Concept Paper on Empirical Analysis and Benchmarking To Be Used in the Renewed Regulatory Framework for Electricity

Report to the Ontario Energy Board

December 2012

Pacific Economics Group Research, LLC

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1. Introduction

On October 18, 2012, the Ontario Energy Board (the Board) released a Report of the Board titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the RRFE Board Report). The RRFE Board Report says that "(t)he renewed regulatory framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers."[1] The RRFE Board Report outlines policy objectives and parameters in three main areas: 1) rate setting; 2) planning; and 3) measuring performance.

The RRFE Board Report sets out three rate-setting options: 4th Generation Incentive Rate-setting (4th Gen IR), which the Board considers suitable for most distributors; Custom Incentive Rate-setting (Custom IR) for distributors with large or highly variable capital requirements; and an Annual Incentive Rate-setting Index (Annual IR) for distributors with limited incremental capital requirements. The 4th Gen IR and Annual IR options will use rate adjustment formulas that are calibrated using estimates of more Ontario-specific industry input price and total factor productivity (TFP) trends, as well as benchmark-based information on each distributor's relative efficiency. Pacific Economics Group Research (PEG) has been retained by Board staff to undertake empirical research that can inform the Board's choices for these empirical measures.

This report is a primer on the empirical metrics and methods that will be the subject of PEG's empirical research. Although the report addresses empirical issues, it is nevertheless conceptual in nature since it does not present any actual empirical analysis. Instead, the report is intended to educate and inform stakeholders about important empirical concepts so that they are better prepared to assimilate and comment on the empirical analysis that PEG ultimately develops. This Concept Paper will initiate a process in which stakeholders have an opportunity to examine and comment on critical empirical issues that will arise in 4th Gen IR. The Concept Paper also identifies a number of such issues that will

[1] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012, p. 2.

be discussed at the January 2013 Stakeholder meeting and in the Working Group meetings that follow in January through March 2013.

Following this introduction, the next section briefly reviews the three rate setting options established by the Board. Section Three discusses the key empirical metrics to be estimated in 4th Gen IR, which will also be used to calibrate the rate adjustment formula for the Annual IR. Section Four considers aspects of PEG's empirical analysis that may be potentially useful for the Custom IR approach. Finally, Section Five briefly discusses the next steps PEG will pursue to develop the relevant metrics as well as presenting a list of specific empirical issues to be examined during the Working Group meetings.

2. Overview of Ratemaking in the RRFE Board Report

As discussed, the Board has established three rate-setting options under its Renewed Regulatory Framework for Electricity Distributors (RRFE). Each distributor is allowed to select the method that it believes best meets its needs and circumstances. The options are 4th Generation Incentive Rate-setting ("4th Gen IR"); Custom Incentive Rate-setting ("Custom IR"); and an Annual Incentive Rate–setting Index ("Annual IR"). Before we address the empirical concepts and methods to be used in PEG's work, it is important to understand these rate-setting options and the empirical metrics necessary to implement them. This Section briefly reviews the three rate-setting approaches established under the RRFE.

2.1 Fourth Generation Incentive Regulation

The 4th Gen IR builds on the 3rd Gen IR, which has been in effect since 2008, but is modified to better reflect input price and productivity trends in Ontario. 4th Gen IR is designed to be appropriate for distributors that expect some incremental investment needs during the term of the plan. The Board believes that, in practice, 4th Gen IR will be appropriate for most distributors in the Province.[2]

Under this option, rates are set in the first year of the term using a single, forward test-year estimate of the distributor's cost of service. Rate adjustments over the remaining four years will be set using a comprehensive price cap adjustment formula.

As in the 3rd Gen IR, the allowed change in regulated rates for distribution services is based on the growth in an inflation factor minus an X-factor. The Board has concluded that the inflation factor for the 4th Gen IR will be a more industry-specific inflation factor designed to better track inflation in the prices of inputs used by the Ontario electricity distribution sector.[3]

In 3rd Gen IR, the Board considered using an industry-specific inflation factor but decided against doing so because of concerns about the volatility of such an index. The Board has concluded that concerns regarding volatility will be mitigated by the methodology it selects

[2] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 14.

[3] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 16.

to measure inflation. The Board has said that it will be guided by the following criteria when deciding on an appropriate inflation factor:[4]

- the inflation factor must be constructed and updated using data that are readily available from public and objective sources such as Statistics Canada, the Bank of Canada, and Human Resources and Social Development Canada;
- to the extent practicable, the component of the inflation factor designed to adjust for inflation in non-labor prices should be indexed by Ontario distribution industry-specific indices; and
- the component of the inflation factor designed to adjust for inflation in labor prices will be indexed by an appropriate generic and off-the-shelf labor price index (i.e., the labor price index will not be distribution industry-specific).

The basic architecture for the X-factor in the 4th Gen IR formula is intended to be similar to that developed in 3rd Gen IR. In its July 14, 2008 EB-2007-0673 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, the Board described the components of the 3rd Gen IR X-factor as follows:

> The productivity component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.
>
> The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that distributors are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by distributor and depend on the efficiency of a given distributor at the outset of the IR plan. Stretch factors are generally lower for distributors that are relatively more efficient.[5]

The Board has indicated in the RRFE Board Report that it intends to retain this basic architecture for 4th Gen IR but concluded that the productivity factor will be based on an estimate of industry Total Factor Productivity (TFP) growth in Ontario's electricity distribution

[4] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 16.

[5] EB-2007-0673 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008, p. 12.

sector. A single productivity factor will be set in advance and will apply to all distributors during the term of the 4th Gen IR. The Board used an index-based approach for estimating the industry TFP trend in 3rd Gen IR and intends to use the same approach for 4th Gen IR.[6]

The Board has stated that its basic approach for assigning stretch factors under the 3rd Gen IR will continue under 4th Gen IR, although the approach will be modified to reflect distributors' *total* cost performance.[7] Currently, each distributor is assigned to one of three efficiency cohorts based on two benchmarking evaluations of that distributor's operation, maintenance, and administrative (OM&A) costs. Since 2008, these cohort assignments have been used to assign stretch factors.

The first benchmarking evaluation compares a distributor's OM&A unit cost (*i.e.* OM&A cost divided by a comprehensive index of the distributor's output) to the average OM&A cost for that distributor's designated peer group. The peer groups were created based on PEG's analysis of the variables that drive differences in OM&A costs across the Ontario electricity distribution industry. Each peer group is characterized by a distinct set of significant cost drivers.

The second benchmarking analysis is based on an econometric cost model. Using statistical methods, PEG developed an econometric model of each firm's OM&A cost. The parameters of the model were estimated using Ontario data. After these parameter estimates were obtained, data on the cost "driver" variables for each distributor were inserted into the model to develop an estimate of each firm's predicted (or expected) OM&A cost. Each year, the distributor's actual costs are compared to the predicted cost generated by the model plus or minus a confidence interval around the cost prediction. If actual cost is *below* predicted cost minus the lower bound of this interval, the difference between actual and predicted costs is statistically significant and the distributor is deemed to be a superior cost performer. On the other hand, if actual cost is *above* predicted cost plus the upper bound of the confidence interval, the difference between actual and predicted costs is statistically significant and the distributor is deemed to be an inferior cost performer. If the difference between actual and predicted cost is within the confidence interval, the distributor is deemed to be an average cost performer.

[6] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 17.

[7] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 17-18.

The efficiency cohorts in 3rd Gen IR are determined using both benchmarking evaluations. If a distributor is a superior cost performer and in the top third of the industry on the unit cost benchmark, it is in efficiency cohort I and assigned a stretch factor of 0.2 per cent. If a distributor is an inferior cost performer and in the bottom third of the industry on the unit cost benchmark, it is in efficiency cohort III and assigned a stretch factor of 0.6 per cent. All other distributors are in efficiency cohort II and assigned a stretch factor of 0.4 per cent. Larger stretch factors are assigned for relatively less efficient firms since they are deemed to have greater potential to achieve incremental productivity gains. [8]

In 4th Gen IR, the Board will continue to use the general approach developed in 3rd Gen IR to inform its choices for stretch factors, although PEG's analysis will now involve total cost evaluations. More precisely, instead of having stretch factor values be informed by how a distributor performs on unit OM&A costs (relative to a peer group) and econometric benchmarks of OM&A costs, stretch factors in 4th Gen IR will be now be informed by how a distributor performs on total unit costs (relative to a peer group) and econometric benchmarks of total cost. The Board will determine the appropriate stretch factor values for the three efficiency groups (i.e., whether the current values of 0.2 per cent, 0.4 per cent, and 0.6 per cent continue to be appropriate) in conjunction with its determination of the productivity factor for 4th Gen IR.

2.2 Custom IR

The Custom IR method is intended to be customized to fit a specific distributor's circumstances over the five year term of the plan. Accordingly, rates will be set based on a five year forecast of a distributor's revenue requirement and sales volumes.[9] Specifics of how the costs approved by the Board will be recovered through rates over the plan term will be determined in individual rate applications. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor.

[8] The Board's decision on how to establish the three efficiency cohorts is presented in EB-2007-0673 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008, pp. 20-23; the Board's decision on the empirical values for each of the three efficiency cohorts is presented in EB-2007-0673 *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, September 17, 2008, pp. 19-22.

[9] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 18.

The Board expects that a distributor filing a Custom IR proposal will provide robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that time frame.[10] In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

Allowed rate changes under Custom IR will be determined by the Board on a case-by-case basis, and the Board's determination will be informed by empirical evidence including:

- the distributor's forecasts (revenues and costs, including inflation and productivity);
- the Board's inflation and productivity analyses; and
- benchmarking to assess the reasonableness of the distributor's forecasts.

Expected inflation and productivity gains will be built into rate adjustments over the term of the Custom IR plan.[11]

2.3 Annual IR

The Annual IR option is intended to provide a simpler and more streamlined approach to rate-setting than the other alternatives. Initial rates are determined simply by applying a price cap formula to the distributor's existing rates rather than through a cost of service review. Rates are then adjusted by this same price cap formula in subsequent years. Unlike the other ratemaking options, there is no fixed term for the Annual IR, and a distributor may apply for a cost-based rebasing of its rates and the selection of an alternate rate-setting approach at any time.

Every distributor selecting the Annual IR option will be subject to the same rate adjustment formula. This formula will include an inflation factor minus an X-factor. The inflation factor in the Annual IR will be identical to the inflation factor that is established for 4th Gen IR.

There will be two components of the Annual IR X factor: a productivity factor and a stretch factor. The productivity factor will initially be the same as that applied to distributors under 4th Gen IR. If a distributor elects to stay on Annual IR beyond the term of 4th Gen IR (*i.e.*

[10] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012, p. 19.

[11] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012, p. 19-20.

beyond 2019), the productivity factor for Annual IR will be adjusted to reflect the industry TFP trend that is re-estimated during subsequent "generations" of IR.

The stretch factor under Annual IR will be equal to the value of the stretch factor assigned to the efficiency III cohort *i.e.* it will be equal to the highest possible value of the stretch factor. As with the productivity factor for Annual IR, the stretch factor will be updated to reflect the stretch factors established in subsequent generations of IR. Thus if a distributor elects to stay on Annual IR beyond 2019, its stretch factor will be updated after 2019 to reflect the highest value of the stretch factor that prevails for the Ontario electricity distribution industry at that time.

3. Key Empirical Concepts for 4th Generation IRM

As already noted, the 4th Gen IR option will utilize rate adjustment formulas that are calibrated with estimates of industry input price inflation, industry TFP trends, and benchmark-based estimates of distributors' total cost efficiency. The Annual IR option will also make use of these measures. PEG has been retained by Board staff to develop estimates of these metrics. This Section will discuss some of the main conceptual issues involved in developing these measures.

3.1 Inflation Factor

A more industry-specific inflation factor will be used as the inflation measure in 4th Gen IR. This factor should be designed to better reflect inflation in the price of the inputs procured by Ontario's electricity distribution sector. It will be constructed as a weighted average of the growth of input price subindexes, where each subindex is intended to measure the growth in prices for a particular class of inputs. The weight applied to each input price subindex will be equal to the associated input's share of total electricity distribution costs.

Electricity distributors procure three broad classes of inputs: 1) capital; 2) labor; and 3) non-labor, OM&A expenses. The main challenge in developing a more industry-specific inflation factor is identifying the best, publicly available input price sub-indexes for electricity distributors' capital, labor, and non-labor OM&A expenses, respectively. Once these are identified, composite inflation is easily computed as the weighted average of the inflation rates in each subindex, where the weights are equal to each associated input's share in the industry's total cost (the calculation of total power distribution cost is discussed in Section 3.2).

PEG has investigated available input price indexes in Canada on several occasions. PEG also notes that staff's work in the 3rd Gen IR consultations with respect to capital and materials (*i.e.* non-labor OM&A) sub-indices may be informative. Broad inflation measures (such as the GDP-IPI or CPI) have been used to measure materials input prices in other jurisdictions. However, the RRFE Board Report notes that to the extent practicable, non-labor prices should be indexed by Ontario distribution industry-specific indices. With respect to labor, generic and off-the-shelf labor price indices (i.e. not distribution industry-specific) are also available. An important issue for consultation for the Performance, Benchmarking and Rate Adjustment Working Group (PBR Working Group) will be examining the merits of different input price subindices to be used to develop the inflation factor.

Another important consideration when constructing the inflation factor is volatility. In 3rd Gen IR, concern over the volatility of an industry-specific inflation factor was one of the reasons the Board decided against using such an inflation factor at that time.[12] PEG will address this concern by investigating different approaches that mitigate year-to-year volatility in the inflation factor. PEG will also evaluate the historical volatility in the price subindexes and the overall inflation factor that is constructed when developing our recommendation for an appropriate inflation factor for 4th Gen IR. Alternative approaches for mitigating volatility in the inflation factor will be another important area for consultation with the PBR Working Group.

3.2 Ontario TFP Trends

Productivity measures the transformation of inputs into outputs. In the present context, "inputs" refer to the resources an energy network procures in order to provide network outputs. Total factor productivity (TFP) measures the relationship between all the outputs provided by a distributor and all the inputs that the distributor procured to provide those outputs. Partial factor productivity (PFP) measures the relationship between the distributor's comprehensive output and a more narrow measure of inputs. For example, labor productivity would measure the productivity of a distributor with respect to its use of labor inputs only.

In most distributor applications, TFP and PFP are measured with indexes that aggregate several types of output and inputs into comprehensive output quantity and input quantity metrics. Each dimension of output quantity and input quantity is measured by what is sometimes referred to as a subindex. A TFP *level* index is defined as the ratio of an output quantity index to a comprehensive input quantity index.

$$TFP = \frac{Output\ Quantities}{Input\ Quantities}. \qquad [1]$$

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

[12] EB-2007-0673 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008, pp. 10-11.

firm (or group of firms) at different points in time. The latter metric is a measure of TFP growth, and the trend in a TFP index is the difference between the trends in the component output quantity and input quantity indexes.

$$trend\ TFP = trend\ Output\ Quantities - trend\ Input\ Quantities\,. \qquad [2]$$

The measures for PFP are analogous. A PFP level index is defined as the ratio of an index of comprehensive output quantity to an input quantity subindex, such as an index of OM&A input. In this example, the growth in OM&A PFP would be equal to the growth in comprehensive output quantity minus the growth in OM&A input quantity. Mathematically, it can be shown that the growth in TFP can be decomposed into a weighted average of the growth in PFP for the different inputs used in production.

Measuring TFP growth for the Ontario electricity distribution industry therefore involves developing an aggregate index of the industry's output quantity and an aggregate index of the industry's input quantity. We deal with each of these issues in turn.

3.2.1 Output Quantity Index

As discussed in PEG's April 2011 Report to the Board *Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper,* when TFP measures are used in rate setting applications, the appropriate measures of distributor output to be used to develop the output quantity index are the billing determinants.[13] Theoretically each billing determinant should be weighted by its share of regulated distribution revenue, but in practice these revenue share weights are often not available. When that is the case, an appropriate alternative is to weight each billing determinant by its relative cost elasticity, which can be estimated through an econometric cost function. The "relative" cost elasticity of billing determinant *i* would be equal to the estimated elasticity of electricity distribution cost with respect to billing determinant *i*, divided by the sum of the estimated cost elasticities for all billing determinants.

The dominant billing determinants for electricity distributors in Ontario are customer numbers, kWh and, for some customer groups, peak kW. PEG therefore intends to use each of these output quantity measures when developing an aggregate index of industry output quantity.

[13] Kaufmann, L., *Defining, Measuring, and Evaluating the Performance of Ontario's Electricity Networks: A Report to the Board,* April 2011, pp. 30-33.

PEG may also investigate alternate output measures that break down these measures into more disaggregated output measures (*e.g.* rather than using total kWh in the output quantity index, we may investigate using both residential and non-residential kWh deliveries).

Data on the share of each billing determinant in regulated distribution revenue are not readily available in Ontario. Trying to estimate these revenue shares through econometric methods may also not be feasible or desirable. PEG therefore intends to weight each output subindex by its cost elasticity share. These cost elasticity shares will be estimated in our total cost benchmarking work, which is explained further in Section 3.3. The output index PEG developed in 3rd Gen IR also used cost elasticity rather than revenue share weights.

3.2.2 Input Quantity Index

As previously discussed, there are three main classes of inputs for electricity distributors: capital, labor, and non-labor OM&A inputs. The growth in the input quantity index would be constructed as the weighted average of the growth in each of these input quantity subindexes. The weight for each input subindex would be equal to its share of the industry's total electricity distribution cost.

Capital accounts for the largest share of electricity network input costs and poses the most significant measurement problems. PEG will therefore begin by discussing the measurement of capital. We then turn to the measurement of labor and non-labor OM&A inputs.

3.2.2.1 Capital Costs and Inputs

In practical terms, measuring the quantity of capital typically begins with a *benchmark* capital stock, or (price deflated) value of capital in some base year. Benchmark capital stocks are often deflated by a "triangularized weighted average" of capital asset prices over a multi-year period preceding the year of the benchmark capital value.[14] If there was a full series of capital stock additions since the inception of each distributor in the industry, it would not be necessary to start with a benchmark capital stock, for actual data on capital additions could then be used to develop estimates of capital quantity in any given year. In practice, however, it is almost never

[14] See Stevenson (1980) for a discussion of this approach.

possible to obtain the full historical series of capital stock changes, so capital quantity measurement must begin with a benchmark value in a base year.

The base year for the capital quantity should be as distant from the present as is practical. As the base year becomes more distant, the value for the latest values of the capital quantity depend more on observed values for capital additions, which have been added to this benchmark value. The value for the benchmark capital stock therefore becomes relatively less important in terms of the values of capital quantities that are computed.

The following perpetual inventory equation is used to compute subsequent values of the capital quantity index (*i.e.* the capital stock) after the benchmark year:

$$XK_t = (1 - d) \cdot XK_{t-1} + \frac{VI_t}{WKA_t}. \quad [3]$$

Here, the parameter, d, is the economic depreciation rate, VI_t is the value of gross additions to the distributor plant and WKA_t is an index of distributor plant asset prices. In practice, then, developing measures of capital quantities requires:

1. A benchmark capital year
2. Measures of capital additions in subsequent years
3. A measure of the economic depreciation rate on capital
4. An index of distributor plant asset prices

Data used to develop this capital benchmark value will be drawn from MUDBANK. PEG will infer capital additions for the industry between 1989 and 1998 using MUDBANK data. Data are not available for years 1999 through 2001, so PEG will also infer capital additions for these years by using available data on gross capital plant values in 1998 and 2002 and estimates of plant retirements based on average plant retirement data in years where this information is available.[15]

[15] Given the challenges with the capital stock data in Ontario, it may be argued that "physical" capital metrics, such as the km of distribution line, are an acceptable proxy for the monetary capital measures that are typically used in TFP and cost analyses. In 3rd Gen IR, this was advocated by the Coalition of Large Distributors (CLD's), and they proposed an alternate TFP estimate that relied in part on physical capital metrics. In its July 2008 Report (*op cit)*, the Board rejected CLD's TFP estimate and said its "greatest concern" with their methodology was their measurement of capital. This was an appropriate decision because there are almost no circumstances in which physical capital measures are appropriate for use in TFP or cost research. The relative merits of physical and monetary measures of capital are discussed extensively in Appendix Two of Kaufmann *op cit.*

PEG will use historical data from Ontario, as well as studies undertaken in the economics literature and applied by the US Bureau of Economic Analysis (within the Department of Commerce), to determine the most appropriate economic depreciation rate in Ontario. The appropriate value of the depreciation rate will also be an issue for consultation in the PBR Working Group. PEG will use a geometric rate of depreciation (*i.e.* capital depreciates by a constant annual percentage rate each year), which has support in the economic and applied literature. The index of distributor asset prices will be identical to the price subindex that will be used to measure capital asset prices for the inflation factor discussed in Section 3.1.

When computing the growth in the input quantity index, the growth in the capital subquantity index is weighted by capital's share of total electricity distribution cost (*i.e.* electricity distribution capital cost divided by total electricity distribution cost). It is accordingly necessary to develop estimates of capital cost when estimating industry TFP growth. In general terms, capital cost in a given year *t*, CK_t, is computed as the product of a capital rental price (also referred to as a capital service price index) WKS_t and a capital quantity index, XK_{t-1}.

$$CK_t = WKS_t \cdot XK_{t-1}. \qquad [4]$$

The capital rental or service price index may be thought of as the annual cost (including the opportunity cost) of owning a unit of plant.[16] A common formula for the capital service price index, WKS_t, is:

$$WKS_t = r_t \cdot WKA_{t-1} + d \cdot WKA_t - \left(WKA_t - WKA_{t-1}\right). \qquad [5]$$

In equation [5], r_t is a measure of the return on capital assets. This can be measured in various ways. One option in Ontario is to use the Board's approved weighted average cost of capital and other alternatives will be examined in the PBR Working Group. In this formula, the three components of the capital service price correspond to the opportunity cost of capital, depreciation, and capital gains.

[16] For further discussion of the concept of the user cost of capital, see Kaufmann *op cit*, pp. 46-47.

3.2.2.2 OM&A Costs and Inputs

The quantity subindex for OM&A will be estimated as the ratio of distribution OM&A expenses to an index of OM&A prices. The OM&A price index will be a weighted average of the labor and non-labor OM&A subindexes that we use to estimate the inflation factor, as described in Section 3.1. The weights applied to these indexes will be equal to the share of labor and non-labor expenses, respectively, in overall OM&A costs. PEG will then estimate 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.

$$growth\ Input\ Quantities_j = growth\ Cost_j - growth\ Input\ Prices_j. \qquad [6]$$

It follows that the change in OM&A input quantity in each year will be measured as the change in the OM&A expenses in that year minus the inflation in OM&A input prices that year.

3.2.3 Index Form

PEG will calculate 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:

$$\ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(S_{j,t} + S_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \qquad [7]$$

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:

$$\ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(S_{k,t} + S_{k,t-1} \right) \cdot \ln\left(\frac{Y_{k,t}}{Y_{k,t-1}} \right). \qquad [8]$$

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. 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

$$\ln\left(\frac{TFP_t}{TFP_{t-1}}\right) = \ln\left(\frac{\textit{Output}\ \text{Quantities}_t}{\textit{Output}\ \text{Quantities}_{t-1}}\right) - \ln\left(\frac{\textit{Input}\ \text{Quantities}_t}{\textit{Input}\ \text{Quantities}_{t-1}}\right). \quad [9]$$

3.2.4 Sample Period

Because of data constraints, PEG will only be able to compute a TFP trend for the Ontario electricity distribution industry for the 2002-2011 period. This is a relatively short sample period. Most regulatory proceedings where TFP trends have been estimated using indexing methods have used about 10 years or more of historical data. The Board used an even longer, 18 year period to measure industry TFP growth in 3rd Gen IR in Ontario. The period selected should be sufficient for smoothing out short-term fluctuations in TFP that can arise because of changes in output (*e.g.* kWh deliveries that are sensitive to changes in weather and economic activity) and the timing of different types of expenditures. This long-run historical TFP trend is then assumed (either implicitly or explicitly) to be a reasonable proxy for the TFP growth that is expected over the term of the indexing plan.

This is not always an appropriate assumption For example, it is often not warranted to assume that TFP growth measured for relatively short historical periods (like the 2002-2011 period available for Ontario electricity distributors) 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 when the available data only allow TFP to be calculated for a relatively short period. A general rule of thumb is that a minimum of 10 years of data are needed to calculate a reliable estimate of an industry's long-run TFP trend.

3.2.5 Econometric Projection of Industry TFP Growth

Because of these potential concerns regarding the sample period, there may be merit in developing econometric as well as index-based estimates of TFP growth for Ontario electricity distributors. Econometrically-based TFP estimates could supplement, rather than replace, the index-based methods that the Board said it would rely on for 4th Gen IR in the RRFE Board Report. These econometric estimates would also be an adjunct and byproduct of PEG's total cost benchmarking work needed to set stretch factors, so econometric-based estimates of TFP growth are already an implicit part of PEG's workplan. Econometric estimates could provide an independent source of information that the Board can use to assess whether index-based estimates derived from the relatively short, nine year sample period generate an appropriate measure of long-run TFP trends for Ontario electricity distributors.

In general terms, econometric methods can be well-suited for projecting TFP growth when there is a lack of historical time series data. The econometric approach essentially uses statistical methods to estimate the underlying "drivers" of TFP growth, such as technological change and the realization of scale economies. Statistical techniques can estimate the impact of each of these sources of TFP growth by using data from electricity distributors operating under a wide variety of business conditions. Once those underlying TFP drivers are estimated, they can be combined with data on the changes in the business condition variables for the Ontario electricity distribution industry. This information can then be brought together to project TFP growth using a methodological framework that was detailed in Appendix One of PEG's April 2011 Concept 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 long-run business conditions, and "TFP drivers," of the Ontario power networks.

The main disadvantage of the econometric approach is its complexity. Econometrics often involves technically complex statistical methods, and 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. However, as previously discussed, PEG will already be developing econometric models to benchmark total cost efficiency, and the econometric TFP projections would simply be a byproduct of this work. Using econometrics to supplement the index-based estimates of TFP growth for Ontario electricity distributors will be an issue for consultation in the PBR Working Group.

3.3 Total Cost Benchmarking

To update the Board's framework used to set stretch factors, PEG will benchmark the total cost efficiency of Ontario's electricity distributors. Benchmarking evaluations will be undertaken using two benchmarking methods: 1) a total cost econometric model; and 2) comparisons of total unit cost across a selected peer group of distributors. PEG will discuss each of these benchmarking approaches in turn.

3.3.1 Total Cost Econometric Model

An econometric cost function is a mathematical relationship designed to capture the relationship between the cost of service and business conditions. Business conditions are aspects of a company's operating environment that may influence its activities but cannot be controlled. Economic theory can guide the selection of business condition variables in cost function models. According to theory, the total cost of an enterprise depends on the amount of work it performs - the scale of its output - and the prices it pays for capital goods, labor services, and other inputs to its production process.[17] Theory also provides some guidance regarding the nature of the relationship between outputs, input prices, and cost. For example, cost is likely to rise if there is inflation in input prices or more work is performed.

In addition to output quantities and input prices, electricity distributors confront other operating conditions due to their special circumstances. Unlike firms in competitive industries, electricity distributors are obligated to provide service to customers within a given service territory. Distribution services are also delivered directly into the homes, offices and businesses of end-users. Distributor cost is therefore sensitive to the circumstances of the territories in which they provide delivery service.

[17] Labor prices are usually determined in local markets, while prices for capital goods and materials are often determined in national or even international markets.

One important factor affecting cost is customer location. This follows from the fact that distribution services are delivered over networks that are linked directly to customers. The location of customers throughout the territory therefore directly affects the assets that utilities must put in place to provide service. Different spatial distributions for customers can have different implications for network cost.

Cost is also sensitive to the mix of customers served. The assets needed to provide delivery service will differ somewhat for residential, commercial, and industrial customers. Even more importantly, different types of customers have different levels and temporal patterns of demand and different load factors.

In addition to customer characteristics, cost can be sensitive to the physical environment of the service territory. The cost of constructing, operating and maintaining a given network will depend on the terrain over which that network extends. These costs will also be influenced by weather and related factors. For example, costs will likely be higher in areas with high winds, a propensity for ice storms or other severe weather that can damage equipment and disrupt service. Operating costs will also influenced by the type and density of vegetation in the territory, which will be at least partly correlated with precipitation and other weather variables. To a great extent, these conditions accompany the particular territory that the power distributor is required to serve and are therefore beyond management control.

Econometric cost functions require that a functional form be specified that relates cost to outputs, input prices, and other business conditions. Parameters are associated with the variables specified in this cost function. Econometric methods are then used to estimate the parameters of cost function models. Econometric estimates of cost function parameters are obtained using historical data on the costs incurred by utilities and measurable business condition variables that are included in the cost model.

When undertaking analysis of network cost drivers, or making cost comparisons among different energy networks, output measures should be selected on how strongly they correlate with the cost of providing regulated distribution services. Billing determinants like customer counts will still be important output measures in these analyses, but they are not the only potential measures. Any variable that can be defined as an output and impacts network costs is appropriate for econometric cost models and for undertaking cost comparisons.

In econometric cost work, the most important, non-billing output concerns customer location. The spatial distribution of customers is sometimes proxied by the total circuit km of distribution line, or the total square km of territory served. Provided customer numbers is also used as a cost measure, either of these additional variables will reflect the impact of different levels of customer density within a territory on electricity distribution costs.

Peak demand is another variable that can be included as an output measure in cost analysis. Of course, peak demand is a billing determinant for some customers, but peak demand will also be an important cost driver for smaller customers whose peak demands are not metered (and for which peak kW deliveries is therefore not a billing determinant). The reason is that delivery systems must be sized to accommodate peak demands, so there is a direct relationship between customers' peak demands and the costs of the necessary power delivery infrastructure.

It can also be appropriate to consider measures that reflect outputs that are provided by some networks but not others in the samples used for cost analyses. For example, distributors can differ in the extent to which they provide subtransmission service. Some distributors have no subtransmission assets, while others have a significant amount of subtransmission capital. The latter distributors are effectively providing more delivery services, since they are undertaking functions that the transmission utility is providing on behalf of the distributors (that do have subtransmission assets). Ideally a cost study would control for this difference to ensure that "apples to apples" comparisons are made between networks.

Cost analyses can also include variables that reflect the quality of the service provided. Examples include reliability measures of SAIFI or SAIDI, or measures that may be available of energy security. While these are not output measures *per se*, they are clearly quality attributes of the network services that are being provided. Providing "more" of these attributes is costly, so it would be appropriate to include accurate measures of reliability or security in cost analyses.

In this project, PEG will update the OM&A econometric cost model that we developed and applied in 3rd Gen IR so that it is now applied to benchmarking distributors' total cost. Total electricity distribution costs will now be the dependent variable in the statistical model, and PEG will use the same total cost measures in this statistical work that we develop for the TFP analysis. PEG will also investigate whether the form of the model, and the choices of business conditions, should be modified to obtain better statistical results when the model is applied to total electricity distribution cost. The choice of business condition variables in the econometric work will be an issue for consultation in the PBR Working Group.

3.3.2 Total Unit Cost Benchmark Model

PEG will also benchmark distributors' total unit costs rather than their OM&A unit costs. The metric will now be calculated by dividing the total electricity distribution costs computed for each distributor by a comprehensive index of distribution output. This comprehensive output quantity index will be a weighted average of each of the output measures that were found to be statistically significant drivers of total distribution cost in our econometric work. These cost measures may be more extensive than what are used in PEG's TFP work, where the relevant outputs should only include billing determinants. Each of these output measures will be weighted by its cost elasticity share, and these cost elasticities will also be estimated in PEG's econometric cost analysis.

The total unit cost benchmark evaluations will be undertaken by calculating the difference between each distributor's unit cost and the average unit cost of its peer group. A total of 11 peer groups were identified in PEG's earlier work and used to set stretch factors in 3rd Gen IR. PEG will investigate whether the number and composition of these peer groups should be modified in light of the results of the total cost econometric research. For example, if PEG finds variables that were not statistically significant drivers of OM&A costs but are now statistically significant drivers of total cost, then adjustments in the peer groups may be warranted. Potential changes in the peer groups will be an issue for consultation in the PBR Working Group.

3.3.3 Other RRFE Considerations

In 3rd Gen IR, econometric and unit cost benchmarks were used to establish three efficiency cohorts for which different stretch factors were assigned. These benchmarking analyses will be updated in 4th Gen IR so that both are applied on a total cost basis, and these results will inform the choices for stretch factors in the RRFE. Nevertheless, it should be recognized that the RRFE involves more considerations (such as a long-term asset plan and a balanced scorecard) and distributors will report more performance measures than under 3rd Gen IR. There may accordingly be merit in considering whether the broader range of performance measures that the Board will examine in the RRFE should also inform the Board's choices for appropriate stretch factors in 4th Gen IR. This will be an issue for consultation in the PBR Working Group.

4. Potentially Useful Empirical Analysis for Custom IR

Under the Customer IR option, a distributor-specific rate trend for the plan term will be determined by the Board on a case-by-case basis informed by empirical evidence including:

- the distributor's forecasts (revenues and costs, including inflation and productivity);
- the Board's inflation and productivity analyses; and
- benchmarking to assess the reasonableness of the distributor's forecasts.

Expected inflation and productivity gains will also be reflected in the rate adjustments approved by the Board over the term of the Custom IR plan.

Some of PEG's empirical analysis developed for the 4th Gen IR (and Annual IR) ratemaking options could also be applied by the Board to evaluate Custom IR proposals. In addition to the inflation and productivity analysis cited above, some of the metrics coming out of our 4th Gen IR empirical analysis that could be potentially useful for evaluating Custom IR proposals include:

- TFP level benchmarks: these will be developed at the same time that we develop unit cost benchmarks for each distributor; TFP level benchmarks can be used to assess a distributor's total cost efficiency at the outset of its Custom IR proposal;
- Unit cost benchmarks: these will be developed in the total cost benchmarking analysis, and they can also be used to assess a distributor's total cost efficiency at the outset of its Custom IR proposal; and
- Econometric benchmarks: these will be developed in the total cost benchmarking analysis, and they can also be used to assess a distributor's total cost efficiency at the outset of its Custom IR proposal.

An additional metric that could be extracted from the planned empirical analysis is capital and OM&A PFP efficiency. These could be developed by decomposing the TFP level benchmarks into separate measures of partial factor productivity for capital and OM&A inputs, respectively. These PFP level benchmarks can then potentially assess the efficiency of a distributor's capital and OM&A operations separately, which could be relevant if the distributor presents separate capital and OM&A forecasts as part of its Custom IR proposal. However, any such inferences on partial factor productivity must be undertaken with care, because focusing on only a single partial performance metric without considering performance on other partial metrics can lead to misleading and inaccurate conclusions about a distributor's overall cost performance. In addition, it should be recognized that the RRFE Board Report says that the Board "continues to support a comprehensive approach to rate-setting, recognizing the interrelationship between capital expenditures and OM&A expenditures" (p 9).

5. Next Steps

Board staff have posted on the Board's website 10 years of Ontario electricity distributor historical cost data that Board staff extracted from the Ontario Hydro MUDBANK system for the 1989 to 1998 period. The MUDBANK system is Ontario Hydro's Municipal Utility Information System that provided regulatory and statistical functions to support Ontario Hydro's regulatory role for more than 300 Municipal Electric Utilities that were in existence at that time. Board staff have mapped this data to reflect the 77 licensed electricity distributors that exist today.

Board staff have also posted on the Board's website historical cost data filed with the Board by electricity distributors for the 2002 to 2011 period through the Board's Reporting and Record Keeping Requirements. PEG has received this historical cost data. The next steps in PEG's empirical analysis are relatively straightforward.

First, PEG will compile a comprehensive database of all necessary data. This database will include output, capital and cost data for all distributors, as well as input price estimates (including data on the relevant input price sub-indexes) and business condition variables for each distributor to be used in the econometric work. PEG will endeavor to make this dataset as transparent as possible and will make it available to all stakeholders. To the greatest degree practical, this database will document the sources of all data points, for all distributors and for all other non-distributor data, throughout the entire sample period used in our analysis.

PEG will also work with Board staff during the PBR Working Group consultations. These consultations will examine a variety of issues related to performance measurement, benchmarking, and establishing rate adjustment formulas. The issues identified in this Concept Paper that will be considered in the PBR Working Group process are the following:

1. Choices for inflation subindices to be used for the inflation factor
2. Options for mitigating volatility of the inflation factor
3. Appropriate values for the depreciation rate to be used in the TFP analysis
4. Appropriate values for the rate of return to be used in the TFP analysis
5. The merits of using econometrics to supplement index-based TFP estimates
6. Choices for business condition variables in the econometric analysis
7. Possible adjustments of the peer groups used in the unit cost analysis

8. In addition to the benchmarking analyses, whether the Board should examine other performance measures to be provided under the RRFE when establishing values for stretch factors in 4th Gen IR

PEG will begin the input price, industry TFP, total cost econometric benchmarking, and total unit cost benchmarking analysis outlined in this Report while the PBR Working Group is meeting. PEG's subsequent analysis will be informed by these Working Group discussions. Our analysis will be detailed in an April 2013 report by PEG, and the dataset will be made public to all stakeholders at the time this April 2013 report is released.

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