PALIARE ROLAND
BARRISTERS

Richard P. Stephenson
T 416.646.4325 Asst 416.646.7417
F 416.646.4301
E richard.stephenson@paliareroland.com
www.paliareroland.com

File 20242

June 27, 2013

VIA EMAIL

VIA *RESS* FILING AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Walli

Re: Renewed Regulatory Framework for Electricity Transmitters and Distributors – Defining and Measuring Performance of Distributors and Transmitters (EB-2010-0379)

Attached please find the Power Workers' Union's submissions on 4th Generation IR and comments on PEG's report to the OEB, *Empirical Research in Support of Incentive Rate Setting In Ontario*.

We hope you will find the PWU's comments useful.

Yours very truly,
PALIARE ROLAND ROSENBERG ROTHSTEIN LLP

Richard P. Stephenson
RPS:jr

Encl.

c: cc: John Sprackett
Judy Kwik

EB-2010-0379

4th Generation IR for Ontario's Electricity Distributors and PEG Report to the Ontario Energy Board on Empirical Research in Support of Incentive Rate Setting In Ontario

Submission of the Power Workers' Union

1 INTRODUCTION

On October 18, 2012 the Ontario Energy Board (the "Board" or "OEB") issued its report on a renewed regulatory framework for electricity distributors ("RFFE") entitled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") in which it states:

> **The Board needs to regulate the industry in a way that serves present and future customers, and that better aligns the interests of customers and distributors while continuing to support the achievement of public policy objectives, and that places a greater focus on delivering value for money. … [Page 1]**

The Board describes the RRFE as 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".

In addition the Board identifies the following factors as prompting the Board's work on the RRFE: government policy; aging infrastructure; customer concerns regarding rate increases; increased maturity of the industry; and, a need to harmonize and consolidate the Board's policies related to planning and rate setting.

The Board identifies the following outcomes for the RRFE:

> ***Customer Focus:*** **services are provided in a manner that responds to identified customer preferences;**
>
> ***Operational Effectiveness:*** **continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;**

> ***Public Policy Responsiveness:*** **utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and**
>
> ***Financial Performance:*** **financial viability is maintained; and savings from operational effectiveness are sustainable. [Page 2]**

These performance outcomes are to be facilitated by the following three main RRFE policies:

- **Rate-setting: There will be three rate-setting methods: 4th Generation Incentive Rate-setting (suitable for most distributors), Custom Incentive Rate-setting (suitable for those distributors with large or highly variable capital requirements), and the Annual Incentive Rate-setting Index (suitable for distributors with limited incremental capital requirements). These rate-setting methods will provide choices suitable for distributors with varying capital requirements, while ensuring continued productivity improvement. …**

- **Planning: Distributors will be required to file 5-year capital plans to support their rate applications. Planning will be integrated in order to pace and prioritize capital expenditures, including smart grid investments. Regional infrastructure planning will be undertaken where warranted. The Board will also propose amendments to the Transmission System Code to facilitate the execution of regional plans. …**

- **Measuring Performance: The Board will develop standards, and measures that will link directly to the performance outcomes listed above. Using a scorecard approach distributors will be required to report annually on their key performance outcomes. … [Page 3]**

On May 3, 2013 the Board issued for stakeholder comment a report prepared by Pacific Economics Group Research LLC (“PEG”) entitled: *Empirical Research in Support of Incentive Rate Setting In Ontario: Report to the Ontario Energy Board* (the “PEG Report”). Board staff retained PEG to provide advice on the development of 4th Generation Incentive Rate-setting (“4th Generation IR”) and to provide quantitative recommendations on: the inflation factor; the productivity factor that applies to the entire Ontario electricity distribution sector; and, stretch factors that apply to different cohorts of distributors. Board staff and PEG held discussions with a stakeholder working group (“PBR Working Group”) established to provide Board staff with assistance in evaluating proposals on performance standards, measures, benchmarking and rate adjustment indices (i.e. inflation and productivity factors) for 4th Generation IR.

2 THE PWU'S SUBMISSION

The PWU's comments in this submission stem from its energy policy statement:

> **Reliable, secure, safe, environmentally sustainable and reasonably priced electricity supply and service, supported by a financially viable energy industry and skilled labour force is essential for the continued prosperity and social welfare of the people of Ontario. In minimizing environmental impacts, due consideration must be given to economic impacts and the efficiency and sustainability of all energy sources and existing assets. A stable business environment and predictable and fair regulatory framework will promote investment in technical innovation that results in efficiency gains.**

The PWU's vision for a sustainable and long-term regulatory regime for Ontario's electricity distributors is one that focuses on customer value and establishes appropriate and transparent incentives based on Ontario distributors' empirical data analysis to achieve performance levels that align with customer expectations.

To achieve this vision it is necessary to recognize customer value as the key input to the regulatory framework. This key input would be obtained through robust customer Willingness to Pay ("WTP") surveys that will establish the utilities' service quality (i.e. customer service and service reliability) standards and provide the context for the utilities' network investment planning and for the Board's regulatory framework.

In this submission the PWU provides comment and input on the RRFE policies and regulatory issues that the Board still need to address in order to meet its policy objectives. The PWU notes the power of incentives and the importance of understanding the incentives/disincentives created by incentive regulation ("IR") proposals under consideration. The PWU then provides comment on aspects of PEG's analyses and proposals on the Input Price Index ("IPI"), total factor productivity ("TFP"), benchmarking and stretch factors. In doing so, the PWU presents alternative analytical approaches and proposals. The PWU forwards price-dual TFP analysis to test the reasonableness of the outcome of index-based TFP analysis. In addition the PWU forwards DEA analysis to test the reasonableness of PEG's benchmarking analysis. Further, the PWU identifies the need for the Board to incorporate customer-valued service reliability performance determined through WTP studies, as well as line loss performance into TFP analysis to achieve a comprehensive performance-based regulatory framework that provides value for customers.

The PWU's proposals are largely based on analysis presented in Dr. Frank Cronin's report entitled *Submission on 4th Generation IR for Ontario Electricity Distributors*, which the PWU filed with the Board on June 13, 2013. Dr. Cronin's report includes illustrative analysis on: price-dual TFP analysis and its use in testing the reasonableness of index-based TFP; the use of Data Envelopment Analysis ("DEA") in efficiency benchmarking; incorporating customer-valued service reliability performance into TFP; and incorporating line losses into total factor productivity. Dr. Cronin also compares his index-based TFP analysis based on actual distributors' data with PEG's TFP analysis that includes data estimates. In addition Dr. Cronin proposes estimating TFP for 4th Generation IR based on the Board's direction on a weighted TFP for First Generation PBR. Dr. Cronin also compares the outcome of his DEA-efficiency benchmarking analysis with that of PEG's econometric-benchmarking.

3 RRFE POLICIES

3.1 Integrated Approach

The PWU appreciates the opportunity provided by the Board for the PWU's participation on the PBR Working Group. The PWU also participated on the Board's Working Group on 3rd Generation IR and recognizes the enhancements to its IR framework that the Board is pursuing through the RRFE policies. The PWU commends the Board on its objective for a comprehensive performance-based RRFE and believes that the Board has made a good start, especially in correcting some of the flaws implicit in 3rd Generation IR. In the PWU's view, a comprehensive performance-based regulatory framework integrates rate-setting, planning and performance to provide a network that is efficient, reliable, sustainable, and provides value for customers. To get there, the Board still has some significant gaps to fill. These gaps are addressed in this submission.

3.2 Customer Value

The RRFE's focus on providing value to customers of necessity requires an understanding of the value that customers' place on electricity service. As the PWU has submitted to the Board in numerous consultations on IR and service quality regulation ("SQR", i.e., customer service and service reliability), customer value should be established through WTP studies. Regulators in Great Britain, Norway, Italy and Sweden have used WTP studies to ascertain customers' satisfaction with distribution performance, the value customers place on reliability and the amount they would be willing to pay for service improvements. Some of these regulators have taken WTP information and explicitly incorporated the values into their distribution rate regulation.[1] As the PWU has asserted in past submissions to the Board, including its April 20, 2012 submission in the RRFE consultation,[2] effective service quality regulation requires the Board to establish performance standards with appropriate incentives (i.e., penalties and rewards for performance). The WTP studies are essential to the determination of the appropriate incentive levels (i.e., rewards and penalties) required to encourage service quality performance and provide the backstop to service quality deterioration as utilities pursue IR's financial incentive.

Given the lack of provision for direct customer input on the value that they place on electricity service, the RRFE lacks consideration of actual customer-value. This is a short-coming that must be addressed in order for the Board to achieve its RRFE customer focus objective.

---

[1] EB-2010-0249. PWU Submission. Service Reliability and Regulation in Ontario. Francis J. Cronin. October 29, 2010.
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

[2] EB-2010-0379. PWU Submission. Renewed Regulatory Framework for Electricity Transmitters and Distributors – Defining and Measuring Performance of Distributors and Transmitters (EB-2010-0379). April 20, 2012.
http://www.rds.ontarioenergyboard.ca/WEBDRAWER/WEBDRAWER.DLL/webdrawer/rec/339284/view/PWU_Comments_RRFE_0379_20120420.PDF

3.3 Input Price Index

For 3rd Generation IRM the Board adopted a macro-economic inflation index as the input price index. The RRFE calls for a more industry specific IPI for 4th Generation IR. Concern regarding volatility in the IPI is to be mitigated by the methodology selected by the Board. Further, the RRFE provides the following guidance:

> **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;**
>
> **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) [Page 16]**

An industry specific inflation factor sets a realistic input price benchmark for the distributors because it is based on the actual inflationary cost pressures that the distributors face. The PWU views the RRFE's move to an industry IPI as a significant improvement over the use of a macro-economic inflation index that requires the distributors to react to an inflation factor that is not consistent with the actual inflationary pressures they are experiencing. Regardless of how well the macro-economic inflation index may happen to coincide with the industry-based IPI over a given time period, there is always the risk of divergence. A possible outcome of such divergence is cost cuts that adversely impact service quality and that result in higher future catch-up costs. Conversely, it can result in a margin in the rate adjustment mechanism ("RAM") that creates a disincentive for the distributors to pursue the intended productivity growth. Neither outcome is in the customers' interest.

3.4 TFP Index

The RRFE's policy on an index-based TFP (or "quantity-based" TFP) approach based on Ontario distribution sector's empirical data is a significant improvement over 3rd Generation IR's use of a US data base. In theory, this provides for a more realistic productivity improvement expectation (i.e., X-factor) because the TFP benchmark reflects the Ontario distribution sector's experience. Such a benchmark should mitigate the incentive for unreasonable cost cuts that risks service quality performance or the disincentive for productivity improvement. However, while the policy direction is appropriate, as discussed below in Section 5, the realization of a reasonable TFP index is contingent on choices made in the implementation of the index-based TFP analysis (e.g., data choices). The Board therefore needs to be vigilant with regard to the details of the TFP analysis on which it basis the TFP index.

3.5 Benchmarking

According to the RRFE Report the role of benchmarking for 4th Generation IR is to assess the reasonableness of distributor cost forecasts and to assign productivity stretch factors. Service quality is a critical consideration in benchmarking the distributors' cost efficiency given the cost implications of service quality performance. Therefore, for benchmarking to be fair and in-line with the RRFE's integrated approach to regulation, there is the need for the Board to consider service reliability performance in benchmarking. Not to do so results in a disincentive for service reliability performance.

The RRFE policy that moves the Board from benchmarking distributors based on only OM&A costs to total cost is essential given the Board's penchant for benchmarking. The Board first embarked on the comparison of distributors' costs based on OM&A in the 2006 EDR process (EB-2006-0268). Subsequently, OM&A benchmarking was used in assigning productivity stretch factors in 3rd Generation IR. A shift in cost allocation from OM&A to Capital is an expected outcome of the incentive created by OM&A-only benchmarking/cost comparisons. The result is inefficiency in cost allocation (i.e., allocative inefficiency). Indeed evidence submitted by the PWU in the RRFE consultation indicated a substantial increase in overhead and labour capitalization between 2007 and 2010.[3]

[3] EB-2010-0379. PWU Submission. Renewed Regulatory Framework for Electricity Transmitters and

However, as in the case of TFP analysis the realization of reasonable benchmarking is contingent on choices made in the analysis (e.g., data choices) and the Board needs to be vigilant on the details of the analysis.

3.6 Service Quality Regulation

In a 2006 publication, Paul Joskow[4] points out that cost is only one dimension of a utility's multi-dimensional performance. Utility performance also includes "quality" dimensions (e.g. safety performance) and there are inherent trade-offs between cost and quality. For example, service quality performance delivered by electricity distributors (e.g. frequency of outages, duration of outages) may deteriorate under price cap regulation because utilities may be willing to cut corners or even eliminate certain services. Accordingly, a regulatory framework that includes incentives for cost efficiency, of necessity must include incentives for quality performance to mitigate any urge on the part of the regulated entity to cut costs at the expense of quality performance. Targeted incentives are often applied by defining service quality performance standards and imposing penalties on the utility if the standards are not met, or providing rewards if performance exceeds the standards.

At present, despite service reliability reporting requirements since 2000, the Board does not have incentives in place for service reliability performance. According to the RRFE Report the Board sets out delivery on service quality objectives as the desired operational effectiveness outcome. In addition the Board states its objective of developing standards and measures that will link directly to the performance outcomes. However, despite these pronouncements, the RRFE lacks policy direction on standards and incentives for performance that addresses the value that customers place on service

---

Distributors – Defining and Measuring Performance of Distributors and Transmitters (EB-2010-0379). April 20, 2012.
http://www.rds.ontarioenergyboard.ca/WEBDRAWER/WEBDRAWER.DLL/webdrawer/rec/339284/view/PWU_Comments_RRFE_0379_20120420.PDF

[4] Joskow, Paul L. MIT. Incentive Regulation In Theory and Practice: Electricity Distribution And Transmission Networks. January 21, 2006. Page 16.

quality. Incorporating service reliability at the levels that customers value into TFP and benchmarking analysis would form the basis of a comprehensive IR framework that provides incentives for cost and service quality performance.

The Board is in the process of developing cost efficiency incentives for the distributors, but has failed to act on the need to factor in service quality performance in doing so. This is a significant gap in the Board's regulatory framework that needs to be addressed in 4th Generation IR. In his June 13, 2013 report Dr. Cronin provides evidence on the deterioration of service reliability in the province. Dr. Cronin's analysis indicates the urgency with which the Board needs to address service reliability regulation.

3.7 Efficiency Gains Through Line Loss Management

The RRFE Report states that the OEB's legislative objectives of protecting consumers' interest and promoting economic efficiency and cost effectiveness within a financially viable industry are the foundation of the RRFE. However, the RRFE Report does not address incentives to mitigate line loss increases that would contribute to the economic efficiency and cost effectiveness of the industry. In its RRFE submission the PWU identified the need to incorporate an incentive to discourage degradation in line losses. Increases in line losses not only directly result in increased total bill amounts they also constitute a waste of energy that counters the impact of hard-earned CDM penetration.

4 PWU'S COMMENTS AND PROPOSALS

In this section the PWU comments on PEG's report and presents proposals on aspects of 4th Generation IR.

While the PEG Report indicates PBR Working Group agreement on numerous proposals set out in the report, the PWU notes Dr. Kaufmann's acknowledgement at the Board's May 16th, 2013 Question and Answer session that the references to PBR Working Group agreement do not indicate unanimous agreement. This acknowledgement is pertinent for the issues on which the PWU identifies preferred alternatives to PEG's proposals in this submission.

4.1 IR's Explicit and Implicit Incentives

IR is an alternative regulatory approach to traditional cost of service ("COS") regulation that is intended to provide more powerful incentives for regulated companies to increase efficiency, improve quality performance, and pursue innovation. The PEG Report assumes that PEG's IR analysis will provide the appropriate incentives for cost efficiency without consideration of possible unintended incentives/disincentives that can result. In Dr. Cronin's June 13, 2013 report, he notes that 3rd Generation IRM provided a strong incentive for reduced allocative efficiency. In the PWU's RRFE submission, Dr. Cronin noted that on aggregate, labour capitalization for this period increased from 10 per cent in 2000 to 35 per cent in 2010. Based on DEA analysis presented in his June 13, 2013 report, Dr. Cronin finds that allocative efficiency has declined 20 per cent among the distributors that form the efficiency frontier. Dr. Cronin notes that these findings are consistent with the incentives offered by OM&A-only benchmarking. Dr. Cronin had raised the issue of allocative inefficiencies in the Board's consultation on Comparison of Distributors Cost (EB-2006-0268).[5]

In the PWU's view the increase in labour capitalization in response to the incentive created by OM&A-only benchmarking reflects the distributors' choice of funding programs through a shift in cost allocation rather than cutting costs/programs and ignoring system needs. As a result OM&A-only benchmarking created an inadvertent incentive for cost inefficiencies.

It is also clear from evidence provided in Dr. Cronin's June 13, 2013 report that the distributors have lacked incentives for service reliability performance and line loss management over the course of the Board's regulation of the electricity distributors. As demonstrated by the decline in allocative efficiency related to OM&A-only benchmarking, incentives can be powerful and the Board must consider the possible unintended outcomes of its IR framework and not rely on IR's incentive for cost efficiency as a given.

[5] Power Workers' Union Submission. Francis J. Cronin. June 2007. .http://www.ontarioenergyboard.ca/documents/cases/EB-2006-0268/pwu_peg-comments_200700704.pdf

4.2 Input Price Index - IPI

PEG developed two alternative inflation factors:

- A two-factor IPI that uses separate input price sub-indices for capital and OM&A inputs; and,
- A three-factor IPI that uses separate input price sub-indices for capital, labour and non-labour OM&A inputs.

The PWU supports the “three-factor” IPI. As noted in the PEG Report, the “two-factor” IPI is not consistent with the Board’s specification for the selection of separate non-labour and labour price indices. In the PWU’s view the “two-factor” IPI takes away from the precision that separate non-labour and labour price indices are intended to enhance.

While the Board’s guidance on the IPI specifies that labour prices will be indexed by an appropriate generic off-the-shelf labour price index (i.e. not distribution industry-specific), the PWU believes that using the “average weekly earnings for all workers in Ontario” as proposed by PEG is an exaggeration of this guidance and moves the IPI unnecessarily further away from the RRFE’s policy for a more industry specific inflation factor. Instead, the PWU recommends the use of the “Ontario-Utilities Average Weekly Earnings” index available from Statistics Canada. This index reflects the inflation experienced by the broader sector that the distributors belong to and is more in-line with the RRFE’s policy than PEG’s proposed index.

The RRFE Report states that concerns on volatility in the IPI will be mitigated by the methodology selected by the Board. PEG proposes using a three-year rolling average of the annual IPI index to mitigate volatility in the IPI. The PWU notes that using a method that adjusts the actual annual IPI takes away from the efforts that have been expended on developing an accurate inflation factor in the first place. Adjusting the IPI to address volatility sets the wrong input price benchmark and can result in distributors’ revenue shortfalls and cost cuts that adversely impact service quality. Ultimately such cost cuts will result in higher future costs. Conversely, adjusting the IPI can result in a margin in the IRM that creates a disincentive for the distributors to pursue the intended efficiencies. Once again, neither outcome is in the customers’ interest.

The PWU proposes that the Board use a deferral account to smoothen bill impact in years in which the Board determines there is customer concern with bill impacts related to IPI volatility. This prevents the unintended destruction of the carefully developed input price benchmark and the Board can be assured that the IPI remains consistent with the RRFE policy for a more industry-specific inflation factor while addressing the impact of total bill volatility.

4.3 Total Factor Productivity – TFP

As noted earlier in this submission, the Board's RRFE policy specifies an index-based approach for the derivation of an industry TFP index to form the basis for the X-factor. Consistent with this policy PEG conducted index-based TFP analysis as the basis for its recommendation on a TFP index for 4th Generation IR. Dr. Cronin also conducted index-based TFP analysis. However, PEG and Dr. Cronin used different data sets in their respective analysis.

The TFP presented in the May 27th version of the PEG Report's Table 18 indicates an average annual TFP growth of -0.7 per cent for 2006-2011, when Hydro One and Toronto Hydro are excluded. Index-based TFP analysis conducted by Dr. Cronin excluding Hydro One and Toronto Hydro indicates an annual average TFP index for 2006-2011 of -0.9 per cent. For the broader period 2002- 2011, the difference is larger with PEG's average annual TFP growth at 0.10 per cent compared to Dr. Cronin's -0.6 per cent.

In this section the PWU forwards issues for the Board's consideration related to differences in the data sets used in PEG's and Dr. Cronin's analyses that will have contributed to the differences in the TFP estimates.

4.3.1 Data Issues

The PWU understands that robust index-based TFP analysis depends on the availability of substantial amounts of quality data and that PEG's index-based TFP analysis was challenged with significant data issues.

The 2000 Electricity Distribution Rate Handbook required distributors to file Financial, Energy and Demand data, and PBR related information, starting with 1999 data. In addition, the Board requested distributors to submit 1988-1997 PBR data with capital data that span a 20 to 25-year period back to the early 1970's, for use in TFP analysis for First Generation PBR.[6] The PBR related information includes annual Capital Additions and annual Capital Retirements.

Unfortunately PEG did not have some of the filed pre-2000 data available to it (i.e. Capital Additions and Capital Retirements) and used estimates. PBR Working Group discussions led PEG to use estimated data for 2000 and 2001, and estimated Capital Additions for 2002-2011 rather than actual data filed by the distributors. In the PWU's view there was a lack of clarity in the PBR Working Group discussions on the distinction between the specific data concerns as they relate to TFP analysis (i.e., temporal consistency for individual distributors) versus benchmarking (i.e., consistency amongst distributors) that contributed to the sacrifice of quality data (i.e., the actual data filed by the distributors). For the derivation of TFP year-over-year comparability of an individual distributor's information is more important than the comparability amongst distributors' information as is the case in benchmarking.

Dr. Cronin used actual data filed under the Board's direction including the OEB's Reporting and Record Keeping Requirements ("RRR") in his index-based TFP analysis presented in his June 13, 2013 report.

The PWU's view is that the use of data filed by the distributors is preferred to the use of estimates. Unless there was gross negligence in a distributor's filings, the data filed is the appropriate data set for TFP analysis compared to the use of estimates that can come with significant error.

A comparison of PEG's estimated Gross Capital Additions with the RRR Gross Capital Additions data indicates significant variance between the two sets of data that can be expected to contribute to differences in the outcome of index-based TFP analysis.

[6] http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/Data_requirement.PDF

Exhibit 4-1 shows the annual differences between PEG's estimated annual Gross Capital Additions and the RRR annual Gross Capital Additions for all distributors for 2005 through 2011. PEG's annual estimates are substantially lower than the RRR data with variance ranging from -6.4 per cent (2005) to -50 per cent (2009).

Exhibit 4-1

Gross Capital Additions
Variance Between PEG Estimates and RRR Data
All Distributors

Year	(1) PEG Estimated Capital Additions $	(2) RRR Capital Additions $	(1) - (2) $	(1) - (2) %
2005	812,847,578	868,648,410	-55,800,832	-6.4%
2006	941,947,579	1,074,037,660	-132,090,081	-12.3%
2007	983,933,096	1,347,211,657	-363,278,561	-27.0%
2008	1,115,944,161	1,372,884,926	-256,940,765	-18.7%
2009	728,247,294	1,457,372,544	-729,125,250	-50.0%
2010	1,583,156,755	1,804,926,943	-221,770,188	-12.3%
2011	1,460,394,874	1,935,714,418	-475,319,544	-24.6%

The variance for 2005 through 2011, with Toronto Hydro and Ontario Hydro taken out of the sample are shown in Exhibit 4-2. Once again PEG's annual estimates are substantially lower than the RRR data in each year with the variance ranging from -6.9 per cent (2007) to -39.0 per cent (2009).

Exhibit 4-2

Gross Capital Additions
Variance Between PEG Estimates and RRR Data
Distributors Excluding Hydro One and Toronto Hydro

Year	(1) PEG Estimated Capital Additions $	(2) RRR Capital Additions $	(1) - (2) $	(1) - (2) %
2005	395,993,658	426,449,443	-30,455,785	-7.1%
2006	370,100,644	497,481,291	-127,380,647	-25.6%
2007	528,525,114	567,590,953	-39,065,839	-6.9%
2008	448,199,791	603,468,317	-155,268,526	-25.7%
2009	360,027,724	590,047,382	-230,019,658	-39.0%
2010	441,459,445	691,548,391	-250,088,946	-36.2%
2011	503,284,915	734,272,877	-230,987,961	-31.5%

In a presentation made by Board staff at a September 12-13, 2007 Technical Consultation on the Comparison of Distributors Costs[7] the quality of Capital Additions data (5 years of data) filed by the distributors was rated as high. While concerns were identified with the level of detail specified in the Board's data filing requirement, these concerns do not take away from the high quality rating for filed data. In considering PEG's TFP analysis in the determination of a TFP index for 4th Generation IR, the PWU identifies the need for the Board to take into account the variance between the data set used by PEG and the RRR data set. Given the lower Gross Capital Additions estimates reflected in PEG's estimated data set compared to the actual Gross Capital Additions, the Board would need to adjust PEG's TFP estimate downward in considering it as the basis for the X-factor. Not to do so results in an unrealistically high efficiency benchmark that creates inappropriate incentives and results in undesirable outcomes (e.g. service reliability degradation; increased line losses).

[7] http://www.oeb.gov.on.ca/documents/cases/EB-2006-0268/presentations/oeb_20070912.pdf. Slides 8 and 9.

4.3.2 Contributions in Aid of Construction

Index-based TFP analysis can vary significantly depending on whether Contributions in Aid of Construction ("CIAC") are included in the analysis or not. PEG's and Dr. Cronin's analysis excluded CIAC.

PEG's reason for excluding CIAC from TFP analysis is that CIAC is not part of rate base and including it in TFP therefore would create a mismatch:

> **CIAC payments were excluded from the TFP cost measure because CIAC should not be included in PEG's estimate of TFP growth. The reason is that estimated TFP growth will be part of the PCI formula used to adjust regulated distribution rates. CIAC payments are not part of distributors' rate base and therefore not subject to this rate adjustment formula. Including CIAC in our TFP analysis would therefore create a mismatch between the costs used as inputs for IR-based rate adjustments and the costs that are actually subject to that IR mechanism. [PEG Report, Page 37)**

However, PEG's reason for including CIAC in its benchmarking analysis is that it is part of capital stock that distributors use to provide services to customers:

> **PEG also included contributions in aid of construction (CIAC) in the capital cost measure. While CIAC payments are outside of the Board's IR rate adjustment formula, they are part of the capital stock that distributors use to provide service to their customers. If these CIAC were not included in distributors' cost measures used for benchmarking, these costs would differ across distributors simply because of differences in the relative amounts of capital financed by CIAC. [PEG Report, Page 38-39]**

The PWU agrees with PEG's reason for including contributed capital in benchmarking and submits that this is the very reason that contributed capital needs to be included in TFP. As the basis for the stretch factors, the benchmarking analysis including CIAC is used to adjust rates. Similarly, TFP analysis as the basis for the productivity factor (or "X-factor"), is used to adjust rates and, as in the case of PEG's benchmarking analysis, should include CIAC as it is part of the capital stock that distributors use to provide services to customers.

The PWU notes that CIAC was included in TFP analysis for First Generation IR. In his report Dr. Cronin notes that both for individual LDCs and in the aggregate, CIAC makes up a notable share of Capital Additions. The exclusion of CIAC from PEG's and Dr. Cronin's TFP analyses therefore results in the significant understatement of the distributors' input index and overstatement of TFP growth. The Board needs to take this gap in the TFP analysis into account in determining the X-factor for 4th generation IR. The gap would need to be addressed through a downward adjustment of the TFP estimate.

4.3.3 Price-dual TFP – Test of Reasonableness of Index-based TFP for 4th Generation IR

Since different choices on data can account for differences in the index-based TFP estimates, the reasonableness of the TFP analysis should be tested against analysis using a different TFP approach and separate data.

PEG conducted econometric "backcast" of industry TFP growth with the objective of providing additional evidence that may inform the Board in its determination on a productivity factor for 4th Generation IR. The PEG Report indicates that in its econometric backcast information is developed on the sources of TFP growth, and the X-factor is adjusted to reflect the impact on TFP related to differences between a distributor's particular circumstances and what is reflected in historical TFP trends.[8] The econometric backcast therefore involves the data set used in PEG's index-based TFP analysis and is not an effective independent test of the reasonableness of the data used in PEG's index-based TFP analysis.

Over the course of the PBR Working Group meetings Dr. Cronin made two presentations on how the price-dual TFP approach can be used to test the reasonableness of index-based TFP analysis.[9,10] In his June 13, 2013 report, Dr. Cronin provides Illustrative price-dual TFP analysis using a subset of Ontario distributors (including Hydro One and Toronto Hydro) that together account for 80 per cent of Ontario's distribution revenue.

As can be surmised from the PEG Report, PEG's index-based analysis was mired by data issues (e.g. data estimation and interpolations). The price-dual TFP approach does not require the reams of historic data required for the index-based TFP analysis.

[8] PEG Report. Page 97.
[9] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PWU_Cronin_Jan21_RRFE_Presentation_PBR_WG.PDF
[10] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PWU_Cronin_Feb21_Presentation_PBR_WG.PDF

Essentially the change in the price-dual TFP is the difference between the annual rate of change in input prices and the annual rate of change in output prices (i.e. distribution rates). It measures the change in Board approved rates (i.e., output) relative to the change in input prices (i.e., the IPI). The only data required are the IPI and the distributors' approved rates for the two years that form the end-points for the analysis. The rates data set is a separate data category from that used in determining index-based TFP and provides a TFP estimate unencumbered by the data issues faced by PEG in its TFP analysis. Price-dual TFP analysis therefore provides a good test of the reasonableness of an index-based TFP index.

With Hydro One and Toronto Hydro included in the sample, Dr. Cronin's price-dual TFP analysis for 2006-2011 estimates a TFP index of -2.41 per cent which is highly comparable to his index-based TFP estimate of -2.3 per cent. Dr. Cronin's TFP estimates therefore are reasonable and the Board can rely on them in its considerations of an X-factor for 4th Generation IR. Since PEG's TFP analysis excluded Hydro One and Toronto Hydro, Dr. Cronin ran PEG's TFP analysis with Hydro One and Toronto Hydro included. PEG's TFP for 2006-2011 including Hydro One and Toronto Hydro is somewhat lower at -2.14 per cent, which would at least in part, be a result of its lower Capital Additions estimates relative to the actual data. As noted earlier, the Board would need to take this into consideration in relying on PEG's TFP analysis through a downward adjustment of PEG's TFP estimate.

With regard to PEG's analysis, Dr. Cronin notes that there is inconsistency in the use of PEG's sample combinations. PEG maintains that for the "industry" TFP analysis Hydro One and Toronto Hydro are not included in the industry since their inclusion would by their very nature dominate the results. As a result PEG excludes somewhere between 40 and 70 per cent of the weighted industry sample depending on the characteristic under consideration, e.g., number of customers, etc. However, while PEG does not include Hydro One and Toronto Hydro in its final TFP calculations, they are apparently included in the TFP capital analysis (e.g., the depreciation rate calculation). Further Hydro One and Toronto Hydro are included in PEG's cost elasticity in the benchmarking analysis that is used in the TFP analysis, even though Hydro One and Toronto Hydro are not included in the final TFP calculations. This inconsistency will have impacted PEG's analysis and will also need to be addressed in the Board's consideration of PEG's TFP analysis.

4.3.4 TFP for 4th Generation IR

While Dr. Cronin's index-based and price-dual TFP analysis is described as illustrative, the results of the analysis are robust and reflective of the distribution industry's productivity performance. The data used in the analysis are actual data filed by the distributors either with their previous regulator, Ontario Hydro or with the Ontario Energy Board. The distributors included in the price-dual analysis collectively cover 80 per cent of the distribution revenue and as such their data significantly impact the industry TFP estimates. As submitted earlier in this submission, the PWU is of the view that the use of actual data when available has merit over the use of estimations and interpolations. As noted above, some of the data criticism that resulted in PEG's use of data estimates, while pertinent for benchmarking analysis is not so much so for TFP analysis.

The comparability of Dr. Cronin's index-based TFP index to his price-dual TFP index establishes the reasonability of his index-based TFP. The PWU therefore submits that in setting TFP for 4th Generation IR, the Board can rely on Dr. Cronin's TFP analysis.

The PWU agrees with the Coalition of Large Distributors ("CLD") expert consultant PSE that Hydro One and Toronto Hydro ought to be included in the TFP analysis.[11] They are an integral and significant part of Ontario's distribution sector and were both included in TFP analysis for 3rd Generation IR.

PEG's index-based TFP and Dr. Cronin's index-based TFP analyses both indicate an increasingly negative TFP trend for the distribution industry in 2002-2011. To give consideration to this trend, Dr. Cronin developed a weighted TFP in the manner that the Board weighted the TFP time-intervals in its decision[12] on First Generation PBR that gives emphasis to the later sub-interval: 1/3 weight to the earlier time-interval and 2/3

[11] Coalition of Large Distributors. Power System Engineering, Inc. Recommendations on 4th Generation Incentive Regulation. Page 19. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/CLD_Submission_20130614.pdf
[12] Decision with Reasons. RP-1999-0034. http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/dec.pdf

weight to the later time-interval. Dr. Cronin's weighted TFP for 2002-2011 is -1.5 per cent.

PEG's TFP recommendation on a TFP index of 0.1 per cent is based on an un-weighted TFP index for 2002-2011, that excludes Hydro One and Toronto Hydro. PEG postulates that the negative TFP for 2006-2011 is a result of the economic recession and CDM. It does so based on analysis of its aggregate input and aggregate output indices, which according to PEG suggest that the slowdown in output growth is the reason for the negative TFP in 2006-2011. However, PEG finds that for some distributors the growth in inputs has been four or five times higher than the growth in outputs. Dr. Cronin notes that this is consistent with distributors' need to address accumulating aging assets. Dr. Cronin also states that he would expect to see the impact of the economic recession primarily in 2008-2009. In the PWU's view, a weighted TFP that emphasizes the increasingly negative TFP over 2002-2011 would address one of the factors that the Board identified in the RRFE Report as prompting the need for the RRFE: aging infrastructure.

In addition, as the PWU noted in its RRFE submission, the Board needs to recognize the incremental costs of the ongoing workforce renewal efforts including costs for recruiting and training, and reasonable compensation levels to attract suitably skilled and experienced workers. It takes three to five years to develop a recent hire to the "journeyperson" level of knowledge and output, and significantly longer to develop a competent supervisor. Increased investment will be needed to recruit, mentor, train and attract quality new employees to perform functions safely and efficiently. Vast improvement in enterprise-wide systems and processes are required to help trainees get up to speed including appropriate documentation, standardization of processes, and quality and certainty of data. These improvements are essential for the transfer of institutional knowledge to new employees and must be implemented before employees with the institutional knowledge and memory retire. Weighting the TFP index to give emphasis to the increasingly negative TFP trend would help address increased cost pressure related to workforce renewal as well as aging assets.

PEG's recommended TFP of 0.1 per cent overstates TFP potential for 4th Generation IR given the lower Capital Additions estimates used in its analysis compared to the distributors' RRR data. In addition, PEG's TFP analysis excludes two significant distributors, Hydro One and Toronto Hydro. Dr. Yatchew's index-based and cost-based TFP analysis indicates TFP of -0.7 per cent and -0.8 per cent, respectively, and he recommends a productivity factor of -0.75 per cent. PSE recommends that the Board base the productivity factor on a TFP estimate of -1.1 per cent. Dr. Yatchew and PSE's TFP analysis rely on the same data set used by PEG and the error in PEG's data set also results in the overstatement of Dr. Yatchew and PSE's TFP estimates. Further, not giving weight to the declining trend in TFP growth ignores the reality of aging assets and workforce renewal. Applying the Board's First Generation PBR weighting to PEG's TFP analysis that includes Hydro One and Toronto Hydro results in TFP of -1.4 per cent, which is close to Dr. Cronin's weighted TFP analysis of -1.5 per cent.

The PWU recommends that the Board consider Dr. Cronin's weighted TFP of -1.5 per cent as the maximum limit in its consideration of a TFP index for 4th Generation. As noted above, neither PEG nor Dr. Cronin's index-based TFP analysis include CIAC and therefore overstate TFP growth.

4.4 Benchmarking

Flawed benchmarking used to assign TFP stretch factors can result in disincentives for distributor investment in the prudent replacement of accumulating aging assets as efficient distributors are mistakenly identified as inefficient and inefficient distributors are identified as efficient. The impact would be service quality degradation, higher future costs, and risk to the sustainability of the distribution system. As noted at the start of this section, IR is all about incentives and the Board needs to avoid creating unintended undesirable incentives/disincentives.

At the PBR Working Group meetings as well as at the Board's consultation meetings there have been concerns forwarded on the selection of factors and the data to be included in econometric benchmarking. The PWU believes that many of these expressed concerns have not been dealt with to the extent expected in a consultation on

IR rate adjustments and incentives that will be in effect for five years. As examined below, PEG's overwhelming data problems and model instability make it almost a certainty that many distributors will have incorrect efficiency assessments. In fact PEG's analysis results in extremely wide divergences in efficiency amongst the distributors.

In this section some background is provided on benchmarking approaches. The PWU forwards the use of DEA, a benchmarking approach on which Dr. Cronin provided illustrative analysis in his June 13, 2013 report, as a means of checking PEG's econometric benchmarking results. Further comments are provided on the issues associated with PEG's econometric benchmarking approach.

4.4.1 Benchmarking Approaches

Over two decades ago, Shleifer[13] (1985) proposed tournament-type regulation based on peer group competition. Firms would be allowed to price at the group-determined average cost. Firms with costs below the average would profit based on the difference between their own costs and the average; firms with costs above the average would be incented to become more efficient or continue to lose on each unit of production. This tournament would be conducted each period and endogenously introduce incentives to raise static and dynamic efficiencies. Each firm would strive to lower its cost and, as a consequence, the average. The advantages of this approach include a reduction in the overt influence of the regulator, the reliance on more accurate measures of group costs based on central tendencies, and the use of a simulated competition among the firms to reveal the potential for total cost reductions. This endogenous approach was examined for 2nd Generation IR in Ontario. A variant of this approach was used by the US Interstate Commerce Commission for rails, and to set Medicare rates.

As part of electricity sector restructuring, regulators have employed two broad approaches *to establish external-fixed performance benchmarks* (i.e., exogenous approach) for utilities under IR.

[13] Shleifer, A. (1985). A theory of yardstick regulation. The *Rand Journal of Economics, 16*(3), 319–327

First, regulators, especially in North America and especially early in an IR implementation, have employed industry-based targets. Often, these targets represent a sector's average benchmark index such as growth in TFP. This approach was often selected because most North American jurisdictions had a small set of regulated distributors.

Second, because of the larger sets of regulated LDCs, IR implementations in Europe, the U.K., South America and Australia have often relied on peer-based, "yardstick" techniques, both stochastic and most frequently non-parametric. Production frontier techniques like DEA have been used in New South Wales, the United Kingdom and the Netherlands, among numerous other jurisdictions. DEA studies have also been filed in regulatory proceedings in California and Maine.

Exhibit 4-3, taken from Jamasb and Pollitt (2001) lists benchmarking approaches used by regulators in jurisdictions mainly outside of North America.[14] Their independent assessment clearly indicates that DEA was/is the dominant benchmarking technique. As listed, DEA has been applied by regulators in numerous European jurisdictions, South America, and Australia. As Exhibit 4-3 indicates, DEA is the method employed by the majority of regulators listed, in fact 11 out of the 15 listed.

[14] *Jamasb, T. and Pollitt, M.* (2001), Benchmarking and Regulation: International Electricity Experience, *Utilities Policy*, 9 (3): 107-130.

Exhibit 4-3 Benchmarking Techniques used by Regulators

Country	Benchmarking method
Denmark	DEA
Finland	DEA
Great Britain	TFP, DEA, COLS
Northern Ireland	DEA and econometric methods
Netherlands	DEA
Norway	DEA
Spain	Theoretical model of an efficient firm
Sweden	DEA and SFA as control mechanisms
Australia-New South Wales	DEA, TFP, SFA
Australia-Queensland	DEA, econometric methods, TFP
Canada-Ontario	TFP
Japan	Regulation based on benchmarking
Brazil	DEA
Chile	Comparison with sample model enterprise
Columbia	DEA

Source: Jamasb, T. and Pollitt, M. (2001), Benchmarking and Regulation: International Electricity Experience, Utilities Policy, 9 (3): 107-130.

In the case of DEA, some observers have noted that the use of non-inferential, deterministic techniques to establish efficiency magnifies errors within regulators' badly implemented benchmarking, introducing significant biases for efficiency rankings. However, these concerns were not substantiated in Dr. Cronin's multiple applications of DEA to Ontario distributors starting in 2001. During the development of First Generation PBR in Ontario, yardstick techniques were examined for the hundreds of Municipal Electric Utilities ("MEUs"). DEA was specifically reviewed for potential use. The OEB First Generation PBR Cap Mechanism Task Force recommended that this approach be examined for use in 2nd generation. Subsequently, Dr. Cronin used the comprehensive data collected for First Generation PBR in DEA to benchmark Ontario distributors. Findings were presented at academic conferences[15] and workshops,[16] at several

[15] See, F. J. Cronin and Stephen A. Motluk, *Inter-Utility Differences in Technical and Allocative Efficiency*, presented at the Canadian Economic Association Conference, Montreal, May 2001.
[16] See, F. J. Cronin and Stephen A. Motluk, and *The (Mis)Specification of Efficiency Benchmarks among Electric Utility Peer Groups* at the North American Productivity Workshop, Union College, June 2002.

regulatory forums,[17] and also published.[18] In these applications employing historical Ontario LDC data, DEA was found to be a stable robust technique for performance benchmarking.

Advocates of DEA point to such advantages as:

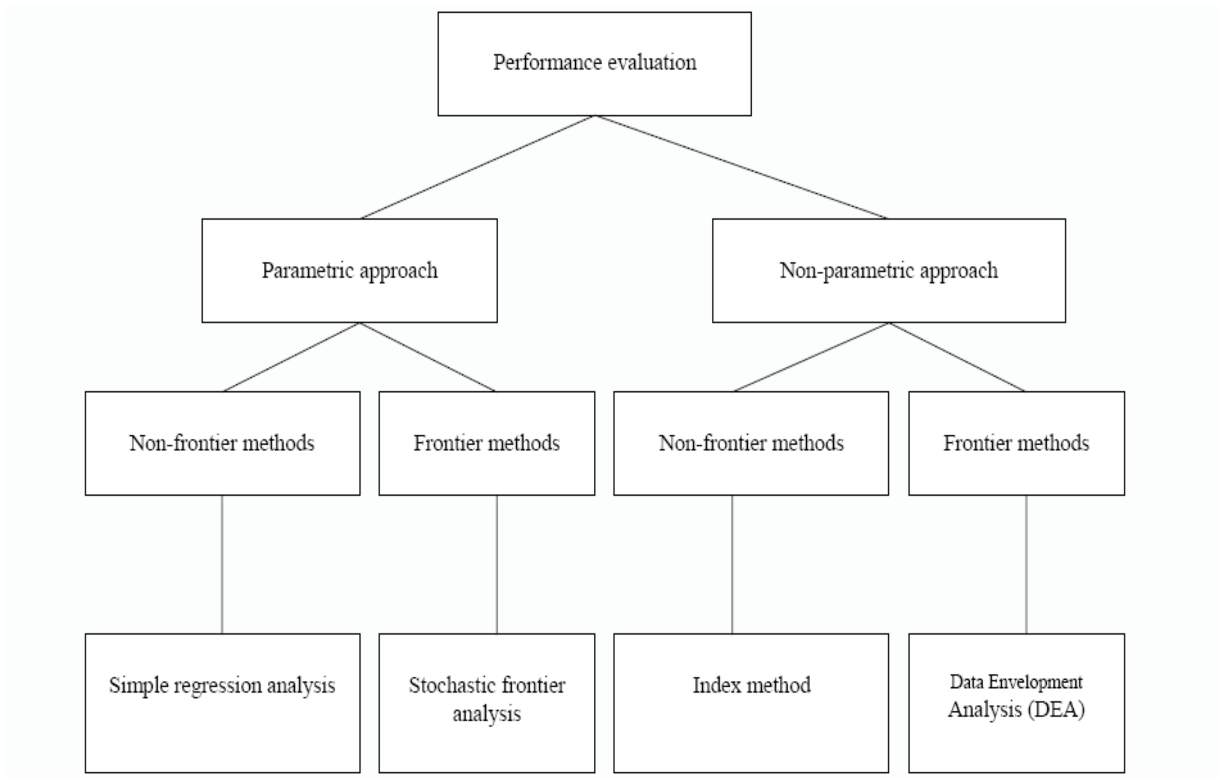
- the ease of incorporating multiple outputs and inputs;
- no requirement to specify a functional form for the production function;
- no requirement to specify a behavioural assumption such as cost minimization;
- limited data requirements (i.e., one year for the firms or utilities in the sample);
- the ability to assign firms to peer groups that define a reference point of potential efficiency for each firm and thus a calculated level of relative efficiency;
- the ability to decompose efficiency into component elements such as technical efficiency, allocative efficiency and scale efficiency; and,
- the ability to calculate efficiency measures without the incorporation of prices.

To put PEG's econometric benchmarking approach and DEA in perspective, a schematic of different performance benchmarking approaches is provided in Exhibit 4-4. On the left-hand side we have stochastic techniques like regression analysis and stochastic frontier analysis, which represent non-frontier and frontier (i.e., best performers) approaches, respectively. On the right-hand side we have non-parametric techniques like Index and DEA, which represent non-frontier and frontier approaches, respectively. PEG uses the far-left box, regression analysis; Dr. Cronin provides illustrative analysis using the far-right box, DEA. One could argue that the majority of non-North American regulators and quite possibly the majority of world-wide regulators have advocated and relied upon the far right-hand box, non-parametric DEA as a means of benchmarking LDCs' performance results and not on the parametric econometric approach.

[17] Michigan State University, Institute for Public Utilities (IPU), Regulatory Conference, Charleston, SC December 2003 and the 46th NARUC Annual Regulatory Studies Program, Michigan State University, Institute for Public Utilities, East Lansing, August 2004.

[18] The policy implications of this work are discussed in Cronin and Motluk, "The Road Not Taken: PBR with Endogenous Market Designs," *Public Utilities Fortnightly*, March 2004.

Exhibit 4-4 Performance Benchmarking Approaches



4.4.2 PEG's Econometric Benchmarking Approach

In Exhibit 4-5 the PWU summarizes data issues related to PEG's benchmarking approach. In addition, the PWU provides correction measures to address the issues, and comments on the implications of the issues.

Exhibit 4-5 Summary of PEG's Data Issues

Concept	Available Data	PEG Implementation	Implication
Capital Additions	**2002-2011**: Annual filings under the PBR data requirement of the OEB's RRR.[i] **1999-2001**: Annual filing under the OEB's PBR data filing requirement in the 2000 Distribution Rate Handbook, Chapter 12.[ii] **1998**:	**2003-2011 and 1990-1997**: PEG has "inferred" net Capital Additions by taking the difference between reported gross plant from one year to the next (net of CIAC for PEG's TFP analysis, inclusive of CIAC for PEG's benchmarking analysis). PEG then estimates Gross Capital Additions by adding	**PEG has not used any actual Capital Additions data** that has been filed by all Ontario LDCs for over a decade. PEG's Capital Additions data has been estimated. PEG has not used actual retirements for any individual LDC.

Concept	Available Data	PEG Implementation	Implication
	Partial availability under OEB's First Generation PBR data collection process. **Pre-1997**: Partial but fairly extensive coverage available back to 1980s and even 1970s through First Generation PBR data collection process.	assumed retirements (see following table row on Capital Retirements). **1998-2002**: PEG infers Capital Additions by taking the difference between gross plant in 2002 and 1997 and dividing by 5. In some instances, PEG grossed up the value of gross plant in 2002 due to "precipitous" drops in values reported between 1977 and 2002. Gross up was based on the ratio of accumulated depreciation to gross asset. Note: Six LDCs in PEG's analysis use 2003 to 2011 only. These are Hydro One, Algoma Power, PUC Distribution, Canadian Niagara Power, Greater Sudbury Hydro, and Innisfil Hydro.	The implication of this is PEG's Gross Capital Additions data used to derive the critical capital stock is based on estimates only. The result is significantly different from the "actual" annual Gross Capital Additions of distributors' RRR reports. In some years between 2005 and 2011, this discrepancy was as much as 50% (see Exhibit 4-1). **From 2005 to 2011, PEG underestimated industry "gross additions" by more than $2.2 billion.** The differences for individual LDCs are substantial and varied and would notably affect benchmarking results.
Capital Retirements	**2002-2011**: Annual filings under the PBR data requirement of the OEB's RRR. **1999-2001**: Annual filing under the OEB's PBR data filing requirement in the 2000 Distribution Rate Handbook. **1998**: Partial availability under OEB First Generation PBR data collection process. **Pre-1997**: Partial but fairly extensive coverage available back to 1980s and even 1970s through First Generation PBR data collection process.	**All years (1989-2011):** PEG has assumed retirements to be 0.5% of gross capital values for every LDC in each year. PEG has based this on the distributors' RRR data.	**PEG has not used any actual retirements data.** All of PEG's retirements data has been estimated. The implication of this is PEG's Gross Capital Additions data used to derive the critical capital stock is based on estimates only. PEG's estimated retirements are significantly different from the reported "actual" annual retirements of LDCs through the OEB reporting requirements. **In some years between 2005 and 2011, this discrepancy for the**

Concept	Available Data	PEG Implementation	Implication
			industry was as much as 200%. In 2009 PEG underestimated industry retirements by more than $0.2 billion. In 2008-2011, excluding Hydro One and Toronto Hydro, actual industry retirements are 100% to 300% larger than PEG's estimates. The differences for individual LDCs are substantial and varied and would notably affect benchmarking results.
Annual Depreciation Expense	**2002-2011**: Annual filings under the PBR data requirement of the OEB's RRR. **1999-2001**: Annual filing under the OEB's PBR data filing requirement in the 2000 Distribution Rate Handbook. **1998**: Partial availability under OEB First Generation PBR data collection process. **Pre-1997**: Available for all Municipal Electric Utilities (MEU's) through the Ontario Hydro Annual Financial & Statistical Summary to at least the 1950s. May be available in legacy electronic form through MUDBANK data files into 1980s.	PEG does not appear to explicitly incorporate LDC specific annual depreciation expense anywhere in its analysis. PEG assumes an economic depreciation rate of 4.59% for all LDCs. PEG calculated the value of the economic, "geometric" depreciation rate based on: 1) the estimated declining balance parameters for structures and equipment (0.91 and 1.65 respectively) in Hulten and Wykoff's seminal depreciation study; 2) OEB data on average asset lives in Ontario for different categories of assets, as estimated by Kinetrics Inc. in its July 8, 2010 report Asset Depreciation Study for the Ontario Energy Board; and 3) the share of each asset category in the Ontario electricity distribution industry's total gross capital stock in 2011, as calculated from RRR data.	The implications are significant. **PEG assumes the depreciation rate for every Ontario LDC is identical.** In fact, it varies notably across LDCs. The differences for individual LDCs are substantial and varied and affect benchmarking results. PEG assumes the share of asset classes in each LDC is identical based on only 1 year of data (2011). The depreciation expense is used to determine the economic depreciation rate which is a critical input to the capital service price (i.e., capital cost) as is explained in section 4.3 of PEG's report. **PEG's approach assigns an identical capital cost to every LDC in the province for any given year**, since the WACC and EUCPI asset price are also

Concept	Available Data	PEG Implementation	Implication
			identical for each LDC. This affects the TFP analysis and especially benchmarking. It also affects PEG's calculated IPI, making all these results questionable.
Accumulated Depreciation	**2002-2011:** Annual filings under the PBR data requirement of the OEB's RRR. **1999-2001**: Annual filing under the OEB's PBR data filing requirement in the 2000 Distribution Rate Handbook. **1998**: Partial availability under OEB First Generation PBR data collection process. **Pre-1997**: Available for all Municipal Electric Utilities (MEU's) through the Ontario Hydro Annual Financial & Statistical Summary to at least the 1950s. May be available in legacy electronic form through MUDBANK data files into 1980s.	1989 or 2002 to calculate benchmark year. 1989 from MUDBANK, 2002 from RRR filings.	Data are available to calculate benchmark year prior to 1989. OEB data should be available from 1999.
Gross Plant In Service	**2002-2011:** Annual filings under the PBR data requirement of the OEB's RRR. **1999-2001**: Annual filing under the OEB's PBR data filing requirement in the 2000 Distribution Rate Handbook. **1998:** 1998 partial availability under OEB First Generation PBR data collection process. **Pre-1997:** Available for all Municipal Electric Utilities (MEU's) through the Ontario Hydro Annual Financial &	1989-1997 from MUDBANK, except for Hydro One, Algoma Power, PUC Distribution, Canadian Niagara Power, Greater Sudbury Hydro, and Innisfil Hydro. 2002-2011 from RRR filings.	Data are available to calculate benchmark year prior to 1989. OEB data should be available from 1999.

Concept	Available Data	PEG Implementation	Implication
	Statistical Summary to at least the 1950s. May be available in legacy electronic form through MUDBANK data files into 1980s.		

[i] http://www.ontarioenergyboard.ca/documents/rrr_letter_231002.pdf

[ii] http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/revised_chap12.pdf and http://www.ontarioenergyboard.ca/documents/cases/pbr/filing_letter_211201.pdf

The above exhibit notes numerous deficiencies in the data PEG employs to determine its benchmarking results, and as the exhibit indicates, these deficiencies have significant implications for the benchmarking results PEG is putting forth. For example, as noted in section 4.3.1, PEG uses estimates rather than actual Capital Additions data filed by all Ontario distributors for over a decade. PEG also uses estimates rather than actual Capital Retirements data. For the period from 2005 to 2011, PEG underestimates industry Gross Capital Additions by more than $2.2 billion. The error over the complete analysis period would be even greater. This obviously has major implications for benchmarking results.

PEG also has not used individual distributor depreciation expense to calculate an economic depreciation rate for each distributor, which varies substantially amongst distributors depending on the vintage of a distributor's plant and equipment, the growth and customer profile of its service territory, and management decisions regarding replacement versus repair. Instead, PEG has used assumptions about the "average" share of asset classes for the entire industry in a single year (2011), among other assumptions, to "estimate" a single economic depreciation rate that is applied to all distributors. As a result, PEG makes no distinction between any distributors' individual economic depreciation rate and estimates the same capital cost for every distributor. This has significant implications for benchmarking results because the economic depreciation rate is used to derive the capital service price or "capital cost", a critical input to productivity and benchmarking analysis, as explained in section 4.3 of PEG's Report. Using the same estimate of capital cost for every distributor in a given year affects TFP analysis and especially benchmarking. It also affects PEG's calculated IPI, since the capital service price is an input into the IPI, making all these results questionable.

Furthermore, from the two versions of PEG's reported benchmarking results we surmise that the underlying model is highly unstable. For example, Exhibit 4-6 shows the substantial change in unit cost between the two versions for the top and bottom performers as reported in PEG's Table 25. The change for the top performer is 40.28 per cent and the change for the bottom performer is -22.22 per cent. The only apparent difference between the two versions is a correction related to LV data.

Exhibit 4-6 PEG's Unit Cost Valuations Revisions

Rank	PEG May 3 Report	PEG May 31 Report	% Change
1	-35.50%	-49.80%	40.28%
73	109.80%	85.40%	-22.22%

This instability is in marked contrast to the benchmarking results reported by Dr. Cronin since 2001 in his publications, conference presentations and submissions.

Dr. Cronin also finds that PEG has an apparent inconsistent distributor sample combination in its analysis. PEG included Hydro One and Toronto Hydro in its benchmarking but not in its TFP analysis, which would tend to bias the estimated coefficients and lead to inaccurate predicted distributor costs and ranking. As a result of these biased coefficients none of the distributors' efficiency is being estimated accurately.

The PWU has absolutely no issues with econometrics as an analytical tool. The issues in this instance relate to the robustness of the data and the proper specification used in PEG's econometric model. The distribution of efficiency rankings and individual LDC's results changed markedly between versions one and two of PEG's model. The results from PEG's model have only recently been made available, have not been properly vetted, and as a result of the data used produce implausible results. Dr. Cronin's Ontario distributors' DEA results have been available for a decade; have been published and reviewed in multiple settings; and, show an underlying stability and plausibility obtained through non-parametric analysis based on sound data. Of interest is PSE's observation that PEG included two variables that were not found to be statistically significant at the 90 per cent level, in designing its peer groups and calculating the bilateral output index.[19]

The PWU submits that in considering PEG's econometric benchmarking as a basis for its assignment of stretch factors, the Board needs to do a thorough review of PEG's data. This review needs to take into account the comments provided by Dr. Yatchew, PSE and Dr. Cronin with regard to the role that the data deficiencies have had on the instability and bias underlying the efficiency rankings. These data deficiencies are easily correctable and the Board needs to ensure that they are corrected if the Board is to rely on PEG's econometric benchmarking.

Moreover, as the PWU notes earlier in this submission additional measures that are critical to determine true distribution performance have not been considered in PEG's analysis: service reliability and line losses. Exclusion of these critical output (reliability) and input (line losses) measures biases the benchmarking results. In fact PEG cites the following quote from a 2008 Paul Joskow publication that speaks to this point:

> **…, any incentive regulation mechanism that provides incentives only for cost reduction also potentially creates incentives to reduce service quality when service quality and costs are positively related to one another. The higher powered are the incentives to reduce costs, the greater the incentive to reduce quality when cost and quality are correlated. Accordingly, price cap mechanisms are increasingly accompanied by a set performance standards and associated penalties and rewards for the regulated firm for falling above or below these performance norms. Similar mechanisms are used by several U.S. states and in other countries that have liberalized their electricity sectors (for example, New Zealand, Netherlands, and Argentina).**[20]

Therefore, in ranking the distributors, the Board needs to take into account the distributors' service reliability and line loss performance.

---

[19] Coalition of Large Distributors. Power System Engineering, Inc. Recommendations on 4th Generation Incentive Regulation. Page10.
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/CLD_Submission_20130614.pdf

[20] Paul Joskow, "Incentive Regulation and Its Application to Electricity Networks," Review of Network Economics (2008), p.555.

4.4.3 Ontario Distributor Efficiency Benchmarking using DEA

Using DEA-efficiency benchmarking the distributors can be ranked based on how far away their TFP performance is from that of the best performing distributors (i.e. the frontier). The PWU submits that DEA, a non-parametric analytical approach, is a simpler alternative to the econometric approach that avoids some of the data issues faced in the econometric approach.

In his June 13, 2013 report Dr. Cronin provides illustrative DEA-efficiency analysis for seven Ontario distributors and compares the outcome with PEG's benchmarking results. Dr. Cronin finds very large differences between PEG's and his efficiency results. Dr. Cronin finds that compared to his DEA estimates, PEG's most efficient estimates for this sample of distributors to be notably biased downward and improperly conveys the magnitude of the relative efficiency, i.e., the magnitude of the relative efficiency is understated by 39 per cent. Further, he finds the most inefficient of PEG's estimates for this sample of distributors to be notably biased upward, i.e., the magnitude of the relative inefficiency is overstated by 40 per cent.

The PWU recommends that the Board use DEA to test the reasonableness of PEG's econometric benchmarking analysis conducted with corrected data.

4.5 Stretch Factor

4.5.1 Impact of OM&A-only Benchmarking

The incentive created by the Board's OM&A-only benchmark has had an apparent impact on the distributors' total cost efficiency that the Board needs to consider in assigning productivity stretch factors for 4th Generation IR. In his January 21, 2013 presentation to the PBR Working Group, Dr. Cronin shows an aggregate decrease in OM&A as a percentage of Capital for all distributors between 2000 and 2010 from 130 per cent to 75 per cent.[21] On aggregate, labour capitalization for this period increased

[21] Presentation to the PBR Working Group by Frank Cronin, Expert Consultant to the Power Workers' Union. January 21, 2013. Incentives, Behaviour and Consequences: Data and Potential Benchmarking Alternatives. Slide 4.

from 10 per cent to 35 per cent. These changes in cost allocation will have resulted in allocative inefficiency for some distributors that will be reflected in their efficiency ranking on a total cost basis. The impact of these past cost allocation decisions are now embedded in the distributors' finances and are not reversible. As noted in section 4.1 distributors changed cost allocation policies as the prudent option over service quality degradation. The PWU submits that for the Board to now penalize distributors that reacted prudently to the Board's OM&A-only benchmarking incentive with a more stringent stretch factor for 4th Generation IR's total cost benchmarking would be perverse and would create significant regulatory uncertainty.

4.5.2 Default Stretch Factor

The PWU supports Dr. Yatchew's proposal for introducing a rewards/penalty approach to assigning stretch factors. The PWU agrees with Dr. Yatchew that following the many years that the distributors have been under IR during which there have been sustained efforts to drive efficiencies it is time to reward efficiency. The PWU supports Dr. Yatchew's recommendation for a range of default stretch factors from -0.3 per cent to +0.3 per cent assigned based on the outcome of a reasonable benchmarking approach (e.g. Dr. Cronin's DEA-efficiency approach; PEG's econometric benchmarking using actual data and tested against DEA). Using Dr. Cronin's DEA-efficiency benchmarking approach, distributors at the frontier would be rewarded. As Dr. Yatchew notes:

> **… It is reasonable to expect that lean distributors will use the incremental funds to sustain their preferred ranking, thus establishing a sustainable framework for pursuing this objective. [page 18]**

4.5.3 Stretch Factor Menu Option

The PWU proposes 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 error in the benchmarking analysis. Indeed distributors have highlighted errors in the benchmarking analysis used for 3rd Generation IR at consultation meetings as well as PBR Working Group meetings.

In its Decision on the proposed menu approach for First Generation PBR the Board acknowledged the concern expressed by parties regarding the complexity of the proposed menu:

> **The Board acknowledges the concerns expressed by parties regarding the unnecessary complexity encompassed in the proposed menu. The Board also notes the comments by some parties that the default productivity level would be the preferred choice of most utilities therefore placing into question the effectiveness of the proposed menu. The Board has assessed this concern against the arguments by some parties that a "one size fits all" approach should not be adopted by the Board. On balance, the Board concludes that the proposed menu approach should for first generation PBR be replaced by a single productivity factor for all utilities, combined with an earnings-sharing mechanism as proposed by some parties.**

The PWU submits that given the stakeholders, and especially the distributors' experience with 3rd Generation IR, the menu approach would not be perceived as complex today. In addition, while most distributors might choose its assigned default stretch factor, enough distributors voiced their issues with 3rd Generation IR, that a menu option should have uptake. Even if most distributors go with the default stretch factor, for those distributors who do not believe they can operate within the default option, the menu would provide a reasonable alternative and avoid unintended disincentives for service reliability and line loss degradation.

Imposition of unrealistic productivity expectations can result in perverse incentives with unintended dire outcomes for service quality performance and future costs. As Dr. Yatchew submits:

> **It is critical to note that our analysis of the data reveals that even modest variations in model specification can lead to substantial changes in distributor rankings and migration of individual distributors to other efficiency cohorts. Given the complexities of this sector and its data limitations, it is highly probable that such variations will be present. This could result in incentives that are not aligned with the Board's objectives. [Page iv]**

The PWU therefore recommends that the Board give consideration to the development of an appropriate menu that the distributors can select from as an option to the Board assigned default stretch factor. The menu as well as the Board's default stretch factors should provide for rewards as well penalties and should recognize the declining TFP trend indicated in PEG's and Dr. Cronin's TFP analysis.

5 INCORPORATING THE VALUE THAT CUSTOMERS PLACE ON SERVICE QUALITY INTO TFP

5.1 Customer Value

In its RRFE submission the PWU sets out the following vision:

> **The PWU's vision for a sustainable and long-term regulatory regime for the electricity utilities is one that focuses on customer value and establishes appropriate and transparent incentives based on Ontario utility data to achieve performance levels that align with customer expectations.**
>
> **To achieve this vision it is necessary to recognize customer value as the key input to the regulatory framework. This key input would be obtained through robust customer Willingness to Pay ("WTP") surveys that will establish the utilities' service quality (i.e. customer service and system reliability) standards and provide the context for the utilities' network investment planning and the regulatory framework. [Page 2-3]**

Surveys such as WTP surveys are essential to the determination of the value that customers place on service and the level of service (i.e. customer service and service reliability) that they expect. As the PWU noted in its RRFE submission the Board has made a good first step in Phase 2 of the Board's Service Reliability consultation (EB-2010-0249) with the 2010 Pollara customer surveys.[22,23] This experience will help the Board develop robust and transparent WTP surveys that will provide information on the value that customers place on electricity service. In his June 13, 2013 report Dr. Cronin provides input on how the 2010 Pollara surveys can be improved upon to derive robust WTP information that the Board should heed.

Having established the value that customers place on electricity service, the Board would then be in a position to implement a "comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's

---

[22] Electricity Outage and Reliability Study September 2010 Consumer Component. Survey conducted by Pollara for the Ontario Energy Board. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0249/OEB_Reliabilityper cent20Residentialper cent20Survey_2010.pdf

[23] Electricity Outage and Reliability Study September 2010 Business Component. Survey conducted by Pollara for the Ontario Energy Board. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0249/OEB_Reliabilityper cent20Businessper cent20Survey_2010.pdf

electricity system provides value for money for customers" as envisioned in the RRFE Report.

As Dr. Cronin illustrates in his report and discussed below, the Board can explicitly integrate customer value of service reliability performance into distribution rate regulation by incorporating service reliability performance into TFP analysis.

5.2 Incorporating Customer-valued Service Reliability Performance into TFP

In a 2005 publication on IR for electricity distributors and transmitters, Paul Joskow observed that there has been a shift of focus from reducing operating costs to investments and service quality, but that service quality considerations appear to be added to cost reduction mechanisms and do not effectively incorporate customer valuation.[24]

> **As incentive regulation has evolved in the UK and other countries, the portfolio of incentive mechanisms that is being utilized has grown. While the initial focus was on reducing operating costs it has now shifted to investment and various dimensions of service quality. Ideally these mechanisms should be fully integrated and differences in the power of the individual incentive schemes carefully considered.**
>
> **… Quality of service schemes appear to have been bolted on to schemes designed to provide incentives for cost reduction and do not effectively incorporate information on consumer valuations of quality and the costs of varying quality in different dimensions.**

In Ontario service quality is not even "bolted to" IR focused on cost reduction, as evidenced by the lack of recognition of the link between cost and service quality performance, the lack of incentives for service quality performance, and the general lack of vigilance in the Board's SQR.

In his June 13, 2013 report Dr. Cronin presents Illustrative TFP analysis that incorporates the value that customers place on service reliability performance (i.e., WTP and service

[24] Joskow, Paul. L. Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks. Center for Energy and Environmental Policy Research. 05-014. September, 2005. Pages 83-84.

reliability performance). The WTP levels used are those identified in the Pollara surveys and the service reliability performance levels are the System Average Interruption Duration Index ("SAIDI") levels reported by the distributors and posted on the Board's website. The analysis indicates that the distributors' service reliability performance has a significant impact on TFP.

TFP analysis that includes customer-valued service reliability performance provides estimates of productivity growth that factors-in changes in the distributors' service reliability performance. This is an essential consideration especially given the evidence presented in Dr. Cronin's June 13, 2013 report that indicates increasing service reliability performance degradation in Ontario over the period 2005-6 to 2011 based on the SAIDI performance of sub-samples of small, medium and large distributors.

Dr. Cronin's illustrative analysis conducted on four Ontario distributors shows significant differences in TFP derived with and without service reliability performance (i.e. adjusted for changes in SAIDI valued at customers' WTP) for the period 2002 – 2011. For three of the distributors the differences in TFP with and without service reliability ranged from -1.6 TFP per cent to -3.3 TFP per cent. For the remaining distributor the difference was a moderate -0.3 per cent. The analysis indicates that change in customer-valued service reliability performance can have a significant impact on the TFP index. Where a distributor's reliability performance is deteriorating the TFP estimate is lower when reliability performance is included in the analysis than when reliability is excluded from the analysis (i.e. TFP growth is overstated); and, where a distributor's reliability performance improves, TFP is higher when reliability is included in the analysis than when reliability is excluded from the analysis (i.e. TFP growth is understated).

As in the case of Dr. Cronin's price-dual and index-based TFP analyses, his analysis on the impact of changes in customer-valued service reliability performance on TFP uses actual WTP results and actual reliability data. As noted earlier, what is essential in TFP analysis is the consistency in a distributor's annual filings. In Phase 2 of the Board's consultation on Electricity Distribution System Reliability Standards (EB-2010-0249), the PWU stressed, and Board staff in that consultation acknowledged, the need to preserve the ability to assess individual distributors' historic performance trends.[25] Therefore, while Board staff in this consultation indicated concern at the PBR Working Group meetings with the consistency amongst distributors' reporting of reliability data, if there is consistency in individual distributors' annual reporting, the data can be depended on in assessing temporal trends in service reliability performance. The SAIDI data used in Dr. Cronin's analysis is therefore reasonable as is his analysis on the impact of customer-valued service reliability performance on TFP.

Board staff's consultant, Dr. Kaufman shared his view with the PBR Working Group that including service reliability performance in TFP would create a disincentive for reliability performance improvement. In the PWU's view that would be true of IR's general disincentive for improved productivity in the historic years on which TFP for a future IR term will be based. However disincentives for improving productivity are countered by the incentive for higher returns that comes with improved productivity. Similarly, incentives for service reliability performance need to be included in the Board's IR framework. As the PWU has submitted in many Board consultations, doing so would provide for effective SQR that mitigates the risk of service quality deterioration as distributors pursue IR's financial incentives.

Dr. Cronin's illustrative analysis indicates the need to include customer-valued service reliability performance in TFP analysis and the limitation of TFP analysis that does not do so. Therefore if the Board excludes service reliability performance from TFP analysis and benchmarking for 4th Generation IR, the Board will need to assess and address the disincentive that this inadvertently creates for service reliability performance.

Dr. Cronin observed that some regulators have incorporated WTP information into their distribution price regulation while one regulator has set a goal of achieving the optimal level of reliability that recognizes customers' interruption costs. Dr. Cronin suggests the use of Single-Customer Guarantees in Ontario until such time when the Board has developed incentives based on WTP surveys.

[25] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0249/PWU_Comments_20111220.pdf

In the short run, and in the absence of a more robust incentive regime, Ontario distributors' should face financial penalties for non-compliance with mandated minimum reliability standards. In the medium run, the Board should adopt SQR which combine reliability standards with penalty schemes as well as single customer guarantees with monetary payments for nonperformance. The latter guarantees/payments should be based on some robust measure of customer interruption costs. In the long run, my preference is to develop an incentive approach that internalizes the cost of supply interruptions; i.e., within which LDCs recognize O&M, capital, and customer interruption costs. The Board should move toward the implementation of a "socially optimal" level of reliability; not too little, not too much. Such regimes have been successfully implemented by a number of regulators. These efforts have been under way for years and are well documented (see for example Council of European Energy Regulators). [26]

6 IMPACT OF LINE LOSSES ON TFP

6.1 Incentive for Line Loss Reduction

In his June 13, 2013 report Dr. Cronin notes that line loss rate among Ontario LDC's degraded by 33 per cent in 2009 relative to the 1995-1997 period on a customer-weighted basis and 20 per cent on a simple average basis.

Dr. Cronin also notes that Enmax Power Corporation's line loss rate fell from 3.02 to 2.83 per cent in 2010 after it entered into an agreement with stakeholders intended as an incentive to reduce line losses under its Formula Based Ratemaking. Enmax's experience illustrates how effective incentives can be in reducing line losses.

Distribution line losses are the difference between the amount of electricity delivered by the transmission system to the distribution system and the amount of electricity delivered to customers. Since the distributor must pay for the amount of electricity delivered by the transmission system to its distribution system, the customers are billed for the amount of electricity delivered to them as well as the electricity lost through line losses. Therefore the higher the distribution line losses the higher the customers' electricity bills.

---

[26] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Page 5. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

The distributors have not been responsible for the cost of line losses since electricity industry restructuring when the market design started passing the cost of line losses on to the customers through an increase in the electricity charge. This arrangement does not provide the distributors with an incentive to reduce line losses. However, efficiency gains can be pursued through regulatory incentives for line loss reductions, although such incentives must take into consideration the cost associated with managing line losses. The success of the incentive therefore depends on a regulatory approach that integrates rate setting, network planning and performance.

6.2 Incorporating Line Losses into TFP - Illustrative Analysis

In his June 13, 2013 report, Dr. Cronin provides illustrative analysis that incorporates line losses into TFP for two large urban Ontario distributors ("Utility A" and "Utility B"). The analysis uses the actual line loss data reported by two Ontario distributors and applies the cost of power to the distributors' line losses. While the cost of power associated with line losses is not a distributor's cost, it is a cost to the customer. What Dr. Cronin's analysis illustrates is the impact of the change in line loss rate on a distributor's productivity growth.

Three-factor (capital, labour, material) TFP that does not include line losses and four-factor TFP that includes line losses were calculated for Utility A and Utility B for three time periods: 1988-1997; 1993-1997; and, 2000-2011. The analysis indicates that line loss performance can materially impact TFP performance.

Utility A's line loss performance improved in all three periods. A comparison of the three-factor and four-factor TFP analysis indicates higher TFP growth for Utility A when line losses are included compared to the TFP obtained when line losses are excluded for all three time periods i.e., improved line loss performance is reflected in higher TFP.

Utility B's line losses improved in the first two time periods and degraded in the third time period. Comparison of the three-factor and four-factor TFP analysis indicates higher TFP growth for Utility B when line losses are included for the two time periods when its line losses improved. However, Utility B's TFP growth is lower when line losses are included in TFP analysis for the time period in which its line losses degraded i.e., degradation in line loss performance is reflected in lower TFP.

This illustrative analysis indicates the importance of considering line loss performance in TFP analysis, and the shortcomings of TFP analysis that does not do so. Including line loss performance results in a higher TFP index where line loss performance improved and a lower TFP index where line loss performance degraded. Therefore in setting the X-factor and stretch-factors for 4th Generation IR, the Board needs to assess the incentive created by the absence of a line loss factor in the TFP analysis.

7 CONCLUSION AND RECOMMENDATIONS

The Board's RRFE, "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" will start moving the regulation of Ontario's electricity distributors forward when the Board has established the value that customers place on electricity service and integrates it into the regulatory framework, and when it has introduced effective service quality regulation. This requires the Board to undertake comprehensive and robust WTP studies and set service quality standards and incentives (i.e., rewards and penalties).

The RRFE policies can provide for the establishment of a fair and reasonable IRM. However, the Board needs to ensure that the implementation of the IR does not take away from the intent of the policies. Therefore, in considering implementation options it is essential for the Board to assess the explicit and implicit incentives created by the options.

The Board's guidance in the RRFE Report specifies that "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)". The PWU believes that PEG's recommended use of "the all workers in Ontario" index as the labour price index is an exaggeration of the Board's guidance. Instead, the PWU recommends the use of the "Ontario-Utilities Average Weekly Earnings" index available from Statistics Canada as being more in line with the RRFE's policy for a more industry specific inflation factor.

The RRFE also states that concern on volatility in the IPI will be mitigated by the methodology selected by the Board. PEG proposes using a three-year rolling average of the annual IPI as the IPI index to mitigate volatility. Rather than destroying the carefully constructed IPI by using a three-year rolling average as proposed by PEG, the PWU proposes that the Board apply the actual annual IPI index and use deferral accounts to address significant bill fluctuations when the IPI's volatility is of such scope that it would result in customer bill impact concerns.

The RRFE specifies that an index-based TFP approach is to be used in deriving the productivity factor. In its index-based TFP analysis PEG used estimates of key data (e.g. Gross Capital Additions; all 2000 and 2001 data) rather than using the actual data filed by the distributors. The PWU notes substantive variances between PEG's estimations and the RRR data that requires scrutiny of the data used in PEG's TFP analysis if the Board is to rely on PEG's analysis. PEG's estimated Gross Capital Additions were found to be substantially lower than the actual Gross Capital Additions. Dr. Cronin, expert consultant to the PWU has conducted index-based TFP analysis using the distributors' actual data as filed with the Board (i.e., RRR data) and obtained lower TFP estimates than PEG. Therefore in considering PEG's TFP analysis it is essential that the Board consider the upward impact on TFP of PEG's estimated data in determining an X-factor.

The PWU notes that none of the expert consultants (i.e. PEG, Dr. Cronin, Dr. Yatchew, PSE) included CIAC in their TFP analysis and the Board needs to consider the resulting overstatement of the TFP estimates in determining an X-factor.

The index-based TFP approach requires reams of historic data that comes with high data error risk and jeopardizes the derivation of a reasonable X-factor for 4th Generation IR. The PWU forwards the use of price-dual TFP analysis as a test of reasonableness of index-based TFP analysis. Price-dual TFP analysis is based on the difference between the annual rate of change in input prices and the annual rate of change in output prices (i.e. distribution rates) and is not mired by data issues. Dr. Cronin conducted price-dual TFP analysis that estimates TFP growth for 2006-2011 at -2.41 per cent, compared to his index-based TFP estimate of -2.3 per cent. The comparability of Dr. Cronin's price-dual TFP and index-based TFP analyses indicates the reasonability of his TFP estimates and the Board can rely on them in considering an X-factor for 4th Generation IR. PEG's index-based estimate of -2.14 per cent for all distributors is somewhat lower than the price-dual TFP estimate. The PWU suggests that PEG's lower estimate is at least in part related to its lower estimated Capital Additions data compared to the actual data.

Dr. Cronin's index-based TFP analysis as well as PEG's TFP analysis for 2002-2011 indicate increasingly declining TFP over this time period with significantly lower performance in the late sub-interval, 2009-2011, compared to the early sub-interval, 2002-2005. Given this time trend, Dr. Cronin applied the Board's TFP weighting decision for First Generation PBR to his index-based TFP to apply more weight to the later period by assigning 1/3 weight to the TFP for the first half of the 2002-2011 time period and 2/3 weight to the TFP for the second half. Dr. Cronin's weighted TFP estimate for 2002-2011 is -1.5 per cent.

The PWU does not support PEG's recommended X-factor of 0.1 per cent based on its 2002-2011 TFP index that excludes Hydro One and Toronto Hydro from the analysis. The PWU does not agree with the exclusion of Hydro One and Toronto Hydro, two significant Ontario distributors, from the TFP analysis. The PWU recommends Dr. Cronin's weighted TFP of -1.5 per cent as the upper limit of the Board's consideration for an X-factor. This recognizes the increasing decline in TFP over 2002-2011 and the absence of CIAC from the TFP analysis.

PEG's econometric benchmarking approach is fraught with issues related to the large amounts of data required for its benchmarking approach. The PWU therefore recommends that the Board use DEA efficiency-benchmarking that avoids the data risks related to the econometric approach to test the reasonableness of PEG's econometric benchmarking as the basis for assigning productivity stretch factors to the distributors. In comparing his DEA results with PEG's benchmarking results, Dr. Cronin finds very large differences. PEG's econometric benchmarking understated its best performing distributor's efficiency by 40 per cent compared to Dr. Cronin's results and overstated its worst performing distributor's inefficiency by 39 per cent.

In addition, the Board needs to address the allocative inefficiency created by its OM&A-only benchmarking incentive that will be reflected in the outcome of total-cost benchmarking for 4th Generation IR. Not to do so would result in the Board penalizing distributors with higher productivity stretch factors for having reacted to a past Board incentive.

While the RRFE aims at “outcomes that ensures that Ontario’s electricity system provides value for money for customers”, the proposal on defining and measuring performance for electricity distributors does not include a process by which the value that customers place on service reliability and the level of service that customers expect will be identified and implemented. To obtain the Board’s desired outcome requires consideration of customer-valued service reliability performance in TFP analysis. This is an essential consideration especially given Dr. Cronin’s evidence presented in his June 13, 2013 report that indicates increasing service reliability performance degradation in Ontario over the period 2005 to 2011 based on the performance of samples of small, medium and large distributors. Further, Dr. Cronin’s analysis that incorporates customer-valued service reliability performance illustrates the significant impact that service reliability performance has on TFP. In excluding service reliability performance from TFP analysis and benchmarking for 4th Generation IR, the Board needs to address the disincentive that this inadvertently creates for service reliability performance.

Line losses impact the value that the electricity system provides for customers. Line losses are managed by the distributors and efficiency gains can be pursued through incentives for line loss reductions in a regulatory framework that integrates rate setting, network planning and performance. Dr. Cronin’s analysis that includes line losses in TFP analysis for two Ontario distributors indicates the importance of considering line loss performance in TFP analysis and the limitation of TFP analysis that does not do so. In the illustrations, including line losses results in higher TFP when line loss performance improves. Therefore in setting the X-factor and stretch-factors for 4th Generation IR, the Board needs to assess and address the incentive created by the absence of a line loss factor in the TFP analysis as well as in the benchmarking analysis.

8 PWU INPUT ON QUESTIONS SET OUT BY THE BOARD

The Inflation Factor

Preamble:

On October 18, 2012, the Board issued its Report of the Board entitled "A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach" (the "RRFE Report"). A copy of the RRFE Report is available on the Board's website at www.ontarioenergyboard.ca.

In the RRFE Report, the Board determined that it is now appropriate to adopt a more industry-specific inflation factor [p. 16] and provided the following policy direction:

- **The inflation factor must be constructed and updated using data that is readily available from public and objective sources (e.g. Stats Canada);**

- **To the extent practicable, the component of the inflation factor designed to adjust for non-labor price inflation should be indexed by Ontario distribution industry-specific indices; and**

- **The component of the inflation factor that adjusts for labor prices will be indexed by an appropriate generic and off-the-shelf labor price index.**

The Board also indicated in the RRFE Report that volatility will be mitigated by the methodology adopted by Board.

1. For each expert's recommended approach (including PEG's):

a. Is the proposed approach appropriate? Does it meet the Board's policy direction noted above?

PEG's three-factor IPI with separate input price sub-indices for capital, labour and non-labour OM&A is appropriate and meets the Board's policy direction.

b. Are the recommended sub-indices appropriate?

PEG's recommended use of the index for average earnings for all workers in Ontario as the inflation index for labour prices is an exaggeration of the RRFE guidance for the use of an index that is not distribution industry-specific (see section 4.2 above). Instead the PWU recommends using the "Ontario-Utilities Average Weekly Earnings" index available from Statistics Canada for the Labour component of the IPI.

c. Should the Board be concerned with volatility in the inflation factor?

The Board should assess on an annual basis whether it needs to address total bill impact volatility related to IPI volatility.

2. What is your preferred approach and why?

In a year in which the Board finds total bill volatility resulting from volatility in the IPI to be significant, the impact should be addressed through a bill impact smoothing mechanism such as a deferral account rather than by destroying the carefully constructed IPI benchmark (see section 4.2 above). In years where the total bill impact is not significant, there would be no need to for any bill impact smoothing mechanism.

<u>The Productivity Factor</u>

Preamble:

With respect to the productivity factor, the Board provided the following policy direction in the RRFE Report [p. 17]:

- **It is intended to be the external benchmark which all distributors are expected to achieve;**
- **It will be based on Ontario Total Factor Productivity (TFP) trends; and**
- **It will continue to use an index-based approach for the derivation of an industry productivity trend to form the basis for the productivity factor.**

3. For each expert's recommended approach (including PEG's):

a. Is the proposed approach appropriate? Does it meet the Board's policy direction noted above?

PEG does not address the possible impact of excluding service reliability and line loss performance. This is a major short-coming that together with PEG's high TFP estimate creates a disincentive for service quality and line loss performance. While PEG's use of the index-based TFP approach meets the Board's policy direction on TFP analytical approach, this does not preclude the need to address possible inappropriate disincentives that may result from the proposed approach (see sections 5 and 6 above).

b. Are the recommended inputs and outputs appropriate?

There are apparent errors in the estimates that PEG has used in deriving the input price index that renders them inappropriate (see section 4.3 above). Further, the lack of consideration of service reliability and line loss performance are major issues with the recommended inputs (see sections 5 and 6 above). The variance between the actual filed data and PEG's estimates indicates that PEG's, Dr. Yatchew's and PSE's input indices are significantly understated and as a result their TFP growth estimates are overstated.

4. What is the appropriate value for an Ontario electricity distribution Total Factor Productivity trend? Why?

The appropriate maximum TFP value for the Board's consideration in determining the X-factor for 4th Generation IR is -1.5 per cent based on Dr. Cronin's weighted TFP analysis (see section 4.3 above). In considering the X-factor, the Board needs to take into account that none of the expert consultants included CIAC in their TFP derivations. To allow for this gap, the recommended TFP estimates need to be adjusted downward. As noted in section 4.3.2, CIAC was included in the TFP analysis that the Board relied on for First Generation IR.

Total Cost Benchmarking

Preamble:

The Board states in the RRFE Report that benchmarking models will continue to be used to inform rate setting, and that 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 [p. 60].

5. For each expert's recommended approach (including PEG's):

a. What do you perceive to be the strengths and weakness of the various consultants' approaches?

Board staff indicated at the consultation meetings and PBR Working Group meetings that service reliability performance will not be included in the benchmarking analysis. The absence of service reliability performance is the primary weakness in the benchmarking analysis for 4th generation IR.

With regard to PEG's benchmarking approach the data issues identified by the other expert consultants is a significant weakness.

b. Are the outputs and recommended business condition variables appropriate?

The PWU notes PSE's comments on the lack of statistical significance of a couple of business condition variables PEG has included in its analysis. In addition, PSE has added a list of business condition variables to PEG's in its analysis that suggests gaps in PEG's business variables.

6. What is your preferred approach and why?

The PWU prefers the DEA-efficiency approach described by Dr. Cronin because it avoids the risk of data errors and miss-identification of business condition variables.

7. In PEG's unit cost/peer group model:

a. Are the recommended peer groups appropriate?
b. If not, what peer groups would you recommend and why?
c. Should each distributor's unit cost be compared to the average unit cost for the peer group or to the median unit cost for the peer group?

Please see the responses to questions 5 and 6 above.

Preamble:

Electricity distributors in Ontario procure high voltage (HV) and low voltage (LV) services in different ways. Some distributors own HV equipment, others do not. Also, LV costs differ depending on who the services are purchased from. The costs associated with each situation are accounted for differently and reside in different places. Without approximating these differences in the total cost benchmarking, the total costs for some distributors may appear understated while the total costs for other distributors may appear overstated.

This matter was a subject of consultation with the Performance and Benchmarking Working Group.

8. In general, is the approach to dealing with differences in HV & LV services modelled by PEG appropriate?

Given all the discussions that have already taken place on this issue, the PWU suggests that an approach to benchmarking that precludes the need to deal with these issues (e.g. DEA-efficiency analysis as illustrated by Dr. Cronin) is preferred.

9. Specific to LV services, on December 6, 2012 Board staff posted on the Board's website a set of data that was provided by Hydro One to support the empirical analysis on payments to Hydro One for LV service for each distribution company for the period 2002-2011 (Summary of Hydro One Low Voltage Charges to Distributors 2002–2011). During the Stakeholder Conference the issue of appropriate LV costs to be included in the benchmarking models was raised.

a. Which of the following LV-related charges should be included in total cost benchmarking? If you recommend excluding a charge, please explain.

- **Common ST Lines**
- **HVDS-HIGH**
- **HVDS-LOW**
- **LVDS**
- **Meter Charge**
- **Monthly Service Charge**
- **Shared LV Line**
- **Shared LVDS**
- **Specific Distribution Line**
- **Specific LV Line**
- **Specific Primary Lines**
- **Specific St Lines**

Please see the response to question 8 above.

b. The Performance and Benchmarking Working Group raised concern that in circumstances where a shared LV line spans sparsely populated areas of Hydro One's service area, the inclusion of 100% of the "Shared LV Line" costs in the embedded distributor's benchmarking costs may unfairly overstate the LV costs for that distributor.

How might the Board identify these circumstances and only allocate "Shared LV Line" costs in proportion to the "Shared LV Line" that is in the embedded distributor's service territory?

Please see the response to question 8 above.

Efficiency Cohorts/Rankings & Stretch Factors

Preamble:

The Board notes in the RRFE Report that stretch factors are intended to reflect the incremental efficiency gains that distributors are expected to achieve under incentive regulation and can vary by distributor and depend on the efficiency of a given distributor at the outset of the incentive regulation plan [p. 17]. The Board provided the following policy direction:

- **The Board's approach in relation to the use and assignment of stretch factors will continue;**
- **Distributors will continue to be assigned annually to efficiency cohorts;**
- **Assignments will be made on the basis of total cost benchmarking evaluations; and**
- **The Board will further consider whether the current stretch factor values continue to be appropriate or whether there should be greater differentiation between the values.**

10. For each expert's recommended approach:

a. Is the proposed approach appropriate? Does it meet the Board's policy direction noted above?

The PWU agrees with Dr. Yatchew that following the many years that the distributors have been under IR during which there have been sustained efforts to drive efficiencies it is time to reward efficiency. The PWU supports Dr. Yatchew's recommendation for a range of default stretch factors from -0.3 per cent to +0.3 per cent assigned based on the outcome of a reasonable benchmarking approach (e.g. Dr. Cronin's DEA-efficiency approach).

b. What is your preferred approach and why?

See response to Question 10a.

11. What are appropriate stretch factor values? Why?

See response to Question 10a.

Implementation Considerations

Preamble:

Under all three of the rate setting approaches set out in the RRFE Report, a regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels [p. 13].

Performance is measured after the price cap index ("PCI")[1] formula has been applied to adjust the distributor's rates (i.e., ex post).

12. What indicators should the Board consider monitoring on an on-going basis to test the reasonableness of the results of its PCI formula before it is applied to adjust the distributor's rates (i.e., ex ante)?

Service reliability performance; line losses; ROE.

Preamble:

In the RRFE Report, the Board states that it will update the industry productivity factor every five years (e.g., the update after 2014 would be in 2019) [p. 17]. Furthermore, when updated by the Board, the new X-factor will automatically be applied to all distributors that are then on the Annual IR Index mechanism [p. 22].

13. When the Board updates the industry productivity factor every five years, should the new productivity factor be automatically applied to all distributors that are then on 4th Generation IR? Why or why not?

Given the unexpected declining TFP trend that has come to light in this consultation process, the PWU recommends that the Board assess on an annual basis the distributors' TFP together with service quality performance and line loss performance to determine the effectiveness of the Board's IR. Depending on the outcome of this assessment, the Board can then determine the appropriateness of automatically applying an updated productivity factor to all distributors that are still on 4th Generation IR in five years. While it is always important to analyse the impact of an IR framework, it is especially so when the outcome is not consistent with the Board's RRFE objectives.

Dr. Cronin notes in his June 13, 2013 report, that over the period 2006-2011 the distributors' rates were regulated under different combinations of several rate adjustment approaches (2^{nd} Generation IR; 3^{rd} Generation IR; and, Cost of Service). Under 4^{th} Generation the variety of rate adjustment approaches in effect in a single year will increase as a result of the RRFE's three rate setting methods, assuming that 4^{th} Generation IR, like 3^{rd} Generation IR will be introduced for "tranches" of distributors over a number of years. Assessing the impact of the various regulatory approaches including 4^{th} Generation IR will undoubtedly be formidable and the Board needs to consider how it will address this challenge.

General

14. With respect to your preferred approaches, as identified in your answers to prior questions, what other implementation matters, if any, need to be considered by the Board?

The Board needs to address the impact of excluding CIAC from the TFP analysis (see section 4.3.2 above).

The Board also needs to examine the impact of the variance between PEG's data estimates and the actual data filed by the distributors.

The incentives/disincentives created by the absence of the following considerations need to be addressed in the Board's implementation of 4^{th} Generation IR: customer value of services (see section 5 above); service reliability performance (see section 5 above); and, line loss performance (see section 6 above).

Further, the Board needs to address the impact of its OM&A-only benchmarking in 3^{rd} Generation IR on its total cost benchmarking for 4^{th} Generation IR (see section 4.4 above).

All of which is respectively submitted.