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

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Table of Contents

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 $\left(growthPCI\right)$ 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.

[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

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[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

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[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:

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

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:

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

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

$$\ln\left(\frac{TFP_t}{TFP_{t-}} \right) = \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}} \right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right). \qquad [14]$$

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.

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

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}).

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[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	Quantity Subindexes: 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	Materials & Services	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.

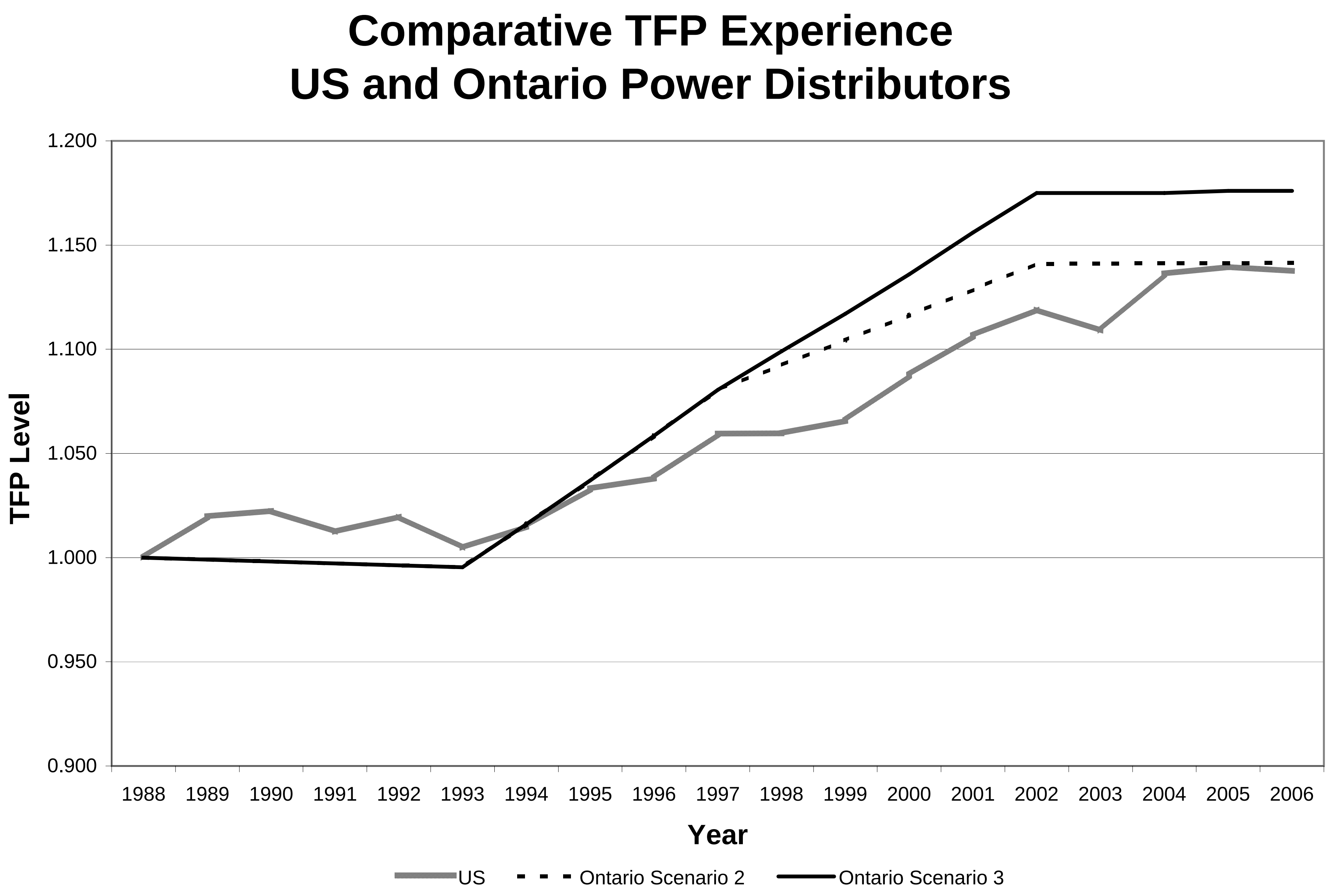
Scenario 3 had transpired, Ontario's distributors would have registered average TFP growth of 0.90% over the 1988-2006 period. The analogous TFP growth rate for US distributors was 0.72% for this period. Figure One compares the TFP experience for the US and Ontario industries under Scenarios Two and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

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[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

	Years Benchmarked	Translog Model: Actual/Predicted [A]	Translog Model: Deviation from Sample Mean [A]-1	Translog Model: P-Value	Translog Model: Excess Cost in $	Translog Model: Rank	Double Log Model: Actual/Predicted [A]	Double Log Model: Deviation from Sample Mean [A]-1	Double Log Model: P-Value	Double Log Model: Excess Cost in $	Double Log Model: 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

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[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

[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.

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[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

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[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

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[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)

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[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

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[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

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

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

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

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

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

And

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

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

$$T\dot{F}P = \dot{Y} - \left(\dot{C} - \dot{W}\right)$$

$$= \dot{Y} - \left[\left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_n \varepsilon_{Z_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right) - \dot{W}\right]$$

$$= \dot{Y} - \left[\left\{\left[\left(1 - \frac{1}{\sum \varepsilon_{Y_i}}\right) \cdot \sum \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_i \frac{\varepsilon_{Y_i}}{\sum_i \varepsilon_{Y_i}} \cdot \dot{Y}_i\right] + \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right\} - \dot{W}\right] \quad [A2.8]$$

$$= \dot{Y} - \left\{\left[\left(\frac{1}{\sum \varepsilon_{Y_i}} - 1\right) \cdot \sum \varepsilon_{Y_i} \cdot \dot{Y}_i + \dot{Y}^{\varepsilon} + \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right] - \dot{W}\right\}$$

$$= \cdot\left(1 - \sum \varepsilon_{Y_i}\right) \cdot \dot{Y}_i + \left(\dot{Y} - \dot{Y}^{\varepsilon}\right) - \left(W^* - \dot{W}\right) - \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n - \dot{g} - \dot{\eta}$$

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.

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[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

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

where

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

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

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

The formula for the capital quantity index is thus

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

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

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

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

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

where

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

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.

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[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:

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

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.

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

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:

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

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

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

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:

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

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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