Ontario Energy Board

EB-2010-0379

Report of the Board

Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario’s Electricity Distributors

Issued on November 21, 2013 and as corrected on December 4, 2013

intentionally blank

Table of Contents

intentionally blank

1 Introduction

The Board has employed incentive regulation (“IR”), including formula-based and cost-based rate setting, since it began regulating the rates of Ontario electricity distributors in 2001. The Board’s rate setting policies have evolved over the years culminating in three alternative rate setting methodologies that will be available to distributors starting in 2014. These methodologies 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 build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to 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.

On September 6, 2013, the Board issued its “Draft Report of the Board on Empirical Research to Support Incentive Rate setting for Ontario’s Electricity Distributors” (the “Draft Report”) seeking further stakeholder comments before finalizing its determinations. The Board held a Stakeholder Conference on September 11, 2013 to hear stakeholders views on the proposed policies set out in the Board’s Draft Report. Following the conference, the Board received further written comments from stakeholders.

[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.

This Report provides the Board's final determination on its policies and approaches to the distributor rate adjustment parameters and the benchmarking of electricity distributor total cost performance for the period 2014 to 2018.

Stakeholder 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 as it incorporates incentives for distributors to improve efficiency, which in turn leads to lower distribution costs and distribution rates. These consultations have given the Board an 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 between distributors and ratepayers.

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 between the distributor/shareholder and their customers throughout the rate setting term. 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 approach set out in this Report, the Board has considered the input from all stakeholders and their expert consultants.

[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.

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 policies set out in this Report.

The materials generated for and through the consultations 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 Report.

Organization of this Report

This Report is organized as follows. The Board's policy for, and analysis of, incentive rate setting parameters are outlined in Chapter 2. In Chapter 3 the Board sets out its policy for benchmarking of electricity distributor cost performance. Details on how and when the parameters will be implemented are provided in Chapter 4. Stakeholder comments and the Board's responses to alternatives proposed are summarized in an appendix to this Report. The 2014 inflation factor calculations and the 2014 stretch factor assignments are also set out 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 RRF provides a comprehensive performance-based approach to regulation that is based on the achievement of outcomes to ensure that Ontario's electricity system provides value to consumers. The Board believes that emphasizing results rather than activities, will better respond to consumer 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.

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 a price cap index formula which is used to adjust the distribution rates to reflect expected growth in the distributors' input prices (the **inflation factor**) less allowance for appropriate rates of productivity and efficiency gains (the **X-factor**).

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.

2.1 Inflation Factor

The Board indicated in the RRF Report that it wanted to adopt a more Ontario industry specific inflation factor than the Canadian economy-wide index used in 3rd Generation IR. The economy-wide index used was the year-over-year change in the Canada Gross Domestic Product Implicit Price Index for final domestic demand [GDP-IPI (FDD)]. In the RRF Report the Board also set out its intention to select a methodology that would address concerns that were raised in prior consultations regarding inflation factor volatility. The appropriate methodology should 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).

In response to the principles and guidance set out in the RRF Report, PEG proposed a "3-factor" input price index ("IPI") submitting that it may more closely track input price inflation evident in the industry.[3] The 3-factor IPI included capital, labour, and non-labour indices. However, the Board and many stakeholders were concerned that the resulting numbers generated do not appear reasonable and result in unacceptable volatility. In order to mitigate volatility, one option explored in consultations was to adopt a three-year moving average of the IPI. However, the Board does not find this 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. Mr. Fenrick proposed a 3-factor IPI that included a Triangularized Weighted Average of the EUCPI as the capital sub-index and demonstrated that this approach yields volatility

[3] PEG's "3-factor" IPI is described in its report released on May 31, 2013, entitled "Empirical Research in Support Of Incentive Rate Setting in Ontario"

comparable to the GDP-IPI (FDD). While this approach may address some concerns over volatility, the Board continues to share stakeholders' concerns over the complexity of Mr. Fenrick's proposed capital sub-index and its exclusion of WACC from the calculations. The Board remains of the view that the inflation factor calculations need to be transparent, easily understood, and aligned with regulatory rate setting practices.

In the Draft Report, the Board proposed a 2-factor IPI methodology to track inflation and help mitigate volatility. The methodology included:

1. A labour sub-index comprised of the average weekly earnings for workers in Ontario[4]; and

2. A non-labour sub-index comprised of the Canada GDP-IPI (FDD).[5] The GDP-IPI is the federal government's featured index of inflation in the domestic economy's final goods and services. It covers inflation in the prices of capital equipment used by industry as well as inflation in consumer product prices. This broad coverage makes it stable and, for a macroeconomic measure, reasonably reflective of inflation in the prices of distributor inputs.[6]

The Board will adopt the 2-factor IPI methodology. The Board acknowledges stakeholders' concerns with excluding a capital sub-index however the Board finds that the 2-factor IPI is the most appropriate approach at this time because of a lack of confidence in the proposed approaches for addressing the concerns which arise from introducing the capital sub-index. The Board's concerns with other alternatives proposed by stakeholders outlined in its Draft Report are listed in Appendix A.

---

[4] 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.

[5] Statistics Canada. *Table380-0066 - Price indexes, gross domestic product, quarterly (2007=100 unless otherwise noted),* CANSIM (database).

[6] Pacific Economics Group, LLC., Calibrating Rate Indexing Mechanisms For Third Generation Incentive Regulation In Ontario, Report To The Ontario Energy Board, February 2008.

The Board finds that the 2-factor IPI is comprised of components that are the best, practicable price indices for satisfying its objectives. 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 notes that the Alberta Utilities Commission ("AUC") in its September 12, 2012 Decision 2012-237 on Distribution Performance-Based Regulation[7] adopted a 2-factor IPI. The AUC's approach also excludes a capital sub-index.

The labour and non-labour weights that the Board will use in the 2-factor IPI are weights estimated from a review of the cost shares of medium to large distributors. This is in contrast to the methodology that was proposed by PEG which calculated the weights as an average OM&A of all distributors[8]. Most of the province is served by medium, large, and/or very large electricity distributors; therefore the Board believes this weighting is a

[7] The Alberta Utilities Commission. Decision 2012-237: Rate Regulation Initiative. Distribution Performance-Based Regulation. Application No. 1606029. Proceeding ID No. 566. September 12, 2012.

[8] Pacific Economics Group Research, LLC. Empirical Research in Support Of Incentive Rate Setting in Ontario. May 2013. p. 24 (http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Report_to_OEB_4Gen_%20IR_20130531.pdf)

more reasonable representation for the industry as a whole. Based on estimates of Ontario electricity distributor cost shares (in Table 1), the **Board will use component weights of 30% for labour and 70% for non-labour**.

Table 1: 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 Board acknowledges stakeholder comments that the 70% assumption with respect to the labour component of OM&A is based on analysis done for 1st Generation PBR, and therefore may be outdated. The data to update the analysis is not available at the time of issuing this report. However, Board will review the data requirements to be able to update the analysis in the future.

[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%

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

Table 2: 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%
Average	1.9%	2.45%	2.1%

Implementation

The inflation factor will be calculated and reported annually along with the cost of capital parameters to be used in setting distribution rates. The inflation factor will be used to adjust rates for both January 1st and May 1st implementation.

The Board will use the year-over-year change in the GDP-IPI (FDD) and the AWE-All Employees-Ontario to calculate the 2-factor IPI. The Board agrees with stakeholder comments that the most recently available annual change in the GDP-IPI

(FDD) sub-index should be used in this calculation. 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:

- 70% of the annual percentage change in the GDP-IPI (FDD) [from Statistics Canada CANSIM Table 380-0066, the most recently available annual change] for the prior year relative to the index value for two years prior; and

- 30% of the annual percentage change in the AWE [from Statistics Canada CANSIM Table 281-0027, available in early April] for the prior year relative to the data for two years prior.[11]

2014 Inflation Factor Value

Consistent with the policy determinations set out in this Report, and the most recent Statistics Canada data available for GDP-IPI (FDD), the Board has calculated the value of the inflation factor for incentive rate setting under Price Cap IR and the Annual Index for rates effective in 2014 to be 1.7%. A detailed calculation is provided in Appendix C.

2.2 X-factor Components

As stated in the RRF Report, expected productivity gains will be included in each of the three rate setting methods. This is to help ensure that the benefits from increased productivity are appropriately shared throughout the rate setting term between the distributor/shareholder and its customers. Under Price Cap IR and the Annual Index, an X-factor will be used for this purpose.

---

[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.

The Board first 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 RRF Report stated 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.

PEG made specific recommendations in its May 2013 Updated PEG Report for the productivity and stretch factor components of the X-factor. These recommendations provided the basis for stakeholder consultations. PEG updated its analyses to include 2012 electricity distributor data and presented the results in a report released on September 6, 2013, entitled "Empirical Research in Support of Incentive Rate setting: 2012 Update" (the "2012 Update PEG Report"). PEG's final recommendations to the Board are set out in its report released on November 21, 2013, entitled "Empirical Research in Support of Incentive Rate Setting in Ontario" (the "Final PEG Report")[13].

---

[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.

[13] Pacific Economics Group Research, LLC. Empirical Research in Support Of Incentive Rate Setting in Ontario. November, 2013. (http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379_Final_PEG_Report_20131111.pdf)

2.2.1 Productivity Factor

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 the productivity factor determination under the new Price Cap IR will continue to rely on the index-based approach**. The Board also stated its intention to update the productivity factor every five years (e.g., the update after 2014 would be in 2019).

The indexing method to estimating Industry TFP continues to be the most common basis for setting a productivity factor in rate setting formulas. In addition, the Board concludes that the approach is simpler than the alternative "econometric" approach proposed by Prof. Yatchew and therefore may be better understood by stakeholders and consumers.

The Board invited written comment on its intention to update TFP next in 2019.[14] Some stakeholders expressed concern over how this may impact distributors, particularly if it is applied to all distributors regardless of where they are in their IR term. 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 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. As such**, the Board has determined that the productivity factor will remain in effect until a distributor's next rebasing**. The stretch factor however will change annually,

[14] Ontario Energy Board. Letter to Stakeholders re: Update on Timeline for Expert Reports and Written Comments. May 30, 2013.

depending on the performance of the distributor, so as to add an additional incentive for distributors to improve performance year after year. This is addressed in section 4.1.

As detailed in the May 2013 Updated PEG Report, PEG calculated TFP trends using an index-based approach on Ontario data for the period 2002-2011.[15] PEG noted the results of the analysis were being materially impacted by outliers[16], Toronto Hydro and Hydro One, and recommended that the data for the two companies be excluded from the industry calculation. The Board agrees with PEG that an industry productivity measure reflective of 73[17] 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 showed a slowdown in productivity over the time period and expressed uncertainty of whether this trend would persist in the future. PEG and the other experts in this consultation expressed the view that the slow growth in Ontario Industry TFP may be attributable to the 2008-09 recession, a one-time event that is not expected to continue, as well as slow output growth, a factor which is expected to continue with Ontario's continued emphasis on conservation.

In section 4.5 of the Final PEG Report, PEG explained 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 5 in the Final PEG Report summarizes the cost measure used to estimate TFP. In brief, excluded costs include contributions in aid of construction and low voltage charges collected from embedded

[15] PEG has subsequently updated this analysis to include 2012 data, and those results are presented further below.
[16] An outlier is a value that "lies outside" (is much smaller or larger than) most of the other values in a set of data.
[17] Four distributors are excluded from PEG's analysis because their RRR data is not available: Attawapiskat First Nation; Fort Albany First Nation; Kashechewan First Nation; and Hydro One Remote Communities Inc.

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. As explained in the Final PEG Report, it would not be appropriate for costs previously recovered outside of base rates to be reflected in the TFP trend, and therefore the rate adjustment mechanism, that will apply during an IR term. Doing so would mean increasing future customer rates to pay for costs that have already been recovered in previous customer rates.

TFP results changed dramatically when the analysis was updated to include 2012 data. While the results indicated an average annual industry TFP *growth* of 0.19% between 2002-2011, average annual industry TFP over the 2002-2012 period *declined* to -0.33%.

Such a dramatic change caused PEG to question the reasonableness of the data included in the analysis. When carrying out its updated TFP analysis to include 2012 data, PEG reported that OM&A expenses in 2012 were 11.14% higher than in 2011.[18] While there may be several reasons for the overall increase in OM&A, staff analysis identified that the largest changes appear to have been caused by three unusual and one-time events: the methodology of reporting 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 in the calculation of industry TFP such that they impact the long-run productivity of the sector. The first two identified events are a function of how data is reported to the Board by distributors. 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.

[18] Pacific Economics Group Research, LLC. Empirical Research in Support Of Incentive Rate Setting in Ontario: 2012 Update. September, 2013. (http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379%202012_PEG_Report_on_Empirical_Work.pdf)

PEG subsequently adjusted its TFP analysis in order to remove the impact of:

- 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

- transfers of balances from deferral accounts to the balance sheet and income statement accounts, especially with respect to smart meters.

The Board will require corrections to distributor RRR balances for some distributors in order to isolate OPA CDM program costs from the TFP analysis. The Board will issue a request to distributors and undertake the associated corrections in due course such that any updates may be reflected in the 2019 TFP calculation.

PEG also expressed concern over the reasonableness of implementing a negative productivity factor for rate setting given the regulatory environment in Ontario. PEG advised stakeholders that the potential for further revenue decoupling, the continued use of rate riders and/or deferrals, and the introduction of choice under RRF of rate setting approaches create a significant probability that a negative productivity factor would either include costs that are already being recovered elsewhere, or reflect the experience of a small number of distributors with atypical investment needs who will likely opt out of Price Cap IR in favour of a Custom IR approach. This latter result, PEG observed, 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, PEG recommended that the productivity factor in Price Cap IR be set at zero.

At the Conference, stakeholders generally agreed that while the Board could spend more time trying to understand the negative TFP growth in Ontario, it may not be a productive study of the current data given the extent of analysis that has already been undertaken. However, Prof. Yatchew suggested that going forward progress may be made with the collection of additional data to help allocate sources of productivity growth, positive or negative.

The Board has determined that the appropriate value for the productivity factor (Industry TFP) for Price Cap IR is zero. The Board believes that setting the productivity factor at zero reflects a reasonable balance of the estimated productivity trend in the sector over the last 10 years and a value that is reasonable to project into the future as an on-going external industry benchmark which all distributors should be expected to achieve.

The Board acknowledges that achieved productivity growth in the Ontario distribution sector has likely slowed in recent years. However, the Board does not believe it appropriate for a rate setting regime to project and entrench declining productivity expectations into the future. The productivity component of the X-factor is intended to be an external benchmark which all distributors are expected to achieve. Setting a productivity benchmark for the industry that would not encourage distributors to achieve and share productivity gains is inconsistent with the Board's policy direction – doing so would be counter to facilitating a culture of continuous improvement. In addition, the Board agrees with the analysis by PEG (supported by the OM&A analysis by Board Staff) that the 2012 TFP results appear anomalous and therefore may not be a reliable indicator of the future productivity trend. As a consequence, the Board has determined that, at this time, where the estimate of achieved long-run Industry TFP is negative, the productivity factor used in the rate-adjustment formula to set rates will 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, there are rate setting tools in the Board's Price Cap IR framework to deal with these circumstances (e.g. cost of service rebasing at start of term; Off-ramp; Z-factor, LRAM, deferral and variance accounts to deal with Government policy directives, and the ability to apply for an Incremental Capital Module during the term).

At the Stakeholder Conference and in the subsequent written comments, distributors expressed the view that setting the productivity factor to zero when estimated TFP growth is negative constitutes an implicit stretch factor in the X-factor. The Board notes that if that argument is accepted, then the 2-factor IPI may also be considered to constitute an implicit, and offsetting, input price differential in the overall price cap index ("PCI") adjustment. For the 2002 to 2012 period, the PCI growth that would have resulted from the combination of the 2-factor IPI inflation and a zero productivity factor exceeds the growth that would have resulted from the combination of the 3-factor IPI inflation and PEG's estimated -0.33% TFP growth by an average of 0.5% per annum.[19]

All stakeholders supported the Board's efforts to estimate an Ontario TFP trend; however, some proposed alternative methods to indexing and others proposed alternative inputs and/or assumptions for the indexing method. The alternatives proposed are outlined in Appendix A. While the Board finds that there may be merit in some of the alternatives presented; there is insufficient 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.

2.2.2 Stretch Factor

In its RRF Report, the Board determined that its approach in relation to the use and assignment of non-negative (i.e., >0 or =0) stretch factors under 3rd Generation IR will continue under the Board's Price Cap IR. The Board believes that stretch factors continue to be required and is not persuaded by arguments that stretch factors are only

[19] Table 2 on page 12 shows that GDP-IPI (FDD) grew by 1.9% per annum between 2002 and 2012, and AWE-All Employees-Ontario grew by 2.45% over the same period. The 2-factor IPI over that period would have yielded 2.1% (i.e., 0.7*GDP-IPI(1.9%) + 0.3*AWE(2.45%)). Table 1 in the Board's Draft Report shows that industry input price index as estimated by the 3-factor IPI grew by 1.3% between 2002 and 2012. The input price differential (inflation factor minus input price inflation) is therefore 2.1% - 1.3% = 0.8%. The 2-factor IPI exceeds the industry's computed growth in input price inflation by an average of 0.8% per annum, over the same historical period used to estimate the -0.33% productivity factor. Combining these two effects yields the 0.5% PCI growth differential.

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, rather than the two OM&A cost benchmarking evaluations used in 3rd Generation IR. 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.

The Board re-iterates its earlier conclusion:

> It 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. [20]

With the development of total cost benchmarking, and in light of continuing concerns with the use of peer group analysis, **the Board has determined that distributors will be assigned to one of five groups 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. The models are described in the May 2013 Updated PEG Report. Also in

[20] 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.

that report, 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 aligns with the approach used in 3rd Generation IR, the Board has decided to rely solely on the econometric model to assign stretch factors to distributors. In general, there is lack of support amongst stakeholders for the use of peer groups and the Board finds the reasons cited compelling. In particular, 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 expects that the use of one benchmarking model to produce a single efficiency ranking be more transparent and understandable for customers and distributors. Consequently, it should be easier for a distributor to identify its relative cost efficiency, act to improve it, move up the efficiency ranking and be rewarded through the annual group assignments by moving into a more efficient group. Benchmarking is further discussed in Chapter 3.

The five groups will be established by segmenting the resultant efficiency ranking based on the percentage deviation between actual and predicted costs. The use of an odd number of groups continues to provide a middle group of “average” performers, while increasing the number of groups to five should facilitate the movement of distributors into more efficient groups.

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 described above, the Board has determined an approach to assigning stretch factors to distributors based on a distributor’s actual costs relative to its predicted costs. The approach does not compare one distributor to another distributor. While most stakeholders expressed general support for this new approach, some commented on the specific demarcation points between the five groups. Prof. Yatchew proposed alternative demarcation points, commenting that the Board's demarcation points placed a disproportionate number of distributors in the less efficient groups. The Vulnerable Energy Consumers' Coalition ("VECC") commented that the overall result should be one where the bulk of the distributors are assigned to the three central cohorts.

The Board sees merit in starting out with an allocation across the five groups that more closely resembles a normal distribution curve. There are no compelling reasons to start off with an asymmetrical distribution of disproportionate groupings at either end of the spectrum. The Board acknowledges that a curve based on today's sector performance will shift as distributors improve their performance and views this as a positive feature of the approach.

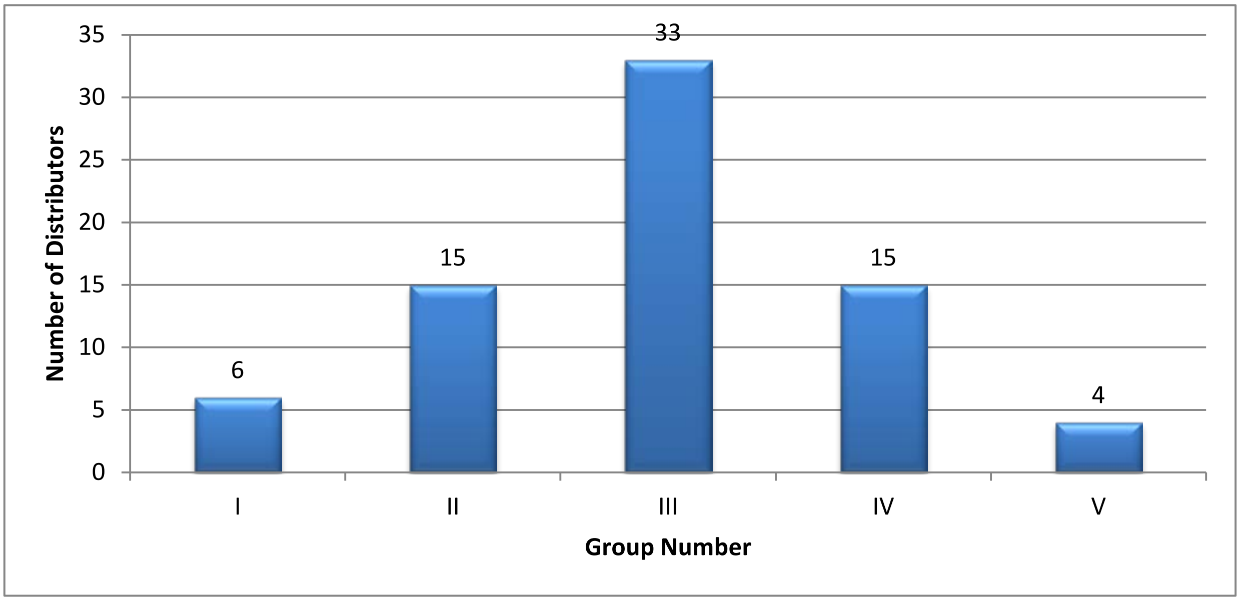
Accordingly, based on the Board's analysis of the cost evaluation ranking set out in Table 17 in the Final PEG Report, the Board has determined that the appropriate stretch factor values for each of the five groups will be as follows.

Table 3: Demarcation Points and Stretch Factor Values

Group	Demarcation Points for Relative Cost Performance	Stretch Factor
I	Actual costs are 25% or more below predicted costs	0.00%
II	Actual costs are 10% to 25% below predicted costs	0.15%
III	Actual costs are within +/-10% of predicted costs	0.30%
IV	Actual costs are 10% to 25% above predicted costs	0.45%
V	Actual costs are 25% or more above predicted costs	0.60%

As shown in Figure 1, the demarcation points listed in Table 3 produce a relatively normal distribution curve across the stretch factor assignment groups.

Figure 1: Allocation of Distributors across the Groups based on Table 17 in the Final PEG Report



When published, each group will be sorted in alphabetical order. **Based on these determinations and the cost evaluation ranking set out in Table 17 in the Final PEG Report, the Board's 2014 stretch factor assignments are set out in Appendix D.**

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.

The Board's concerns with other alternatives to assign stretch factors proposed by stakeholders and outlined in its Draft Report issued on September 6, 2013 are listed in Appendix A.

3 Benchmarking

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

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).

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., Data Envelopment Analysis) and other alternative approaches proposed in consultations to benchmarking performance in the future. The alternatives proposed are outlined in Appendix A.

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 statistically 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 econometrically derived predicted value.

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 for an opportunity to refine them (i.e., the definitions of the proposed adjustments and/or the data) stating that further analysis is needed. VECC, Hydro One Networks Inc., and the Cornerstone Hydro Electric Concepts Association, made specific recommendations on what adjustments should be made. In its Draft Report, the Board directed staff to consult further with distributors on the LV and HV adjustments. The recommendations offered in written comment were to provide a basis for this consultation. Staff facilitated an industry workshop on October 7, 2013 to achieve stakeholder agreement on how to determine LV costs for each distributor that should be included in total cost benchmarking. Board staff enlisted the help of representatives with specific expertise from the industry to plan and lead the workshop. The Board accepts the resultant agreement that is posted on the Board's website and thanks workshop participants for their time and advice.

The Board acknowledges the concerns raised by some workshop participants that a host distributor's costs to own, operate, maintain and refurbish sub-transmission and LV facilities used by embedded distributors have not been fully reflected in the agreed upon LV adjustments. The LV workshop summary alludes to this issue vis-à-vis common sub-transmission line charges. Specifically, workshop participants advised that some of these charges should be included, but since data is not available to help determine how much to include, participants agreed to exclude the charges completely. The Board notes that the broader issue of how to better estimate LV adjustments so that a host distributor's overall total costs are not overstated needs to be addressed in future benchmarking studies.

Unless otherwise determined by the Board, all distributors[21] 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.

[21] Four distributors are excluded from PEG's analysis because their RRR data is not available: Attawapiskat First Nation; Fort Albany First Nation; Kashechewan First Nation; and Hydro One Remote Communities Inc.

intentionally blank

4 Implementation and Periodic Review

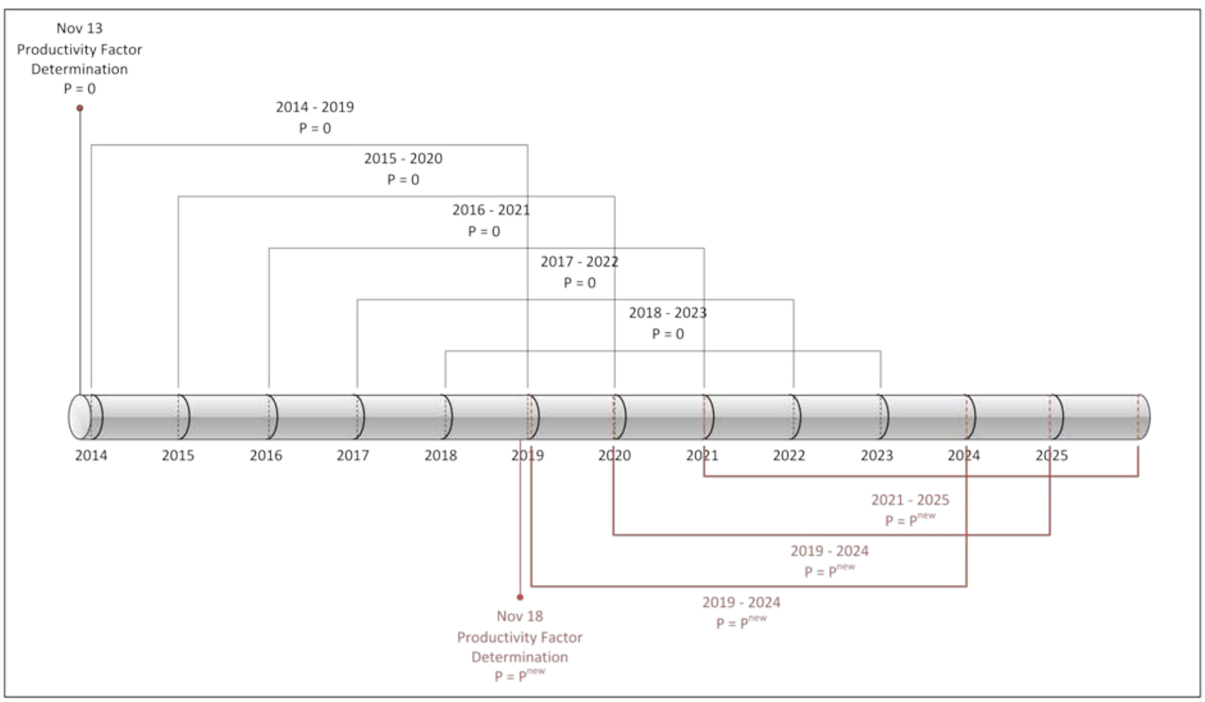
4.1 Stretch Factor Assignments Every Year

The total cost benchmarking model will be run annually to determine efficiency ratings for the purpose of setting stretch factors. The model will be updated using electricity distributor RRR data.

4.2 Productivity Factor Update Every 5 Years

Total factor productivity will be updated every five years. (e.g., the update after 2014 would be in 2019). The updated productivity factor will be applied to all distributors 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 entire 4 year IR term.

Figure 2: Productivity Factor Update



4.3 Information to Support the Board’s Empirical Work

The total cost benchmarking model adopted by the Board uses information from electricity distributors that is not currently reported to the Board through RRR.

The February 26, 2013 Data Request

On February 26, 2013, the Board issued a letter to electricity distributors asking them to file the following information with the Board in order to support the Board’s empirical work:

- smart meter investment data from all distributors;
- HV cost data from distributors that own HV equipment that has been deemed a distribution asset; and
- LV cost information from Hydro One (i.e., summary of payments to Hydro One for LV service from each distributor) and from other host distributors on the dollar amounts that they have billed each of the distributors embedded in their respective distribution systems for delivery services.

The Board will amend its RRR in due course to ensure the relevant data is filed as part of the annual reporting requirements.

Deferral Account Disposition Amounts

As previously noted, a significant increase in OM&A costs was evident in reported costs for 2012 as compared to that reported in 2011. There are several reasons for the overall increase in OM&A of which the largest seem to have been caused by the transfers of balances from the deferral accounts to the balance sheet and income statement accounts, especially with respect to smart meters.

After Board approval, balances in deferral accounts are cleared every year for different reasons by the distributors. More distributors applied to clear their smart meter balances in 2012 than in prior years. Instructions have been issued through the Accounting Procedures Handbook FAQs to clear balances to the income and expense accounts and categories as if the items had been earned or incurred in the current year. As a result, several years of costs that were accumulated in the deferral accounts were recorded as OM&A in 2012. The Board's empirical work was directly affected by the step increase in reported OM&A caused by several years of costs being cleared to expense in 2012. **The Board will review whether there are any other circumstances in which the clearance of deferral accounts can affect the timing of when costs are recorded, and if necessary establish appropriate accounting and reporting requirements in due course.**

4.4 Periodic Review

The Board will review the models used in this Report every five years. Over time, and as the sector further 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 continue to 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).

4.5 The Incremental Capital Module

In its RRF Report, the Board indicated that the Board's policies in respect of the incremental capital module ("ICM") would continue to apply under the RRF. At the Stakeholder Conference SEC presented analysis of the rate impact under the current IR regime of the ICM and how the impact might carry forward under Price Cap IR. SEC expressed concern over the potential level of rate increases which might result. Distributors have also raised issues with respect to the operation of the ICM.

The Board will continue to monitor the use of the ICM. To date there have been relatively few applications for an ICM, and most of these have been for discrete projects, such as transformer stations. The Board expects that the ICM will continue to be used on an exception basis by distributors on Price Cap IR. Distributors with significant ongoing capital requirements will be expected to propose a Custom IR, rather than rely on serial ICM applications within their Price Cap IR term. The Board's monitoring of this issue may result in a review of the methodology and application of the ICM.

Appendix A: Alternatives Raised in Consultations

Alternatives to the "2 factor" IPI

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.
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 Triangularized 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.

Alternatives to the index based Industry TFP

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

The Board finds that while 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.

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 a 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.

School Energy Coalition ("SEC") 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[22].

Dr. Cronin introduced the use of price-dual TFP analysis as a means of assessing the reasonableness of index-based TFP analysis (which is a quantity-based TFP analysis). He also assessed TFP for sub-intervals within the 2000-2011 study period and recommended sample specific TFP indexes as the historical basis for Price Cap IR. Furthermore, and 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 distributors' TFP performance. The data used in these analyses differed[23] from that used by PEG, but was used 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 a weighting approach similar to that 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.

---

[22] 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)

[23] 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 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.

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.

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[24], PEG presented 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.

[24] 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)

Alternative	**Estimated TFP**	**Concern**
Estimate using average, not aggregate, index-based approach.	-0.20[25]	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 advised 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.
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.

[25] Ibid.

Alternative	Estimated TFP	Concern
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 3: 2011 Ontario Conservation Results

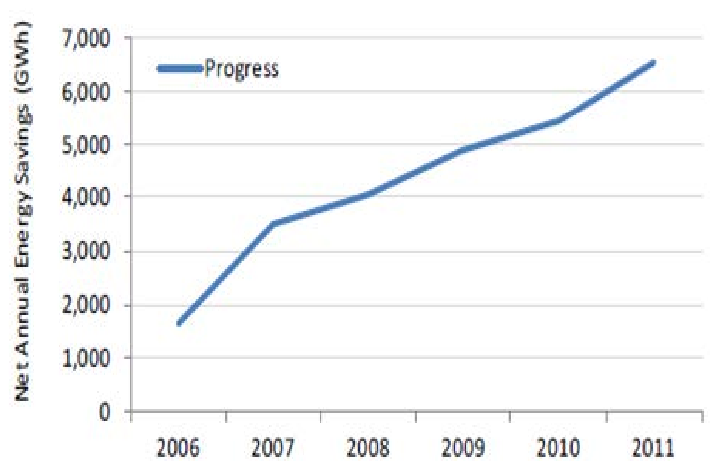


Table 4: Net Annual Energy Savings (GWh)

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 3). The results of that work are discussed in the Final 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.

Alternatives to the Stretch Factor assignments

Prof. Yatchew and Mr. Fenrick proposed different benchmarking models for the purpose of assigning stretch factors. Benchmarking is discussed in Chapter 3.

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 doing 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. Prof. Yatchew commented that some distributors have suggested 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 that 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'.

The Power Workers' Union 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.

SEC 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, SEC proposed that the determination of peer groups be done through a "crowd-sourcing" process. 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.

Alternatives to the econometric benchmarking

Prof. Yatchew estimated an econometric cost model that is similar to that estimated in the May, 2013 Updated PEG Report. However, Prof. Yatchew's model includes two additional business condition variables: % of Capital Costs In Aid of Construction; and % of Net LV-HV Charges. Prof. Yatchew explained that he included these variables because there remain questions about which LV and HV charges should remain in the cost data. Furthermore, he commented that costs incurred by a distributor are affected by the magnitude of capital contributions in aid of construction. Consequently, Prof. Yatchew's model 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 overall 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. 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 Data Envelopment Analysis, 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 Final 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[26]. 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 Data Envelopment Analysis to avoid the risk of data errors and miss-identification of business condition variables	Data Envelopment Analysis may be considered in the future.

[26] 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.

Alternative	Concern
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).

intentionally blank

Appendix B: Inflation Factor

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

intentionally blank

Appendix C: 2014 Inflation Factor Value

Consistent with the policy determinations set out in this Report, the Board has calculated the value of the inflation factor for incentive rate setting under Price Cap IR and the Annual Index for rates effective in 2014 to be 1.7% as shown in the following table:

	Inputs and Assumptions										Resultant Values - Annual Growth of the 2-factor IPI	
Year	Non-Labour GDP-IPI (FDD)							Labour AWE-All Employees-Ontario				
	Q1	Q2	Q3	Q4	Annual	**Annual Change**	**Weight**	Annual	**Annual Change**	**Weight**	Annual	**Annual % Change**
2011	106.2	106.8	107.6	108.3	107.2			$ 894.71			100.0	
2012	108.7	109.1	109.3	109.5	109.2	**1.8%**	**70%**	$ 908.00	**1.5%**	**30%**	101.7	**1.7%**

Sources:

- GDP-IPI (FDD): Statistics Canada. Table 380-0066 - Price indexes, gross domestic product, quarterly (2007=100 unless otherwise noted) – 2013Q2, issued August 30, 2013
- Average Weekly Earnings: Statistics Canada. Table 281-0027 - Average weekly earnings (SEPH), by type of employee for selected industries classified using the North American Industry Classification System (NAICS), annual (current dollars), issued March 27, 2013

Data Accessed October 30, 2013.

The Board will adjust the price escalator in each distributor's 2014 Incentive Regulation Mechanism model such that this change is reflected in distribution rates effective January 1, 2014 and May 1, 2014.

intentionally blank

Appendix D: 2014 Stretch Factor Assignments

Group I	Group II	Group III	Group IV	Group V
Stretch Factor of 0.0%	**Stretch factor of 0.15%**	**Stretch factor of 0.3%**	**Stretch Factor of 0.45%**	**Stretch Factor of 0.6%**
• E.L.K. Energy Inc. • Halton Hills Hydro Inc. • Hearst Power Distribution Company Limited • Hydro Hawkesbury Inc. • Northern Ontario Wires Inc. • Wasaga Distribution Inc.	• Cooperative Hydro Embrun Inc. • Enersource Hydro Mississauga Inc. • Entegrus Powerlines • Espanola Regional Hydro Distribution Corporation • Essex Powerlines Corporation • Grimsby Power Incorporated • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Kitchener-Wilmot Hydro Inc. • Lakefront Utilities Inc. • London Hydro Inc. • Newmarket-Tay Power Distribution Ltd. • Oshawa PUC Networks Inc. • Rideau St. Lawrence Distribution Inc. • Welland Hydro-Electric System Corp.	• Bluewater Power Distribution Corporation • Brantford Power Inc. • Burlington Hydro Inc. • Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Collus Power Corporation • Greater Sudbury Hydro Inc. • Guelph Hydro Electric Systems Inc. • Hydro 2000 Inc. • Hydro One Brampton Networks Inc. • Hydro Ottawa Limited • Innisfil Hydro Distribution Systems Limited • Kenora Hydro Electric Corporation Ltd. • Kingston Hydro Corporation • Lakeland Power Distribution Ltd. • Milton Hydro Distribution Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Norfolk Power Distribution Inc. • North Bay Hydro Distribution Limited • Orangeville Hydro Ltd • Orillia Power Distribution Corporation • Ottawa River Power Corporation • Parry Sound Power Corporation • PowerStream Inc. • PUC Distribution Inc. • Sioux Lookout Hydro Inc. • St. Thomas Energy Inc. • Thunder Bay Hydro Electricity Distribution Inc. • Veridian Connections Inc. • Waterloo North Hydro Inc. • Westario Power Inc. • Whitby Hydro Electric Corporation	• Atikokan Hydro Inc. • Brant County Power Inc. • Canadian Niagara Power Inc. • Chapleau Public Utilities Corporation • Enwin Utilities Ltd. • Erie Thames Powerlines Corporation • Festival Hydro Inc. • Fort Frances Power Corporation • Midland Power Utility Corporation • Oakville Hydro Electricity Distribution Inc. • Peterborough Distribution Incorporated • Renfrew Hydro Inc. • Tillsonburg Hydro Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc.	• Algoma Power Inc. • Hydro One Networks Inc. • Toronto Hydro-Electric System Limited • Woodstock Hydro Services Inc.