Defining and Measuring Performance of Electricity Distributors
(EB-2010-0379)

Electricity Distributors Association

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Preface

The distributor rate-setting mechanism that the Board implements through this initiative will significantly impact ratepayers, distributors, and other stakeholders throughout the Province. It will be critical for promoting regulatory efficacy and efficiency, for stabilizing rate changes and for ensuring the sufficiency of funding of critical infrastructure.

This initiative comes at a difficult time for the sector. Irrespective of the broader societal benefits, the Province of Ontario's policy priorities of green energy, conservation and smart grid technologies put upward pressure on the electricity bill. These pressures include cost pressures for distributors which deliver many of these policies and programs. The Board, ratepayers, distributors, and other stakeholders share concern for minimizing electricity rates, including distribution rates.

In order to balance the full spectrum of interests it is essential that the forthcoming incentive rate mechanism be based on realistic and empirically supported assessments of costs in the distribution segment of the sector.

The analysis of productivity and performance can be of a highly technical nature. In order to contribute to the discussion, without sacrificing precision, we have attempted to describe the central threads of the analysis in the main document, and to relegate technical details to Appendices.

EXECUTIVE SUMMARY

Summary of Observations and Recommendations

A. We have estimated the productivity factor using two methodologies – an index based approach, and a cost based approach. The resulting estimates are approximately -0.7% and -0.8% respectively, indicating significant upward cost pressures in the industry. In our view, the productivity factor proposed by the Pacific Economics Group (+0.1%) does not adequately take into account evolving cost patterns in the electricity distribution industry.

B. Estimation of relative efficiencies is difficult and subject to considerable risk of misclassification. Even minor model variations can lead to migration of distributors from one efficiency cohort to another. Among the available alternatives, the cost model provides the better indicator of relative efficiency, though even this model can lead to anomalous results for some distributors. A second tool that the Board might consider is the distributor specific index based productivity factor.

C. Peer group analysis, as currently implemented, is contentious and unlikely, in its present formulation, to contribute productively to the assignment of distributors to efficiency cohorts. There are a number of factors that contribute to differences amongst distributors. Further, there are significant data limitations that preclude adequately identifying and quantifying some of those variations. Peer group analysis in this context is unreliable and may lead to unreasonable rate-setting.

D. Ontario distributors have been under incentive regulation for many years, during which there have been sustained efforts to drive out inefficiencies. We believe it is time to start rewarding efficiency and that therefore stretch factors should range from -0.3% to +0.3%.

E. The industry specific inflation factor proposed by the Pacific Economics Group is 0.5% for 2012. Although it is based on a three year average, it remains highly sensitive to shifts in interest rates. As interest rates rise, the methodology – if implemented – could yield inflation factors of 4% or even higher. We recommend that the Board consider implementing a regulatory formula which reduces the rate shock to customers through a smoothing mechanism. One possibility would be to increase the allowed inflation factor during periods when the industry-specific rate of inflation is below broader inflation measures, and to use this differential as an offset during periods when the industry specific inflation factor is higher.

F. The analyses and empirical work described in this report have been conducted within a very short time-frame, and should therefore be viewed as preliminary. Furthermore, it is our understanding that additional (2012) data will be incorporated in the calibration of the incentive regulation mechanism. We therefore request that, prior to the Board Decision, distributors and stakeholders be accorded the opportunity to review the data and provide amendments and revisions, as has been accorded to the Board's consultant in the course of this process.

Background

The Ontario Energy Board regulates approximately 75 electricity distributors. Over the course of several years, the Board has been engaged in a consultative process with the objective of renewing its regulatory framework and developing a 4th Generation Incentive Regulation Mechanism.

Since the 2008 3GIRM proceeding, the Board, stakeholders and distributors have implemented important steps to improve the efficacy and efficiency of the regulatory process. These include the development of detailed Ontario distributor data, (previously, U.S. data were used to inform the selection of the productivity factor). The process has required a massive data development effort. The use of Ontario data is even more important now as Ontario's electricity policies (in particular, the implementation of FIT programs) diverge from those in the U.S. The data assembled through the Board's current process also permits total cost benchmarking, rather than benchmarking based on OM&A data, as was the case in the 2008 proceeding. There has been further development of an industry specific price index and the provision of multiple rate-setting options to distributors.

The present report focuses primarily on the methodology and empirical work in support of 4GIRM, and on the empirical analyses conducted by the Pacific Economics Group (PEG).

Productivity Analysis

There are two widely studied methods for measuring productivity growth. In broad terms these may be characterized as follows:

- Indexed based approaches, which compare rates of growth of inputs to rates of growth of outputs.

- Cost based approaches, which focus on the estimation of technology driven cost trends and scale effects.

Properly implemented with suitable data, the two should lead to similar results. Wide differences require reconciliation. The two approaches are related as follows:

Productivity Growth = Output Growth – Input Growth = Technology Effects + Scale Effects

The first approach is appealing in part because of its interpretation. For example, if inputs are growing at a rate of 2% and output is growing at 3%, then productivity is growing at 1%.

The second approach also affords an intuitive interpretation. For example, if real costs are trending downward at 0.8% and scale economies are generating an additional reduction of 0.2% per year, then productivity is again growing at 1%. The cost-based approach is also appealing because it permits the attribution of cost changes to specific causative factors.

One usually thinks of "technology effects" as inexorably leading to lower unit costs, but that is not necessarily the case, especially when new, evolving technologies are being introduced. For example, the adoption of renewable electricity and smart grid technologies may lead to increases in electricity costs. Demand management programs which slow demand growth, may in turn reduce potential gains from scale economies, at least in the medium term. Over time, as technology and the policies and processes associated with it stabilize and mature, cost savings may be realized.

It has been argued that index modeling is 'more transparent' than cost modeling. The appropriateness and accuracy of index modeling relies on a host of assumptions that are critical to its validity. Furthermore, certain key coefficients estimated in the cost model are used to calibrate the index model. Therefore, one cannot be satisfied that the index model findings are valid without having faith in the underlying cost model upon which it relies.

We appreciate that the Board has settled on the index approach for calculating productivity. That determination does not specify the particular variant of the index approach that is to be implemented, which observations should be given greater or lesser weight, and which should simply be excluded from the analysis. Nor does the Board's determination preclude the Board from seeking to understand anomalies arising out of widely different results using each of the two approaches.

Productivity Estimates

We have estimated productivity growth using each of the above two methodologies. The index-based and cost-based calculations yield values of -0.7% and -0.8% respectively. That is, unit costs have been *rising* at a rate of 0.7% to 0.8% per year in real terms.

The index-based approach proposed by PEG assigns weights to distributors that are roughly proportional to their size. The two largest distributors are excluded from the calculation, but the remaining large distributors are weighted much more heavily than medium or small distributors. We avoid these problems by assigning equal weights to all distributors. In particular, we calculate an individual productivity index for each distributor, then average across distributors. Our preliminary estimates lead to an average productivity factor of -0.7%.

Our cost-based estimates consist of two components: the technology effect is estimated to be 1.2% (this is the trend coefficient in the cost model); it indicates significant upward cost pressures. The effect is partly offset by a favorable scale effect which has been reducing unit costs at a rate of about -0.4% for the 'average' distributor.[1] Combining the two effects yields a productivity factor of -0.8%.

We note that, going forward, this scale effect may over-estimate future potential gains, particularly if growth in demand slows as a result of conservation.[2]

Benchmarking and Stretch Factor Assignments

The same cost model that is relied upon to calibrate the output index in the index modeling approach is used to compare the relative efficiencies of distributors. Relative efficiencies are obtained by calculating costs predicted by the model for each distributor to their actual costs in recent years.

It is important to distinguish between the accuracy with which industry-wide productivity factors can be estimated, and the accuracy with which one can assess relative efficiencies of individual distributors. Though both can be obtained from the same model, the former is an average effect and can therefore be estimated with much greater precision than the latter, which involves a separate prediction for each individual distributor. This creates real potential for classification of a distributor into the incorrect efficiency cohort.

It is critical to note that our analysis of the data reveals that even modest variations in model specification can lead to substantial changes in distributor rankings and migration

[1] The effect of business conditions on industry-wide productivity growth has been small. These factors are, however, part of the cost model and can have material impacts when comparing performance of individual distributors.

[2] Furthermore, this scale effect is not appropriate for addressing issues of potential efficiency gains that may arise from consolidations or mergers of distributors. A separate analysis would be required which is beyond the scope of the present proceeding.

of individual distributors to other efficiency cohorts. Given the complexities of this sector and its data limitations, it is highly probable that such variations will be present. This could result in incentives that are not aligned with the Board's objectives.

In our view, the use of peer group analysis to inform the process of cohort classification is problematic, largely because of the difficulty in determining appropriate peer groups. There are too many variables that can affect distributor costs to give one confidence in the allocation to peer groups. We respectfully submit that this is an imprudent risk for the Board to take given that more reasonable alternatives are now available.

Instead, given the Board's reliance on index based calculation of an industry-wide productivity factor, it may be worth considering distributor-specific productivity growth factors in the assignment of distributors to efficiency cohorts.

We also recommend that the Board use this opportunity to shift its approach to stretch factors by modifying the range to include rewards as well as penalties. PEG has proposed shifting the penalties such that they are generally less severe. We propose going a step beyond the initial PEG proposal and introducing a reward for top tier efficiency, that is, stretch factors that range from -0.3% to +0.3%. This reward/penalty mix is conceptually attractive and practical. It is reasonable to expect that lean distributors will use the incremental funds to sustain or advance their preferred ranking, thus establishing a sustainable framework for pursuing this objective.

Inflation Factor

Although industry-specific measures of inflation have been explored by the Board in the past, a broader measure of inflation was used during 3GIRM. Broader measures have several advantages. First, they are widely available and therefore easy to obtain. Second, they generally display less variability than industry-specific measures. Third, they are likely to be better understood and accepted by electricity users because they track the inflationary pressures experienced by consumers.

The rationale for using an industry-specific measure is that electricity distribution is very capital intensive and therefore distributor costs evolve differently from general consumer or even producer price indexes. Certain specific materials widely used in electricity distribution may also be subject to cost fluctuations that diverge from broad measures of inflation. For these reasons, distributors have sought to explore industry-specific indices.

The PEG report proposes to use industry-specific measures and to implement a three year moving average to smooth the series, thereby reducing volatility. Because monetary policies, among them quantitative easing, have led to low interest rates, the current value, based on the three year period 2010-2012, would be 0.5%. However, rising interest rates could push the industry-specific inflation factor to levels of 4% or even higher. Such volatility would not only impact distributors, but also ratepayers. Moreover, as the evidence in this initiative has illustrated, modest changes in interest rates can have a dramatic impact on the industry specific inflation factor, largely because of the capital intensity of electricity distribution.

For this reason, we recommend that the Board explore additional options for rate-smoothing, in particular mechanisms that mitigate the rate impacts of the *differential* between the industry-specific inflation factor and a broader inflation measure.

Recommendations on Allowable Rate Increases

The incentive regulation mechanism is given by

Allowable Rate Increase = Inflation Factor – Productivity Factor – Stretch Factor.

Based on the most recent updates available from the Pacific Economics Group, the calibration would be as follows:

a. an industry specific inflation factor of 0.5% (based on the 2010-2012 period);
b. an industry-wide productivity factor of +0.1%;
c. a "stretch factor" ranging from 0.0% to +0.6%.

Allowable rate increases based on PEG figures would therefore range from -0.2% to +0.4%. For most distributors, this would in effect constitute a rate freeze.

In our view, this is inappropriate at a time when there is clear evidence of upward pressure on distributor costs, aside from the usual inflationary effects. Such an arrangement may prove to be unsustainable and could even undermine the Board's objective to "facilitate the maintenance of a financially viable electricity industry".

We recommend a productivity factor of -0.75% and stretch factors ranging from -0.3% to +0.3%. Accepting for the moment the industry specific inflation factor of 0.5%, this would result in allowable rate increases ranging from 0.95% to 1.55%. Most distributors would receive an increase of about 1.25%.

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1. INTRODUCTION AND BACKGROUND

In December 2010, the Ontario Energy Board began a consultative process on incentive regulation of Ontario's electricity distributors as part of a broader renewal of the regulatory framework for electricity distribution. Since three incentive-based regimes preceded the present process, the objective has been to develop a "4th Generation Incentive Regulation Mechanism" (4GIRM).

In February 2011, an initial stakeholder consultation meeting was held, at which interested stakeholders had the opportunity to exchange ideas. In the course of the intervening months, numerous stakeholder meetings were held with a view to developing a coherent framework which would be sufficiently flexible to accommodate the wide range of circumstances and operating environments within which Ontario's many distributors must function. In these proceedings Board Staff was assisted and supported by the Pacific Economics Group, LLC (PEG).

On November 8, 2011, the Board issued its first set of key documents:

- *Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper*, prepared by the Pacific Economics Group, LLC, and authored by Lawrence Kaufmann, Ph.D., April 2011.

- *Staff Discussion Paper on Defining and Measuring Performance of Electricity Transmitters and Distributors*, Ontario Energy Board, November 8, 2011.

The purpose of these two papers was to assist in the Board's determination of its policies in relation to performance measures by identifying the issues for consideration, and describing the options available for 4GIRM.

At the end of 2012, these were followed by another paper entitled *Concept Paper on Empirical Analysis and Benchmarking to Be Used in the Renewed Regulatory Framework for Electricity*, prepared by the Pacific Economics Group, LLC, and authored by Lawrence Kaufmann, Ph.D., December 2012. This latter PEG concept paper provided a primer on the empirical methods that would form the core of PEG's recommendations to the Board.

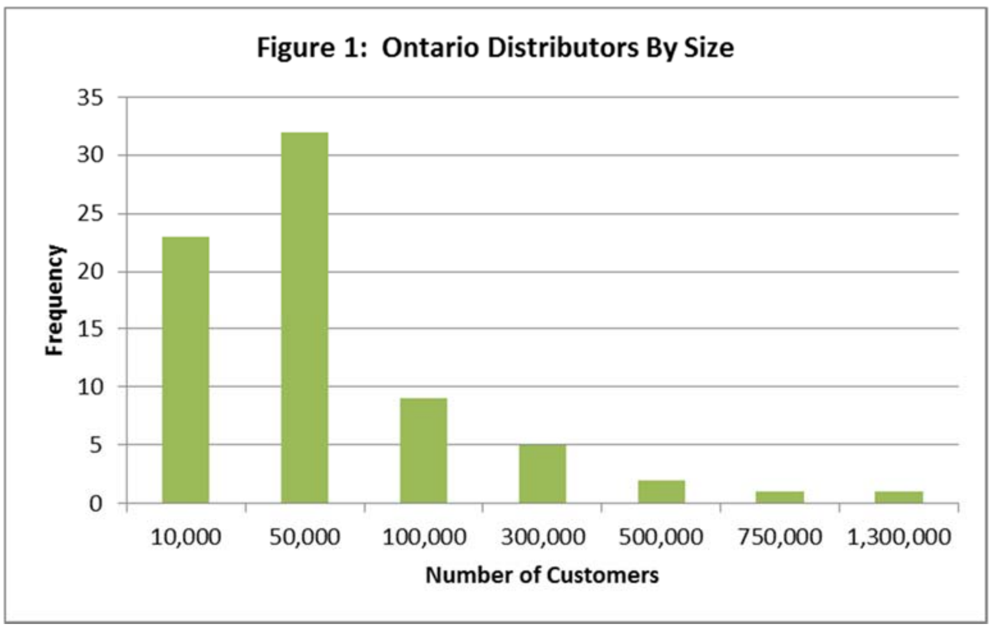
In May 2013, the Board issued *Empirical Research in Support of Incentive Rate Setting In Ontario: Report to the Ontario Energy Board*. Pacific Economics Group, authored by Lawrence Kaufmann, Ph.D., Dave Hovde MA, John Kalfayan MA, and Kaja Rebane MA. In this report, henceforth the "PEG Report," the Pacific Economics Group presented its recommendations on the inflation, productivity and stretch factors to be used in 4GIRM, and on the benchmarking of electricity distributors.

Board Staff has requested that comments on the proposals that have been put forth in the "PEG Report" be submitted by June 13, 2013. The purpose of the present document is to provide commentary and preliminary analysis on behalf of the Electricity Distributors Association.

2. THE CURRENT POLICY SETTING

A. THE CHANGING POLICY ENVIRONMENT

At present, the Ontario Energy Board regulates over 70 electricity distributors, ranging in size from just over one thousand customers, to over one million. Together these distributors provide service to over 4.8 million customers. The ten largest distributors together serve over 70% of Ontario customers.



During the late 1990's there was a concerted effort to corporatize distributors and move the generation and retail elements of the industry towards a competitive model. This led to a major restructuring of the industry.

Starting in 2004, the Provincial Government began to shift to a centralized model in which the Ministry of Energy and provincial agencies (e.g. Ontario Power Authority) began to play more active roles through directives, central planning, and province-led initiatives. In 2009, the Provincial Government passed the Green Energy and Green Economy Act, the central purpose of which was to promote renewable electricity production, conservation and demand management programs and smart grid technologies. The Act established feed-in-tariff programs for renewable energy and required distribution and transmission entities to connect such facilities. Distributors were permitted to own small-scale renewable energy generating facilities. The Act also introduced new objectives for the OEB, including the promotion of renewable energy, conservation and demand management, and smart grid technologies. It also required distributors to achieve conservation and demand management targets to be set by the OEB.

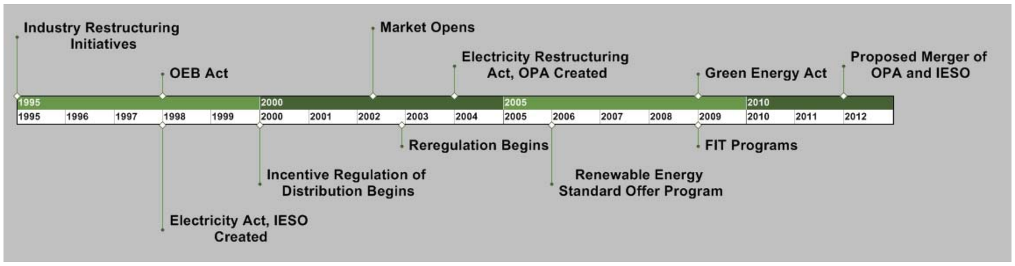


Figure 2: Timeline of Major Policy and Legislative Changes

Notably, the Act provided for more active Government involvement in the management of renewable energy, conservation and smart grid initiatives through Ministerial directives, which the Government has actively used.

Distributors are now permitted to own and operate distributed generation facilities. They are involved in the delivery of Conservation and Demand Management (CDM) programs, they have been required to install smart meters and many have investigated or implemented improved grid technologies. Distributors have also been charged with the implementation of government initiatives such as the Ontario Clean Energy Benefit (as amended) and other responsibilities. These expanded roles and accountabilities have not been realized without associated increases in costs.

During this period, through legislative and regulatory processes, distributors have also become responsible for implementing a number of policies with societal objectives that differed from the traditional obligations. Among these were low income customer programs, prescriptive customer service processes, and energy consumer protection.

B. FEED-IN-TARIFF PROGRAMS AND THE DECARBONIZATION AGENDA

Over the past twenty years, many countries have expanded their renewables programs as part of a broader decarbonization agenda. Some have introduced feed-in tariff (FIT) programs which fix prices paid for renewable energy, thereby providing for assurance of a long term revenue stream to the generator. Others have introduced programs which fix the quantity of renewable energy to be procured. These can take various forms, among them renewable portfolio standards (RPS) and tradable green certificate (TGC) schemes.[3]

Insight into the effectiveness in promoting renewable energy can be gleaned by examining the experience of various countries with FIT, RPS and TGC programs. For example, Denmark, Germany and Spain have relied primarily on evolving and aggressive FIT programs, while Great Britain and the U.S. (for example, the State of Texas) have instituted TGC and RPS programs. We note that the design of the Ontario FIT program was influenced by those in Germany, Denmark and Spain.[4]

Figure 3 below graphs the market share of renewables in a number of these jurisdictions over the course of the last two decades. Figure 4 graphs residential electricity prices over the same period.[5] In both graphs, jurisdictions with FIT programs are represented by solid lines; those with TGC or RPS programs have dashed lines.

FIT programs are highly effective in stimulating market penetration by renewable suppliers. However, jurisdictions that have implemented such

[3] Government renewable support policies can be grouped into three broad categories. The first group of policies consists of fiscal incentives, such as various forms of subsidies and tax incentives. The second group, public financing, includes public investments, loans and grants. The third group, and that most relevant to the electricity industry, consists of policies, such as FITs, RPS and TGCs, that require electricity consumers or companies to pay for renewable power. For further discussion, see Green, R. and Yatchew, A. (2012). "Support Schemes for Renewable Energy: An Economic Analysis." Economics of Energy & Environmental Policy, vol. 1(2), pages 83-98.

[4] See e.g., http://fit.powerauthority.on.ca/background/fit-program-benefits.

[5] Sources: National data on market shares are obtained from Renewables Information 2011, page 57, Table 3. National data on residential electricity prices are obtained from Electricity Information 2011, International Energy Agency, Table 3.7. The figures for Spain are adjusted to include the 'tariff deficit'. For Texas data see the US Energy Information Administration Electric Power Annual 2009, State Data Tables, http://www.eia.gov/cneaf/electricity/epa/epa_sprdshts.htm.

programs have also experienced substantial rate increases.[6] It is not necessarily the case that the rate increases were caused exclusively by the FIT programs themselves (one would need to do an analysis assessing what rates would have been in the absence of such programs).

Nor does this constitute an argument against renewables programs in general, and FIT programs in particular. Nevertheless, politicians, ratepayers and other stakeholders need to be realistic about what to expect. The long-term success of decarbonization programs is critically dependent on their public acceptability. Unexpected consequences can lead to policy reversals, often causing havoc in nascent local renewables industries.

Increasing the market share of renewable electricity will – until such technologies achieve grid parity – drive up electricity rates, primarily through commodity rates.

Furthermore, there are also cost and therefore rate impacts within the wires segments of the industry, both at the transmission and distribution levels. The integration of intermittent technologies (such as wind and solar) require investment in new technologies at the wires level.

It is important to ensure that, in the result, distribution rates are not restricted inappropriately as this could delay expenditures on vital infrastructure investments which would serve both new renewable generation and traditional load customers. Delaying expenditures in the short term can lead to higher overall costs in the longer term. Ensuring the timely planning of network investment and co-ordinating those investments on a regional basis with a view to the long term is an expressed priority for the Board's renewed regulatory framework.

[6] For example, between 1990 and 2010 the largest increase in renewable market share of any OECD country is exhibited by Denmark. Over the same period, Denmark also experienced the largest increase in electricity prices of this group.

Figure 3: Market Share of Renewables

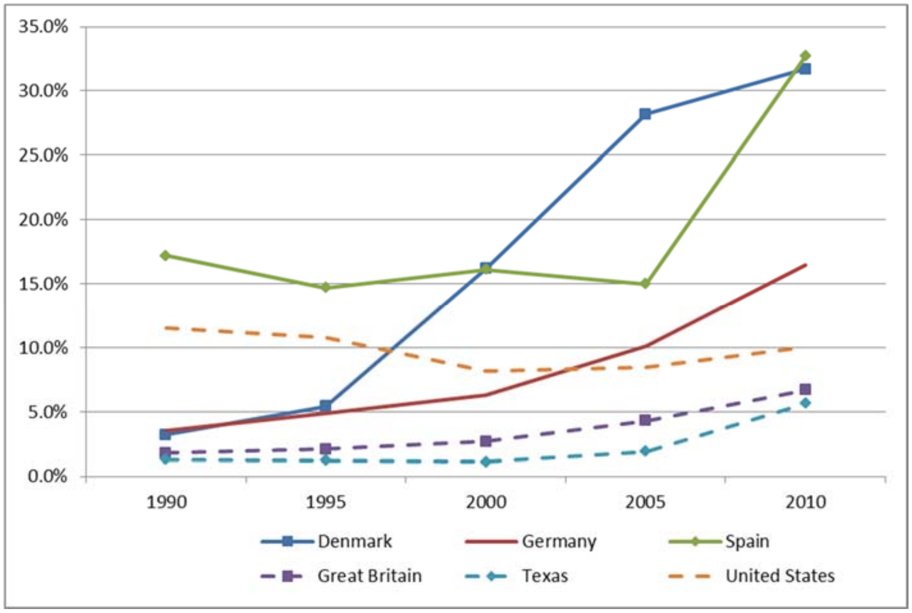
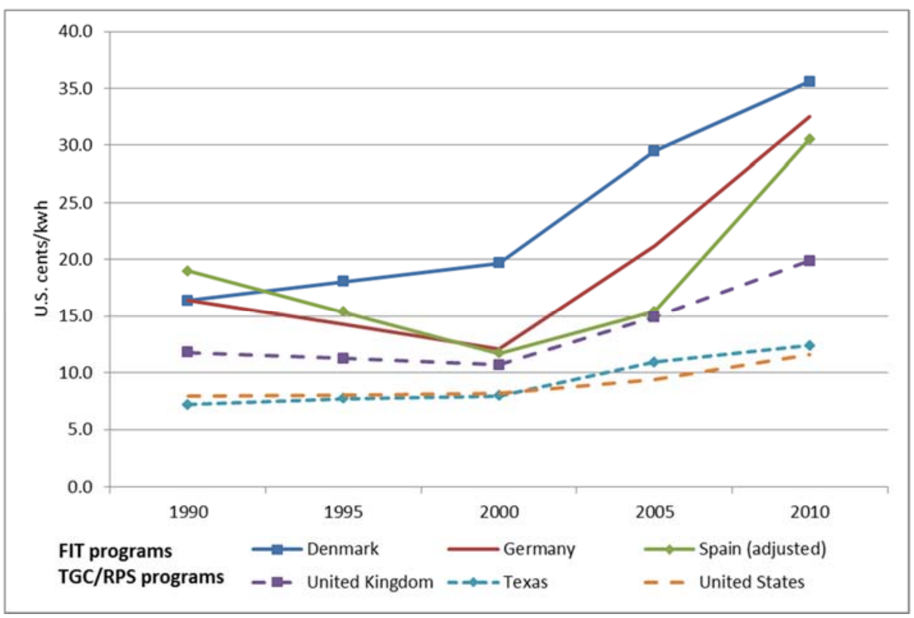


Figure 4: Residential Electricity Prices



C. THE CHALLENGES FACING DISTRIBUTION

The electricity distribution industry has faced a series of challenges over the past decade. Among these are the following.[7]

Infrastructure Refurbishment. In recent years, infrastructure investment in distribution has been driven by the need for replacement, expansion and upgrades. Such investments must be undertaken on a continuous basis if long-term costs are to be minimized and reliability is to be ensured. Major portions of distribution infrastructure were put in place many years ago and are approaching the end of their useful lifetime. Replacement of these assets at current prices puts significant upward pressure on rates. Furthermore, aging assets that remain in service require greater OM&A expenditures, which adds further pressure to costs.

New and Emerging Technologies. The Ontario distribution industry has been among the leaders in deployment of new technologies, among them smart meter / smart grid devices. These have put upward pressure on costs.

Conservation and Demand Management. Distributors are required to meet conservation and demand management targets set by the Ontario Energy Board. The OPA has developed a series of Province-wide programs and distributors have relied upon these programs to achieve their conservation and demand management objectives. In some cases, larger distributors have proposed additional programs.

Renewable and Distributed Generation. Policies and legislation towards renewable and distributed generation passed by the Ontario Government have dramatically increased the role that renewable technologies will play in forthcoming years. As the share of variable energy resources increases, the challenges of balancing the system also increase, mainly because of the variability and difficulty in predicting supply from these sources. Distribution systems originally conceived and engineered to deliver electricity will need to be modified to incorporate distributed generation.

Costs Pressures. Recent projections indicate that Ontario electricity prices will grow very significantly over the coming years. This realization has put pressure on cost structures throughout the industry. The commodity price of electricity is likely to increase much more quickly than distribution rates in the province.

Regulation and Government Policy. The Green Energy Act has created new obligations for wires companies, such as the requirement to connect renewable resources. The increased direct role of Government, through the

[7] A more detailed description may be found in "The Power to Deliver. Recommendations for the Future of Electricity Distribution in Ontario" EDA submissions to the Ontario Distribution Sector Review Panel, August 2012. ,

issuance of directives, is also likely to increase the uncertainty of the policy environment within which distributors operate.

3. TFP ANALYSIS – A SIMPLE EXPOSITION

A. THE MAIN IDEA

The measurement of productivity growth using total factor productivity (TFP) has been studied extensively and applied widely.[8] Broadly speaking, there are two methodologies for its implementation.

> The first is the index approach which is motivated by a simple, intuitively appealing idea. It compares the rate of growth of inputs into a production process to the rate of growth of output.
>
> The second is the cost function approach which attempts to determine the sources and drivers of productivity growth. Usually, the most important drivers are technological change and scale effects.

How are the two related?

For the purposes of the analysis here, productivity growth, as measured by the index model should be approximately equal to the combined effects of technology and scale.[9] That is,

Productivity Growth = Output Growth – Input Growth = Technology Effect + Scale Effect

The index model calculation estimates the first part – "Output Growth – Input Growth". The cost model approach estimates the second part – "Technology Effect + Scale Effect".

[8] The term "factor" refers to the inputs into the production process, such as capital and labour; and, "total" signifies that the measure is intended to capture the collective productivity of all inputs.

[9] The idea of relating and combining the two approaches was first put forth in a paper by Michael Denny, Melvyn Fuss, and Leonard Waverman 1981, "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, With An Application To Canadian Telecommunications"; in Productivity Measurement In Regulated Industries, ed. T. Cowing and R. Stevenson, 179–218. New York: Academic Press.

The above equation provides a simple template for framing a number of the issues at hand:

- PEG bases its recommendations on the index model formulation. It concludes that distributor output is growing faster than input at about 0.1% per year, which would reduce costs by about 0.1% per year. This is the first part of the equation.[10]

- The "Technology Effect" is estimated using the "trend coefficient" which is +1.2%, suggesting that cost pressures are *increasing* real costs at a rate of about 1.2% per year.[11] This is offset in part by the "Scale Effect" but the magnitude of the trend coefficient calls into question the index-based result and requires reconciliation.

- PEG's calculation of the combined technology and scale effects using the cost function approach yields a value of 0.07%, which would appear to be similar to the index based value of 0.10%.[12]

- Calculations provided by PSE on behalf of the Coalition of Large Distributors (CLD) dispute PEG's calculation and this conclusion.[13]

Before addressing these points and providing our own estimates of TFP growth, we provide some further background and elaboration.

B. MULTIPLE INPUTS, OUTPUTS AND BUSINESS CONDITIONS

In order to implement the index model approach, the following steps are required. First one needs to determine the quantities of each input into production (usually labour and capital). Even this step is challenging. To estimate the 'quantity' of labour one might be inclined to count the number of employees, or labour-hours. But how does one aggregate line workers,

[10] PEG report, May 31, 2013 (Table 18, page 67). http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379_PEG_Report_20130503.pdf

[11] Ibid. Table 12, page 55. The "Trend" coefficient is 0.012.

[12] Ibid. Tables 19-20 pages 71-72. The effect of business conditions is minimal.

[13] Research and Recommendations on 4th Generation Incentive Regulation, The Coalition of Large Distributors (CLD), Steven A. Fenrick, Power Systems Economics, May 27, 2013. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/CLD_DefiningMeasuringPerformance_Presentation.pdf.

administrative, management and other staff? A common approach is to first construct a price index for labour, then divide expenditures on labour by this index to determine a quantity index for labour. This just moves the problem back one step -- now one must find a sensible way to construct a labour price index that aggregates various kinds of employees.

If there are multiple outputs (in our case, the number of customers, capacity and deliveries) then a separate methodology is required for aggregating them. The approach taken by PEG is to import coefficient estimates from the cost model to construct weights for the three components of the output index.

Once all these steps are completed, then one can compare output growth to input growth in order to estimate productivity growth. The interpretation is appealing, but the result is only as reliable as the series of steps and assumptions that underpin it.

Calculation of TFP growth using the cost model actually requires fewer steps. Once the cost model has been estimated, the technology effect is simply the trend coefficient. Scale effects can be calculated directly from the estimated coefficients without the calculation of input indexes.

The cost model separately identifies the technological and scale effects, and it permits incorporation and evaluation of the effects of changing business conditions on costs and productivity.[14]

The index-based approach, as put forth in this proceeding, does not provide for such a decomposition. This shortcoming is especially important at a time when the policy and technological environment is changing, as has been the case in Ontario.

A further advantage of the cost model is that once it has been estimated, it can be used to compare efficiencies amongst distributors.

Figure 5 provides an overview of the steps involved in the estimation of TFP using each of the two methodologies outlined above. Two observations are worthy of attention and reiteration:

- First, the 'cost model' is estimated whether one is going to calculate TFP by comparing output growth to input growth, or whether one does so by calculating technology and scale effects.

- Second, the cost model approach permits the identification of the components of productivity changes (technology, scale and even business condition effects).

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[14] For simplicity, we have omitted the latter from the discussion to this point, but they can be readily incorporated into the calculation. We note that the calculations provided by PEG indicate that the impact of business conditions included in their model on productivity has been very small.

In view of these points it could be argued that the index model is only as transparent as the indexes upon which it is based. On the other hand, the ability of the cost model to distinguish between factors causing productivity change would seem to *increase* rather than reduce transparency – one can assess the plausibility of estimates by examining the contribution of each factor.

An analogy with medical diagnostics may be helpful. Allow for the moment that the index approach is akin to an X-ray, and the cost modeling approach is like an MRI. The X-ray is widely used and provides useful information of certain types. However, suppose one has back pain. The cause of the pain can usually be identified more clearly using an MRI. The X-ray may not even identify the problem until there is skeletal damage arising, for example, from the failure of a disc to provide a buffer between vertebrae.

In the present case, the use of the cost model to calibrate the index model[15] is akin to undergoing an MRI, then using the results to implement the X-ray procedure. It would seem that if the results of the two were dissonant, one would not want to ignore those contained in the MRI report. Rather, one would want to give it careful consideration.

Why then are index models used so widely? A key contributory factor is that the data required for implementing cost models are not widely available, (just as X-rays are often used because MRIs are much more expensive or simply not available). However, given that we have the capability to perform an MRI, it would seem imprudent to rely solely on X-ray results.

[15] See Figure 5.

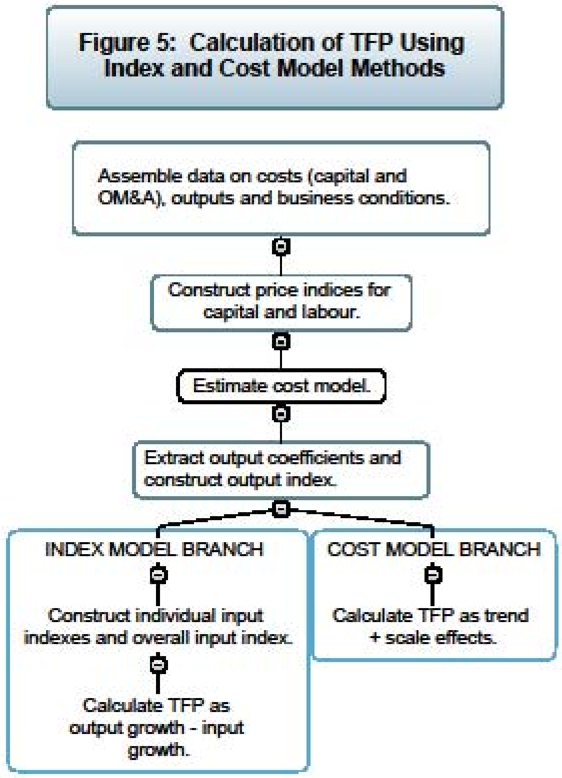
Figure 5: Calculation of TFP Using Index and Cost Model Methods
Assemble data on costs (capital and OM&A), outputs and business conditions.
Construct price indices for capital and labour.
Estimate cost model.
Extract output coefficients and construct output index.
INDEX MODEL BRANCH
Construct individual input indexes and overall input index.
Calculate TFP as output growth - input growth.
COST MODEL BRANCH
Calculate TFP as trend + scale effects.

4. PRODUCTIVITY ESTIMATES

A. THE COST MODEL

In conventional economic theory, a cost function maps the relationship between a firm's costs of production and the various conditions faced by the firm. Total costs depend on the prices of the inputs used in production, the scale of production, the various business conditions faced by the firm, the technology used for production, as well as the progression of this technology.

Given historical data on costs, inputs prices, output quantities and business conditions, statistical methods can be used to measure the cost structure of firms in an industry. The estimated cost function can, in turn, be used for industry analyses, for example, to study the pattern of changes in total factor productivity, or to evaluate the relative efficiency of different firms in the industry.

For electricity distributors, the key input prices are those that drive its capital costs, and the various labour and material resources required to operate, maintain and administer the enterprise (OM&A costs). Production scale can be inferred based on the total number of customers served, the kWh of electricity delivered, as well as the system capacity of the distributor, the latter reflecting peak demand.

Various other business conditions may also be important in electricity distribution, including: the density and spatial distribution of the customer base, the physical environment of the service territory, the percent of electricity lines buried underground, and the rate of growth of the distributor's customer base. We test the statistical significance of these factors in arriving at our preliminary model.

Configuration and ownership of transformation and other facilities may differ across distributors, leading to different types of charges to distributors. Considerable effort has been expended at this proceeding to attempt to assess which charges should be included and which excluded in order to provide for a fair comparison.

There remain questions about which low-voltage (LV) and high-voltage (HV) charges should remain in the cost data.[16] Furthermore, costs incurred by a distributor are affected by the magnitude of capital contributions in aid of construction (CIAC).

One of the methods for dealing with such variables is to include them as business condition variables, the impacts of which are estimated by the model.

[16] Indeed, PEG uses different measures of total costs in their index and cost models.

The cost model we estimate is in great degree similar to that estimated in the PEG Report. The main differences are in the inclusion of two additional business condition variables just described, and in the specification of the unexplained (random) component of the model. Technical details are provided in an appendix.

B. COST MODEL ESTIMATES

Estimates of our cost model (based on the 73 distributors for which data are available) are presented in Table 1. The estimated coefficients of input prices, business conditions and the "first order" terms of the output variables can be interpreted as cost elasticities for the 'average' distributor in the sample.

The estimate on the capital input price (WK) implies that a 10% increase in the price of capital will result in approximately a 6% increase in the costs of a distributor. Since OM&A costs constitute the other major component of total costs, this implies that a 10% increase in the price of OM&A will result in approximately a 4% increase in total costs.

The estimates on the output variables are all of the expected sign and statistically significant. By adding the coefficients together,[17] we obtain the implied scale elasticity for the average firm of approximately 0.63. That is, for the 'average firm' if output increases by 10%, costs will increase by 6.3%, the remainder of the increase being absorbed by improvements in scale economies.

Our estimate of the time trend implies that there have been significant cost pressures in the distribution industry between 2002 and 2011, leading to higher costs for distributors, on the order of 1.2% per year.

C. ESTIMATES OF TFP USING THE COST MODEL

The cost model may now be used directly to estimate TFP:

- Technology Effect: Since costs are increasing, the impact on TFP is -1.24% (the trend coefficient in Table 1).

- Scale Effect: From the previous section, the output scale elasticity is 0.63. Furthermore, during the 2002-2011 period, the output index

[17] 0.353 + 0.175 + 0.101 = 0.629

has been growing at 1.33% per year.[18] Combining these one obtains the scale effect to be $(1-0.63)\times 1.33\% = 0.49\%$.

- Cost Based TFP: TFP calculated using the cost model is just the sum of the technology and scale effect, that is -0.75%.[19]

The incorporation of business conditions within the calculation does not materially alter these results.

D. ESTIMATES OF TFP USING THE INDEX MODEL

The index-based approach implemented by PEG assigns weights to distributors that are roughly proportional to their size. The two largest distributors are excluded from the calculation, but the remaining large distributors are weighted much more heavily than medium or small distributors.

For example, the seven largest distributors remaining in the sample (those with more than 100,000 customers) are accorded approximately the same weight as all the other 64 distributors combined. This seems odd given that the objective is to estimate an average productivity factor that is to apply to each individual distributor.

We avoid these problems by assigning equal weights to all distributors. In particular, we calculate an individual productivity index for each distributor, then average across distributors. This calculation leads to an average index based productivity factor of -0.7%, (If the two largest distributors are excluded, the productivity factor changes to -0.6%.)

[18] The PEG Report, May 31, 2013, Table 14, page 62 reports a similar figure of 1.36%.

[19] It is useful to compare our cost based estimate of TFP growth rate with the corresponding estimate calculated in Tables 19 and 20, pages 71-72 of the PEG report. Their trend coefficient is 1.2%, the same as ours. The sum of the output elasticities is 0.75 resulting in a scale effect of (1.0-0.75)×1.36% = 0.34%. Therefore, using PEG coefficient estimates we obtain a cost based TFP growth rate of -0.86%.

Table 1

Cost Function Coefficients

VARIABLE KEY

Input Price:	WK = Capital Price Index
Outputs:	N = Number of Customers
	C = System Capacity Peak Demand
	D = Retail Deliveries
Other Business Conditions:	L =Average Line Length (km)
	CICA = % of Capital Costs In Aid of Construction
	LVHV = % of Net LV-HV Charges
	TREND = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.6088	53.392
N*	0.3529	5.318
C*	0.1747	2.721
D*	0.1011	2.666
WKxWK*	0.3182	13.532
NxN	-0.0516	-0.231
C*C	0.5213	2.432
DxD	0.1212	1.590
WKxN*	0.0366	2.437
WKxC	-0.0005	-0.032
WKxD*	0.0153	2.554
NxC	-0.2104	-1.048
NxD	0.1438	1.739
CxD*	-0.2252	-2.825
L*	0.3968	12.826
CICA*	-0.0202	-6.313
LVHV*	0.0029	2.452
Trend*	0.0124	10.602
Constant*	12.8649	396.148
Sample Period	2002-2011	
Number of Observations	730	

***Variable is significant at 95% confidence level**

5. BENCHMARKING AND THE ASSIGNMENT OF STRETCH FACTORS

The same cost model that is relied upon to calibrate the output index in the index modeling approach can be used to compare the relative efficiencies of distributors. Relative efficiencies are obtained by comparing costs predicted by the model for each distributor to their actual costs in recent years.

It is important to distinguish between the accuracy with which industry-wide productivity factors can be estimated, and the accuracy with which one can assess relative efficiencies of individual distributors. Though both can be obtained from the same model, the former is an average effect and can therefore be estimated with much greater precision than the latter, which involves predictions for each individual distributor. This creates real potential for classification of a distributor into the incorrect efficiency cohort.

Our analysis of the data reveals that even modest variations in model specification can lead to substantial changes in distributor rankings and migration of individual distributors to other efficiency cohorts. Table 2 contains our preliminary evaluations of relative efficiency using the cost model.

In our view, the use of peer group analysis to inform the process of cohort classification is problematic, largely because of the difficulty in determining appropriate peer groups. There are too many variables that can affect distributor costs to give one confidence in the allocation to peer groups. Further work on this approach would be needed if it is to be effective.

Given the Board's reliance on index based calculation of an industry-wide productivity factor, it may be worth considering distributor-specific productivity growth factors in the process of determining efficiency cohorts.

Distributors often make the point that their individual circumstances cannot be captured effectively by a model common to the industry as a whole. Differentiating variables such as reliability, urban core effects and system configuration have been among those that have emerged in discussions. Some distributors have suggested that one should examine a distributor's performance over time to see whether its unit costs are declining or increasing. This approach is worthy of consideration.

We also recommend that the Board use this opportunity to shift its approach to stretch factors by modifying the range to include rewards as well as penalties. Under the 3GIRM approach, every distributor was presented with an incentive to become more efficient through positive stretch factors of 0.2%, 0.4%, and 0.6%. Inherent in this approach is an assumption of additional inefficiency beyond that which the productivity factor is designed to address.

We propose going a step beyond the initial PEG proposal and introducing a reward for top tier efficiency, that is, stretch factors that range from -0.3% to +0.3%. This reward/penalty mix is conceptually attractive and practical. It is reasonable to expect that lean distributors will use the incremental funds to sustain their preferred ranking, thus establishing a sustainable framework for pursuing this objective.

Conceptually, it presents a balanced approach following a sustained period of efforts to drive out inefficiencies in the industry. A time comes in the lifecycle of maturing models where, after extensive refining of outcome-oriented behaviour, it is time to start rewarding a commitment to those efficiency outcomes.

Table 2: Preliminary Relative Efficiency Results

Report ID	Actual Minus Predicted Cost	Report ID	Actual Minus Predicted Cost
73	-53.6%	1	0.1%
5	-49.2%	56	1.6%
15	-43.0%	22	1.7%
69	-37.4%	64	2.2%
17	-35.8%	50	2.9%
44	-34.4%	53	3.0%
24	-30.2%	6	3.4%
10	-26.6%	4	4.3%
18	-22.1%	71	4.9%
59	-21.2%	27	5.7%
38	-19.9%	8	7.8%
35	-18.5%	16	8.2%
11	-15.6%	20	8.5%
14	-13.3%	31	8.6%
58	-13.1%	41	9.0%
63	-11.6%	12	9.9%
39	-11.2%	13	11.4%
43	-11.2%	47	11.9%
54	-10.6%	37	12.7%
65	-9.5%	46	13.0%
52	-8.4%	70	13.5%
23	-7.3%	3	14.1%
19	-7.1%	36	14.5%
2	-6.0%	42	16.6%
28	-5.2%	51	16.9%
57	-4.9%	33	17.4%
21	-4.4%	72	18.6%
60	-3.8%	40	19.4%
62	-2.3%	55	19.7%
7	-2.2%	45	23.7%
32	-2.0%	61	25.9%
67	-1.9%	34	27.0%
29	-1.3%	48	27.6%
25	-0.4%	66	28.2%
30	-0.3%	68	30.0%
		26	34.4%
		9	44.3%
		49	57.0%

6. THE INFLATION FACTOR

Although industry specific measures of inflation have been explored by the Board in the past, a broader measure of inflation was used during 3GIRM. Broader measures have several advantages. First, they are widely available and therefore easy to obtain. Second, they generally display less variability than industry-specific measures. Third, they are likely to be better understood and accepted by electricity users because they track the inflationary pressures directly experienced by consumers.

The rationale for using an industry-specific measure is that electricity distribution is very capital intensive, and therefore distributor costs evolve differently from general consumer or even producer price indexes. Certain specific materials used in electricity distribution may also be subject to cost fluctuations that diverge from broad measures of inflation. For these reasons, distributors have sought to explore industry-specific indices.

The PEG report proposes to use industry specific measures and to implement a three year moving average to smooth the series, thereby reducing volatility. Because monetary policies such as quantitative easing, have led to declines in interest rates, the current value, based on the three year period 2010-2012, would be 0.5%.

However, rising interest rates could push the industry-specific inflation factor to levels of 4% or even higher. In periods of volatile interest rates, increases and decreases could follow in quick succession. Such changes could result in confusion and resistance from ratepayers. For this reason, we recommend that the Board explore additional options for rate-smoothing, in particular mechanisms that mitigate the rate impacts of the *differential* between the industry specific inflation factor and a broader inflation measure.

One such mechanism could be as follows. When the industry-specific inflation factor is lower than a broad inflation measure, the allowable rate increase would use the latter to calibrate the allowable rate increase. The differential would then be used by the regulator to reduce the inflation factor in a future year when the industry-specific inflation rate exceeds the broad inflation measure.

For example, suppose that the current industry-specific inflation measure is at 0.5% and the broad inflation measure is 1.5%. The regulator sets the current inflation factor at 1.5%, banking the 1% differential. Suppose in the following year the industry-specific inflation rate is say 4% and the broad inflation measure is 2%, the regulator reduces the inflation factor by 1% (the amount that has been banked) to 3%.

7. CONCLUSIONS AND RECOMMENDATIONS

We have entered a period where productivity growth in the Ontario electricity industry -- as assessed using conventional measures -- may appear to be negative. This is likely because conventional measures do not fully reflect the broader range of activities that distributors are now undertaking as agents of provincial energy and social policies. (Economic turmoil in recent years is also a contributory factor.) There is every reason to expect that this period will last for the duration of 4GIRM or longer.

A greener industry will, for the foreseeable future, mean a costlier industry, not only for generation but for the wires companies that connect and serve renewable distributed generators. This is consistent with cost increases in other jurisdictions that have implemented ambitious conservation and FIT programs.

Thus, while a distributor's productivity growth in relation to conventional activities may in fact be positive, the rapid and substantial introduction of new activities may offset those advances and, from an aggregate view, result in apparent negative productivity.

It is important to reflect the actual productivity experience and reasonable expectations for productivity in the rate-setting process. Just as in situations where productivity is expected to improve in aggregate, distributors are pressed with reductions, where productivity is expected to decline in aggregate, distributors should be permitted their due increases. Failure to strike this balance will result in underfunding of distributors.

Where there is underfunding, less investment can be expected. This would perpetuate the "rate step" pattern that occurs in cost of service years. In order to provide ratepayers with steady, predictable rates, the incentive regulation rate-setting mechanism needs to reflect real cost pressures, including expected enhancements or reductions in productivity.

The incentive regulation mechanism is given by

Allowable Rate Increase = Inflation Factor – Productivity Factor – Stretch Factor.

Based on the most recently updates available from the Pacific Economics Group, the calibration would be as follows:

a. an industry specific inflation factor of 0.5% (based on the 2010-2012 period);
b. an industry-wide productivity factor of +0.1%;
c. a "stretch factor" ranging from 0.0% to +0.6%.

Allowable rate increases based on PEG figures would therefore range from about -0.2% to +0.4%. For most distributors, this would in effect constitute a rate freeze. Such an arrangement may prove to be unsustainable and could even undermine the Board's objective to "facilitate the maintenance of a financially viable electricity industry".[20]

In our view, this is inappropriate at a time when there is clear evidence of novel, externally-driven upward pressure on distributor costs, aside from the usual inflationary effects.

We recommend a productivity factor of -0.75% and stretch factors ranging from -0.3% to +0.3%. Accepting for the moment the industry specific inflation factor of 0.5%, this would result in allowable rate increases ranging from 0.95% to 1.55%. Most distributors would receive an increase of about 1.25%, which would be well in line with the broader inflation measures faced by consumers.

[20] Ontario Energy Board Act, 1998, Part 1.

APPENDIX A – NOTES ON TFP MEASUREMENT

The measurement of productivity growth[1] can be motivated by a simple, intuitively appealing idea which compares the rate of growth of inputs into a production process to the rate of growth of output.

Total factor productivity (TFP) is a commonly used term where

- "factor" refers to the inputs into the production process (such as capital and labour),
- "total" signifies that the measure is intended to capture the collective productivity of all inputs.

To illustrate the idea, assume for the moment that there is a single input X , and a single output Y . Then the growth in total factor productivity is given by

$$\dot{TFP} = \dot{Y} - \dot{X}$$

Productivity Growth = Output Growth – Input Growth (A.1)

where (as is customary in the literature) we use an elevated dot to denote the percentage rate of growth of a variable.

For example, if the input is growing at 2% and the output is growing at 3% then productivity is growing at 1%. Long run productivity growth is most importantly attributed to technological innovations but also to other effects, such as scale economies.

[1] The ideas in this section may be found in a paper by Michael Denny, Melvyn Fuss, and Leonard Waverman, 1981 entitled "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, With an Application To Canadian Telecommunications"; in Productivity Measurement In Regulated Industries, ed. T. Cowing and R. Stevenson, 179–218. New York: Academic Press.

Of course, managers, accountants and regulators scrutinize costs. In the one-factor setting, total costs (TC) are simply the price of the input times its quantity. Thus the rate of growth of total costs equals the rate of growth in prices plus the rate of growth in inputs. That is,

$$\dot{TC} = \dot{P} + \dot{X}$$

Total Cost Growth = Inflation + Input Growth

Using this expression, TFP growth in (1) can also be written as

$$\dot{TFP} = \dot{Y} - \left(\dot{TC} - \dot{P}\right)$$

Productivity Growth = Output Growth – Total Cost Growth Adjusted for Inflation

Alternatively, we may think of cost increases as being driven by inflation and increases in the level of output, offset in part by technological innovation and improved economies of scale. That is,

$$\dot{TC} = \dot{P} + \dot{Y} - \dot{T} - \dot{SE}$$

Total Cost Growth = Inflation + Output Growth – Technology Effects – Scale Effects

This decomposition of growth in total costs can be substituted into the immediately preceding equation to obtain

$$\dot{TFP} = \dot{T} + \dot{SE} \qquad \text{(A.2)}$$

Productivity Growth = Technology Effects + Scale Effects

Equations (A.1) and (A.2) are fundamental to understanding the present discussion (and disagreements) in the measurement of productivity growth.

- Equation (A.1) summarizes the index model approach. It expresses productivity growth as the difference between the output growth and input growth.

- Equation (A.2) summarizes the cost model (econometric benchmarking) approach. It expresses growth in terms of driving factors (technology and scale effects).

Equations (A.1) and (A.2) may now be combined to obtain:

$$\dot{TFP} \quad = \quad \dot{Y} - \dot{X} \quad = \quad \dot{T} + \dot{SE}$$

Productivity Growth = Output Growth – Input Growth = Technology Effects + Scale Effects

Economists scrutinize the causes of productivity growth and so the latter is attractive because it provides an explanation of the sources of growth.

Properly implemented, the two approaches should yield similar values.

APPENDIX B – THE COST MODEL

Specification

We use a translog specification for our cost model that takes into account the panel structure of the data. For distributor $i = 1, \ldots, N$ at time $t = 1, \ldots, T$ the total cost function is given by

$$\begin{aligned} \ln TC_{it} = \quad & \beta_0 + \sum_j \beta_j \ln Q_{j_{it}} + \sum_m \beta_m \ln \mathrm{W}_{m_{it}} \\ & + \frac{1}{2}\left(\sum_j \sum_l \gamma_{jl} \ln Q_{j_{it}} \ln Q_{l_{it}} + \sum_m \sum_n \gamma_{mn} \ln \mathrm{W}_{m_{it}} \ln \mathrm{W}_{n_{it}} \right) + \sum_j \sum_m \gamma_{jl} \ln Q_{j_{it}} \ln W_{m_{it}} \\ & + \sum_p \delta_p z_{p_{it}} + \delta_t t + \left(u_i + \varepsilon_{it} \right) \end{aligned} \tag{B.1}$$

where TC_{it} is total costs; $Q_{j_{it}}$ is the quantity of output j for $j = 1, \ldots, J$; $W_{m_{it}}$ is the price of input factor m for $m = 1, \ldots, \mathrm{M}$; $z_{p_{it}}$ is business condition variable p for $p = 1, \ldots, P$; t is time trend; and the composite error $u_i + \varepsilon_{it}$ consists of a time-invariant firm-specific effect combined with a transitory effect.

Most right-hand-side variables are first divided by their mean value. The approximation is therefore centered at a notional ‘average firm’. This is important as one generally expects approximations to deteriorate as one moves further away and from the point of expansion.

While estimation of the parameters is possible via Equation (B.1), this approach would not utilize all available information. A more efficient estimate may be obtained by augmenting the total cost equation with the set of share equations implied by Shepard's Lemma

$$S_{m_{it}} = \quad \beta_l + \sum_j \gamma_{jm} \ln Q_{j_{it}} + \sum_n \gamma_{mn} \ln \mathrm{W}_{n_{it}} + (v_{m_i} + \eta_{m_{it}}) \tag{B.2}$$

where the composite error of each share equation again consists of a time-invariant firm-specific effect combined with a transitory effect.

Since, by definition, the factor shares sum to unity, one cost share equation is redundant and thus can be excluded from the model. Since there are two factors (capital and OM&A), we include only the capital factor share.

Let lower case variable denote logarithms. The system of equation implied by our model now becomes

$$\begin{aligned} tc_{it} = \quad & \beta_0 + \sum_j \beta_j q_{j_{it}} + \beta_k wk_{it} + \frac{1}{2}\left(\sum_j \sum_l \gamma_{jl} q_{j_{it}} q_{l_{it}} + \gamma_{kk} {wk_{it}}^2 \right) + \sum_j \gamma_{jk} q_{j_{it}} wk_{it} \\ & + \sum_p \delta_p z_{p_{it}} + \delta_t t + \left(u_i + \varepsilon_{it} \right) \end{aligned} \tag{B.3}$$

$$SK_{it} = \quad \beta_k + \sum_j \gamma_{jk} q_{j_{it}} + \gamma_{kk} wk_{it} + (v_i + \eta_{it}) \tag{B.4}$$

where total costs and the price of capital have been divided by the price index for OM&A.

Formally, the equations in (B.3) and (B.4) comprise a "seemingly unrelated regression" model. Fix distributor i and consider the structure of second order moments of the errors. Within equations, we have

$$\begin{aligned} Var\left(u_i + \varepsilon_{it}\right) &= \sigma_u^2 + \sigma_\varepsilon^2 \quad \textit{and} \quad Cov\left(u_i + \varepsilon_{is}, u_i + \varepsilon_{it}\right) = \sigma_u^2 \;\; \textit{if } s \neq t \\ Var\left(v_i + \eta_{it}\right) &= \sigma_v^2 + \sigma_\eta^2 \quad \textit{and} \quad Cov\left(v_i + \eta_{is}, v_i + \eta_{it}\right) = \sigma_v^2 \;\; \textit{if } s \neq t \end{aligned} \tag{B.5}$$

and between equations, we have

$$\begin{aligned} Cov\left(u_i + \varepsilon_{is}, v_i + \eta_{it}\right) &= \sigma_{uv} + \sigma_{\varepsilon\eta} \quad \textit{if } s = t \\ Cov\left(u_i + \varepsilon_{is}, v_i + \eta_{it}\right) &= \sigma_{uv} \qquad\qquad \textit{if } s \neq t. \end{aligned} \tag{B.6}$$

This implies the following matrix Ω_i for the covariance structure for the composite error terms of distributor i :

$$\begin{bmatrix} \sigma_u^2 + \sigma_\varepsilon^2 & \sigma_u^2 & \cdots & \sigma_u^2 & \sigma_{uv} + \sigma_{\varepsilon\eta} & \sigma_{uv} & \cdots & \sigma_{uv} \\ \sigma_u^2 & \sigma_u^2 + \sigma_\varepsilon^2 & \cdots & \sigma_u^2 & \sigma_{uv} & \sigma_{uv} + \sigma_{\varepsilon\eta} & \cdots & \sigma_{uv} \\ \vdots & \vdots & \ddots & \vdots & \vdots & \vdots & \ddots & \vdots \\ \sigma_u^2 & \sigma_u^2 & \cdots & \sigma_u^2 + \sigma_\varepsilon^2 & \sigma_{uv} & \sigma_{uv} & \cdots & \sigma_{uv} + \sigma_{\varepsilon\eta} \\ & & & & & & & \\ \sigma_{uv} + \sigma_{\varepsilon\eta} & \sigma_{uv} & \cdots & \sigma_{uv} & \sigma_v^2 + \sigma_\eta^2 & \sigma_v^2 & \cdots & \sigma_v^2 \\ \sigma_{uv} & \sigma_{uv} + \sigma_{\varepsilon\eta} & \cdots & \sigma_{uv} & \sigma_v^2 & \sigma_v^2 + \sigma_\eta^2 & \cdots & \sigma_v^2 \\ \vdots & \vdots & \ddots & \vdots & \vdots & \vdots & \ddots & \vdots \\ \sigma_{uv} & \sigma_{uv} & \cdots & \sigma_{uv} + \sigma_{\varepsilon\eta} & \sigma_v^2 & \sigma_v^2 & \cdots & \sigma_v^2 + \sigma_\eta^2 \end{bmatrix}. \tag{B.7}$$

The independence between firms yields:

$$\Omega = \begin{bmatrix} \Omega_1 & 0 & \dots & 0 \\ 0 & \Omega_2 & \dots & 0 \\ \vdots & \vdots & \ddots & \vdots \\ 0 & 0 & \dots & \Omega_N \end{bmatrix}.$$

The basic formulation of our cost model is identical to that of PEG's, except for the specification of the covariance structure of the econometric term. We explicitly take into consideration panel structure of data, and model a composite error that consists of a firm-specific time-invariant effect combined with a random transitory effect.

PEG Residual Structure

PEG uses a heteroskedastic first-order vector autoregressive model for the residual. In the notation of equations (B.3) and (B.4) the PEG specification sets u_{it} and v_i equal to zero, but introduces additional structure on the remaining residuals as follows:

$$Var(\varepsilon_{it}) = \sigma^2_{\varepsilon i} \qquad Var(\eta_{it}) = \sigma^2_{\eta i} \qquad Cov(\varepsilon_{it}, \eta_{it}) = \sigma_{\varepsilon\eta i} \ .$$

$$Cov(\varepsilon_{it}, \varepsilon_{it-s}) = \rho^s_{\varepsilon}\sigma^2_{\varepsilon i} \qquad Cov(\eta_{it}, \eta_{it-s}) = \rho^s_{\eta}\sigma^2_{\eta i} \ .$$

There are also non-contemporaneous covariances between equations of the form:

$$\begin{aligned} Cov(\varepsilon_{it}, \eta_{it-s}) &= \rho^s_{\varepsilon}\sigma_{\varepsilon\eta i} \quad for \;\; s = 1, \dots, T-1 \\ Cov(\eta_{it}, \varepsilon_{it-s}) &= \rho^s_{\eta}\sigma_{\varepsilon\eta i} \quad for \;\; s = 1, \dots, T-1. \end{aligned}$$

Estimation

We use generalized least squares (GLS) to estimate our model.[1] Equations (B.3) and (B.4) are first jointly estimated using ordinary least squares while imposing cross-equation constraints on common parameters. The residuals are used to compute their associated second-order moments, and an estimate of the covariance matrix Ω which is then inserted in the GLS estimator.

[1] "Chapter 7: Estimating Systems of Equations by OLS and GLS," in Wooldridge, J.M. (2002). *Econometric Analysis of Cross Section and Panel Data*. MIT Press.

Data

We use data developed by the Pacific Economics Group Research LLP (PEG) for their report to the Ontario Energy Board. Two minor adjustments are made to the data prior to estimation:

1. The 2004 observation for Erie Thames Powerlines Corporation contains an anomaly in its record of retail deliveries. PEG deal with this observation by dropping it from the sample altogether. Instead, we replace the recorded 2004 deliveries with the average of 2003 and 2005 deliveries.

2. The 2002 observation for Canadian Niagara Power Inc. appears to contain an anomaly: although there are apparently no LV-HV charges, the recorded OM&A costs net of LV-HV charges differ from the recorded OM&A costs gross of LV-HV charges. We use the OM&A costs gross of LV-HV charges for this observation.

Variations

Initially, the model we estimate differs from the PEG specification only in the structure of the (unobserved) residual. We also consider variations on this specification. Among them are the following:

1. PEG includes CIAC as well as LV charges, but excludes HV charges in its measures of total costs for the cost econometric model. The index model TFP analysis excludes CIAC and LV charges and includes HV charges are included. As a robustness check, we consider a specification of our model where costs are constructed using the index model definitions.

2. As the discussion surrounding the measurement and appropriate role of CIAC, LV and HV charges is ongoing, we include these as business condition variables in our model.

3. We evaluate the consequences of excluding statistically insignificant variables in order to assess the extent of migration between efficiency cohorts.