit costs to the peer group's average unit cost is more likely to be distorted by outliers within the peer group. This critique has merit. Accordingly, PEG concluded that groups 1, 6 and 10 have too few firms to be stand-alone peer groups, and distributors in these three groups should be combined into other peer groups. This eliminates groups 1, 6, and 10 from consideration and thereby reduces the number of peer groups from nine to six.

PEG's six recommended peer groups are presented in Table 23. It can be seen that all of the distributors with above average output have now been grouped together into Peer Group A (Large Output, Extensive Area). Groups 6 and 7 have been consolidated into Peer Group B (Small Output, Extensive Area, Above Average Customer Growth). Group 8 is Peer Group C (Small Output, Extensive Area, Below Average Undergrounding and Growth). Groups 10 and 11 have been combined into Peer Group D (Small Output, Small Area, Above

Table 22

Potential Ontario Distibutor Peer Groups

Quadrant	Group 1: Above average output, above median area, above average undergrounding	Group 2: Above average output, above median area, above average customer growth	Group 3: Above average output, above median area, above average undergrounding and customer growth	Group 4: Above average output, above median area, below average undergrounding and customer growth
II	ENWIN UTILITIES LTD.	None	KITCHENER-WILMOT HYDRO INC.	HYDRO ONE NETWORKS INC.
	LONDON HYDRO INC.		VERIDIAN CONNECTIONS INC.	
	HORIZON UTILITIES CORPORATION		HYDRO OTTAWA LIMITED	
	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED		ENERSOURCE HYDRO MISSISSAUGA INC.	
			POWERSTREAM INC.	
			HYDRO ONE BRAMPTON NETWORKS INC.	

Quadrant	Group 5: Below average output, above median area, above average undergrounding	Group 6: Below average output, above median area, above average customer growth	Group 7: Below average output, above median area, above average undergrounding and customer growth	Group 8: Below average output, above median area, below average undergrounding and customer growth
III	OSHAWA PUC NETWORKS INC.	CANADIAN NIAGARA POWER INC.	WATERLOO NORTH HYDRO INC.	ATIKOKAN HYDRO INC.
		BRANT COUNTY POWER INC.	CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.	ALGOMA POWER INC.
		INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMI	HALTON HILLS HYDRO INC.	SIOUX LOOKOUT HYDRO INC.
		NIAGARA-ON-THE-LAKE HYDRO INC.	MILTON HYDRO DISTRIBUTION INC.	HALDIMAND COUNTY HYDRO INC.
			BURLINGTON HYDRO INC.	NORFOLK POWER DISTRIBUTION INC.
			WHITBY HYDRO ELECTRIC CORPORATION	PUC DISTRIBUTION INC.
			OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	NORTH BAY HYDRO DISTRIBUTION LIMITED
				THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
				ERIE THAMES POWERLINES CORPORATION
				LAKELAND POWER DISTRIBUTION LTD.
				GREATER SUDBURY HYDRO INC.
				NIAGARA PENINSULA ENERGY INC.
				BLUEWATER POWER DISTRIBUTION CORPORATION

Quadrant	Group 9: Below average output, below median area, above average undergrounding	Group 10: Below average output, below median area, above average customer growth	Group 11: Below average output, below median area, above average undergrounding and customer growth	Group 12: Below average output, below median area, below average undergrounding and customer growth
IV	PETERBOROUGH DISTRIBUTION INCORPORATED	LAKEFRONT UTILITIES INC.	ST. THOMAS ENERGY INC.	NORTHERN ONTARIO WIRES INC.
	FESTIVAL HYDRO INC.	MIDLAND POWER UTILITY CORPORATION	COLLUS POWER CORPORATION	RENFREW HYDRO INC.
	TILLSONBURG HYDRO INC.	GRIMSBY POWER INCORPORATED	CENTRE WELLINGTON HYDRO LTD.	CHAPLEAU PUBLIC UTILITIES CORPORATION
	KINGSTON HYDRO CORPORATION		COOPERATIVE HYDRO EMBRUN INC.	ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION
	WOODSTOCK HYDRO SERVICES INC.		WASAGA DISTRIBUTION INC.	PARRY SOUND POWER CORPORATION
	BRANTFORD POWER INC.		NEWMARKET-TAY POWER DISTRIBUTION LTD.	KENORA HYDRO ELECTRIC CORPORATION LTD.
	E.L.K. ENERGY INC.		GUELPH HYDRO ELECTRIC SYSTEMS INC.	RIDEAU ST. LAWRENCE DISTRIBUTION INC.
	ORANGEVILLE HYDRO LIMITED			FORT FRANCES POWER CORPORATION
	ESSEX POWERLINES CORPORATION			OTTAWA RIVER POWER CORPORATION
				WELLINGTON NORTH POWER INC.
				HYDRO 2000 INC.
				HYDRO HAWKESBURY INC.
				HEARST POWER DISTRIBUTION COMPANY LIMITED
				ORILLIA POWER DISTRIBUTION CORPORATION
				WEST COAST HURON ENERGY INC.
				WESTARIO POWER INC.
				ENTEGRUS POWERLINES
				WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Table 23

Peer Groups for Ontario Distributors

Group A- Large Output, Extensive Area	Group B- Small Output, Extensive Area, Above Average Customer Growth	Group C- Small Output, Extensive Area, Below Average Undergrounding and Growth
ENERSOURCE HYDRO MISSISSAUGA INC.	BRANT COUNTY POWER INC.	ALGOMA POWER INC.
ENWIN UTILITIES LTD.	BURLINGTON HYDRO INC.	ATIKOKAN HYDRO INC.
HORIZON UTILITIES CORPORATION	CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.	BLUEWATER POWER DISTRIBUTION CORPORATION
HYDRO ONE BRAMPTON NETWORKS INC.	CANADIAN NIAGARA POWER INC.	ERIE THAMES POWERLINES CORPORATION
HYDRO ONE NETWORKS INC.	HALTON HILLS HYDRO INC.	GREATER SUDBURY HYDRO INC.
HYDRO OTTAWA LIMITED	INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	HALDIMAND COUNTY HYDRO INC.
KITCHENER-WILMOT HYDRO INC.	MILTON HYDRO DISTRIBUTION INC.	LAKELAND POWER DISTRIBUTION LTD.
LONDON HYDRO INC.	NIAGARA-ON-THE-LAKE HYDRO INC.	NIAGARA PENINSULA ENERGY INC.
POWERSTREAM INC.	OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	NORFOLK POWER DISTRIBUTION INC.
TORONTO HYDRO-ELECTRIC SYSTEM	WATERLOO NORTH HYDRO INC.	NORTH BAY HYDRO DISTRIBUTION LIMITED
VERIDIAN CONNECTIONS INC.	WHITBY HYDRO ELECTRIC CORPORATION	PUC DISTRIBUTION INC.
		SIOUX LOOKOUT HYDRO INC.
		THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

Group D- Small Output, Small Area, Above Average Customer Growth	Group E- Small Output, Small Area, Below Average Customer Growth	Group F- Small Output, Above Average Undergrounding, Below Average Customer Growth
CENTRE WELLINGTON HYDRO LTD.	CHAPLEAU PUBLIC UTILITIES CORPORATION	BRANTFORD POWER INC.
COLLUS POWER CORPORATION	ENTEGRUS POWERLINES	E.L.K. ENERGY INC.
COOPERATIVE HYDRO EMBRUN INC.	ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	ESSEX POWERLINES CORPORATION
GRIMSBY POWER INCORPORATED	FORT FRANCES POWER CORPORATION	FESTIVAL HYDRO INC.
GUELPH HYDRO ELECTRIC SYSTEMS INC.	HEARST POWER DISTRIBUTION COMPANY LIMITED	KINGSTON HYDRO CORPORATION
LAKEFRONT UTILITIES INC.	HYDRO 2000 INC.	ORANGEVILLE HYDRO LIMITED
MIDLAND POWER UTILITY CORPORATION	HYDRO HAWKESBURY INC.	OSHAWA PUC NETWORKS INC.
NEWMARKET-TAY POWER DISTRIBUTION	KENORA HYDRO ELECTRIC CORPORATION LTD.	PETERBOROUGH DISTRIBUTION INCORPORATED
ST. THOMAS ENERGY INC.	NORTHERN ONTARIO WIRES INC.	TILLSONBURG HYDRO INC.
WASAGA DISTRIBUTION INC.	ORILLIA POWER DISTRIBUTION CORPORATION	WOODSTOCK HYDRO SERVICES INC.
	OTTAWA RIVER POWER CORPORATION	
	PARRY SOUND POWER CORPORATION	
	RENFREW HYDRO INC.	
	RIDEAU ST. LAWRENCE DISTRIBUTION INC.	
	WELLAND HYDRO-ELECTRIC SYSTEM CORP.	
	WELLINGTON NORTH POWER INC.	
	WEST COAST HURON ENERGY INC.	
	WESTARIO POWER INC.	

Average Customer Growth). Group 12 becomes Peer Group E (Small Output, Small Area, Below Average Customer Growth). Finally, groups 5 and 9 are consolidated into Peer Group F (Small Output, Above Average Undergrounding, Below Average Customer Growth).

PEG believes that these are reasonable peer groups for the purposes of undertaking unit cost comparisons. The composition of the peer groups depends primarily on similarity in the cost drivers identified in the econometric analysis. Each peer group contains at least 10 distributors, which addresses the concern that some peer groups used in 3rd Gen IR were too small and apt to be distorted by outliers. PEG also endeavored to make the process for winnowing the groups to the six that are recommended as transparent as possible.

7.3 Unit Cost Comparisons

The unit cost benchmarking evaluations for each of the six peer groups are presented in Table 24. This table has two columns. The first is the 2009-2011 unit cost average. This column presents the average unit cost for each distributor in the peer group. At the bottom of this column, in bold, is the average unit cost measure for the entire peer group. The second column is the "Benchmark Unit Cost Comparison." The values in this column are equal to each distributor's unit cost minus the group average unit cost (*i.e.* "the benchmark" unit cost), with this difference then divided by the group average unit cost.

Table 25 arrays the benchmark unit cost comparisons from lowest (*i.e.* distributors registering the largest *negative* difference between their actual unit costs and the peer group benchmark unit costs) to highest (distributors with the largest *positive* difference between their actual unit costs and the peer group benchmark unit costs). Distributors with more negative differences between their actual and benchmark unit costs would be viewed as relatively more efficient, all else equal.

It can be seen that only one top performer on the unit cost benchmarking analysis has unit costs that are more than 30% below those of their designated peers, on average. In contrast, there are four distributors whose unit costs are 30% or more above the average unit costs of their peers. Two of these distributors have unit costs that are 50% or more above their peer group average.

Table 24

Unit Costs By Peer Group

Group A- Large Output, Extensive Area

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
ENERSOURCE HYDRO MISSISSAUGA INC.	44,171,342.06	-3.5%
ENWIN UTILITIES LTD.	52,733,099.86	15.2%
HORIZON UTILITIES CORPORATION	37,404,874.85	-18.3%
HYDRO ONE BRAMPTON NETWORKS INC.	42,873,918.64	-6.3%
HYDRO ONE NETWORKS INC.	58,869,958.84	28.6%
HYDRO OTTAWA LIMITED	42,402,993.49	-7.3%
KITCHENER-WILMOT HYDRO INC.	34,862,300.65	-23.8%
LONDON HYDRO INC.	35,693,442.92	-22.0%
POWERSTREAM INC.	43,521,777.95	-4.9%
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	70,787,098.03	54.7%
VERIDIAN CONNECTIONS INC.	40,069,784.87	-12.4%
Group Average	**45,762,781.10**	

Group B- Small Output, Extensive Area, High Growth

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
BRANT COUNTY POWER INC.	50,356,575.90	13.3%
BURLINGTON HYDRO INC.	39,463,700.77	-11.2%
CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.	39,158,703.46	-11.9%
CANADIAN NIAGARA POWER INC.	50,197,876.81	12.9%
HALTON HILLS HYDRO INC.	36,020,522.44	-19.0%
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	42,966,128.84	-3.3%
MILTON HYDRO DISTRIBUTION INC.	47,353,397.43	6.5%
NIAGARA-ON-THE-LAKE HYDRO INC.	45,087,493.43	1.4%
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	48,452,933.21	9.0%
WATERLOO NORTH HYDRO INC.	43,463,668.88	-2.2%
WHITBY HYDRO ELECTRIC CORPORATION	46,426,167.71	4.4%
Group Average	**44,449,742.63**	

Group C- Small Output, Extensive Area, Below Average Undergrounding and Growth

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
ALGOMA POWER INC.	86,301,012.53	85.4%
ATIKOKAN HYDRO INC.	52,273,319.23	12.3%
BLUEWATER POWER DISTRIBUTION CORPORATION	41,588,544.77	-10.6%
ERIE THAMES POWERLINES CORPORATION	48,903,704.04	5.1%
GREATER SUDBURY HYDRO INC.	45,892,569.66	-1.4%
HALDIMAND COUNTY HYDRO INC.	35,008,338.00	-24.8%
LAKELAND POWER DISTRIBUTION LTD.	44,442,370.17	-4.5%
NIAGARA PENINSULA ENERGY INC.	44,553,279.32	-4.3%
NORFOLK POWER DISTRIBUTION INC.	44,304,189.59	-4.8%
NORTH BAY HYDRO DISTRIBUTION LIMITED	43,240,820.23	-7.1%
PUC DISTRIBUTION INC.	36,987,434.72	-20.5%
SIOUX LOOKOUT HYDRO INC.	37,960,463.65	-18.4%
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION	43,588,404.83	-6.3%
Group Average	**46,541,880.83**	

Table 24 (cont)

Unit Costs By Peer Group

Group D- Small Output, Small Area, High Growth

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
CENTRE WELLINGTON HYDRO LTD.	38,809,015.11	-7.0%
COLLUS POWER CORPORATION	41,008,125.56	-1.8%
COOPERATIVE HYDRO EMBRUN INC.	51,051,765.03	22.3%
GRIMSBY POWER INCORPORATED	37,102,188.55	-11.1%
GUELPH HYDRO ELECTRIC SYSTEMS INC.	48,983,647.69	17.3%
LAKEFRONT UTILITIES INC.	36,944,557.62	-11.5%
MIDLAND POWER UTILITY CORPORATION	44,602,078.09	6.8%
NEWMARKET-TAY POWER DISTRIBUTION LTD.	41,074,924.28	-1.6%
ST. THOMAS ENERGY INC.	40,913,971.74	-2.0%
WASAGA DISTRIBUTION INC.	36,982,324.00	-11.4%
Group Average	**41,747,259.77**	

Group E- Small Output, Small Area, Slow Growth

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
CHAPLEAU PUBLIC UTILITIES CORPORATION	42,055,472.80	4.0%
ENTEGRUS POWERLINES	41,094,587.59	1.6%
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	38,852,915.81	-3.9%
FORT FRANCES POWER CORPORATION	48,152,849.74	19.1%
HEARST POWER DISTRIBUTION COMPANY LIMITED	28,679,825.65	-29.1%
HYDRO 2000 INC.	34,730,444.52	-14.1%
HYDRO HAWKESBURY INC.	20,289,273.44	-49.8%
KENORA HYDRO ELECTRIC CORPORATION LTD.	44,189,418.71	9.3%
NORTHERN ONTARIO WIRES INC.	33,646,419.79	-16.8%
ORILLIA POWER DISTRIBUTION CORPORATION	41,706,341.96	3.1%
OTTAWA RIVER POWER CORPORATION	42,939,091.97	6.2%
PARRY SOUND POWER CORPORATION	45,240,103.16	11.9%
RENFREW HYDRO INC.	50,178,128.48	24.1%
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	37,285,466.09	-7.8%
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	36,266,449.98	-10.3%
WELLINGTON NORTH POWER INC.	54,780,232.87	35.4%
WEST COAST HURON ENERGY INC.	44,809,620.80	10.8%
WESTARIO POWER INC.	43,123,590.05	6.6%
Group Average	**40,445,568.52**	

Group F- Small Output, Above Average Undergrounding, Below Average Growth

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
BRANTFORD POWER INC.	42,708,771.79	-4.1%
E.L.K. ENERGY INC.	37,326,747.36	-16.2%
ESSEX POWERLINES CORPORATION	40,981,405.89	-8.0%
FESTIVAL HYDRO INC.	49,276,104.35	10.6%
KINGSTON HYDRO CORPORATION	40,315,352.43	-9.5%
ORANGEVILLE HYDRO LIMITED	45,189,614.78	1.4%
OSHAWA PUC NETWORKS INC.	39,709,013.51	-10.9%
PETERBOROUGH DISTRIBUTION INCORPORATED	44,808,269.63	0.6%
TILLSONBURG HYDRO INC.	44,484,426.14	-0.2%
WOODSTOCK HYDRO SERVICES INC.	60,745,230.93	36.3%
Group Average	**44,554,493.68**	

Table 25

Unit Cost Evaluations

Company Name	2009-2011 Average / 2009-2011 Group Average	Efficiency Ranking
HYDRO HAWKESBURY INC.	-49.8%	1
HEARST POWER DISTRIBUTION COMPANY LIMITED	-29.1%	2
HALDIMAND COUNTY HYDRO INC.	-24.8%	3
KITCHENER-WILMOT HYDRO INC.	-23.8%	4
LONDON HYDRO INC.	-22.0%	5
PUC DISTRIBUTION INC.	-20.5%	6
HALTON HILLS HYDRO INC.	-19.0%	7
SIOUX LOOKOUT HYDRO INC.	-18.4%	8
HORIZON UTILITIES CORPORATION	-18.3%	9
NORTHERN ONTARIO WIRES INC.	-16.8%	10
E.L.K. ENERGY INC.	-16.2%	11
HYDRO 2000 INC.	-14.1%	12
VERIDIAN CONNECTIONS INC.	-12.4%	13
CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.	-11.9%	14
LAKEFRONT UTILITIES INC.	-11.5%	15
WASAGA DISTRIBUTION INC.	-11.4%	16
BURLINGTON HYDRO INC.	-11.2%	17
GRIMSBY POWER INCORPORATED	-11.1%	18
OSHAWA PUC NETWORKS INC.	-10.9%	19
BLUEWATER POWER DISTRIBUTION CORPORATION	-10.6%	20
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	-10.3%	21
KINGSTON HYDRO CORPORATION	-9.5%	22
ESSEX POWERLINES CORPORATION	-8.0%	23
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	-7.8%	24
HYDRO OTTAWA LIMITED	-7.3%	25
NORTH BAY HYDRO DISTRIBUTION LIMITED	-7.1%	26
CENTRE WELLINGTON HYDRO LTD.	-7.0%	27
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION IN	-6.3%	28
HYDRO ONE BRAMPTON NETWORKS INC.	-6.3%	29
POWERSTREAM INC.	-4.9%	30
NORFOLK POWER DISTRIBUTION INC.	-4.8%	31
LAKELAND POWER DISTRIBUTION LTD.	-4.5%	32
NIAGARA PENINSULA ENERGY INC.	-4.3%	33
BRANTFORD POWER INC.	-4.1%	34
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPO	-3.9%	35
ENERSOURCE HYDRO MISSISSAUGA INC.	-3.5%	36
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	-3.3%	37
WATERLOO NORTH HYDRO INC.	-2.2%	38
ST. THOMAS ENERGY INC.	-2.0%	39
COLLUS POWER CORPORATION	-1.8%	40
NEWMARKET-TAY POWER DISTRIBUTION LTD.	-1.6%	41
GREATER SUDBURY HYDRO INC.	-1.4%	42
TILLSONBURG HYDRO INC.	-0.2%	43

Table 25 (cont)

Unit Cost Evaluations

Company Name	2009-2011 Average / 2009-2011 Group Average	Efficiency Ranking
PETERBOROUGH DISTRIBUTION INCORPORATED	0.6%	44
ORANGEVILLE HYDRO LIMITED	1.4%	45
NIAGARA-ON-THE-LAKE HYDRO INC.	1.4%	46
ENTEGRUS POWERLINES	1.6%	47
ORILLIA POWER DISTRIBUTION CORPORATION	3.1%	48
CHAPLEAU PUBLIC UTILITIES CORPORATION	4.0%	49
WHITBY HYDRO ELECTRIC CORPORATION	4.4%	50
ERIE THAMES POWERLINES CORPORATION	5.1%	51
OTTAWA RIVER POWER CORPORATION	6.2%	52
MILTON HYDRO DISTRIBUTION INC.	6.5%	53
WESTARIO POWER INC.	6.6%	54
MIDLAND POWER UTILITY CORPORATION	6.8%	55
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	9.0%	56
KENORA HYDRO ELECTRIC CORPORATION LTD.	9.3%	57
FESTIVAL HYDRO INC.	10.6%	58
WEST COAST HURON ENERGY INC.	10.8%	59
PARRY SOUND POWER CORPORATION	11.9%	60
ATIKOKAN HYDRO INC.	12.3%	61
CANADIAN NIAGARA POWER INC.	12.9%	62
BRANT COUNTY POWER INC.	13.3%	63
ENWIN UTILITIES LTD.	15.2%	64
GUELPH HYDRO ELECTRIC SYSTEMS INC.	17.3%	65
FORT FRANCES POWER CORPORATION	19.1%	66
COOPERATIVE HYDRO EMBRUN INC.	22.3%	67
RENFREW HYDRO INC.	24.1%	68
HYDRO ONE NETWORKS INC.	28.6%	69
WELLINGTON NORTH POWER INC.	35.4%	70
WOODSTOCK HYDRO SERVICES INC.	36.3%	71
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	54.7%	72
ALGOMA POWER INC.	85.4%	73

7.4 Recommended Efficiency Cohorts and Stretch Factors

In 3rd Gen IR, three efficiency cohorts were determined based on both the econometric and unit cost/peer group benchmarking evaluations. If a distributor was a superior cost performer and in the top quartile of the industry on the unit cost benchmark, it was in efficiency cohort I and assigned a stretch factor of 0.2 per cent. If a distributor was an inferior cost performer and in the bottom quartile of the industry on the unit cost benchmark, it was in efficiency cohort III and assigned a stretch factor of 0.6 per cent. All other distributors were in efficiency cohort II and assigned a stretch factor of 0.4 per cent. Larger stretch factors are assigned for relatively less efficient distributors since they are deemed to have greater potential to achieve incremental productivity gains.

PEG recommends that both benchmarking models again be used to assign stretch factors in 4th Gen IR. While significant progress has been made in developing a total cost econometric benchmarking model for the Ontario electricity distribution sector, we do not recommend that the Board rely exclusively on econometric benchmarking to inform stretch factor assignments. Unit cost benchmarking analysis is not as technically sophisticated as econometric benchmarking, but it is more transparent and accessible. The unit cost benchmarking results are also broadly consistent with the econometric results, which implies that the unit cost benchmarking provides generally reliable information on relative cost performance. For these reasons, PEG believes that the unit cost benchmarking exercise has value and should be used by the Board to inform its assignment of company-specific stretch factors to distributors.

However, PEG also recommends that the number of efficiency cohorts be expanded from three to five. This recommendation is based on PBR Working Group discussions in which company representatives claimed that 3rd Gen IR cohorts are too large and make it difficult for distributors to migrate out of their existing cohort and into higher cohorts through cost-cutting efforts. All else equal, increasing the number of cohorts should facilitate the movement of distributors into higher cohorts and thereby reward companies that have improved their relative cost efficiency with reductions in their stretch factors. Because increasing the number of cohorts from three to five appears to be consistent with Board's objectives for encouraging efficiency improvements, PEG recommends that the number of cohorts be expanded from three to five.

PEG recommends that these five cohorts be established in the following manner. Distributors will be assigned to efficiency cohort I if they are significantly superior cost performers at a 90% confidence level and if they are in the top quintile of distributors on the peer group/unit cost benchmarking analysis. Eight distributors satisfy these criteria, and we recommend that the six distributors in cohort I be assigned a stretch factor of 0. Distributors will be assigned to efficiency cohort II if they are significantly superior cost performers at a 90% confidence level and if they are in the second quintile of distributors on the peer group/unit cost benchmarking analysis. Four distributors satisfy these criteria, and we recommend that the four distributors in cohort II be assigned a stretch factor of 0.15%.

Conversely, PEG recommends that distributors be assigned to efficiency cohort V if they are significantly inferior cost performers at a 90% confidence level and if they are in the bottom quintile of distributors on the peer group/unit cost benchmarking analysis. Thirteen distributors satisfy these criteria, and we recommend that the 13 distributors in cohort V be assigned a stretch factor of 0.6%. Distributors will be assigned to efficiency cohort IV if they are significantly inferior cost performers at a 90% confidence level and if they are in the fourth quintile of distributors on the peer group/unit cost benchmarking analysis. Four distributors satisfy these criteria, and we recommend that the four distributors in cohort IV be assigned a stretch factor of 0.45%. The remaining 44 distributors are in cohort III and will be assigned a stretch factor of 0.3%. These cohort and stretch factor assignments are presented in Table 26.

By increasing the number of cohorts from three to five, this approach for assigning stretch factors would make it easier for distributors to migrate into higher cohorts by controlling costs. The recommended maximum stretch factor remains 0.6%, but PEG recommends that the minimum stretch factor be reduced to zero to encourage and reward efforts to reduce unit cost. PEG also recommends that the stretch factor for the largest group of distributors be reduced from 0.4% to 0.3% to reflect the expectation that, on average, incremental efficiency gains become more difficult to achieve over time.

Table 26

Efficiency Cohorts for Ontario Electricity Distributors

Cohort I	Cohort II	Cohort III	Cohort IV	Cohort V
Distributor 73	Distributor 5	All Other	Distributor 47	Distributor 61
Distributor 24	Distributor 35		Distributor 45	Distributor 53
Distributor 69	Distributor 38		Distributor 55	Distributor 37
Distributor 14	Distributor 54		Distributor 66	Distributor 42
Distributor 44				Distributor 36
Distributor 15				Distributor 34
Distributor 11				Distributor 72
Distributor 21				Distributor 40
				Distributor 48
				Distributor 26
				Distributor 9
				Distributor 68
				Distributor 49

7.5 Recommended Cost/Efficiency Measure for Scorecard

Finally, PEG was asked to advise Board Staff on which cost/efficiency measures should appear on the Scorecard. PEG believes the Scorecard should report each distributor's overall efficiency assessment as reflected in its assigned cohort. This is the most consequential evaluation of efficiency from a ratemaking perspective, since the cohort assignment is directly tied to the value of the stretch factor and therefore rate adjustments for distributors that elect 4th Gen IR. The cohort assignment is also the most comprehensive assessment of a distributor's efficiency since it is based on a consideration of both the econometric and unit cost/peer group benchmarking models.

In addition, it would be instructive to report the outcomes of the two benchmarking assessments. Doing so can provide context and further detail on why a distributor has been assigned to its particular cohort. On the econometric test, these outcomes would be either: 1) significantly superior cost performer, 2) average cost performer, or 3) significantly inferior cost performer. On the unit cost/peer group test, the outcomes would be 1) top quintile of industry, 2) second quintile of industry, 3) third quintile of industry, 4) fourth quintile of industry, or 5) bottom quintile of industry.

In summary, PEG recommends that the cost/efficiency measure on the scorecard report the following:

Efficiency Assessment:	Cohort Ranking I through V
Econometric benchmarking:	One of three outcomes listed above
Unit cost/peer group benchmarking:	One of five outcomes listed above

8. Concluding Remarks

PEG was asked to develop specific, quantitative recommendations for three elements of the 4th Gen IR rate adjustment formula: 1) the inflation factor; 2) the productivity factor that applies to the entire industry; and 3) stretch factors that apply to different cohorts of distributors in the industry. PEG was also asked to develop a total cost benchmarking approach. PEG endeavored to base our recommendations on all three factors using rigorous and objective empirical research that could be replicated, refined and extended in future IR applications. Our recommendations were also informed by, and consistent with, the principles for effective incentive regulation and salient regulatory precedents from around the world.

On the inflation factor, PEG recommends that it be constructed as a weighted average of inflation in three separate indices: 1) a capital service price that PEG has constructed using publicly available information; 2) average weekly earnings for workers in Ontario; and 3) the GDP-IPI. The weights that apply to each index are equal to the estimated shares of capital, labor, and non-labor OM&A expenses, respectively, in total distribution cost for the Ontario electricity distribution industry. This inflation factor can be updated and computed each year using publicly-available information on inflation in the selected indices and, when relevant, changes in the Board's approved rates of return.

We also recommend that, in each year, the inflation factor be measured as the average value of inflation in our recommended input price index (IPI) over the three most recent years. Measuring inflation as the three-year moving average in our recommended IPI substantially reduces the volatility of the inflation factor. Evidence over the 2002-2011 period suggests that the volatility of PEG's recommended IPI will be similar to the volatility of the inflation factor that is currently used in 3rd Gen IR.

PEG obtained two estimates of TFP growth for Ontario electricity distributors over the 2002-2011 period. Both estimates excluded Toronto Hydro and Hydro One because of evidence showing that these firms directly impacted the industry's estimated TFP growth, and the measured TFP growth trend in an IR plan should be "external" to utilities industry that are potentially subject to that plan. Using index-based methods, PEG estimated that TFP for the

Ontario electricity distribution sector grew at an average annual rate of 0.10% per annum. PEG also used an econometric cost model estimated for the industry to backcast TFP growth between 2002 and 2011. The backcast analysis predicted average TFP growth of 0.07% over the sample period.

Given that the index-based and econometric-based TFP estimates are both close to 0.1%, PEG recommends that the productivity factor for 4th Gen IR be set equal to 0.1%. In addition to being consistent with the two empirical estimates, PEG believes a productivity factor of 0.1% is reasonable for several reasons. First, PEG's analysis shows that the industry's slower TFP growth stems primarily from a slowdown in output growth rather than an acceleration in distributors' spending. The slower output growth has been particularly pronounced since the introduction of CDM programs in 2006. PEG believes the continued emphasis on CDM policies in Ontario will continue to limit the potential for output quantity and TFP gains for the industry.

Second, we find the available evidence does not support a negative productivity factor. While TFP growth for the Ontario electricity distribution industry has been negative since 2007, much of this decline is attributable to the severe recession in 2008-09. This was a one-time event and is not anticipated to recur during the term of 4th Gen IR. PEG also concludes that the experience since 2007 is not long enough to be the basis for a productivity factor; TFP trends should be calculated over at least a nine-year period. We also do not favor treating sub-periods within a sample period differently (*e.g.* by placing more weight on one sub-period rather than another), since such an approach can give rise to "cherry picking" and artificial manipulation of the available data. The nine-year industry TFP trend is more consistent with a productivity factor of 0.1% than a substantially negative productivity factor.

Third, an IPI inflation factor combined with a productivity factor of 0.1% would mean electricity distributor prices grow at nearly the same rate as the industry's input price inflation, if all else is held equal. PEG's research shows that input price inflation for the electricity distribution industry has been slightly below GDP-IPI inflation. It is not unusual for price inflation in a particular sector (such as electricity distribution) to be similar to average price inflation in the economy. If the productivity factor was the only component of the X factor, a productivity factor equal to 0.1% would likely mean that electricity distribution prices grow at rates similar to the prices of other goods and services in the economy. Price inflation in a particular sector that is similar to aggregate, economy-wide inflation is not necessarily a sign of sub-par productivity performance in that sector.

However, the productivity factor is *not* the only component of the X factor, nor is it the component of the X factor that is designed to ensure that consumers benefit from incentive rate setting. Stretch factors are intended to reflect distributors' incremental efficiency gains under incentive ratemaking. Adding a stretch factor to the productivity factor allows customers to share in these anticipated efficiency gains.

PEG used econometric and unit cost/peer group models that we developed to benchmark distributors' total cost performance and inform stretch factor assignments. As in 3rd Gen IR, both benchmarking methods were used to identify efficiency cohorts in the industry, but we recommend expanding the number of these cohorts from three (in 3rd Gen IR) to five. This recommendation is designed to facilitate the movement of distributors into higher cohorts. Since distributors in higher cohorts are subject to lower recommended stretch factors, a larger number of cohorts strengthens distributors' incentives to pursue efficiency.

PEG recommends that distributors be assigned to efficiency cohort I if they are significantly superior cost performers at a 90% confidence level and if they are in the top quintile of distributors on the peer group/unit cost benchmarking analysis. Eight distributors satisfy these criteria, and we recommend that the eight distributors in cohort I be assigned a stretch factor of 0. Distributors will be assigned to efficiency cohort II if they are significantly superior cost performers at a 90% confidence level and if they are in the second quintile of distributors on the peer group/unit cost benchmarking analysis. Four distributors satisfy these criteria, and we recommend that the four distributors in cohort II be assigned a stretch factor of 0.15%.

Conversely, PEG recommends that distributors be assigned to efficiency cohort V if they are significantly inferior cost performers at a 90% confidence level and if they are in the bottom quintile of distributors on the peer group/unit cost benchmarking analysis. Thirteen distributors satisfy these criteria, and we recommend that the 13 distributors in cohort V be assigned a stretch factor of 0.6%. Distributors will be assigned to efficiency cohort IV if they are significantly inferior cost performers at a 90% confidence level and if they are in the fourth quintile of distributors on the peer group/unit cost benchmarking analysis. Four distributors satisfy these criteria, and we recommend that the four distributors in cohort IV be assigned a stretch factor of 0.45%. The remaining 44 distributors are in cohort III and will be assigned a stretch factor of 0.3%.

By increasing the number of cohorts from three to five, this approach for assigning stretch factors would make it easier for distributors to migrate into higher cohorts by controlling costs. The recommended maximum stretch factor remains 0.6%, but PEG recommends that the minimum stretch factor be reduced to zero to encourage and reward efforts to reduce unit cost. PEG also recommends that the stretch factor for the largest group of distributors be reduced from 0.4% to 0.3% to reflect the expectation that, on average, incremental efficiency gains become more difficult to achieve over time.

Particularly because PEG has recommended positive stretch factors for most distributors, electricity distributor prices will fall in "real," inflation-adjusted terms under the index-based rate adjustments in 4th Gen IR. A productivity factor of 0.1% is therefore not incompatible with the Board's incentive rate-setting objectives of encouraging cost efficiency and ensuring that customers share in these efficiency gains.

PEG's recommendations are based on empirical techniques that we believe strike an appropriate balance between rigor, objectivity and feasibility given the data currently available in Ontario. Our recommendations have also been informed by economic reason, approved precedents in North America and valuable regulatory approaches around the world. Our methods have also built on information sources and techniques that PEG has developed in our previous comparative cost and IR work for Board Staff.

PEG believes that the methods used to develop the inflation factor and X factor recommendations in 4th Gen IR can provide a solid foundation for future incentive regulation proceedings in Ontario. Our approach brings together a wealth of techniques and alternative data sources that can be useful in future IR applications. These techniques include index-based measures of industry TFP trends in Ontario and econometric and unit cost/peer group benchmarking of Ontario distributors' total cost performance. At the same time, our methodology is flexible enough to allow the techniques used to estimate inflation factors and X factors to evolve and/or be refined as new or additional information becomes available in Ontario.

Appendix One: Econometric Decomposition of TFP Growth

There are rigorous ways to set X factors so that they are tailored to utility circumstances that differ materially from industry norms (either historically or at a given point in time). This can be done by developing information on the sources of TFP growth and adjusting the X factor to reflect the impact on TFP resulting from differences between a utility's particular circumstances and what is reflected in historical TFP trends. To provide a conceptual foundation for such adjustments, below we consider how the broad TFP aggregate discussed above can be decomposed into various sources of productivity change.

Our analysis begins by assuming a firm's cost level is the product of the minimum attainable cost level C^* and a term η that may be called the inefficiency factor.

$$C = C^* \cdot \eta . \qquad \text{[A1.1]}$$

The inefficiency factor takes a value greater than or equal to 1 and indicates how high the firm's actual costs are above the minimum attainable level.[34]

Minimum attainable cost is a function of the firm's output levels, the prices paid for production inputs, and business conditions beyond the control of management. Let the vectors of input prices facing a utility, output quantities and business conditions be given by $\boldsymbol{W}$ (= $W_1, W_2 \ldots W_J$), $\boldsymbol{Y}$ (= $Y_1, Y_2 \ldots Y_I$), and $\boldsymbol{Z}$ (= $Z_1, Z_2 \ldots Z_N$), respectively. We also include a trend variable (T) that allows the cost function to shift over time due to technological change. The cost function can then be represented mathematically as

$$C^* = g(\boldsymbol{W}, \boldsymbol{Y}, \boldsymbol{Z}, T). \qquad \text{[A1.2]}$$

Taking logarithms and totally differentiating Equation [A1.2] with respect to time yields

$$\dot{C} = \left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j \varepsilon_{W_j} \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} \right) + \dot{g}. \qquad \text{[A1.3]}$$

[34] A firm that has attained the minimum possible cost has no inefficiency and an inefficiency factor equal to 1. The natural logarithm of 1 is zero, so if a firm is operating at minimum cost, the inefficiency factor drops out of the analysis that follows.

Equations [A1.1] and [A1.3] imply that the growth rate of *actual* (not minimum) cost is given by

$$\dot{C} = \left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j \varepsilon_{W_j} \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} \right) + \dot{g} + \dot{\eta}. \qquad [A1.4]$$

The term ε_{Y_i} in equation [A1.4] is the elasticity of cost with respect to output i. It measures the percentage change in cost due to a small percentage change in the output. The other ε terms have analogous definitions. The growth rate of each output quantity i is denoted by $\dot{Y}$. The growth rates of input prices and the other business condition variables are denoted analogously.

Shephard's lemma holds that the derivative of minimum cost with respect to the price of an input is the optimal input quantity. The elasticity of minimum cost with respect to the price of each input *j* can then be shown to equal the optimal share of that input in minimum cost (SC_j^*). Equation [A1.4] may therefore be rewritten as

$$\begin{aligned} \dot{C} &= \sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j SC_j^* \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} + \dot{g} + \dot{\eta}. \\ &= \sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \dot{W}^* + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} + \dot{g} + \dot{\eta}. \end{aligned} \qquad [A1.5]$$

The W^* term above is the growth rate of an input price index, computed as a weighted average of the growth rates in the price subindexes for each input category. The *optimal* (cost-minimizing) cost shares serve as weights. We will call W^* the optimal input price index.

Recall from the indexing logic presented earlier that

$$T\dot{F}P = \dot{Y} - \dot{X} \qquad [A1.6]$$

And

$$\dot{X} = \dot{C} - \dot{W} \qquad [A1.7]$$

The input price index above is weighted using actual rather than optimal cost shares. Substituting equations [A1.6] and [A1.7] into [A1.4], it follows that

$$
\begin{aligned}
T\dot{F}P &= \dot{Y} - \left(\dot{C} - \dot{W}\right) \\
&= \dot{Y} - \left[\left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_n \varepsilon_{Z_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right) - \dot{W}\right] \\
&= \dot{Y} - \left[\left\{\left[\left(1 - \frac{1}{\sum \varepsilon_{Y_i}}\right) \cdot \sum \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_i \frac{\varepsilon_{Y_i}}{\sum_i \varepsilon_{Y_i}} \cdot \dot{Y}_i\right] + \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right\} - \dot{W}\right] \\
&= \dot{Y} - \left\{\left[\left(\frac{1}{\sum \varepsilon_{Y_i}} - 1\right) \cdot \sum \varepsilon_{Y_i} \cdot \dot{Y}_i + \dot{Y}^{\varepsilon} + \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right] - \dot{W}\right\} \\
&= \cdot\left(1 - \sum \varepsilon_{Y_i}\right) \cdot \dot{Y}_i + \left(\dot{Y} \text{-} \dot{Y}^{\varepsilon}\right) - \left(W^* - \dot{W}\right) - \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n \text{ - } \dot{g} - \dot{\eta}
\end{aligned}
$$

[A1.8]

The expression above shows that growth rate in TFP has been decomposed into six terms. The first is the **scale economy effect**. Economies of scale are realized if, when all other variables are held constant, changes in output quantities lead to reductions in the unit cost of production. This will be the case if the sum of the cost elasticities with respect to the output variables is less than one.

The second term is the **nonmarginal cost pricing effect**. This is equal to the difference between the growth rates of two output quantity indexes. One is the index used to compute TFP growth. The other output quantity index, denoted by $\dot{Y}^{\varepsilon}$, is constructed using cost elasticity weights. The Tornqvist index that we use to measure TFP should theoretically be constructed by weighting outputs by their shares of revenues. It can be shown that using cost elasticities to weight outputs is appropriate if the firm's output prices are proportional to its marginal costs, but revenue-based weights will differ from cost elasticity shares if prices are not proportional to marginal costs. Accordingly, this term is interpreted as the effect on TFP growth resulting from departures from marginal cost pricing.[35]

The third term is the **cost share effect**. This measures the impact on TFP growth of differences in the growth of input price indexes based on optimal and actual cost shares. This term will have a non-zero value if the firm utilizes inputs in non-optimal proportions.

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[35] See Denny, Fuss and Waverman *op cit*, p. 197.

The fourth term is the **Z variable effect.** It reflects the impact on TFP growth of changes in the values of the Z variables that are beyond management control.

The fifth term is **technological change**. It measures the effect on productivity growth of a proportional shift in the cost function. A downward shift in the cost function due to technological change will increase TFP growth.

The sixth term is the **inefficiency effect**. This measures the effect on productivity growth of a change in the firm's inefficiency factor. A decrease in a firm's inefficiency will reduce cost and accelerate TFP growth. Firms decrease their inefficiency as they approach the cost frontier, which represents the lowest cost attainable for given values of output quantities, input prices, and other business conditions.

Appendix Two: Econometric Research

A.2.1 Form of the Cost Model

The functional form selected for this study was the translog.[36] This very flexible function is the most frequently used in econometric cost research, and by some account the most reliable of several available alternatives.[37] The general form of the translog cost function is:

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

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

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

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

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

[36] 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.

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

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

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

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

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

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

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

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

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

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

A.2.2 Estimation Procedure

We estimated this system of equations using a procedure first proposed by Zellner (1962).[38] It is well known that if there exists contemporaneous correlation between the errors in the system of regressions, more efficient estimates can be obtained by using a Feasible Generalized Least Squares (FGLS) approach. To achieve even a better estimator, PEG iterates this procedure to convergence.[39] Since we estimate these unknown disturbance matrices consistently, the estimators we eventually compute are equivalent to Maximum Likelihood Estimation (MLE).[40]

Before proceeding with estimation, there is one complication that needs to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[41] This does not pose a problem since another property of the MLE procedure is that it is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

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

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

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

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

Appendix Three: Tests on Output and Trend Parameters

This appendix tests whether Hydro One and Toronto Hydro have had a statistically significant impact on four parameters in PEG's econometric cost model. These are the parameters on the customer, system capacity peak, and kWh delivery outputs, and on the time trend. To test this hypothesis, we began with the econometric cost model presented in Tables 10 and 12 but added a number of interaction terms which interacted a dummy variable (which takes a value of 1 for Toronto Hydro and Hydro One but 0 for all other distributors) with these four variables and other variables in the model.

We call the model that includes the interaction terms the "unrestricted model," while the model where the four parameters of interest are restricted to be equal to zero is called the "restricted model." Each product of the dummy variable and one of the four variables of interest is an "impact effect," and the set of all four of these products is known as the "impact effects." The econometric results for the unrestricted and restricted models are presented in Tables A3-1 and A3-2, respectively.

We test whether the four interaction parameter estimates are jointly significant using three widely recognized test statistics: 1) a Chi-Squared Test; 2) a Joint F-Test; and 3) a Wald Statistic. Formulas and a description of these tests in the SUR context are given in J. Wooldridge 2010, Econometric Analysis of Cross Section and Panel Data , 2^{nd} edition MIT Press, pp. 172-3, 180 and 184.

Test #1: Chi-Squared test The difference between the sum of squared residuals in the restricted model (with the four impact effects constrained to be zero) and the sum of squared residuals in the unrestricted model, is distributed chi-squared with four degrees of freedom under the null hypothesis that the four interaction terms in question have true values of zero. To do this test the residuals are transformed by the method of Feasible GLS that is used to estimate the model. The calculated test statistic is 51.83, with an associated probability value of .0000. This test therefore rejects the hypothesis that the four impact effects are jointly equal to zero.

Table A3-1

Econometric Models Assessing Impact of Hydro One and Toronto Hydro on Industry TFP

Variable Key

N = Number of Customers
C = System Capacity Peak Demand
D= Retail Deliveries
A = Service Territory Area
U = Percentage of Lines Underground
L = Average Line Length (km)
NG = % of 2011 customers added in the last 10 years
TH = Toronto Hydro Electric and Hydro One Networks dummy variable
W_K = Capital Input Price
Trend = Time Trend

Explanatory Variable	Estimated Coefficient	T-Statistic	P-Value	Explanatory Variable	Estimated Coefficient	T-Statistic	P-Value
N*	0.311	4.722	0.000	**TH Trend***	0.001	6.416	0.000
C*	0.285	4.575	0.000	**TH·N***	-4.823	-7.544	0.000
D*	0.069	2.084	0.038	**TH·C***	-18.746	-8.835	0.000
W_K*	0.630	78.173	0.000	**TH·D**	-1.079	-1.761	0.079
N·N	-0.512	-1.623	0.105	**TH·W_K**	-0.026	-1.251	0.211
C·C	0.330	1.130	0.259	**TH·N·N***	0.259	4.825	0.000
D·D*	0.119	1.488	0.137	**TH·C·C***	4.274	8.218	0.000
W_K·W_K*	0.058	1.304	0.193	**TH·D·D***	-0.949	-7.073	0.000
N·C	0.118	0.412	0.680	**TH·W_K·W_K**	0.011	2.084	0.038
N·D	0.164	1.384	0.167	**TH·W_K·N***	-0.004	-1.838	0.067
C·D	-0.267	-2.641	0.008	**TH·W_K·C***	0.013	1.793	0.074
N·W_K*	0.032	1.675	0.094	**TH·W_K·D**	0.001	0.216	0.829
C·W_K	0.029	1.612	0.107	**TH·N·C***	1.541	9.330	0.000
D·W_K	0.000	-0.045	0.964	**TH·N·D**	0.056	1.287	0.199
A*	0.019	1.473	0.141	**TH·D·C***	1.332	8.534	0.000
U*	0.049	6.995	0.000				
L*	0.248	8.065	0.000				
NG*	0.018	2.295	0.022				
TH*	32.187	7.851	0.000				
Trend*	0.011	7.169	0.000				
Constant*	12.749	333.764	0.000				

System Rbar-Squared	0.984
Sample Period	2002-2011
Number of Observations	729

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

Table A3-2

Econometric Models Assessing Impact of Hydro One and Toronto Hydro on Industry TFP

Variable Key

N = Number of Customers
C = System Capacity Peak Demand
D= Retail Deliveries
A = Service Territory Area
U = Percentage of Lines Underground
L = Average Line Length (km)
NG = % of 2011 customers added in the last 10 years
TH = Toronto Hydro Electric and Hydro One Networks dummy variable
W_K = Capital Input Price
Trend = Time Trend

Explanatory Variable	Estimated Coefficient	T-Statistic	P-Value	Explanatory Variable	Estimated Coefficient	T-Statistic	P-Value
N*	0.294	4.260	0.000	**TH·W_K**	-0.002	-0.118	0.906
C*	0.291	4.455	0.000	**TH·N·N***	-0.190	-10.492	0.000
D*	0.101	2.918	0.004	**TH·C·C***	-0.425	-5.045	0.000
W_K*	0.631	78.067	0.000	**TH·D·D**	-0.183	-2.552	0.011
N·N	-0.386	-1.160	0.246	**TH·W_K·W_K**	0.002	0.420	0.675
C·C	0.494	1.608	0.108	**TH·W_K·N***	-0.006	-2.560	0.011
D·D*	0.194	2.310	0.021	**TH·W_K·C**	0.004	0.583	0.560
W_K·W_K*	0.084	1.893	0.059	**TH·W_K·D**	0.002	0.535	0.593
N·C	0.010	0.035	0.972	**TH·N·C***	0.217	11.056	0.000
N·D	0.134	1.066	0.287	**TH·N·D**	-0.013	-1.718	0.086
C·D	-0.313	-2.938	0.003	**TH·D·C**	0.200	2.648	0.008
N·W_K*	0.032	1.676	0.094				
C·W_K	0.031	1.678	0.094				
D·W_K	-0.001	-0.124	0.901				
A*	-0.007	-0.514	0.607				
U*	0.020	2.590	0.010				
L*	0.252	7.778	0.000				
NG*	0.021	2.496	0.013				
TH	-0.010	-1.155	0.249				
Trend*	0.018	12.482	0.000				
Constant*	12.704	319.957	0.000				

System Rbar-Squared	0.983
Sample Period	2002-2011
Number of Observations	729

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

Test #2: Joint F test When the difference in the sum of squared errors used in the chi-squared test is divided by the sum of squared residuals from the unrestricted model, and then multiplied by (n*g – k)/q, where n is the number of observations (729), g the number of equations (2), k the number of explanatory variables in the unrestricted model (46), and q is the number of restrictions (4), this test statistic is distributed F(4, 1412). This test statistic has a value of 12,58, with a probability value of .0000. This test therefore rejects the hypothesis that the four impact effects are jointly equal to zero

Test #3: Wald Test The Wald Statistic provides a robust significance test calculated using a q x k matrix of restrictions R placed on the k x 1 vector b of estimated coefficients with an estimated k x k variance covariance matrix V(b) and qx1 vector of restrictions r:

$(R \cdot b - r)' \cdot (R \cdot V(b) \cdot R')^{-1} \cdot (R \cdot b - r)$ is distributed chi-squared with q=4 degrees of freedom.

Here, r is a column of 4 zeros and R is constructed of zeros and ones to satisfy $R \cdot b = r$. The calculated test statistic is 90.12 which has a probability level of .0000. This test therefore rejects the hypothesis that the four impact effects are jointly equal to zero.

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