Ontario Energy Board

EB-2010-0379

Draft Report of the Board

on Empirical Research to Support Incentive Rate-setting for Ontario's Electricity Distributors

September 6, 2013

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1 Introduction

The Board has employed incentive regulation ("IR"), including formula-based and cost-based rate-setting, since it began regulating the rates of electricity distributors in 2001. The Board's current rate-setting policies have evolved over the years culminating in the three alternative rate-setting methodologies that will be available to distributors in 2014 which are set out in Chapter 2 of the Board's October 18, 2012 Report of the Board entitled "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (the "RRF Report").

In its RRF Report, the Board concluded that benchmarking models will continue to be used to inform rate setting[1]. The Board also stated that it will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes and that it will continue to engage stakeholders in this effort. Consultation with stakeholders on development of total cost benchmarking, an Ontario TFP study, and on input price trend research began with the release of the RRF Report.

This Draft Report sets out the Board's proposed policies and approaches to the rate adjustment parameters for incentive rate setting for electricity distributors and the benchmarking of electricity distributor total cost performance. This is a Draft Report for the purposes of consultation. The Board is interested in further hearing the views of stakeholders before finalizing the approach to the methodology for incentive regulation for the period 2014 to 2018.

[1] The empirical work on the electricity distribution sector will inform the rate-adjustment mechanisms under the two price cap index methods, and will inform the Board's review and approval of applications under the custom method. Consequently, regardless of the rate-setting plan under which a distributor's rates are set, the distributor will continue to be included in the Board's benchmarking analyses.

What consultations set out to do

Consultations were guided by the policy direction set out in the Board's RRF Report. An objective of the further research undertaken in order to implement this policy direction was to better align indexing of rates with the inflation faced by distributors in Ontario and to strengthen the efficiency incentives inherent in the rate-adjustment mechanism. In particular, these consultations considered:

- the development of a more Ontario-specific inflation factor;
- the estimation of long-run Ontario electricity distribution industry total factor productivity (TFP) trend; and
- the development and implementation of total cost benchmarking.

Board staff undertook research, commissioned expert advice and consulted with stakeholders on these matters. All materials in relation to the consultations are available on the Board's website.

Consultations were informed by the advice of several expert consultants: Dr. Lawrence Kaufmann of Pacific Economics Group Research, LLC ("PEG"), staff's consultant; Prof. Adonis Yatchew of the University of Toronto, consultant to the Electricity Distributors Association; Dr. Francis Cronin, consultant to the Power Workers' Union; and Mr. Steve Fenrick of Power System Engineering, Inc., consultant to The Coalition of Large Distributors (Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc.).

Consultation began with the release of the RRF Report and has culminated in the proposed policies set out in this Draft Report.

The Board's consultations

Over the past ten years, the Board has undertaken several consultations to consider practical and empirical issues related to incentive rate-setting parameters. The Board remains convinced that incentive based rate making is a preferred approach over traditional annual cost of service rate making since it incorporates incentives for distributors to be as efficient as possible, which in turn leads to lower costs and prices. These extensive consultations have given the Board a solid appreciation of the importance of understanding the underlying principles guiding empirical research, and that appropriate trade-offs may be necessary to maintain an alignment of interests.

The Board's incentive rate-setting is grounded in empirical analysis, takes account of the differences in the operations of distributors, and ensures that the benefits from greater efficiency are appropriately shared throughout the rate-setting term between the distributor/shareholder and the distributor's customers. Building on this foundation, the Board's approach to determining incentive rate-setting parameters will continue to be based on economic theory[2] and empirically derived from objective, data-based analysis.

In developing the proposed approach set out in this Draft Report, the Board has considered the input from all stakeholders and their expert consultants. The materials generated for and through the consultation related to performance and benchmarking as well as in relation to the RRF overall have provided useful background and context for the issues considered in this Draft Report.

[2] Going into IR, distribution rates are set based on a cost of service review. Subsequently, rates are adjusted based on changes to the input price index and the productivity and stretch factors set by the Board. IR decouples the price that the distributor charges for its service from its cost. Since price adjusts according to a simple formula, if the distributor can reduce its costs by more than the productivity and stretch factor, it can keep the cost savings in the form of higher operating profits. Thus, IR provides strong incentives for distributors to find efficiencies in their operations. Consumers also benefit during the IR period because the productivity and stretch factors are built into the formula.

Organization of this Draft Report

This Draft Report is organized as follows. The Board's policy for, and analysis of, incentive rate-setting parameters are outlined in Chapter 2. Chapter 1 sets out the Board's policy for benchmarking of electricity distributor cost performance. Both chapters provide brief descriptions of the matters being addressed, the Board's proposed rate-setting parameters and rationale, and comments on the alternatives put forward in consultations. Details on how and when the parameters will be implemented are also noted. Supporting material associated with the development of the parameters set out in this Draft Report is contained in the Appendix.

2 Rate Adjustment Parameters

As stated in the Board's RRF Report, the Board continues to support a comprehensive approach to rate-setting, recognizing the interrelationship between capital expenditures and OM&A expenditures. The 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. The Board believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation. Rate-setting that is comprehensive creates stronger and more balanced incentives and is more compatible with the Board's implementation of an outcome-based framework.

This Chapter sets out the Board's policies in relation to a more Ontario-specific inflation factor, the estimated long-run Ontario electricity distribution industry total factor productivity (TFP) trend, and stretch factor components for the IR rate adjustment mechanism.

The Board will continue with a price cap formula. Under this method, distribution rates are set on a forward test-year cost of service basis and subsequently indexed by the price cap index formula which reflects expected growth in the distributors' input prices (the inflation factor) less allowance for appropriate rates of productivity and efficiency gains (the X-factor).

2.1 Inflation Factor

Under price cap mechanisms, output prices are adjusted to reflect the expected growth in the distributor's input prices ((i.e., indices adjust allowed prices with inflation).

What the Board Said

In 3rd Generation IR, the Board used the year-over-year change in the Canada Gross Domestic Product Implicit Price Index for final domestic demand (GDP IPI FDD) to calculate price escalation. The Board concluded in its RRF Report that it is now appropriate to adopt a more Ontario industry specific inflation factor. The Board determined it would select a methodology that would address the concerns regarding the resulting volatility in the inflation factor that were raised in prior consultations. The Board also stated that in setting an appropriate inflation factor, it would be guided by the following:

- the inflation factor must be constructed and updated using data that is readily available from public and objective sources such as, for example, Statistics Canada, the Bank of Canada, and Human Resources and Social Development Canada, and therefore, readily understandable to consumers.;

- to the extent practicable, the component of the inflation factor designed to adjust for inflation in non-labour prices should be indexed by Ontario distribution industry-specific indices; and

- the component of the inflation factor designed to adjust for inflation in labour prices will be indexed by an appropriate generic and off-the-shelf labour price index (i.e., not distribution industry-specific).

Proposed Policy and Rationale

The Board intends to use the 2-factor input price index (the “2-factor IPI”)**, described below, as the inflation factor**. The 2-factor IPI is a more Ontario-specific inflation factor than what was previously used under 3rd Generation IR. The IPI will be constructed and annually updated using data from the Statistics Canada publication for the previous year. The adjustment in rates will be the difference between that number and the input price index built into the previous year's rates.

While a "3-factor" IPI was considered by PEG because it may more closely track input price inflation evident in the industry, the Board is concerned that the resulting numbers generated by such an IPI do not seem reasonable and result in unacceptable volatility. It is also less readily understood by the average consumer than a 2-factor index.

PEG's recommended 3-factor IPI is described in its report released on May 31, 2013, entitled "Empirical Research in Support Of Incentive Rate Setting in Ontario" (the "May, 2013 Updated PEG Report")[3]. In brief, it is comprised of:

1. A capital sub-index constructed using the Canada Electric Utility Construction Price Index (EUCPI)[4], the weighted average cost of capital ("WACC") calculated using Board-approved cost of capital parameters, and PEG's calculated value of the economic, "geometric" depreciation rate;
2. A labour sub-index comprised of the average weekly earnings ("AWE") for workers in Ontario[5]; and
3. A non-labour OM&A sub-index comprised of the Canada GDP-IPI (FDD)[6].

PEG's approach to calculating WACC combined the cost of capital parameters in effect January to April and the parameters in effect May to December (i.e., each WACC component was weighted as follows: $\frac{4}{12} \times parameter^{y-1} + \frac{8}{12} \times parameter^{y}$). The Board in considering this option estimated the annual WACC without this specificity (i.e.,

[3] Pacific Economics Group Research, LLC. Empirical Research in Support Of Incentive Rate Setting in Ontario. May 2013. (http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Report_to_OEB_4Gen_%20IR_20130531.pdf)
[4] Statistics Canada. *Table327-0011 - Electric utility construction price indexes (EUCPI), annual (index, 1992=100),* CANSIM (database).
[5] Statistics Canada. Table281-0027 - Average weekly earnings (SEPH), by type of employee for selected industries classified using the North American Industry Classification System (NAICS), annual (current dollars), CANSIM (database). Geography = Ontario, Type of employees = All employees, Overtime = Including overtime.
[6] Statistics Canada. *Table380-0066 - Price indexes, gross domestic product, quarterly (2007=100 unless otherwise noted),* CANSIM (database).

assume the cost of capital parameters determined by the Board are in effect for the whole year). The resultant values for the annual growth of the 3-factor IPI, including this modification, are summarized in Table 1. A more detailed summary for this table is provided in Appendix A.

Table 1: Three-factor Input Price Index

	Inputs and Assumptions			
	Non-Labour OM&A	**Labour**	**Capital**	
Weights	11.30%	26.30%	62.40%	
Year	**GDP-IPI (FDD)** March, 2013	**AWE-All Employees-Ontario** April, 2013	**PEG Capital Sub-Index** April, 2013	**Resultant Values - Annual Growth of the 3-factor IPI**
2003	1.6%	2.43%	0.47%	1.1%
2004	1.7%	2.78%	0.19%	1.0%
2005	2.2%	3.60%	0.92%	1.8%
2006	2.3%	1.59%	-3.91%	-1.8%
2007	2.3%	3.77%	5.59%	4.7%
2008	2.5%	2.32%	0.30%	1.1%
2009	1.4%	1.31%	5.04%	3.6%
2010	1.3%	3.82%	-0.44%	0.9%
2011	2.2%	1.41%	0.36%	0.8%
2012	1.6%	1.47%	-0.85%	0.0%

The estimated annual growth for this inflation measure in 2012 is zero. Further, staff estimates that the annual growth for this inflation measure in 2013 and 2014 may be -3.1% and +3.4%, respectively. Details on the inputs and assumptions underlying these estimates are provided in Appendix A.

The Board's primary concern with the 3-factor IPI is this volatility. In order to mitigate volatility, PEG suggested using a three-year moving average. The Board does not find this is appropriate. Doing so would embed any extreme swings in the IPI into the inflation factor over a three year period.

The primary source of volatility in the 3-factor IPI is the capital sub-index. This was also the case in the IPI implemented in 1st Generation PBR, and in the IPI proposed by staff during the 3rd Generation IR consultations.

PEG recommended a 62.4% weight be given to the capital sub-index in its 3-factor IPI. The weights for all three factors were estimated based on the 2011 industry cost shares derived from the Ontario electricity distributor data used in PEG's empirical analysis. Such a large weight can be expected in a capital-intensive industry. However, the Board is not persuaded that using 62.4% weighting for capital is indicative of what most distributors would face in such a heterogeneous sector, as illustrated in Table 2. Using PEG's benchmarking data set, and segmenting by total cost as a proxy for size, the 2012 total cost shares for distributors are summarized in Table 2.

Table 2: Sample Average Capital Cost Shares

Distributor Segment	Average Capital Cost Share
33 Small (total cost < $10 million)	41.05%
28 Medium (total cost $10 < $40 million)	56.55%
10 Large (total cost $40 - $300 million)	60.71%
2 Very Large (total cost >$300 million)	62.52%

While 62.4% approaches the capital share for large and very large distributors, it overstates that experienced by medium and small distributors. Regardless, the Board's primary concern continues to be the volatility of the 3-factor IPI.

PEG also considered a 2-factor IPI that included its constructed capital sub-index, and a combined OM&A and labour sub-index comprised of the AWE. The weightings given to each sub-index in this 2-factor IPI were 62.4% and 37.6%, respectively. Continued inclusion of the capital sub-index did not ameliorate volatility.

To mitigate the volatility in the resultant inflation factor, the Board intends to use a 2-factor IPI methodology. The annual growth in the 2-factor IPI will be used. The

Board's 2-factor IPI will exclude a specific capital sub-index and be comprised of:

1. The labour sub-index comprised of the average weekly earnings for workers in Ontario[7]; and

2. A non-labour sub-index comprised of the Canada GDP-IPI (FDD).

The Board notes that the Alberta Utilities Commission ("AUC") in its September 12, 2012 Decision 2012-237 on Distribution Performance-Based Regulation[8] adopted a 2-factor IPI. The AUC's approach also excludes a capital sub-index.

Rather than deriving the labour and non-labour weights from the average OM&A of all distributors as PEG did, the Board is proposing to use weights estimated from a review of the cost shares of medium to large distributors. Most of the province is served by medium, large, and/or very large electricity distributors; therefore the Board believes this weighting is a more reasonable representation for the industry as a whole.

To verify this, the Board asked staff to carry out additional analysis. The resulting estimates of Ontario electricity distributor cost shares are listed in Table 3. Based on these estimates, the **Board intends to use component weights of 30% for labour and 70% for non-labour**.

[7] Statistics Canada. Table281-0027 - Average weekly earnings, as noted previously.
[8] The Alberta Utilities Commission. Decision 2012-237: Rate Regulation Initiative. Distribution Performance-Based Regulation. Application No. 1606029. Proceeding ID No. 566. September 12, 2012.

Table 3: Sample Average OM&A Cost Shares

Distributor Segment	Average Capital Cost Share	Average OM&A Cost Share	Labour component of OM&A (70% assumption[9])
33 Small (total cost < $10 million)	41.05%	58.95%	41.27%
28 Medium (total cost $10 < $40 million)	56.55%	43.45%	30.42%
10 Large (total cost $40 - $300 million)	60.71%	39.29%	27.50%
2 Very Large (total cost >$300 million)	62.52%	37.48%	26.24%

The resultant values for the annual growth of the 2-factor IPI are summarized in Table 4. A more detailed summary for this table is provided in Appendix A.

Table 4: Two Factor Input Price Index

	Inputs and Assumptions		
	Non-Labour	**Labour**	
Weights	70%	30%	
Year	**GDP-IPI (FDD)** March, 2013	**AWE-All Employees-Ontario** April, 2013	**Resultant Values - Annual Growth of the 2-factor IPI**
2003	1.6%	2.43%	1.8%
2004	1.7%	2.78%	2.0%
2005	2.2%	3.60%	2.6%
2006	2.3%	1.59%	2.1%
2007	2.3%	3.77%	2.7%
2008	2.5%	2.32%	2.5%
2009	1.4%	1.31%	1.3%
2010	1.3%	3.82%	2.1%
2011	2.2%	1.41%	2.0%
2012	1.6%	1.47%	1.6%

The estimated annual growth for this inflation measure in 2012 is 1.6%. Staff estimates that the annual growth for this inflation measure in 2013 and 2014 may be 1.6% and

[9] Ontario Energy Board, *Staff Discussion Paper on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, February 28, 2008, p. 52. The 70% assumption has been estimated based on the fixed cost shares that were used in 1st Generation PBR for establishing the weights of each input are summarized in the table below.

Input	1st Generation	Share
Capital w_k	**0.5110**	
OM&A	**0.4989**	**100%**
Labour w_l	0.3514	70%
Materials w_m	0.1475	30%

1.9%, respectively. Details on the inputs and assumptions underlying these estimates are provided in Appendix A.

The Board finds that 2-factor IPI is comprised of components that are the best, practicable price indices for satisfying its criteria listed on page 6. The 2 factor IPI can be implemented just as easily as the GDP-IPI (FDD), but provides a better indication of Ontario input price fluctuations than the economy-wide measure. Finally, the 2-factor IPI achieves this without introducing unreasonable volatility.

The Board has further determined that it will no longer be calculating rate setting parameters, including the cost of capital parameters used in setting base rates in a cost of service review, more than once a year. Consequently, the Board will calculate the inflation factor to be used once annually for each rate year. This inflation factor will be used to adjust rates for both January 1st and May 1st implementation.

Alternatives Raised in Consultation

Most stakeholders supported the implementation of a more Ontario-specific IPI; however, some preferred the continued use of GDP-IPI (FDD). Some stakeholders suggested alternative 3-factor IPI's that employed additional smoothing mechanisms or different sub-index components. The Board's concerns with alternatives proposed are summarized below.

Alternative	Estimated Inflation Factor Value	Concern
Establish GDP IPI FDD as floor & bank differential.		Inconsistent with policy direction to better align inflation with more Ontario industry specific inflation. Also inconsistent with Board determination to provide a more accurate and timely reflection of input price inflation in the rate adjustment.

Alternative	Estimated Inflation Factor Value	Concern
Establish a deferral account to smooth any material impacts on customer bills that are due to changes in the IPI.		Inconsistent with policy direction to better align inflation with more Ontario industry specific inflation. Also inconsistent with Board determination to provide a more accurate and timely reflection of input price inflation in the rate adjustment.
Include changes in the Triangulized Weighted Average in the EUCPI.	2.16	Overly complex without additional benefit.
Include Ontario-Utilities AWE index.		Inconsistent with policy direction to use a non-utility industry specific labour index
Use GDP-IPI (FDD).	1.6	Inconsistent with policy direction to better align inflation with more Ontario industry specific inflation.

Implementation

The Board intends to use the year-over-year change in the GDP IPI FDD and the AWE- All Employees-Ontario to calculate the 2-factor IPI. To ensure that the two sub-indexes are aligned for the same period[10], the percent change will be calculated as the weighted sum of:

- The annual percentage change in the GDP-IPI (FDD) [from CANSIM Table 380-0066, available at the beginning of March] for the prior year relative to the index value for two years prior; and

- The annual percentage change in the AWE [from CANSIM Table 281-0027, available in early April] for the prior year relative to the data for two years prior[11].

As stated previously, this same inflation factor will apply to rate years with both January 1st and May 1st effective dates.

[10] The GDP-IPI is available as a quarterly index, the AWE is an annual number.
[11] For example, for 2015 the IPI would be based on annual Statistics Canada data for 2013 relative to the corresponding data for 2012, and would be calculated once the 2013 data are available in 2014.

2.2 X-factor Components

Similar to many price cap formulas and building on the Board's 3rd Generation IR, the IR formula will reflect expected growth in distributors' input prices (the inflation factor) less allowances for appropriate rates of productivity and efficiency gains (the X-factor).

As stated in the RRF Report, to ensure that the benefits from greater efficiency are appropriately shared throughout the rate-setting term between the distributor/shareholder and the distributor's customers, the expected benefits will be taken into account in establishing the rate adjustment mechanisms applicable to each rate method through the X-factor.

The Board described the components of an X-factor in its 3rd Generation IR report 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 [efficiency] 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.[12]

The Board also determined in its RRF Report that X-factors for individual distributors under this next version of IR ("Price Cap IR") will continue to consist of an empirically derived industry productivity trend (productivity factor) and a stretch factor.

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

The May, 2013 Updated PEG Report makes specific recommendations for the productivity and stretch factor components of the X-factor and provided the basis for consultations.

2.2.1 Productivity Factor

What the Board Said

In its RRF Report, the Board determined that the productivity factor will be based on Ontario electricity distribution industry TFP (“industry TFP”) trends and should be derived from objective, data-based analysis that is transparent and replicable. Furthermore, the Board determined that it will continue to use an index-based approach. Also in its RRF Report, the Board determined that all distributors will be subject to the same productivity factor that will be set in advance for the purposes of the Price Cap IR method. The Board will update the productivity factor every five years (e.g., the update after 2014 would be in 2019).

Proposed Policy and Rationale

The Board has determined that for the first productivity factor determination under the new Price Cap IR, the Board will continue to rely on the index-based approach. The index-based approach is widely used in other jurisdictions for the purpose of calculating TFP. PEG advises that the indexing method to estimating Industry TFP continues to be the most commonly used basis for setting a productivity factor in rate-setting formulas. In addition, the Board concludes that the approach is simpler compared to the alternative “econometric” approach and is therefore better understood by stakeholders.

The Board invited written comment on its intention to update TFP next in 2019[13] and some stakeholders expressed concern over how this may impact distributors. The Board acknowledges that updating industry-wide productivity every five years will provide for benchmark stability, but could also mean that some distributors' X-factors will change part way through their IR term (e.g., next update planned for 2019; a distributor that rebases in 2016 and enters into 4-years of IR will have the 2014 productivity factor in place for 2 years and the 2019 productivity factor in place for 2 years). However, the Board's approach is intended to provide greater certainty as to the time to achieve or surpass the external benchmark and retain any achieved savings. For distributors to benefit from that certainty, the industry benchmark needs to be in place for a reasonable period of time. The period of time generally used coincides with the IR plan term, and is a common feature of many IR plans. The approach in Ontario to "tranching" the filing of cost of service applications from electricity distributors staggers distributors' commencement onto IR, but also means that some distributors' X-factors change part way through their IR term. The Board is concerned that allowing for a change in the productivity factor midway through an IR term will erode the incentive benefits of providing stability and predictability in the achievable industry external benchmark. **Therefore, the Board intends to set a productivity factor that remains in effect until a distributor's next rebasing**. As discussed in section 2.2.2, the stretch factor however will change annually, depending on the performance of the distributor, so as to add an additional incentive for distributors to improve performance year after year.

As detailed in the May, 2013 Updated PEG Report, TFP trends were computed using an index-based approach on Ontario data for the period 2002-2011[14]. PEG noted the results of the analysis were being materially impacted by outliers[15], Toronto Hydro and Hydro One, and therefore excluded the outliers. The Board agrees with PEG that an

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[13] Ontario Energy Board. Letter to Stakeholders re: Update on Timeline for Expert Reports and Written Comments. May 30, 2013.
[14] PEG has subsequently updated this analysis to include 2012 data, and those results are presented further below.
[15] An outlier is a value that "lies outside" (is much smaller or larger than) most of the other values in a set of data.

industry productivity measure reflective of 73[16] distributors operating in Ontario should not be materially impacted by only two distributors, and therefore will exclude the two outliers in the industry calculation. Furthermore, the Board is of the view that for as long as they remain outliers, these distributors should be excluded from the Industry TFP data set.

With the exclusion of the outliers, PEG also noted the results of its analyses show a slowdown in productivity over the period and expressed uncertainty of whether this trend would persist in the future. PEG and indeed other experts in this consultation expressed the view that the slow growth in Ontario Industry TFP may be attributable to the severe recession in 2008-09, a one-time event that is not expected to continue, and slow output growth, a factor which is expected to continue with Ontario's continued emphasis on conservation.

In section 4.4 of the May, 2013 Updated PEG Report, PEG explains that because TFP growth will be part of the formula used to adjust base rates, only costs recovered through base rates should be included in the estimation of TFP growth. Table 7 in the May, 2013 Updated PEG Report summarizes the cost measure that PEG used to estimate TFP. In brief, excluded costs include contributions in aid of construction and low voltage charges collected from embedded distributors. PEG explains that including these costs in the TFP analysis would create a mismatch between the costs used as inputs for the rate adjustments and the costs that are actually subject to that rate adjustment, skewing the resultant TFP growth estimate.

PEG also expressed some uncertainty over some of the data included in the analysis and its impact on the trend. When carrying out its updated TFP analysis to include 2012 data, PEG reported that OM&A expenses in 2012 were 13.38% higher than in 2011. While there are several reasons for the overall increase in OM&A, staff analysis

[16] Four distributors are excluded from PEG's analysis because they do not file RRR data with the Board: Attawapiskat First Nation, Fort Albany First Nation, Kashechewan First Nation, and Hydro One Remote Communities Inc.

identified that the largest change seems to have been caused by three unusual and one-time events: lack of clarity in reporting requirements in relation to OPA CDM program costs; the adoption of IFRS by some distributors again impacting on RRR reporting; and unusually large deferral account dispositions. The Board does not believe that any of these events should be included such that they impact the long-run productivity of the sector. The first two identified events are primarily data reporting events. The last event is associated with the significant investment in smart meters in Ontario. For the purposes of estimating long-run TFP, PEG advised that these unusual and one-time events should be excluded from the TFP analysis.

As a result, the Board reviewed the data reported in 2012, identified and adjusted for the reporting anomalies and directed PEG to adjust its TFP analysis to:

- recognize adoption of IFRS affecting amounts recorded on the balance sheet for fixed assets (NBV) as well as a reduction in depreciation and capitalized OM&A; and
- recognize transfers of balances from deferral accounts to the balance sheet and income statement accounts, especially with respect to smart meters.

The Board's review has determined that to be able to confirm that OPA CDM program costs have been eliminated or isolated from the regulatory trial balance before reporting RRR balances, and adjust for any errors in reporting, the Board would have to issue a data request to distributors. The Board will review and clarify the related reporting requirements.

PEG's 2012 update is described in its report released on September 6, 2013, entitled "Empirical Research in Support of Incentive Rate Setting in Ontario: 2012 Update" (the "September, 2013 Updated PEG Report")[17].

PEG's analysis concluded that on average, industry TFP *declined* by 0.33% per annum over the 2002-2012 sample period. This compares with an average *growth* in industry

[17] Pacific Economics Group Research, LLC. Empirical Research in Support Of Incentive Rate Setting in Ontario: 2012 Update. September 2013.

TFP of 0.19% per annum over the 2002-2011 period. PEG notes that some, or perhaps all, of this impact may be due to the 2012 data anomalies, described above.

PEG expresses concern over the implementation of a negative productivity factor in the Board's rate setting given the regulatory environment in Ontario. PEG advises that the potential for further revenue decoupling, the continued use of rate riders and/or deferrals, and the advent of choice under RRF of rate-setting approaches create a significant probability that a negative productivity factor would either double-count costs that are being recovered elsewhere, or reflect the experience of a small number of distributors with atypical investment needs who elect to opt out of Price Cap IR altogether. This latter result, PEG observes, would be counter to the Board's intended purpose of Price Cap IR, which is to be appropriate for most distributors in the Province who do not have high or variable capital requirements. Because of these concerns, and notwithstanding the current, tentative estimate of negative TFP growth for the Ontario electricity distribution industry, PEG recommends that the productivity factor in Price Cap IR be no lower than zero.

The Board acknowledges that achieved productivity growth in the Ontario distribution sector has slowed in recent years. However, the Board does not believe it appropriate for its regulation to project and through rate-setting entrench a decline in productivity into the future. The productivity component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. Furthermore, the productivity factor is used in the rate-setting formula as an offset to inflation. Setting a productivity benchmark for the industry that would not encourage productivity gains is counter to the Board's policy direction – doing so would be counter to facilitating a culture of continuous improvement. As a consequence, the Board has determined that where the estimate of achieved long-run Industry TFP is negative, the productivity factor used in the rate-adjustment formula to set rates should be set to zero. The Board acknowledges that achieved Industry TFP may be negative due to unforeseen events and/or situations in which costs may be incurred with no corresponding increase in output. However, rate setting tools exist in the Board's Price Cap IR framework to deal with these circumstances (i.e., cost of service rebasing at start of term; and Off-ramp; Z-factor, LRAM, deferral and variance to deal with Government policy directives, and the ability to apply for an Incremental Capital Module during term).

Accordingly, the Board has determined that the appropriate value for the productivity factor (Industry TFP) for Price Cap IR is zero. The Board acknowledges this value is different than the value implemented in the 3rd Generation IR. The Board's determination as discussed above has been informed by PEG's analysis based on 10-years (2002-2012) of Ontario electricity distributor data; whereas the 0.72% was based on U.S. electricity distributor data and was the average annual productivity growth over 19-year period (1988-2006). The Board believes that setting the productivity factor at zero reflects a reasonable balance of the estimated productivity achieved in the sector over the last 10 years, absent the identified one-time and unusual events that occurred during the study period, and a value that can be reasonably projected into the future as an on-going external industry benchmark which all distributors should be expected to achieve.

Alternatives Raised in Consultation

All stakeholders supported the Board's efforts to estimate an Ontario TFP trend; however, some proposed alternative methods to indexing while others proposed alternative inputs and/or assumptions for the indexing method.

The Board finds that there may be merit in some of the alternatives presented; the Board finds that it does not have sufficient information at this point to incorporate them into the calculation of the TFP to be used for setting rates for 2014 and beyond. The Board may further explore some of these alternatives when carrying out the 2019 update.

Alternative Methods

The consultants retained by participants generally agreed that the index-based approach is most commonly used. However, alternative approaches were illustrated and proposed.

Prof. Yatchew expressed a preference for an econometric method of estimating TFP because conventional measures may not fully reflect activities that distributors are now undertaking as agents of provincial energy and social policies. Using econometrics, Prof. Yatchew proposed that the Board use the trend variable in a cost model plus consideration for scale effect as proxy for total factor productivity. Econometric cost models used to predict cost efficiency control for known changes in input prices, output and other business condition variables. Any residual effects are captured in the "trend variable" as unexplained by the model.

One stakeholder proposed that using the index approach, productivity be estimated using average, not industry aggregate measures of TFP growth. For discussion purposes, PEG carried out these estimates and reported the results in the June 14, 2013 Supplemental Empirical Analysis report[18].

Dr. Cronin introduced the use of price-dual TFP analysis as a means of assessing the reasonableness of index-based TFP analysis (i.e. quantity-based TFP analysis). He also assessed TFP for sub-intervals in the study period 2000-2011 and recommended sample specific TFP indexes as the historical basis for Price Cap IR. Furthermore, in light of the Board's outcome-based approach to regulation, Dr. Cronin assessed the impact of line loss performance and customer-valued service reliability performance on the distributors TFP performance. The data used in these analyses differed[19] from that

[18] Pacific Economics Group Research, LLC. Supplementary Empirical Analyses. June 14, 2013. (http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Supplementary_Empirical_Analysis.pdf)

[19] The data set used in Dr. Cronin's analysis differs from that used by PEG in that PEG used estimates of capital additions and capital retirements rather than the actual data filed. PEG has a limited capital series covering 1989-1998 and 2002-2011; for some LDCs, only the latter period of data is available. A further

used by PEG, but was needed to illustrate the alternative approaches presented. In the results of his analysis, Dr. Cronin found an increasingly declining trend in TFP over the period 2000-2011. Unlike the sub-interval 2002-2005, over the 2006-2011 period he found widespread negative growth in productivity across a broad sample of distributors. Furthermore, Dr. Cronin expressed the view that the impact of the economic recession would primarily be in 2008-2009. Consequently, Dr. Cronin recommended that the Board adopt the approach it used in 1st Generation PBR. At that time, the Board found a similar situation with highly divergent TFP growth rates for sub-intervals. In its RP-1999-0034 decision the Board weighted the first five-year period by 1/3 and the second five-year period at 2/3, thus giving double the weight to the more recent subinterval's results.

Other alternatives proposed by stakeholders addressed how the Board might interpret the results of the TFP analysis or adopt a simplified approach.

Alternative Inputs and Assumptions

Mr. Fenrick generally supported PEG's TFP analysis commenting that it is based on sound principles. However, Mr. Fenrick disagreed with PEG's exclusion of outliers from the analysis and PEG's exclusion of bad debt expenses on the basis they are not likely to continue at the same recent levels in the future.

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difference is that Dr. Cronin's analysis is based on the Board's 1st Generation PBR sample of 48 distributors that together served more than 70 percent of Ontario distribution customers. PEG includes all distributors in its sample.

The Board's concerns with proposed alternatives are summarized below.

Alternative	Estimated TFP	Concern
Methods		
Use econometrics and use the trend variable in cost model plus consideration for scale effect.	-0.75	Contrary to the Board's determination as set out above that for the first productivity factor determination under the Price Cap IR, the Board will continue to rely on the index-based approach. Furthermore, it is unclear how "residual unexplained effects" in a cost model are synonymous with "industry productivity". In Appendix One of its April, 2011 Concept Paper[20], PEG presents a decomposition of TFP growth so as to show how aggregate TFP can be decomposed into various sources of productivity change. The trend variable is identified as one of several components needed to estimate productivity change.
Estimate using average, not aggregate, index-based approach.	-0.20[21]	The Board accepts PEG's recommendation and rationale in relation to this matter. After considering its results on the "average" TFP trends, PEG continued to recommend using the "aggregate". In its June 14, 2013 Supplementary Empirical Analyses, PEG advises that aggregate TFP measures are preferred in conceptual terms. The reason is that placing equal weight on every distributor, even when some distributors provide relatively greater shares of industry output or account for greater shares of industry cost, will lead to a type of "aggregation bias." PEG continues to believe that this is the case. While the average TFP growth measures presented above may be informative to stakeholders, Staff and the Board, PEG continues to recommend that the productivity factor be set using the aggregate TFP trend (excluding HONI and THESL). Furthermore, the Board notes that while PEG was able to estimate and average measure of TFP growth for electricity distributors over the 2002 to 2011 period, the individual distributor estimates did not include complete distributor-specific information. Distributors do not currently report information to the Board at a detailed-level sufficient to support accurate estimation of distributor-specific TFP trends. In particular, information on labour cost shares are not being reported.

[20] Pacific Economics Group Research, LLC. Defining, Measuring And Evaluating The Performance Of Ontario Electricity Networks: A Concept Paper. April, 2011. (http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379_PEG_Concept_Report_to_OEB.pdf)
[21] Ibid.

Alternative	Estimated TFP	Concern
Use price-dual approach.	-2.40	Circularity. Board-approved rates (some having been adjusted with price cap index) are an input to the calculation.
Give recent trend greater weight	-1.50	Contrary to Board policy direction. Not reflective of long-run Ontario electricity distribution industry TFP trend. The Board expressed its views on this matter in its 3rd Generation IR report and the Board is still not persuaded that increased weight ought to be given to the most recent TFP trend. The merit of using the full data set is that the resultant TFP trend can be reasonably expected to reflect the ebbs and flows experienced over a relatively long period of time. To weight the most recent trend would undermine one of the virtues of using the full data set.
Use simple % of GDP IPI FDD [e.g., 40%].	0.64	Contrary to Board policy direction. Not reflective of long-run Ontario electricity distribution industry TFP trend or empirically based.
Simple average of the top half of individual TFPs of the distributors, updated annually.	0.85	Contrary to Board policy direction. Not reflective of long-run Ontario electricity distribution industry TFP trend. Annual updates increase rate-adjustment uncertainty for distributors and ratepayers and reduce incentive power (i.e., distributors should be able to retain any savings associated with efficiency gains achieved when they "beat" the productivity benchmark that is in place for the term of the IR plan).
Inputs and/or Assumptions		
Include all distributors.	-1.10	Estimation of achieved long-run Industry TFP trend should not be materially impacted by outliers.
Do not exclude data from Industry TFP data set.	Not estimated	Support PEG's expert advice that tax changes and bad debt expenses over 2002-2011 were anomalous (due to government policy and recession, respectively) and including them could provide a misleading estimate of the TFP and input price trends that could be expected over the next five years.

Sensitivity of the long-run TFP trend to the Province-wide conservation program savings reported by OPA

Figure 1: 2011 Ontario Conservation Results

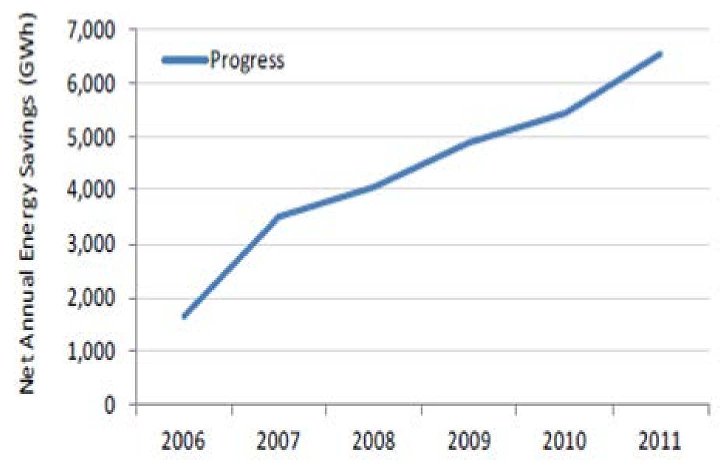

Table 5: Net Annual Energy Savings (GWh)

2006	2007	2008	2009	2010	2011
1,621	3,501	4,037	4,859	5,439	6,545

In his report, Prof. Yatchew commented that conventional measures of productivity may not fully reflect the broader range of activities that distributors are now undertaking. One area identified was a focus on conservation in the Province. This is one area, where provincial results are being reported annually. In response to the impact of slow output growth on the TFP trend, the Board asked PEG to test the sensitivity of the long-run TFP trend to the Province-wide conservation program savings reported by OPA in the 2011 Conservation Results Report (summarized in Figure 1). The results of that work are discussed in the September, 2013 Updated PEG Report. In brief, the sensitivity analysis incorporates the savings reported by the OPA to approximate what kWh deliveries would have been over the 2002 to 2012 period in the absence of OPA programs. It can be seen that output quantity growth under this scenario would have averaged 1.36% per annum in the 2002-2012 period. This is six basis points higher than the 1.30% output quantity growth measured for the same period. Input quantity growth is unchanged when the OPA program savings are added to the industry's kWh deliveries. The resultant 2002-2012 industry TFP trend is estimated to be -0.27%, a six basis point rise in comparison to the -0.33% estimate absent the kWh deliveries adjustment.

2.2.2 Stretch Factor

What the Board Said

In its RRF Report, the Board determined that its approach in relation to the use and assignment of stretch factors under 3rd Generation IR will continue under the Board's Price Cap IR. Consistent with the policies set out in the Board's 3rd Generation IR report, non-negative (i.e., >0 or =0) stretch factors will be included in the X-factor. The Board believes that stretch factors continue to be required and is not persuaded by arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to IR. Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation. However, the Board in its RRF Report concluded that it will make the stretch factor assignments under Price Cap IR on the basis of total cost benchmarking evaluations. The assignments will continue to be revised annually to reflect changes in efficiencies.

The Board also stated in its RRF Report that it would consider whether the current three stretch factor values of 0.2%, 0.4%, and 0.6% continue to be appropriate or whether there should be greater differentiation between the three values, and that it would determine the appropriate stretch factor values in conjunction with its determination of the productivity factor for Price Cap IR.

Proposed Policy and Rationale

The Board re-iterates that "[i]t is important to note that stretch factors are consumer benefits. They are somewhat analogous to earnings sharing mechanisms, although stretch factors take effect immediately with the application of the formula and are not dependent on the realization of any productivity gains or excess earnings, as would be the case with an earnings sharing mechanism. Stretch factors are an integral part of the IR formula, and are not dependent on future performance by the distributor." [22]

Under the 3rd Generation IR, the Board assigned stretch factors to distributors based on the results of two OM&A cost benchmarking evaluations to divide the Ontario industry into three efficiency "cohorts." The first benchmarking evaluation used an econometric model to assess the efficiency of each distributor's costs. The second evaluation was based on comparisons of distributors' OM&A costs per unit of comprehensive distribution output, and these unit cost evaluations were based on a comparison between a given distributor's unit OM&A costs and the average unit OM&A costs of a peer group.

With the development of total cost benchmarking, and in light of continuing concerns with the use of peer groups, **the Board has determined that distributors will be assigned to one of five tranches with stretch factors based on their efficiency as determined through PEG's econometric total cost benchmarking model**.

PEG developed two benchmarking models, one econometric and one unit cost using peer groups. PEG recommended that the Board rank distributors according to their relative cost efficiency and unit cost performance, and that the Board assign distributors to one of five groups based on statistical significance and quintile alignment between the two rankings.

While this approach aligns with that used in 3rd Generation IR, the Board has decided to rely solely on the econometric model to assign stretch factors to distributors. The Board finds the lack of support over the use of peer groups in benchmarking compelling. Stakeholders persuasively argued that there are too many variables that can affect distributor costs to be confident in peer group allocations. The Board notes that unit cost comparisons can still be done without pre-defining peer groups. The Board

[22] Ontario Energy Board. EB-2007-0673 Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. September 17, 2008. p. 19.

expects that the use of one benchmarking model to produce a single efficiency ranking be more transparent and understandable for distributors and stakeholders. Consequently, it should be easier for a distributor to identify its relative cost efficiency, act to improve it, and be rewarded through the annual tranche assignments. Benchmarking is further discussed in section 4.2.

The five tranches will be established by segmenting the resultant efficiency ranking into groupings based on the percentage deviation between actual and predicted costs. The use of an odd number of tranches continues to provide for a middle tranche of “average” performers, while increasing the number of tranches to five should facilitate the movement of distributors into higher tranches and thereby reward those that have improved their relative cost efficiency with more timely reductions in their stretch factors.

The Board has determined that the appropriate stretch factor values range from 0.0% to 0.6%. The Board is setting the lower-bound stretch factor value to zero to strengthen the efficiency incentives inherent in the rate-adjustment mechanism and in doing so reward the top performers. As a result of what it heard in consultations, the Board does not believe it appropriate to increase the upper-bound stretch factor value at this time.

The Board has determined that the appropriate stretch factor values for each of the five tranches are as follows:

Table 6: Stretch Factor Values

Tranche	Relative Cost Performance	Stretch Factor
One	Actual costs are at least 20% below predicted costs	0.00%
Two	Actual costs are between 15% and 20% below predicted costs	0.15%
Three	Actual costs are between 0 and 15% below predicted costs	0.30%
Four	Actual costs are between 0 and 15% above predicted costs	0.45%
Five	Actual costs are more than 15% above predicted costs	0.60%

When published, each tranche will be sorted in alphabetical order.

During this consultation, some distributors wrote to the Board claiming extenuating circumstances that they believe should make them eligible for specific treatment in relation to stretch factor assignments. The Board believes that these requests should be addressed on a case-by-case basis. Consistent with practice to date, distributors that apply to the Board for exclusions and/or exceptions and satisfy the Board that their reasons are compelling may be assigned the middle stretch factor (i.e., 0.30%).

Alternatives Raised in Consultation

Prof. Yatchew and Mr. Fenrick proposed different benchmarking models for the purpose of assigning stretch factors. Benchmarking is discussed in Chapter 1.

Mr. Fenrick preferred that one econometric benchmarking model be used to assign stretch factors to distributors. He proposed that his benchmarking model be used to rank distributors according to their relative cost performance and that distributors be assigned to one of six groups based on their position in the ranking. Mr. Fenrick also recommended decreasing the upper bound value of the stretch factor range from 0.6% to 0.5%, explaining that do so would recognize that over time stretch factors should be reduced with experience under IR. Mr. Fenrick's recommended lower bound value of the stretch factor range was 0.0%.

Prof. Yatchew proposed that two econometric benchmarking models be used to rank distributors according to: (a) their relative cost efficiency; and (b) their productivity growth over the last three years. Prof. Yatchew suggested that 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 stretch factors. He noted that 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, Prof. Yatchew commented, that a distributor's performance over time should be examined to see whether its unit costs are declining or increasing. Consequently, Prof. Yatchew proposed that stretch factor assignments could be based on relative cost performance and growth in productivity. Under such an approach, distributors which have demonstrated recent productivity improvements (relative to other distributors) would be viewed favourably, even if their costs may appear to be high relative to other distributors.

Prof. Yatchew also proposed negative stretch factors based on his view that Ontario distributors have been under IR for many years, during which there have been sustained efforts to drive out inefficiencies. Prof. Yatchew stated that he believes it is time to start rewarding efficiency. Furthermore, Prof. Yatchew suggested that yardstick competition, which is a fundamental rationale for differentiated treatment of distributors, does not require positive ‘stretch factors’.

One stakeholder proposed that the Board allow distributors to select from a stretch factor-ROE menu as an option to a Board assigned default stretch factor. The menu would allow distributors to mitigate risk related to potential error in any benchmarking analysis.

Another stakeholder proposed that the Board use an “analog stretch factor formula” that assigns unique stretch factors to each distributor based on their unit cost performance relative to all other distributors. Once unit cost comparisons have been done, each distributor would have a ranking which is a percentage variation (plus or minus) between their unit costs and the median of their peer group. In response to concerns expressed over empirically derived peer groups, this stakeholder proposed that the determination of peer groups be done through a “crowd-sourcing”. In brief, each distributor would be required to provide a ranked list of ten other distributors to whom it feels it is similar. Board staff would review the lists and remove any names that it believes are obviously not comparable (e.g. a high cost rural distributor on the list of predominantly urban distributors). Distributors would be incented to provide fair lists because to seek to game the process would risk having their views not counted at all.

Once the revised lists are prepared, they should be matched using normal computer software designed for this purpose, and the collective peer group lists thus created for Board approval.

The Board's concerns with proposed alternatives are summarized below.

Alternative	**Concern**
Use two econometric benchmarking models to rank distributors according to: (a) their relative cost efficiency; and (b) their productivity growth over the last three years.	Contrary to the Board's decision to rely on one econometric model. Furthermore, the theoretical discussion an approach that might reward not only the 'Most Valuable Player', but also the 'Most Improved Player' is worthy of consideration. However, without a working model, the Board is unable to assess its strengths.
Negative stretch factors	Contrary to Board policy. As previously noted, stretch factors are consumer benefits. They are somewhat analogous to earnings sharing mechanisms, although stretch factors take effect immediately with the application of the formula and are not dependent on the realization of any productivity gains or excess earnings, as would be the case with an earnings sharing mechanism.
Lower upper bound value for stretch factors	Lack of empirical evidence that sustained efficiency gains have been maxed out. Counter to spirit policy direction re: continuous improvement.
Menu approach	Contrary to Board policy. The Board has not adopted a "menu" approach.
"Analog stretch factor formula"	Creative, but complex. The proposal to assign each distributor its own stretch factor value has the advantage of providing the distributor with annual feedback on its continuous improvement efforts to move up the efficiency ranking. However, the Board is concerned that such an approach would put too much weight on the absolute position of a distributor in the ranking of 73 distributors. Contrary to the Board's decision to move away from the use of peer groups.
Crowd source Peer Groups	Complexity and resource intensity. Contrary to the Board's decision to move away from the use of peer groups.

3 Benchmarking

The Board's regulatory oversight of electricity distributors is supported by benchmarking. For example, since 2008 benchmarking, based only on operations, maintenance and administration ("OM&A") cost data, has provided the basis for the annual assignment of stretch factors to distributors.

The Board anticipates in its RRF Report that expanded use of benchmarking will be necessary to support the Board's renewed regulatory framework policies.

What the Board Said

In its RRF Report, the Board concluded that benchmarking will continue to be used to inform rate setting. The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including total cost benchmarking for the 2014 rate year. Future work will involve comprehensive benchmarking (i.e., model(s) that combine standards for customer service, including distribution system reliability, and cost performance).

Proposed Policy and Rationale

The Board has determined that PEG's econometric model will be used for benchmarking distributor cost performance and, as previously noted, for informing the Board's annual assignment of stretch factors to distributors. The Board may explore other methodologies (e.g., DEA) and other approaches to benchmarking performance (e.g., 'Most Valuable Player' and 'Most Improved Player') in the future.

PEG's model controls for the impact of various factors beyond management control on a distributor's total costs. These factors, determined by PEG's analysis to be significant drivers of total costs, include:

- the number of customers served;
- kWh deliveries;
- system capacity peak demand;
- average circuit km of line; and
- share of customers served that were added over the last 10 years.

Furthermore, PEG's model employs a well-established estimation procedure, does not rely on peer grouping, and does not assume constant returns to scale.

This benchmarking model will be used to predict each distributor's total costs, and the distributor's actual total costs will be compared to the econometric prediction.

With respect to data issues, staff and stakeholders developed and proposed certain adjustments to the benchmarking data set to make distributors more comparable. Specifically, adjustments were proposed in relation to high voltage ("HV") equipment and low voltage ("LV") services. This work was carried out as planned subsequent to the issues identified at the end of the 3rd Generation IR consultations. Many stakeholders expressed concern over the proposed adjustments and asked the Board in their written comments for an opportunity to refine them stating that further analysis is needed. Three stakeholders made specific recommendations on what adjustments should be made. The Board directs staff to consult further with distributors on the LV and HV adjustments. The recommendations offered in written comment should provide a basis for this consultation.

Unless otherwise determined by the Board, all distributors[23] will be included in the Board's total cost benchmarking analyses. The concern over outliers is restricted to the estimation of Industry TFP for the purpose of setting rates.

Alternatives Raised in Consultation

Prof. Yatchew estimated an econometric cost model that is similar to that estimated in the May, 2013 Updated PEG Report. However, Prof. Yatchew includes two additional business condition variables: % of Capital Costs In Aid of Construction; and % of Net LV-HV Charges. Prof. Yatchew explains that he has included these variables because there remain questions about which LV and HV charges should remain in the cost data. Furthermore, he comments that costs incurred by a distributor are affected by the magnitude of capital contributions in aid of construction. Consequently, Prof. Yatchew treats LV, HV, and contributions in aid of construction as if they are conditions beyond a distributor's control.

Prof. Yatchew advised that estimation of relative efficiencies is difficult and subject to considerable risk of misclassification. He noted that even minor model variations can lead to migration of distributors from one efficiency cohort to another. Prof. Yatchew commented that 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. As previously noted, he also proposed that a second tool that the Board might consider is the distributor's own, index-based productivity growth. Prof. Yatchew suggested that such an approach might reward not only the 'Most Valuable Player', but also the 'Most Improved Player'.

Mr. Fenrick proposed a unit cost econometric benchmarking model to estimate the impact of several business conditions on the cost-per-customer for each distributor.

[23] Four distributors are excluded from PEG's analysis because they do not file RRR data with the Board: Attawapiskat First Nation, Fort Albany First Nation, Kashechewan First Nation, and Hydro One Remote Communities Inc.

Compared to PEG's model, Mr. Fenrick's model excludes one business condition variable (kWh deliveries), and includes six other business condition variables: service area; percentage of large and general service loads; hourly high winds above 10 knots; percent of lines that are single phase; load factor; and percent of lines underground. Mr. Fenrick's model assumes a linear relationship between business conditions and costs per customer, and constant returns to scale (i.e., a translog functional form). Mr. Fenrick explained that his model has been designed to be transparent and easier to understand and explain. The parameter coefficients are unit cost elasticities, which means a one percent increase in the cost driver will result in a change in the unit cost benchmark of one percent times the coefficient value. Furthermore, Mr. Fenrick noted that his model is neutral to distributor size and does not pre-judge efficiency gains through the realization of economies of scale. If two distributors decide to merge and are able to lower overall costs, those cost savings will be reflected in an improved benchmark score and ranking. This provides incentives that are aligned with customer interests. Distributor rankings will improve if they uncover efficiency gains, including realization of scale economies.

Dr. Cronin discussed different options for benchmarking such as DEA, a non-parametric approach to estimating production frontiers using linear programming techniques. Dr. Cronin and others proposed that consideration be included in the Board's benchmarking work for distribution system reliability performance.

In addition, some stakeholders commented on potential adjustments to the benchmarking data set.

The Board's concerns with proposed alternatives are summarized below.

Alternative	Concern
Adopt an approach that might reward not only the 'Most Valuable Player', but also the 'Most Improved Player'.	This architecture will be considered in the future.

Alternative	Concern
Assume linear relationship between business conditions and costs and constant returns to scale.	The Board's primary concern with Mr. Fenrick's model is that it assumes a linear relationship between business conditions and costs per customer, and constant returns to scale. These assumptions are unique to Mr. Fenrick's model and are not features of Prof. Yatchew's or Dr. Kaufmann's models. Those models employ less restrictive assumptions about the structure of electricity distribution costs. Consequently, Mr. Fenrick's model's estimate of which business conditions are statistically significant cost drivers is not comparable to the other models. This has made it difficult for the Board to assess the model. Furthermore, the Board does not believe that the assumption of constant returns to scale in benchmarking is appropriate. Dr. Kaufmann advised that when benchmarking and ratemaking do not assume constant returns to scale, achieved efficiency gains are rewarded by a lower stretch factor and consequently distributors receive the right signal to engage in continuous improvements in their operations.
Do not exclude data from benchmarking data set.	PEG's rationale for excluding certain data from the benchmarking data set is set out in the May, 2013 Updated PEG Report. The Board finds PEG's rationale to be reasonable.

Alternative	Concern
Include more business conditions (e.g., wind variable, load factor, distribution transformers/customer, % single-phase lines, age (acc. Dep./gross plant), % Embedded kW or kWh, Forestation Variable using GIS, % of Capital Costs In Aid of Construction; and % of Net LV-HV Charges)	With respect to the specific options identified, PEG has expressed interest in development and testing of the wind variable. Consultation is needed to confirm the data that would be used to measure the business condition. Also, PEG advises that while load factor, distribution transformers/customer, and % single-phase lines were tested in their model, they were not statistically significant. In general terms, the benchmarking model will determine what is statistically significant; business conditions cannot be forced into a model. This is a technical matter that was discussed at the May 28, 2013 Stakeholder Conference[24]. With respect to "age", PEG's model includes a proxy for age in the share of customers served that were added over the last 10 years. To be able to test % embedded kW or kWh and a potential forestation variable using GIS, Mr. Fenrick acknowledged that data is not yet available to measure these business conditions. Further work would be required to define the conditions. With respect to % of Net LV-HV Charges, the Board has directed staff to consult further with distributors on the LV and HV adjustments and expects the results of that consultation should address Prof. Yatchew's identified concerns over the uncertainty on what costs should be included in the benchmarking data set.
Ontario-only data set may not be appropriate.	The Board's benchmarking work on the distribution sector needs to consider the performance of all Ontario distributors. If concern is rate setting impacts, alternative rate setting approaches are available to distributors (e.g., Custom IR).
Use DEA to avoid the risk of data errors and miss-identification of business condition variables	DEA may be considered in the future.
Include consideration for distribution system reliability performance	Future work will involve comprehensive benchmarking (i.e., model(s) that combine standards for customer service, including distribution system reliability, and cost performance).

[24] Ontario Energy Board. Transcript for Stakeholder Conference: "Empirical Work In Support Of Incentive Rate Setting In Ontario". Starting at line 23 on page 75; ending at line 12 on page 79.

4 Implementation and Periodic Review

4.1 Stretch Factor Assignments Every Year

The total cost benchmarking model will be run annually to determine efficiency rankings for the purpose of setting stretch factors. With each run an additional year of electricity distributor RRR data will be added.

4.2 Productivity Factor Update Every 5 Years

With respect to the productivity factor, as previously indicated the Board will carry out an update every five years (e.g., the update after 2014 would be in 2019). Under Annual IR, the new productivity factor will automatically be applied to all distributors that are then on the Annual IR Index. However, under Price Cap IR, productivity factor changes will only be implemented for a distributor at the start of an IR term and will remain in effect for the IR term.

4.3 Periodic Review

The Board intends to review the models used in this Draft Report every five years. Over time, as the sector evolves, it is possible that different business conditions will become more or less statistically significant as cost drivers in the total cost benchmarking model. Furthermore, the Board has indicated that it may further explore some of the alternative approaches to benchmarking and to estimating TFP identified in these consultations when carrying out the 2019 update.

The Board believes that this ensures that the models continue to meet the objective of maintaining regulatory efficiency and transparency. Accordingly, the Board intends to conduct its first regular review in 2019 and any changes to the models made as a result of that review would apply to the setting of rates for the 2020 rate year (since 2019 would be the first rebasing year for those rebasing in 2014).

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Appendix A: Inflation Factor

3-Factor Inflation Measure

	OM&A Input Price						Capital Service Price								Inflation Measure		
Year	GDP IPI FDD (Mar 1, 2013 Data)	Annual Growth	Weight	AWE- All Employees- Ontario (including Overtime)	Annual Growth	Weight	EUCPI	Annual Growth	WACC (unweighted)	Annual Growth	Depreciation Rate	Index	Annual Growth	Weight	Index	Annual Growth	Three Year Moving Average
2001							129.6										
2002	90.4			710.73			130.5		8.3%		4.59%	16.74			100.00		
2003	91.8	1.6%	11.3%	728.23	2.43%	26.3%	130.6	0.1%	8.3%	0.0%	4.59%	16.82	0.47%	62.4%	101.12	1.1%	
2004	93.4	1.7%	11.3%	748.78	2.78%	26.3%	131.1	0.4%	8.3%	0.0%	4.59%	16.85	0.19%	62.4%	102.18	1.0%	
2005	95.5	2.2%	11.3%	776.19	3.60%	26.3%	133.6	1.9%	8.3%	0.0%	4.59%	17.01	0.92%	62.4%	104.00	1.8%	1.3%
2006	97.7	2.3%	11.3%	788.62	1.59%	26.3%	142.4	6.4%	7.4%	-12.1%	4.59%	16.36	-3.91%	62.4%	102.18	-1.8%	0.3%
2007	100.0	2.3%	11.3%	818.93	3.77%	26.3%	148.8	4.4%	7.4%	0.0%	4.59%	17.30	5.59%	62.4%	107.15	4.7%	1.6%
2008	102.6	2.5%	11.3%	838.14	2.32%	26.3%	150.3	1.0%	7.0%	-4.6%	4.59%	17.35	0.30%	62.4%	108.31	1.1%	1.4%
2009	104.0	1.4%	11.3%	849.15	1.31%	26.3%	151.1	0.5%	7.5%	6.9%	4.59%	18.24	5.04%	62.4%	112.33	3.6%	3.2%
2010	105.4	1.3%	11.3%	882.21	3.82%	26.3%	155.1	2.6%	7.3%	-2.9%	4.59%	18.16	-0.44%	62.4%	113.32	0.9%	1.9%
2011	107.7	2.2%	11.3%	894.71	1.41%	26.3%	160.1	3.2%	7.0%	-4.1%	4.59%	18.23	0.36%	62.4%	114.28	0.8%	1.8%
2012	109.5	1.6%	11.3%	908.00	1.47%	26.3%	161.6	0.9%	6.7%	-5.2%	4.59%	18.07	-0.85%	62.4%	114.32	0.0%	0.6%
2013 (est.)*		1.8%	11.3%		1.10%	26.3%	163.4	1.1%	5.9%	-11.9%	4.59%	17.05	-5.82%	62.4%	110.79	-3.1%	-0.8%
2014 (est.)*		2.0%	11.3%		1.70%	26.3%	165.2	1.1%	6.3%	5.7%	4.59%	17.80	4.31%	62.4%	114.58	3.4%	0.1%
Average		**1.91%**			**2.27%**			**1.96%**		**-2.35%**			**0.51%**			**1.13%**	**1.13%**
Standard Deviation		**0.40%**			**1.01%**			**1.88%**		**5.83%**			**3.35%**			**2.19%**	**1.10%**
Standard Deviation/ Average		**20.9%**			**44.3%**			**95.7%**		**-248.0%**			**652.7%**			**192.8%**	**97.1%**

* Note:

The 2013 and 2014 rows show scenarios based on staff's interim estimates for inputs and assumptions *shaded in blue*.

The July 2013 Consensus Forecasts, has estimates of 1.1% for CPI for 2013 and 1.7% for 2014.

- Based on staff's experience, staff expects GDP-IPI to be slightly higher than this. Therefore, for GDP-IPI FDD, staff assumed annual growth of 1.8% for 2013 and 2.0% for 2014;
- Staff assumed annual growth for AWE of 1.1% for 2013 (over 2012) and 1.7% for 2014 (over 2014); and
- Staff assumed 1.1% annual growth for EUCPI for each of 2013 and 2014.

2-Factor Inflation Measure

	OM&A Input Price						Inflation Measure		
Year	GDP IPI FDD (Mar 1, 2013 Data)	Annual Growth	Weight	AWE- All Employees- Ontario (including Overtime)	Annual Growth	Weight	Index	Annual Growth	Three Year Moving Average
2001									
2002	90.4			710.73			100.00		
2003	91.8	1.6%	70.0%	728.23	2.43%	30.0%	101.84	1.8%	
2004	93.4	1.7%	70.0%	748.78	2.78%	30.0%	103.94	2.0%	
2005	95.5	2.2%	70.0%	776.19	3.60%	30.0%	106.68	2.6%	2.2%
2006	97.7	2.3%	70.0%	788.62	1.59%	30.0%	108.95	2.1%	2.2%
2007	100.0	2.3%	70.0%	818.93	3.77%	30.0%	111.98	2.7%	2.5%
2008	102.6	2.5%	70.0%	838.14	2.32%	30.0%	114.77	2.5%	2.4%
2009	104.0	1.4%	70.0%	849.15	1.31%	30.0%	116.32	1.3%	2.2%
2010	105.4	1.3%	70.0%	882.21	3.82%	30.0%	118.76	2.1%	2.0%
2011	107.7	2.2%	70.0%	894.71	1.41%	30.0%	121.12	2.0%	1.8%
2012	109.5	1.6%	70.0%	908.00	1.47%	30.0%	123.04	1.6%	1.9%
2013 (est.)*		1.8%	70.0%		1.10%	30.0%	125.01	1.6%	1.7%
2014 (est.)*		2.0%	70.0%		1.70%	30.0%	127.42	1.9%	1.7%
Average		**1.91%**			**2.27%**			**2.02%**	**2.05%**
Standard Deviation		**0.40%**			**1.01%**			**0.42%**	**0.29%**
Standard Deviation/ Average		**20.9%**			**44.3%**			**20.9%**	**14.1%**

* Note:

The 2013 and 2014 rows show scenarios based on staff's interim estimates for inputs and assumptions *shaded in blue*.

The July 2013 Consensus Forecasts, has estimates of 1.1% for CPI for 2013 and 1.7% for 2014.

- Based on staff's experience, staff expects GDP-IPI to be slightly higher than this. Therefore, for GDP-IPI FDD, staff assumed annual growth of 1.8% for 2013 and 2.0% for 2014;
- Staff assumed annual growth for AWE of 1.1% for 2013 (over 2012) and 1.7% for 2014 (over 2014); and