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File 20242

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 OEB File No. EB-2010-0379

Attached please find expert comment and analysis prepared by Dr. Francis Cronin entitled *Submission on 4th Generation IR for Ontario Electricity Distributors.*

Yours very truly,
PALIARE ROLAND ROSENBERG ROTHSTEIN LLP

Richard P. Stephenson

RPS:jr

encl.
cc: Judy Kwik
John Sprackett

Submission on 4th Generation IR for

Ontario Electricity Distributors

By

F. J. Cronin

For

The Power Workers' Union

June 13, 2013

1. Introduction

On October 18, 2012 the Ontario Energy Board (the Board or OEB) issued a report setting out its Renewed Regulatory Framework for Electricity Distributors (RRFE), its 4th Generation framework for incentive regulation (IR). The Board describes RRFE as a "comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensures that Ontario's electricity system provides value for money for customers". The Board identifies work required to implement the renewed regulatory framework, including the development of a rate adjustment mechanism under 4th Generation IR and statistical methods for evaluating distributor performance (i.e. benchmarking).

On May 3, 2013 the Board posted on its website a report prepared by PEG entitled "Empirical Work in Support of Incentive Rate Setting in Ontario" (the PEG Report) that develops proposals on a rate adjustment mechanism (RAM) for 4th Generation IR and a benchmarking method. The Board invited stakeholders to file written comments on the PEG Report as well as to file their own expert reports. The Power Workers' Union has retained me to prepare a report in response to the Board's invitation for expert reports.

In section 3 of my report I introduce the use of price-dual total factor productivity (TFP) estimate as a means of assessing the reasonableness of index-based TFP analysis (i.e. quantity-based TFP analysis). In section 4 of my report I provide my index-based TFP analysis. I assess TFP for sub-intervals in the study period 2000-2011 and recommend sample specific TFP indexes as the historical basis for 4th Generation IR.

In section 5 I consider the OEB's stated goal of implementing "regulation that is based on the achievement of outcomes that ensures that Ontario's electricity system provides value for money for customers". To that end, I assess the impact of *line loss performance* and *customer-valued service reliability performance* on the distributors TFP performance. Obviously the former has notable green and monetary implications and the latter is rife with potential end-user welfare losses. I discuss the regulatory treatment of line losses and service reliability in other jurisdictions. In section 6, I present Data Envelopment Analysis (DEA) as an option in efficiency benchmarking. I compare my efficiency findings to those of PEG. I examine stability and plausibility for both. I also compare the efficiency frontier in 2011 with the frontier in 1997 and 2000. A summary of my findings are presented in section 2.

2. Summary

In this section I discuss the research undertaken and presented below in sections 3 through 6. Topics covered and related findings and conclusions are reviewed.

Section 3

In section 3 I present two alternative methodologies for estimating the total factor productivity (TFP); i.e. the quantity-based (also called index-based) and the price-dual approaches. We have developed data supporting both approaches and compared the results over the 2006-2011 period.

Economic assessments of productivity can be derived from either quantities (physical) or prices (called price-dual or price-based). In the former case we base TFP calculations on the comparison between output quantities and input quantities. This is the approach PEG has used. Similarly, we can use prices to calculate TFP: output prices (e.g. rates) are compared with input prices (i.e., Input Price Index or IPI) to estimate trends in productivity growth. Both approaches have been used by Canadian and US regulators.

Given the acknowledged, significant data quality and availability issues related to the quantity-based TFP approach that remain unresolved, the price-based approach has a very notable advantage for the Ontario electricity distributors' TFP analysis: the amount of data required to implement the price-based approach (in particular capital data) is significantly less than that required for the physical approach. Proper quantification of capital for the quantity-based approach requires decades of capital stock (gross value of plant, accumulated depreciation, additions, retirements, and depreciation). The price-dual approach does not require the decades of capital data just the rate and input price performance.

I estimated TFP growth rates for Ontario LDCs over the 2006 to 2011 period for both the price-dual and the quantity approaches. For the latter I employed two different weighting schemes: a fixed and a linked (variable) weight (Tornquist). The resulting TFP estimates are quite similar: -2.4 percent for the price-dual; -2.3 percent for the fixed weight quantity-based; and, -2.4 percent for the Tornquist quantity-based.

Section 4

In section 4 I focus on PEG's and my quantity-based methodology primarily. I examine the 2000-2011 period as well as sub-intervals. I examine these results vis a vis those developed in 1st Generation Performance Based Ratemaking (PBR).

PEG's TFP for 2002-2011 ranges from -1.10 percent for the sample including all distributors to 0.10 percent for the sample excluding Toronto Hydro and Hydro One. Over the latter half of the period, 2006-2011, PEG estimates a decline in TFP ranging from -2.14 percent for the sample including all distributors to -0.70 percent when Toronto Hydro and Hydro One are excluded. Over the 2002-2011 period, my estimates of TFP growth rates range from -0.60 percent when Toronto Hydro and Hydro One are excluded and decline to -1.46 percent when they are included. Over the later sub-interval, 2006-2011, my estimate of TFP growth is -0.9 percent when Toronto Hydro and Hydro One are excluded and -2.55 percent when they are included.

I find an increasingly declining trend in TFP over the period 2000-2011. Unlike the sub-interval 2002-2005, over the 2006-2011 period I find widespread negative growth in productivity across a broad sample of LDCs. This impact is pronounced, broad based, and persistent. I would expect only a small portion of this result to be caused by the economy. I would also expect the impact of the economic recession to be primarily in 2008-2009.

In 1st Generation PBR the Board found a similar situation with highly divergent TFP growth rates for sub-intervals. In its 2000 decision the Board weighted the first five-year period by 1/3 and the second five-year period at 2/3, thus giving double the weight to the more recent sub-interval's results.

Using PEG's results when Toronto Hydro and Hydro One are excluded from the analysis, if the Board's 2000 decision split-approach of one-third and two-thirds weights were applied to the sub-intervals (i.e., 2002-2006 and 2006-2011) the resulting TFP would be -0.10 percent for 4th Generation IR. Based on my results, the weighted TFP would be -0.67 percent. When Toronto Hydro and Hydro One are included in the analysis PEG's weighted result is -1.36 versus a weighted TFP based on my results of -1.52.

Furthermore, both PEG's and my results understate the actual decline in TFP. Neither estimate includes contributed capital in the capital additions data; both for individual LDCs and in the aggregate, contributed capital is notable share of additions. I should note that the 1st Generation research included contributed capital.

Section 5

In section 4, I developed a traditional quantity-based estimate based on only three factors: capital, labour, and materials. In section 5 I incorporate line losses and service reliability in assessments of TFP performance.

Line Losses, Rate Payer Costs, and TFP Performance

My analysis of the Ontario distributors' historic line loss data indicates that between 1995-1997 and 2009 line losses have degraded (i.e. increased) by 33 percent on a customer-weighted basis and 20 percent on a simple average basis.

On aggregate the cost of line losses for Ontario distributors based on an average electricity charge of $0.08 per kWh exceeded $86 million in 2010.[1] Per customer, the *increased losses* noted above currently cost about *$18 a year*. For some customers the yearly cost is over *$32*.

[1] EB- 2010-0379. Ontario Energy Board Consultation on a Renewed Regulatory Framework for Electricity Transmitters and Distributors. PWU Submission RRFE Performance Initiative – Attachment A. Cronin F.J. Assessing Distributor Incentives and Performance: 2000-2012. http://www.rds.ontarioenergyboard.ca/WEBDRAWER/WEBDRAWER.DLL/webdrawer/rec/339284/view/PWU_Comments_RRFE_0379_20120420.PDF

And, of course this figure does not include the costs of legacy losses which can be substantial themselves. Total costs of loss can be more than $150 per customer per year.

I provide illustrative examples showing that at the present time, line losses are a substantial share of distribution costs and vary substantially among seemingly similar LDCs. Line losses vary greatly over time depending on regulatory incentives and relative prices (e.g., prices of electricity versus labour or capital). I also document that including this cost input in TFP analysis can materially impact LDCs' TFP performance. The analysis confirms that line losses are a critical input. Utilities use information on relative prices, regulatory incentives, and their own understanding of utility operations to make their decisions. These include the composition of the inputs they use in both capital additions and OM&A.

Reliability, Customer Willingness to Pay, and TFP

For over 10 years, I have advocated incorporating reliability directly within the Board's IR. Many regulators have included reliability standards or financial consequences as part of their PBR frameworks. I examine the performance of a sample of 16 Ontario distributors and focus on the period 2005-2011. I present these results broken into three groups: large, medium-sized, and small LDCs.

Exhibit 5.5 presents annual System Average Interruption Duration Index (SAIDI) performance for a select sample of five small LDCs relative to their 2005-2007 mean.

Exhibit 5.5. SAIDI Performance for Selected Small Ontario LDCs: 2005-2011

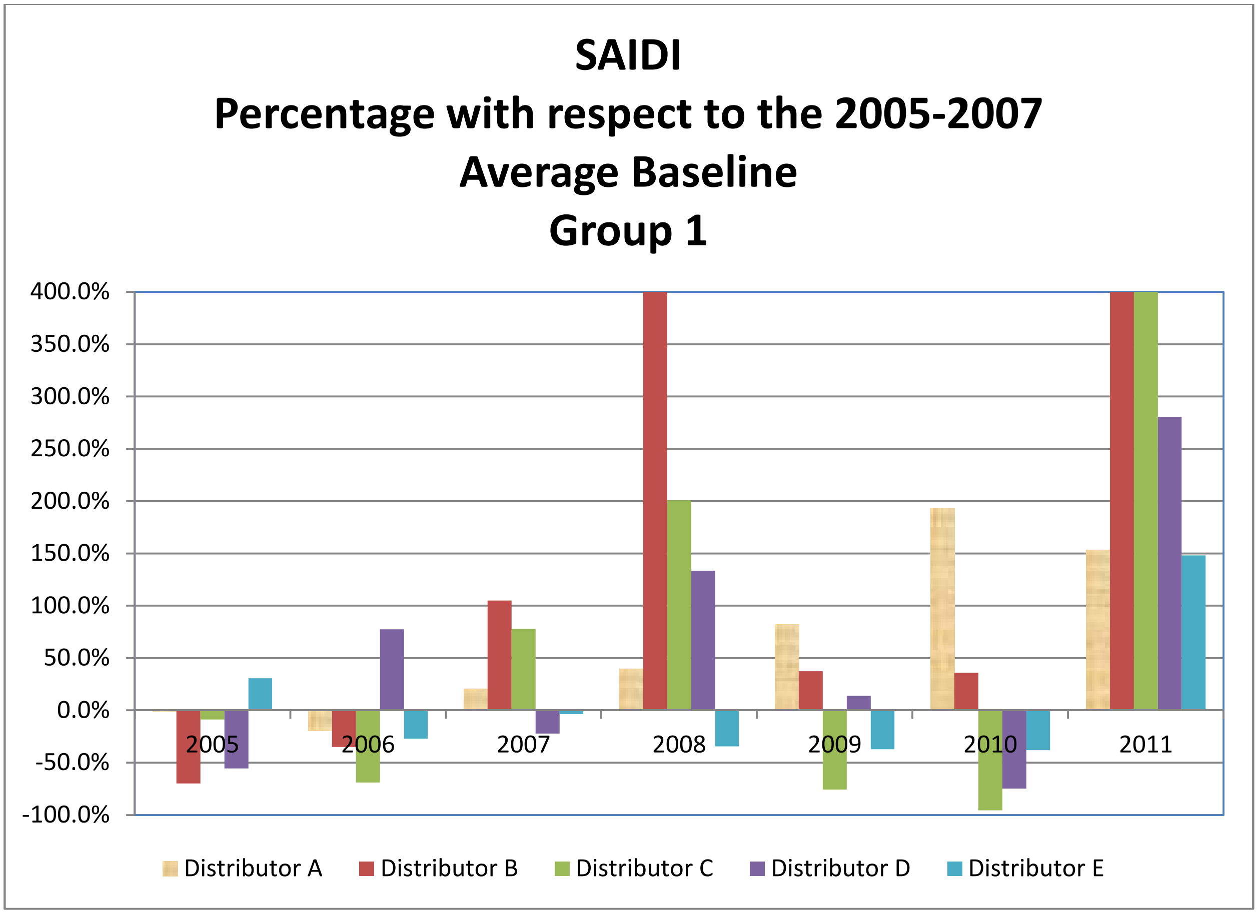
Distributor	2005	2006	2007	2008	2009	2010	2011	2005-2007 Average Baseline
A	5.36	4.34	6.50	7.54	9.86	15.86	13.69	5.40
B	0.36	0.78	2.46	10.00	1.65	1.63	9.75	1.20
C	1.24	0.42	2.41	4.08	0.33	0.06	15.39	1.36
D	1.25	4.99	2.19	6.56	3.20	0.71	10.69	2.81
E	4.45	2.48	3.28	2.23	2.14	2.11	8.44	3.40

Blue is < Mean
Brown = 10% > Mean
Red = 25% > Mean
Green = 50% > Mean
Purple = 100% > Mean

Note the preponderance of purple shaded results (100 percent or more above the baseline) in 2011. In fact 9 out of 20 entries (45 percent) between 2008 and 2011 are shaded purple. We also note three entries in red and one in green. So 65 percent of entries over 2008-2011 indicate that SAIDI was 25, 50, or 100 percent higher than the three-year average baseline. Note the predominance of blues (< mean) in the first three years of the time series, 2005-2007.

Exhibit 5.6 presents the same SAIDI data as in Exhibit 5.5 but expressed as deviations from the three-year mean for each of the five distributors by year. Note the preponderance of smaller deviations in the first three years. Starting in 2008 and especially in 2011, we see deviations that are many times greater than we see in the earlier period. In fact, in 2011 all the distributors have very large positive deviations indicating a substantial decline in service reliability.

Exhibit 5.6. SAIDI Performance Relative to 2005-2007 Mean Select Small LDCs



I find similar results for the medium and large distributors. These results are not at all surprising. IR has been found consistently to incent and produce perverse outcomes, including reliability degradation. Numerous regulators have put in place long-standing policies to deal with the reliability problem under IR.

Willingness to Pay Surveys (WTP)

For many regulators customer-based WTP surveys, have been the foundation of their IR-incentive programs on service reliability. For example, Ofgem has included side conditions/consequences within its PBR and based their service guarantees (i.e., financial penalties) on WTP surveys.

OEB has undertaken WTP surveys of its own conducted by Pollara.

Of critical importance, Pollara finds 57 percent of residential customers in Ontario would be unwilling to accept any compensation in return for degraded service. For the small proportion of respondents willing to accept compensation for degradation, the average value offered was $27.90 per bill or $334.20 per year. *This would be the minimum value in converting to an overall residential customer average.*

Note that the average LDC distribution bill amount in Ontario is $28.38 per month (2009). We can see from the Pollara survey results that customers' value degradation loss as equivalent to what they pay for distribution.

Pollara finds Ontario business customers place an even higher value on the maintenance of distribution service. *62 percent of business customers in Ontario would be unwilling to accept any compensation in return for degraded service.* For the small proportion of respondents willing to accept compensation for degradation, the average value offered was $125.1 per bill or $1501.2 per year. *This would be the minimum value in converting to an overall business customer average.*

A Customer-centric Measure of Utility Output and TFP

In order to provide a more customer-centric measure of utility output, I have employed the Pollara findings as inputs to an adjusted TFP estimate.

In adjusting TFP for reliability, I used reported changes in service reliability together with the Pollara reported WTP and WTA (i.e. Willingness to Accept payment) for improvements and degradations. These "customer valued" improvements/decrements were then weighted with changes in the reported LDCs' outputs.

We consider 4 examples of distributor's TFP estimates adjusted for degradations in reliability and find that the incorporation of customer valued service changes can have a significant effect on the calculated growth or decline in average annual TFP from 2002 - 2011. The difference in TFP for the four distributors ranged from 3.3 to 0.3 TFP percentage points.

Quality of Data, Errors and Potentially Biased Findings in PEG's Analysis

I believe it is imperative that PEG provide confirmatory analyses regarding their reported TFP and benchmark findings. This would be expected under normal economic/statistical analyses. In the current instance, with the acknowledged limitations in required LDCs' information, the need is even greater. "Backcasting" is not enough assurance when efficiency rankings are involved together with rates, revenue, and profits.

We must be independently reassured that the missing data, estimated-in-place-of-actual data, and data gaps spanning years of complete data for the complete sample of LDCs, have not collectively undermined the validity of the TFP and most importantly the benchmarking analyses.

The quantity-based TFP and statistical modeling methodologies used by PEG are very data intensive and extensive. That is, they need:

- a substantial list of data for each LDC (e.g., gross stock, additions, retirements, deprecation, contributed capital, outputs, inputs, prices, etc.)
- capital data for decades
- about 10 years of operating data

I believe the 4th Generation work undertaken by PEG does *not* have all the data needed for unbiased, robust estimates of either TFP performance or efficiency/cost benchmarking. PEG has a limited capital series covering 1989-1998 and 2002-2011; for some LDCs, only the latter period of data is available. This is insufficient based on normal applications of TFP analyses. Furthermore it does not employ required data such as actual capital additions nor retirements to provide accurate estimates of LDCs' capital.

Some of my earlier work has shown that such gaps in data have resulted in substantial errors in estimates of capital, total costs, TFP growth, and efficiency for both individual LDCs and in aggregate TFP growth estimates. These errors could undermine the 4th Generation framework if implemented. Inaccurate information would be used to assess industry TFP growth. Furthermore, individual LDCs would be subject to highly inaccurate estimates of efficiency and rankings. Indeed, we have seen just this set of outcomes under 3rd Generation.

There are, however, alternative methodologies that could be applied to circumvent these deficiencies such as DEA.

Section 6

In section 6, I provide illustrative DEA/efficiency benchmarking.

DEA is a non-parametric approach to estimating production frontiers using linear programming techniques. It has been widely adopted by regulators to estimate efficiency. Parametric or stochastic techniques can also be applied in benchmarking. These include standard regression analysis like ordinary least squares (OLS), “corrected” OLS, and stochastic frontier analysis (SFA). Outside of North America, DEA is arguably the most widely used benchmarking methodology used by regulators. Numerous regulators have employed DEA to guide the design of regulatory mechanisms.

Based on DEA I find that for the Ontario distributors over a ten-year period “efficiency” is defined by a consistent set of distributors. I have similar results over a longer 20 and even 24-year period.

Further, I find that the pre-restructuring Ontario electricity industry frontier has degraded. Overall, Ontario LDCs 2011 efficiency has fallen from 1997. Efficiency in 2011 has also fallen from 2000 and from 2002 levels. Technical efficiency for the pre-restructuring frontier distributors has fallen consistently. This degradation tends to make frontier LDCs less distinguishable from the interior LDCs that operated off the frontier. Allocative efficiency for these pre-restructuring frontier firms has also degraded. This degradation is significant, falling by more than 20 percent. These findings are consistent with the incentives offered by OM&A-only benchmarking.

The PEG analysis misidentifies the firms comprising the frontier. Furthermore, PEG’s analysis underestimates the efficiency of the most efficient Ontario LDCs. These LDCs have consistently formed the efficiency frontier in the span of time from 1988-2011 that we examined. By and large, the same set of the most efficient LDCs that formed the frontier in 1997 and 2000 form the frontier in 2011.

PEG’s efficiency results and rankings for individual LDCs appear in a number of cases to be significantly and substantially different from those I obtain with DEA. I find the most efficient of PEG’s estimates in this sample to be notably biased downward and not properly conveying the magnitude of the relative efficiency, i.e., understating the magnitude of the relative efficiency by 39 percent. I find the most inefficient of PEG’s estimates in this sample to be notably biased upward, i.e., overstating the magnitude of the relative inefficiency by 40 percent.

3. Alternative Methodologies for Estimating Total Factor Productivity: the Quantity-Based versus the Price-Dual Approach

I believe it is imperative that PEG provide confirmatory analyses regarding their reported TFP and benchmark findings. This would be expected under normal economic/statistical analyses. In the current instance, with the acknowledged limitations in required LDCs' information, the need is even greater. We must be independently reassured that the missing data, estimated-in-place-of-actual data, and data gaps spanning years of complete data for the complete sample of LDCs, have not collectively undermined the validity of the TFP and most importantly the benchmarking analyses.

3.1 Background: Alternative TFP Methodologies

The quantity-based TFP methodology used by PEG is very data intensive and extensive. That is, it needs:

- a substantial list of data for each LDC (e.g., gross stock, additions, retirements, deprecation, contributed capital, outputs, inputs, prices, etc.)
- capital data for decades
- about 10 years of operating data

I believe the 4th Generation work undertaken by PEG does *not* have all the data needed for unbiased, robust estimates of either TFP performance or efficiency/cost benchmarking. PEG has a limited capital series covering 1989-1998 and 2002-2011; for some LDCs, only the latter period of data is available. This is insufficient based on normal applications of TFP analyses. Furthermore it does not employ required data such as actual capital additions nor retirements to provide accurate estimates of LDCs' capital.

Some of my earlier work[2] has shown that such gaps in data have resulted in substantial errors in estimates of capital, total costs, TFP growth, and efficiency for both individual LDCs and in aggregate TFP growth estimates. These errors could undermine the 4th Generation framework if implemented.

There are, however, alternative methodologies that could be applied to circumvent these data deficiencies. PEG relies upon their "competitive equilibrium condition" (i.e., revenue equals costs) to specify their total factor productivity estimate. This formulation relies upon input and output quantities. That equilibrium condition can also be used to re-specify TFP estimates based on input and output prices (i.e., a price-dual estimate). In fact, all the data are available to produce a robust, comprehensive price-dual TFP estimate.

[2] EB-2007-0673. Frank Cronin May 6th, 2008 Presentation
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/presentation_PWU_Cronin_20080506.pdf

The price-dual approach has a strong theoretical basis, just as strong as the index-based TFP approach (e.g., quantity-based TFP) used by PEG. This is so noted by PEG's formulaic illustration of TFP as shown in section 3.2 below. In addition, the price-dual has a compelling advantage in the requirement for substantially less data, and no need for any historical decades of capital data required in the quantity-based approach. All the price-dual requires is data on LDCs' rates and input prices (e.g., an IPI).

In this section I employ a price-dual TFP analysis as supplementary analysis to the quantity-based TFP analysis. Using data for the period 2006-2011, a price-dual TFP for Ontario LDCs is estimated and compared with a quantity-based TFP estimate. The latter is developed with all required actual data, including capital stock, additions, retirements, and depreciation covering over a 40 year the period (1972-2011).

3.2 The Price-Dual TFP Approach: Theoretical Equivalence to the Quantity-Based Approach

Economic assessments of productivity can be derived from either quantities (physical) or prices (called price-dual or price-based). In the former case we base TFP calculations on the comparison between output quantities and input quantities. This is the approach PEG has used. Similarly, we can use prices to calculate TFP: output prices (e.g. rates) are compared with input prices (e.g. Input Price Index - "IPI") to estimate trends in productivity growth. Both approaches have been used by Canadian and US regulators.

Let's examine the quantity-based TFP methodology. On slide 11 of PEG's Primer[3] on the quantity-based approach the underlying equilibrium condition is presented, i.e., revenue equals costs. Both the quantity and price-dual approach rely on this equation to develop TFP estimates. As PEG's Primer shows, the two approaches are based on the same mathematical decomposition of this budget constraint.

However, the empirical calculations involved in the two approaches rely on different data: quantities in the quantity-based approach[1]; and, prices for the price-dual approach[4]. The latter requires significantly less data: on the order of 80-90 percent less data.

Let us define the following terms relating to output and input prices and TFP.

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[3] Larry Kaufman. January 21, 2013 *Presentation to PBR Working Group* slides 10 and 11, Primer on Productivity and Efficiency Concepts.

[4] Frank Cronin. *Presentation to Working Group*, January 21, 2013 slides 13 and 14.

$\dot{P}$ = growth in industry output price index

$\dot{W}$ = growth in industry input price index

$\dot{TFP}$ = industry total factor productivity trend

According to equation (8) on slide 11 of PEG's Primer the difference between the growth in input prices and the growth in LDCs' rates *is the growth in TFP*.

$$\dot{P} = \dot{W} - \dot{TFP} \qquad (8)$$

For ease of exposition lets rearrange terms in (8) to derive (8*), the exact same condition but with terms rearranged.

By rearranging the terms,(8) becomes an expression of the difference in input and output prices (8):*

$$\dot{W} - \dot{P} = \dot{TFP} \qquad (8^*)$$

PEG's Primer concerns the quantity-based TFP and focuses on the right hand side of equation (8*); my work focuses on the left hand side of (8*).

The two sides are identical as PEG's Primer indicates. What (8) clearly shows is that the growth in industry total factor productivity is equal to the difference between the growth in the industry input price index and the growth in the industry output price index, i.e., in this case the distributors' rates.*

Let's see how we can use plausible data on rates and input prices to estimate the resulting growth in TFP. Let us first assume that input prices rise more than output prices, specifically we assume $\dot{W}$ is 2 percent and $\dot{P}$ is 1 percent. In this case, $T\dot{F}P$ is 1 percent. What about the reverse when output prices rise more than input prices. Let us say, $\dot{W}$ is 1 and $\dot{P}$ is 2, then $T\dot{F}P$ is -1.

These findings make perfect sense: when input prices rise more than output prices the firm must have improved its productivity to offset some of the rise in the IPI. In our first case the firm would have offset half of the rise in the IPI by productivity improvements. In the second case we have the opposite situation, where output prices rise more than input prices. The firm would have experienced a fall or degradation in productivity which adds to the impact of the IPI on output prices. In the second case, the increase in rates exceeds the increase in the IPI by the fall in TFP.

3.3 The Price-Dual TFP Approach: Regulatory Applications

Regulators in both Canada and the US have employed the price dual in IR applications. Initial regulatory policies have numerous examples of applications or inquiries regarding the equilibrium value condition relating a firm's revenues to costs. The initial local exchange carrier (LEC) Price Cap Plan was based on two Federal Communications Commission (FCC) staff studies which employed the price-dual approach.

Similar regulatory staff analyses had been relied on for the productivity offsets employed in the earlier price cap plan for long distance carrier, AT&T. Subsequently several FCC staff studies using the price dual approach were used in modifying the LEC Price Cap Plan.

In Canada, the Canadian Radio-television and Telecommunications Commission (CRTC) applied the "historical price approach" in their regulation of its international carrier Teleglobe (CRTC 1996). In the LEC Price Cap Plan (Stentor price cap review), the CRTC (1996) raised this possibility of applying the price-dual.

3.4 The Price-Dual TFP Approach: Comparing Alternative Estimates of Ontario TFP Growth

Let's use the available Ontario LDC Performance Based Ratemaking (PBR) data and calculate a price-dual TFP estimate. Then, let's compare that with a quantity-based TFP estimate. For the quantity-based TFP estimates I employ the PBR data provided by the distributors for the OEB's 1st Generation PBR updated with 1998-2011 data filed by the distributors. This data is among the best LDC-regulatory data in the world and now encompasses over four decades of capital data and two decades of operating data. The sources of data and derivation of the rates and IPI data are examined further later on in this report.

What can we say about the growth in rates and input prices in Ontario over the 2006 to 2011 period? Exhibit 3.1 presents my findings on the growth in rates in Ontario. As we can see, over the 2006 to 2011 period, the input price index (i.e., a weighted average of the prices of inputs used specifically by LDCs) increased by 1.0 percent per year. This is consistent for the generally low rate of inflation experienced by the economy during this period.[5]

In terms of rates, we see that on average LDCs' rates rose 3.4 percent per year over the period 2006-2011. However, the rate performance experience differed significantly among the Rate Adjustment Mechanisms that the LDCs were subjected to. For example, the rates for LDCs under 3rd Generation rose on average 0.1 percent. For LDCs under Cost of Service (COS) rate adjustments, average rate increases were 8.6 percent over the 2006-2011 period.

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[5] Although some inputs were subject to stronger cost pressure especially at the beginning of our study period, the pressures cooled somewhat after. In 2006, the IPI rose 3.4 percent. However, by 2009 the increase was only 0.1 percent.

Exhibit 3.1. Rate and Input Price Performance for Ontario LDCs 2006-2011

	Average Annual Percent Change
Input Price Index	1.0
Composite Ontario Distributors' Rate Adjustment	3.4
2nd Generation Rate Adjustment	0.3
3rd Generation Rate Adjustment	0.1
Cost of Service	8.6

With the information presented in Exhibit 3.1, we can calculate a price-dual estimate of TFP growth.

Exhibit 3.2 presents the resulting estimated TFP growth rates for Ontario LDCs over the 2006 to 2011 period[6]. That is, our base year is 2006, the year the Board undertook COS reviews for all the LDCs. In 2009, the Board implemented 3rd Generation IR so the 2011 terminal allows us to observe the consequences of several years of IR on LDCs (some LDCs stayed under 2nd Generation through 2011). I choose 2006 for ease of calculation. However, any year since restructuring could theoretically be used as the starting point as long as the required rate and IPI data were available.

Estimates are presented for both the price-dual and the quantity approach. For the latter we employ two different weighting schemes: a fixed and a linked (variable) weight (see section 4 for further descriptions of the two weighting schemes). The linked weight approach is known as the Tornquist approach.

[6] Frank Cronin. *Presentation to Working Group*, February 21, 2013. This presentation also examined the incorporation of line losses and reliability in TFP estimates. This work is discussed below.

Exhibit 3.2 presents the percentage changes over 2006-2011. Note that the resulting TFP estimates are quite similar.

Exhibit 3.2. TFP Growth Estimates Using Alternative Methodologies and Weights

	Price-dual	Quantity-based	
		Fixed Weight	Tornquist
2006-2011	-2.4%	-2.3%	-2.4%

The price-dual TFP estimate is -2.4 percent per year over the period. If we recall the second case described above where output prices rise more than input prices and the firm would have experienced a fall or degradation in productivity, this is in fact what I find for Ontario LDCs: a fall of 2.4 percent per year over the 2006-2011 period. This equates to about a 13 percent fall for the whole period. Recall that this decline in productivity adds to the impact of the IPI on output prices. In this instance we see that the IPI increase of 1.0 percent per year is accentuated by the decline in productivity of 2 percent resulting in a combined effect of a 3.4 percent rise in rates.

How do my findings regarding the price-dual compare with full-information quantity-based TFP estimates?

I have employed a complete set of required data for quantity-based estimates of TFP growth and I have employed both a fixed and variable weight estimate (please see section 4 for details). The estimates of the two quantity-based TFP (fixed weight and Tornquist) are similar. The fixed-weight estimate is -2.3 percent. The variable-weight (Tornquist) estimate is -2.4 percent. Furthermore, both estimates of the quantity-based TFP are quite similar to the price-dual estimate of -2.4 percent.

The development of the quantity-based TFP estimates are further examined and discussed in section 4. Section 5 extends the TFP work by incorporating line losses and reliability performance in the estimates.

3.5 The Price-Dual TFP Approach: Data

What actually are the data used in the analysis, i.e., how are the input prices and output prices determined?

The IPI is the basis for the change in input prices and the distributors’ rates are the basis for the change in output prices.

Input Prices

Input prices are weighted indices. The weights are determined by the number of cost components included in the specification and the respective share of each cost component (i.e., input price sub-indices).

Annual information collected by the OEB from the distributors is used to determine the weighting of the input price sub-indices. Additionally, Stats Canada produces some of the required information. The OEB calculated an IPI for 3rd Generation IRM that did not use any of the distributors' historical capital data.

The derivation of the IPI in my analysis is according to a 1999 OEB Staff report[7]. This material was the basis of the Board's 2000 Decision on TFP and can be accessed on the Board's website at:

http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/ppp1.html

http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/ppp2.html

The IPI derivation is also described in a 2002 backgrounder on the IPI posted on the OEB's website.[8] In addition, please also see the 3rd Generation 2008 Staff report on the IPI:

http://www.ontarioenergyboard.ca/documents/cases/EB-2007-0673/IRM_Staff_Paper_20080228.pdf

Let us look at an actual set of IPI inputs and weights. Exhibit 3.3 is taken from Table 4.4 provided in the 1999 OEB Staff Report on Ontario electricity distribution TFP.[9] It shows the cost shares or input price weights for capital, line losses, labour, and materials. Results are presented by utility size and for all 49 utilities included in the sample, for both the 4-factor and 3-factor analyses.

[7] Ontario Energy Board. Productivity and Price Performance for Electric Distributors in Ontario. Prepared for Ontario Energy Board Staff by F.J. Cronin, M. King and E. Colleran, PHB Hagler Bailly Consulting. July 6, 1999.

[8] Ontario Energy Board. Backgrounder. Input Price Index for 2002. January 21, 2002.

[9] Ontario Energy Board. Productivity and Price Performance for Electric Distributors in Ontario. Prepared for Ontario Energy Board Staff by F.J. Cronin, M. King and E. Colleran, PHB Hagler Bailly Consulting. July 6, 1999.

Exhibit 3.3. 1999 Staff Report Input Weights
"Productivity and Price Performance For Electric Distributors In Ontario"

Table 4.4

1993 Average Weights for Cost Shares									
	Four Factor					Three Factor			
Simple Average	Capital	Line Loss	Labor	Materials	Total	Capital	Labor	Materials	Total
Large	0.45	0.12	0.30	0.13	1.00	0.51	0.34	0.14	1.00
Mid	0.49	0.12	0.28	0.12	1.00	0.55	0.31	0.13	1.00
Small	0.40	0.16	0.30	0.14	1.00	0.48	0.35	0.17	1.00
All Utilities	0.45	0.13	0.29	0.13	1.00	0.52	0.34	0.15	1.00

On average, about 45 percent of a typical utility's total cost is related to capital. Remaining cost shares are 29 percent for labour, 13 for material and 13 for line losses. Medium sized utilities tend to have a slightly higher share for capital and slightly lower shares for labour and material. In the three-factor case the cost shares are 52 percent for capital, 34 percent for labour, and 15 for materials.

These weights are generally consistent with weights reported for utilities in other jurisdictions.

Output Prices (i.e., Rates)

Output prices were calculated for 13 Ontario distributors whose revenue requirements collectively make up 80 percent of the distribution sector. Detailed description of the calculations is provided in Appendix 1.

The output prices are the weighted average of the aggregated rates of each of the distributors. Rates information collected by the Board each year is used to derive the output prices.

The change in output price is calculated on an individual distributor basis.

The change in output price for a distributor is derived from the aggregate rate change which is calculated using monthly distribution billing data.

For each distributor a monthly distribution bill is calculated for the relevant customer classes by applying rates and charges, as set out in the Board's approved rate schedules, to the typical usage for the customer classes;

- Residential: 800 kWh per month
- GS < 50 kW: 2,500 kWh per month
- GS > 50 and Large Use: based on actual usage per customer (i.e. kW-month per customer) using data provided in the most recent cost of service applications.

Board's approved rate schedules can be accessed at:

> http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Applications+Before+the+Board/Electricity+Distribution+Rates

The following rates and charges were used in determining LDC's monthly distribution bill:

- Monthly Service Charge, excluding the component related to the smart meter cost
- Volumetric Rate (i.e. $/kWh or S/kW)
- Lost Revenue Adjustment Mechanism (LRAM) and Shared Savings Mechanism (SSM) Recovery Rate riders

The annual rate change for each customer class is derived from the distribution bill change.

The distributors' aggregate rate change is the summation of customer class rate changes apportioned by revenue requirement shares obtained from the distributor's recent COS application.

Exhibit 3.4 presents the aggregate annual rate change for two large Ontario distributors over the 2007 – 2011 period.

Exhibit 3.4. The Composite Rate Changes for Two Selected Ontario LDCs (percent change)

Utility	2007	2008	2009	2010	2011
A	8.17	-0.12	9.13	0.02	-1.00
B	0.57	-0.76	0.06	16.25	0.42

The composite change in the output price for all the distributors is the summation of each distributors' aggregate rate changes apportioned by their respective distribution revenue share.

3.6 Conclusion: Major Advantages of the Price Dual

The price-based TFP approach will provide supplementary analysis that can be used to assess the outcome of the quantity-based TFP analysis.

Given the significant data issues related to the quantity-based TFP approach that need to be dealt with, the price-based approach has a very notable advantage for the Ontario electricity distributors' TFP analysis: the amount of data required to implement the indirect approach (in particular capital data) is significantly less than that required for the physical approach (i.e., maybe 80 percent less data). Proper quantification of capital for the physical approach requires decades of capital stock (gross value of plant, accumulated depreciation, additions, retirements, and depreciation). The price-dual approach does not require the decades of capital data.

Only IPI and rates data for the two end points are required to calculate the change in TFP over a time period. Intermediate data between the end points would provide additional insights on the time path of TFP but are not required. Data for the period preceding the interval to be studied are not required to calculate a robust estimate. Thus the price-based approach would provide consistent, comprehensive assessments of Ontario LDCs' performance with substantially less data; and no data at all on physical capital inputs. (And this may have been the appeal for the CRTC and FCC.) If the framework is specified correctly and the empirical implementation is consistent with that specification, the price-based approach has no additional disadvantages compared to the physical approach.

4. Estimating Total Factor Productivity: the Quantity-Based Approach

In section 3 we developed the two alternative approaches to estimating TFP growth. We developed data supporting both approaches and compared the results over the 2006-2011 period. In this section, we focus on the quantity-based methodology primarily.

We examine the 2000-2011 period as well as sub-intervals. We examine these results vis a vis those developed in the 1st Generation. We note the important similarities. We examine these results vis a vis those developed by PEG. In some important instances we offer explanations of the observed findings to help put the numbers into context. We think such "contextual information" is critical in any effort to formulate future regulatory frameworks, paradigms or parameters based on an assessment of the past.

We also discuss the relevance of the Board's 2000 Decision. This review by the Board entailed an examination of the Ontario TFP research undertaken by Board staff and consultants. The Decision lays out the Board's reasoning regarding the PF (i.e., productivity factor) selected.

And, finally, what about confirmation? Is there some check we can perform to add to our assurance that the estimated TFP growth rates are an accurate reflection of the performance of Ontario's LDCs? In fact, the price-dual TFP methodology reviewed in Chapter 3 can provide such assurance.

I note that the data set used in my analysis is, by and large, generally the full data set as filed by the distributors. This data set differs from that used by PEG in that PEG used estimates of capital additions and capital retirements rather than the actual data filed. PEG has a limited capital series covering 1989-1998 and 2002-2011; for some LDCs, only the latter period of data is available. A further difference is that my analysis is based on the Board's 1st Generation sample of 48 distributors that together served more than 70 percent of Ontario distribution customers. PEG includes all distributors in its sample.

I believe the 4th Generation work undertaken by PEG does *not* have all the data needed for unbiased, robust estimates of either TFP performance or efficiency/cost benchmarking. This is insufficient based on normal applications of TFP analyses.

4.1 PEG Estimated TFP Growth: 2002-2011

Exhibit 4.1 presents PEG's estimated TFP growth rates with varied samples of Ontario distributors. Results are presented for 1) all LDCs excluding Toronto Hydro and Hydro One, 2) all LDCs including Toronto Hydro, 3) all LDCs including Hydro One but excluding Toronto Hydro, and 4) all distributors.

Exhibit 4.1. PEG TFP Estimates (percent) with Varied Sample Combinations of Toronto Hydro, Hydro One, and the Remaining Distributors

	Toronto Hydro and Hydro One Excluded	Hydro One Excluded	Toronto Hydro Excluded	Toronto Hydro and Hydro One Included
2002-2011	0.10	-0.56	-0.81	-1.10
2002-2006	1.11	0.95	0.18	0.20
2006-2011	-0.70	-1.31	-1.65	-2.14

Source: OEB/PEG Documentation and data files.

Note that PEG's 2002-2011 TFP result ranges from 0.10 to -1.10 depending upon the sample of LDCs included. The latter estimate is for the full sample including the largest LDCs. Over the second half of the period covering 2006-2011, PEG's TFP result ranges from -0.70 percent per year for the sample excluding Toronto Hydro and Hydro One to -2.14 percent for the full sample. I would stress that some of these results must be considered in context.

Since at least 2006, a number of LDCs have issued warnings regarding network aging. These distributors are on the record in the Board's forum as having pointed out that they were facing significant cost pressures brought on by the need for high levels of infrastructure investment in the network related to plant aging. They have made the point that without adequate investment in the network, reliability will certainly degrade. And, in fact, as noted in the PWU's RRFE submission[10] some *degradation has already occurred*.

[10] EB-2010-0379. PWU's Submission Concerning Renewed Regulatory Framework for Electricity Transmitters Distributors - Defining and Measuring Performance of Distributors and Transmitters. April 20, 2012.

With respect to costs/inputs, Board staff's expert in this proceeding, PEG, has found that for some distributors the growth in inputs has been *four or five times higher* than the growth in outputs. I note that this is consistent with the distributors' need to address accumulating aging assets. In fact, the actual discrepancy in input versus output growth rates might be even higher.

4.2 Our Estimated TFP Growth Rates: 2000-2011 and 2002-2011

We have estimated a quantity-based TFP covering the whole period since re-structuring, i.e., 2000 to 2011**.** We also note the results of using the abbreviated period employed by PEG, i.e., 2002-2011.

Exhibit 4.2 presents the results of our quantity-based estimates of TFP over both periods.

Exhibit 4.2. TFP Growth (percent): 2000-2011 Over Mixed Regulatory Approaches (i.e. Cost of Service and IR)

	Toronto Hydro and Hydro One Excluded	Hydro One Excluded	Toronto Hydro Excluded	Toronto Hydro and Hydro One Included
2000-2011	0.10	-0.65	NA	NA
2002-2011	-0.60	-1.28	-1.12	-1.46

Source: OEB data and author calculations.

1st Generation had a TFP growth rate of about 0.86 percent per year for the whole period, 1988 to 1997.

What about the post-2000 period? For the period 2000-2011, we find a growth rate of 0.10 percent for the sample excluding Toronto Hydro and Hydro One. Over the shorter period available to PEG covering 2002 to 2011, we estimate a growth rate of -0.60 percent. PEG's 2002-2011 result at 0.10 percent (See Exhibit 4.1), *is 0.70 percentage points higher* than we find using the full set of actual data.

What about for the sample including Toronto Hydro?

For the sample including Toronto Hydro we find an annual growth rate for 2000-2011 of -0.65 percent. For the abbreviated period of 2002-2011 we find a -1.28 percent per year growth rate compared to the substantially higher level of -0.60 when Toronto Hydro and Hydro One are excluded. Unlike the post-2000 results, in 1st Generation we found results that were similar across all distributor sizes (i.e., small, medium, and large).

For our full sample of distributors we find a 2002-2011 growth rate of -1.46 percent. Note in order to include data for Hydro One earlier than in our price-dual estimate over 2006-2011, we have employed the data compiled by PEG for Hydro One. In fact, in this instance PEG's estimate of Hydro One's TFP over 2006-2011 is close to our price-dual estimate for Hydro One. So on that basis we have compiled an all-inclusive quantity-based TFP data base that includes PEG's data for Hydro One. So, for the period 2002-2011, we find that the TFP growth rate ranges from -0.60 to -1.46 percent depending upon the sample of firms included, with the inclusion of the largest distributors lowering the estimates over the whole period.

What about sub-interval performance? Are the results we obtain altered by time period? I note that significant differences between sub-intervals played an important role in the Board's reasoning and TFP decision in 2000[11].

Let's examine the components. We have broken the whole period into sub-intervals: one covering the first five or six years and the second covering the last six years. The former period was largely comprised of a rate freeze, not unlike that which occurred over the 1993-1997 period examined in 1st Generation. The latter period covers the Board's COS filings in 2006 and its two IR terms: 2nd Generation starting in 2007 and 3rd Generation starting in 2009.

What have we found? How do our findings compare to the findings in 1st Generation: how does the rate freeze covering 2000-2004/5 compare with that covering 1993-1997? How does the post-2006 period compare with the 1st half of the decade? How does the post-2006 period compare with the TFP research covering 1988-1997?

4.3 The 2000-2005 Sub-interval

Exhibit 4.3 presents the results of our quantity-based estimates of TFP over 2000-2004/5.

[11] Recall the Board placed a greater weight on the higher incentive rate-freeze sub-interval's TFP then it did on the low incentive COS period. We might also note the former was the sub-interval immediately preceding the 2000 Decision. We discuss this further below.

Exhibit 4.3. TFP Growth for Ontario Electric Distribution Utilities: the 2000-2005 Rate Freeze (average percent per year)

	Toronto Hydro and Hydro One Excluded	Hydro One Excluded	Toronto Hydro Excluded	Toronto Hydro and Hydro One Included
2000-2004	1.09	1.40	NA	NA
2000-2005	0.94	1.00	NA	NA
2002-2005	-0.20	-0.30	0.36	0.54

Source: OEB data and author calculations.

Similar to PEG we find the 2002-2011 period is divided into two sub-intervals with markedly different TFP results. As shown in section 4.1, *neither sub-interval's TFP growth rate approximates the mean growth rate of the whole 2002-2011 period.* It is critical for evaluating performance and especially for setting parameters for 4th Generation that these very distinct sub-intervals are examined. Let us look at the first sub-interval.

TFP growth rate for 2002-2005 was -0.20 percent when the largest two distributors are excluded. Excluding only Hydro One from the sample reduces this further to -0.30 percent. However, for the complete sample we find a 2002-2005 growth rate of 0.54 percent.[12] So, for the period 2002-2005, we find that the TFP growth rate ranges from -0.20 to 0.54 percent depending upon the sample of distributors included.

4.4 The 2006-2011 Sub-interval

What about the second half of the decade?

RAM Implementation by the OEB

Before we examine the observed productivity performance among LDCs, I think it would be helpful to review the rate adjustment mechanisms (RAM) employed by the OEB over this six year period:

- In 2006 the Board initiated a COS review for all LDCs. This was an antecedent effort prior to implementation of the Board's revised IR framework.

[12] Note in order to include data for Hydro One earlier than with our dual estimate over 2007-2011, we have employed the data compiled by PEG for Hydro One.

- This was followed by the implementation of 2nd Generation IR in 2007. All distributors were subject to this IR's RAM in 2007.
- In the following year, 2008, some LDCs were subject to COS reviews. These COS distributors included Toronto Hydro, Hydro One as well as a sample of others.
- In 2009, the Board initiated 3rd Generation IR based on OM&A benchmarking. Some distributors were put under the 3rd Generation plan. Some distributors remained on 2nd Generation rate adjustments. Some distributors were subject to COS reviews. These COS distributors included Toronto Hydro as well as a sample of others but ***not*** Hydro One.
- In 2010, some distributors were put under the 3rd Generation plan. Some distributors remained on 2nd Generation rate adjustments. Some distributors were subject to COS reviews. These COS distributors included Toronto Hydro as well as a sample of others and ***now*** Hydro One.
- In 2011, many distributors were operating under the 3rd Generation plan. Some distributors were subject to COS reviews. These COS distributors included Toronto Hydro as well as a sample of others and ***again*** Hydro One.

In fact, by 2011, some distributors had ***never*** operated under an IR (with the exception of the 2007 RAM). By 2011, some had only operated under IR for a ***single*** year. And, by 2011, some distributors had not yet operated under the 3rd Generation RAM.

Let's look at how the rate regulation was implemented from a distributor's perspective. Exhibit 4.4 presents the year-by-year implementation of rate regulation by the Board for three randomly selected distributors.

Distributor A is under COS in 2006. In 2007, LDC A is subject to the 2nd Generation RAM. In 2008 the utility goes back under COS for that year. In 2009 and 2010 this distributor is subject to the 3rd Generation RAM. In the last year, distributor A is put back under COS. So, over the six year period this distributor had ***three*** years of COS, two years of 3rd Generation RAM, and one year of 2nd Generation RAM.

Exhibit 4.4. Variations in Rate Regulation across LDCs for a Given Year and Across Time for a Given LDC: Selected Ontario Utilities

LDC	2006	2007	2008	2009	2010	2011
A	COS	2nd	COS	3rd	3rd	COS
B	COS	2nd	2nd	COS	3rd	3rd
C	COS	2nd	2nd	2nd	2nd	COS

Source: OEB rate data and decisions.

Distributor B is under COS in 2006. In 2007 and 2008 Distributor B is subject to the 2nd Generation RAM. In 2009, the utility goes back under COS for that year. In 2010 and 2011 this distributor is subject to the 3rd Generation RAM. So, over the six year period the utility has ***two*** years of COS, two years of 3rd Generation RAM, and two years of 2nd Generation RAM.

Distributor C is under COS in 2006. In 2007, 2008, 2009 and 2010 Distributor C is subject to the 2nd Generation RAM. In the last year, "C" is put back under COS. So over the six year period the utility has ***two*** years of COS and four years of 2nd Generation RAM.

Observed TFP Performance: 2006-2011

So we can see that these three LDCs operated under COS between two and three years of the six year period and that two out of the three operated under three different RAMs. What were the results of such a mix of regulatory approaches over the six years covered by these activities?

Exhibit 4.5 presents the results of our quantity-based estimates of TFP over 2006-2011.

Over the 2006 to 2011 period (covering growth starting in 2007 or the start of 2nd Generation), we estimate a TFP growth rate of -0.90 percent per year for the sample excluding Toronto Hydro and Hydro One.

For the sample including Toronto Hydro we estimate a TFP annual growth rate of -2.36 percent for 2006-2011. Annual TFP growth declines to -2.57 percent over the 2008-2011 period, and declines further to -3.10 over 2009-2011.

What about the whole sample? For the full sample including Toronto Hydro and Hydro One, we estimate a TFP growth rate of -2.55 percent. This percent declines to -2.81 over the 2008-2011 period, and to -3.31 percent over the 2009-2011.

Exhibit 4.5. TFP Growth for Ontario Electric Distribution Utilities: the 2006-2011 IR Period (average percent per year)

	Toronto Hydro and Hydro One Excluded	Hydro One Excluded	Toronto Hydro Excluded	Toronto Hydro and Hydro One Included
2006-2011[a]	-0.90	-2.36	-1.76	-2.55
2008-2011[b]	-0.50	-2.57	-1.75	-2.81
2009-2011	-0.80	-3.10	-1.99	-3.31

Source: OEB data and author calculations.
[a] Covers growth starting in 2007. 2nd Generation started in 2007.
[b] Covers growth starting in 2009. 3rd Generation started in 2009.

So what can we conclude? Over the 2006-2011 period we find widespread negative growth in productivity across a broad sample of LDCs. This impact is pronounced, broad based, and persistent. I would expect only a small portion of this result to be caused by the economy.

We see that for the last three years, i.e., the start of 3rd Generation, growth rates are ***consistently negative***.

Observed TFP Performance by Rate Adjustment Mechanism

What can we say about TFP growth over 2006-2011 under the various RAMs? What can we learn by comparing that data (results by RAM) to earlier periods under similar frameworks?

Exhibit 4.6 presents TFP growth results by RAM for un-weighted means.

Let's start with COS. So, taking all the year-by year results for distributors under COS from 2006 to 2011 we find that across all the distributors the average TFP growth rate was -0.30 percent. What about the results for 2nd Generation RAM? Taking all annual TFP results for distributors under 2nd Generation RAM we can find an un-weighted average. This mean TFP growth for 2nd Generation is 0.0. Toronto Hydro and Hydro One were not under 2nd Generation RAM (with the exception of the 2007 RAM).

Exhibit 4.6. Observed TFP Growth (percent) under COS, Rate Freezes, 2nd and 3rd Generation IR: Un-weighted Means

	Cost of Service	**2nd Gen**	**3rd Gen**
	2006-2011	**2007-2010**	**2009-2011**
TFP Growth	-0.3	0.0[a]	-0.9[b]

Source: OEB data and author calculations.

[a]Toronto Hydro and Hydro One did not operate under 2nd Generation RAM (with the exception of the 2007 RAM).

[b]Toronto Hydro did not operate under 3rd Generation RAM. Hydro One results under 3rd Generation are not included in the mean.

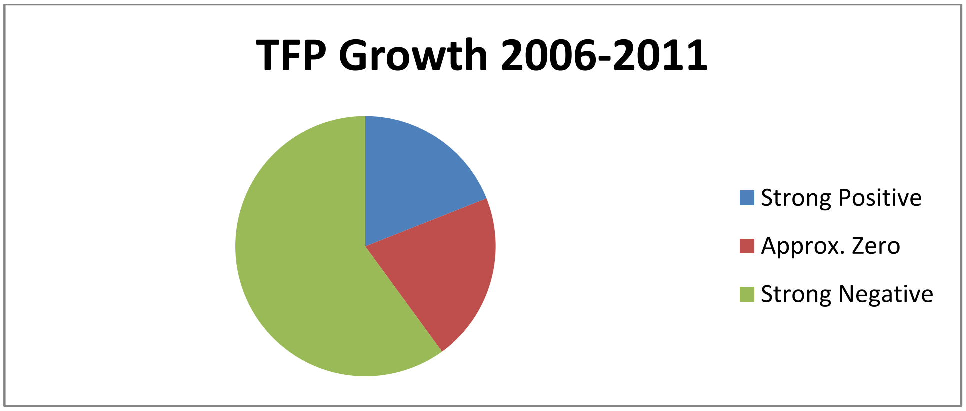
What about the results for 3rd Generation RAM? Taking all year-by-year TFP results for distributors under 3rd Generation RAM we can find an un-weighted average. This mean TFP growth for 3rd Generation is -0.90 percent. Toronto Hydro was not under 3rd Generation RAM. Hydro One results are not included in the mean.

Thus, we can see that the distributors' TFP performance varies between IR frameworks. 2nd Generation has a mean of 0.00 percent versus a mean TFP growth rate for 3rd Generation of -0.90 percent.

How can we summarize our TFP results for 2006-2011?

Exhibit 4.7 presents TFP results by magnitude. We can see that about one-fifth of TFP growth results are strongly positive. About one-fifth of TFP growth results are approximately zero. And, more than half of TFP growth results are strongly negative.

Exhibit 4.7. TFP Size Distribution



Source: OEB data and author calculations.

4.5 Examining the Plausibility of the Results

Is there other research which we could use to assess the plausibility of our findings regarding the TFP performance of LDCs under the 2nd and 3rd Generations? In fact, the findings on the price-dual are directly comparable to an assessment of quantity-based TFP over 2006-2011.

And, not only is the price-dual directly comparable to the 2006-2011 quantity-based TFP performance, it is comparable even though the price-dual relies on a different set of information. The price-dual relies on the approved rates posted on the Board's website for each distributor, for each year. This data is completely independent of the data underlying the quantity-based TFP estimate.

Exhibit 4.8 presents the results of our quantity-based estimates of TFP with our price-dual estimates over 2006-2011.

For the full sample, note the close correspondence between the estimate of quantity-based TFP growth for the full sample and the price-dual TFP. Over the 2006-2011 period the former is -2.55 percent versus -2.41 for the price-dual TFP. Over the 2008-2011 period the quantity-based TFP estimate is -2.81 versus -2.58 for the price-dual TFP. Both methodologies indicate that TFP growth degrades most in the last two years, 2009-2011 Note that while the quantity estimate for the last two years is -3.31 percent the price dual estimate is higher at -3.70 percent.

Clearly, as Exhibit 4.8 indicates, for both samples (Toronto Hydro and Hydro One in and out) both methodologies confirm that aggregate TFP growth for all sub-periods is *strongly* negative over 2006-2011.

Furthermore with Toronto Hydro and Hydro One in the sample both methodologies find that growth rates fall between 0.76 and 1.29 percentage points from the initial sub-interval (2006-2011) to the last sub-interval (2009-2011). Indeed, both methodologies provide very close and comparable estimates.

Exhibit 4.8. Comparing Quantity-based and Price-dual TFP Growth: 2006-2011

	Quantity-based TFP	Price-Dual TFP	Quantity-based Excluding Toronto Hydro and Hydro One	Price-Dual based Excluding Toronto Hydro and Hydro One
2006-2011[a]	-2.55	-2.41	-0.90	-1.30
2008-2011	-2.81	-2.58	-0.50	-0.50
2009-2011[b]	-3.31	-3.70	-0.80	-0.20

Source: OEB data and author calculations.

[a] Covers growth starting in 2007. 2nd Generation started in 2007.

[b] Covers growth starting in 2009. 3rd Generation started in 2009.

For the sample excluding Toronto Hydro and Hydro One we find an estimate of -0.90 for the quantity-based TFP to -1.30 percent for the price-dual TFP from 2006-2011. Estimates across all sub-intervals are negative for both methodologies.

Most importantly, the price-dual TFP approach provides independent estimates of TFP performance that can be used to assess the plausibility of quantity-based TFP estimates. The dual estimate is a much superior assessor relative to a “back-cast” of a quantity-based estimate. The latter cannot provide the same degree of confidence as a form of assessment. Even if one was based on a split sample or split period methodology, the degree of independent information is markedly higher with a dual estimate.

Recall that the data used for the price-dual TFP analysis is completely independent of that relied upon by the quantity-based estimate. The dual uses current rate data as provided by the OEB. The quantity-based TFP estimate requires complete data on multiple inputs and outputs and decades of historical capital data along with its constituent parts (e.g., additions, retirements, etc.). The work underpinning the 4th Generation research has documented the notable and multiple gaps in distribution utility data employed in the quantity-based TFP estimates. Any of these gaps individually in a quantity-based estimate could bias, possibly highly bias, the resulting estimate.

In our case, the quantity-based estimate has all of the required inputs, outputs, and capital components data as filed by the distributors. We should not be surprised therefore, that both estimates, quantity-based and price-dual TFP, are very, very close.

4.6 Divergent Sub-intervals and the Relevance of the OEB's 2000 Decision

Clearly, as Exhibit 4.8 indicates, for both samples (largest LDCs in and largest LDCs out) both methodologies confirm that aggregate TFP growth for all sub-periods is *strongly* negative over 2006-2011. We also know that over the 2000-2004/5 period the results for both samples were strongly positive ranging from 0.94 to 1.40 percent per year.

PEG's report states that PEG favours using the most expansive period. However, in PEG's case, with the more limited time series, that would be 2002-2011. PEG estimates a corresponding TFP growth rate of 0.10 percent (excluding Toronto Hydro and Hydro One). Our quantity-based analysis covers the period 1988-2011. With our more expansive period and complete data set as filed by the distributors, we estimate that TFP growth for the reduced sample is -0.60 percent.

PEG also states that it is not in favour of using different weights for sub-intervals. However, PEG's sub-intervals' results bear no relationship to its full-sample result. Recall, for the sample that excludes Toronto Hydro and Hydro One PEG finds:

- 1.1 for 2002-2006,
- -0.7 for 2006-2011, and
- 0.1 for the overall 2002-2011 period.

The whole is nothing like the parts. If the 0.1 had been used, say for an IR in 2002-2006, the distributors would have benefited and ratepayers would have been disadvantaged. If the 0.1 had been used, say for an IR in 2006-2011, the distributors would have been disadvantaged and ratepayers would have benefited.

The OEB's 2000 PBR Decision

Clearly relying on an overall average growth rate covering highly divergent sub-intervals will provide justification for neither. Are their alternative approaches to such a situation?

Indeed, the Board itself found it in a completely analogous situation in 2000. As part of the research for 1st Generation, Board staff and consultants examined the TFP of Ontario electric distribution utilities over the 1988-1997 period. This information as well as the information on the component sub-intervals was part of the record reviewed by the Board.

Indeed, a similar situation had occurred in the 1980s-1990s with markedly different TFP growth rates found for sub-intervals.

What were the Ontario TFP results reported in the 1999 Board staff analysis? Exhibit 4.9 presents these results.

Exhibit 4.9. 1st Generation TFP Research (percent)

	1988-1993	1993-1997	1988-1997
TFP Results[a]	-0.10	2.05	0.86

Source: OEB data and author calculations.

[a] 48 Utilities representing the vast majority of distribution customers. Almost every large and medium utility (i.e., larger than 50,000 and 10,000 customers, respectively) and a sample of small utilities.

The Board staff/consultant analysis for First Generation found that for the whole period 1988-1997 the growth rate was 0.86 percent per year. However, this aggregate masked a significantly different experience during the two halves of the period. During the 1st half under administrative COS the TFP growth rate was -0.10. This was markedly different from the 2.05 obtained for 1993-1997.

Importantly, the higher growth rate during the 2nd half was consistent around 2.0 percent for all distributors in the sample. Further, performance was similar for large, medium, and small; for older and younger; for high demand growth versus low demand growth; and for newer versus older assets. It is important to note that in the 1988-1997 period the distributors may not have been subject to the cost pressures that they have experienced post de-regulation.

Let's look at the First generation decision by the Board. Concerning PBR incentives the Board noted:

> *By way of commentary, the Board observes that PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. Customers and shareholders alike can gain from efficiency enhancing and cost-minimizing strategies that will ultimately yield lower rates with appropriate safeguards for service quality. Under PBR, the regulated utility will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the Board*[13].

[13] Ontario Energy Board. EB-1999-0034 Decision with Reasons. January 18, 2000. Page 13.

The Decision offered these comments about the appropriate size of the PF (i.e., "level of the base" productivity factor):

> *In assessing a reasonable level for that base, the Board notes that, on the basis of the information provided in the proceeding, the achieved annual average productivity growth for the sample of 48 electric utilities was 0.86 percent for the most recent ten-year period and 2.05 percent for the most recent five-year period. The Board notes the arguments by certain parties that the most recent five-year period ought not to influence the Board's deliberations on the grounds that this period was not representative. Nevertheless the Board considers that some recognition must be given to the results achieved in the most recent five-year period*[14].

On weighting TFP by different weights based on sub-interval performance:

> *The Board has therefore adjusted the base productivity factor by giving a weight of two-thirds to the ten-year average result and one-third to the five-year average result. The Board therefore finds 1.5 percent as the appropriate productivity factor, inclusive of a stretch factor of 0.25 percent*[15].

In essence, the Board weighted the first five-year period by 1/3 and the second five-year period at 2/3, thus giving double the weight to the more recent sub-interval's results.

4.7 Applying Differing Weights to the Post-2006 Divergent Results

Let's see what the composite TFPs are for my and PEG's TFP focusing on the plausibility of a split-weight application. Let's examine the truncated sample first, i.e., the sample without the two largest distributors.

Truncated Sample – Excludes Toronto Hydro and Hydro One

<u>PEG's Results</u>
While PEG reports TFP for the truncated sample of 0.10 for the whole period 2002-2011, PEG's sub-interval results of +1.1 and -0.7 are markedly different and connote completely opposing performances.

If the Board's 2000 Decision split- approach of one-third and two-thirds weights were applied to the sub-intervals (i.e., 2002-2006 and 2006-2011) for 4th Generation, the resulting PF would be about -0.10 percent. In fact, -0.10 percent is not dissimilar from our average annual TFP growth rate for 2002-2011 TFP of 0.10 percent.

<u>Cronin Results</u>
Let's apply the one-third versus two-thirds weighting decision using our TFP results and 2000-2011 period. Recall we found 0.94 and -0.90 percent, respectively for the sub-intervals 2000-

[14] Ontario Energy Board. EB-1999-0034 Decision with Reasons. January 18, 2000. Page 41.
[15] Ibid.

2005 and 2006-2011 With the 2000 Decision weights applied (1/3 to 2000-2005 and 2/3 to 2006-2011) we would have a resulting composite TFP of -0.29 percent.

Using the 2002-2011 period we take 1/3 of -0.2 (TFP for 2002-2005) and 2/3 of -.0.9 to obtain a composite of -0.67 percent. And we note our average 2002-2011 period results of -0.60 percent.

Exhibit 4.10. Alternative TFP Growth Rates: Truncated Sample

	2000-2011 Average TFP	2000-2011 Weighted TFP	2002-2011 Average TFP	2002-2011 Weighted TFP
Cronin	0.10%	-0.29%	-0.60%	-0.67%
PEG	NA	NA	0.10	-0.10%

Source: EB data and author calculations.

So, we end up with a weighted PEG result of -0.10 percent for 2002-2011, versus weighted Cronin results of -0.29 percent for 2000-2011 and -0.67 percent for 2002-2011.

Total Sample – Includes Toronto Hydro and Hydro One

What about the sample including the two large LDCs.

PEG's Results

PEG reports TFP for the total sample of -1.1 percent for 2002-2011. PEG's sub-interval results of +0.20 percent for 2002-2006 and -2.14 percent for 2006-2011 are markedly different and connote completely opposing performances. If the Board's 2000 Decision weights were applied the resulting PF would be about -1.36 percent for 4th Generation.

Cronin Results

Since we are including Hydro One's performance for which we do not have data prior to 2002, we cannot examine the 2000-2011 period. For 2002-2011 we found TFP of -1.46 percent.

Let's apply the one-third versus two-thirds weights to the truncated sub-interval (i.e., 2002-2005 and 2006-2011) TFP results, 0.54 and -2.55 percent, respectively. With the 2000 Decision weights applied we would have a resulting composite TFP of -1.52 percent. And we note our average 2002-2011 period results of -1.46.

Exhibit 4.11. Alternative TFP Growth Rates (percent): Total Sample (inc. Toronto Hydro and Hydro One)

	2002-2011 Average TFP	2002-2011 Weighted TFP
Cronin	-1.46	-1.52
PEG	-1.10	-1.36

So, we end up with a weighted PEG result of -1.36 versus a weighted Cronin result of -1.52.

5. Estimating a Comprehensive TFP: including System Losses and Service Reliability

In section 3 we developed a dual estimate of TFP growth. In section 4, we developed a traditional quantity-based estimate. The latter, however, was based on only three factors: capital, labour, and materials. In presentations made at the January 21st and February 21st 2013 PBR Working Group meetings, I proposed incorporating line loss and reliability in assessments of TFP performance[16,17].

We find that losses vary significantly across distributors. However, this variation is not reflected in the Board's current or proposed IR. In fact, we discuss one distributor which experienced a degradation in its TFP growth from 1.9 to 1.2 when losses are included in the specification. Other similar examples are noted. Distributors found to have improved losses would see their TFP growth increase. However, should losses be included by the Board, LDCs would have stronger incentives to optimize all inputs, including losses.

We present data on a sample of sixteen LDCs and find reliability has declined significantly over 2007/8 to 2011 relative to a baseline of 2005-2007. However, these declines are not reflected in the Board's IR performance rankings or any other measure of performance. As such the Board's regulatory framework does not provide distributors with an incentive to improve reliability. In the past they have had incentives to degrade reliability. This is a critical gap in the IR's framework.

Researchers, regulators, and utilities in North America and in Europe have used Willingness to Pay (WTP) and Willingness to Accept Compensation (WTA) studies for decades. For electricity distributors, these survey-based analyses gauge the value that different classes of customers place on service improvements, degradations, number of outages, length of outages, time of

[16] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010 0379/PWU_Cronin_Jan21_RRFE_Presentation_PBR_WG.PDF
[17] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PWU_Cronin_Feb21_Presentation_PBR_WG.PDF

outage, etc. Ofgem and Norwegian Water Resources and Energy Directorate (NVE) have both employed WTP and/or WTA for a decade to value service not supplied and gauge the efficiency of O&M and capital spending.

In a study conducted for the OEB Pollara finds Ontario customers place a high value on service reliability[18,19]. We have employed these results as inputs to an adjusted TFP estimate. That is, "Customer-valued" changes to service reliability performance have been included with changes in distributors' output over the period examined.

What we stress is that the standard treatment of output in TFP tends to be LDC-centric. That is, customers place no value on, say, line connections; they place value on the continued delivery of power. The treatment of output in TFP needs to be customer-centric. In fact, reliability-adjusted TFP is one approach to more accurately reflect LDCs' performance from the *perspective* of the rate-payer. And, indeed, we find that the incorporation of changes in customer-valued service reliability performance can have a significant effect on the calculated growth or decline in average annual TFP from 2007-2011. For one LDC, the calculated TFP growth goes from 0.20 percent without reliability adjustments to -3.1 percent with such adjustments.

We also discuss the relevance of the Board's 2000 Decision on First Generation PBR[20]. This review by the Board incorporated losses in TFP and in the IPI to optimize incentives. The Decision also laid out the arguments for paying particular attention to reliability following the adoption of IR. We believe the inclusion of reliability is consistent with this admonition and the intent to model TFP as close to LDCs' operating environment as feasible.

5.1 Incorporating System Losses

A 1999 consultant's report and associated analysis prepared for Board staff for First Generation PBR explored alternative specifications for both outputs and inputs[21]. That analysis found losses were a significant share of distribution costs. The analysis further found that losses had been significantly affected by relative factor input prices, incentives, and the elasticity of substitution among LDCs' inputs. Indeed, the research found that the magnitude of losses over time had behaved in a predictable scheme.

[18] 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

[19] 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

[20] http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/dec.pdf

[21] http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/ppp1.html

In the current research, I find that the size of losses varies significantly across LDCs. We also find that losses vary over time and vary based on the relative prices and incentives faced by LDCs. In a higher relative price environment, losses can equal 20 percent of distribution costs.

Clearly, LDCs should be given incentives consistent with the size and significance of these losses. Potential gains should be optimized. Indeed, a sizeable share of the noted improvement in TFP of 0.86 percent adopted by the Board for First Generation PBR was due to improved system losses, especially over the 1993-1997 sub-period.[22]

Historical Performance and Original Intent of PBR Loss Incentive

From 1988-1993, improvements in line losses were found to help offset increases in capital investment among many of Ontario's distribution utilities.[23] Losses averaged about the equivalent of 12–15 percent of the distributors' costs and many utilities responded aggressively to the 40 percent increase in wholesale electricity prices by reducing kWh losses per customer by 27.6 percent. Distribution line losses continued to improve and by 1997, a substantial number of utilities had made significant improvements.

With the deregulation of the electricity industry in 1998, the cost of line losses were included in the electricity charge. This was however, contrary to the original intention of the PBR framework. This removed the direct incentive for distributors to reduce line losses and by 2009, widespread and substantial degradation in line losses had occurred. Some distributors had increases in line losses of over 40 percent.[24] Such treatment of line losses is a very non-green policy: distribution, transmission, and generation resources must be unnecessarily deployed to compensate for the line loss degradation resulting in ancillary costs that are borne by the ratepayers.

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[22] The reduction of distribution line losses will result in efficiency gains and increase value for ratepayers. The Government's energy policy, embodied in Bill 150, the Green Economy and Green Energy Act, 2009 is for the promotion and expansion of energy conservation and to encourage energy efficiency. To seek reductions in distribution line losses therefore is consistent with the Government's energy policy.

[23] F. Cronin and S. Motluk, "Agency costs of third-party financing and the effects of regulatory change on utility costs and factor choices," *Annals of Public and Cooperative Economics* 78:4 2007 pp. 537–565.

[24]EB-2010-0379. Ontario Energy Board Consultation on a Renewed Regulatory Framework for Electricity Transmitters and Distributors. PWU Submission RRFE Performance Initiative – Attachment A. Cronin F.J. Assessing Distributor Incentives and Performance: 2000-2012. http://www.rds.ontarioenergyboard.ca/WEBDRAWER/WEBDRAWER.DLL/webdrawer/rec/339284/view/PWU_Comments_RRFE_0379_20120420.PDF

Ontario Loss Experience and Alberta Comparison

Analysis of the Ontario distributors' historic line loss data indicates that between1995-1997 and 2009 line losses have degraded (i.e. increased) by 33 percent on a customer-weighted basis and 20 percent on a simple average basis.

In comparison, Alberta's high-density LDCs have about 30 percent lower losses than do Ontario high density LDCs: 2.78 for Alberta compared to 3.33 for Ontario. Comparing low-density LDCs, Alberta LDCs have about 70 percent lower losses: 4.6 – 4.95 compared to 6.85 - 8.55 for Ontario.

On aggregate the cost of line losses for Ontario distributors based on an average electricity charge of $0.08 per kWh exceeded $86 million in 2010.[25] Per customer, the *increased losses* noted above currently cost about *$18 a year*. For some customers the yearly cost is over *$32*. And, of course this figure does not include the costs of legacy losses which can be substantial themselves. As we discuss below, total costs of loss can be more than $150 per customer per year.

Applying the 2009 line losses and an average electricity charge of $0.10 per kWh, over the next 5-year period the increase in power losses would be about $541 million on aggregate, or about $113 per customer over the five years. At an average electricity charge of $0.11 per kWh the cost would increase to $595 million on aggregate and $124 per customer over the 5-year period. Customers of distributors with higher than average line losses, would be paying higher amounts to cover the line losses. As an example, customers of a distributor whose 2009 line losses increased by 32 percent on a customer weighted basis compared to 1995-1997 the line loss cost over 5-years would be $155 with electricity at $0.10 per kWh and $171 with electricity at $0.11 per kWh.

The costs of line losses estimated are conservative given the expected increase in the price of electricity over the next five years, as well as the likely increase in electricity consumption as Ontario experiences higher economic growth. The ancillary costs of deploying system resources have not been explicitly calculated in this analysis and would be additional to these amounts. The cost of line losses could in fact easily exceed $750 million over the next five years.

An incentive for line loss reductions could be introduced into the OEB's regulatory framework for the distributors similar to the approach used in Alberta. Enmax Power Corporation's line loss rate fell from 3.02 to 2.83 percent in 2010 following the implementation of an incentive to

[25]EB- 2010-0379. Ontario Energy Board Consultation on a Renewed Regulatory Framework for Electricity Transmitters and Distributors. PWU Submission RRFE Performance Initiative – Attachment A. Cronin F.J. Assessing Distributor Incentives and Performance: 2000-2012. http://www.rds.ontarioenergyboard.ca/WEBDRAWER/WEBDRAWER.DLL/webdrawer/rec/339284/view/PWU_Comments_RRFE_0379_20120420.PDF

reduce line losses under its Formula Based Ratemaking plan. There is a cost that comes with line loss improvements: however, such costs are those that are a result of good investment planning practice that ensure system sustainability and ongoing service quality that stakeholders expect and value.

Examining Losses over Time and across LDCs

Line losses are a substantial share of distribution costs and vary substantially among seemingly similar LDCs.

Let's look at two large urban LDCs (i.e. Utility A and Utility B) for an illustration of cost shares and costs per customer.

Exhibit 5.1 shows data on cost shares (i.e., capital, OM&A, and line losses), total costs per customer and line loss cost per customer.

Exhibit 5.1. Input Costs Shares and Costs per Customer: 2005

	Input Cost Shares			Costs per Customer	
	Capital	OM&A	Line Losses	Total	Line Losses
Utility A	48.7%	36.5%	14.8%	$380.8	$56.4
Utility B	41.9	36.2	21.8	633.6	138.3

According to Exhibit 5.1 Utility A and Utility B have the same share of OM&A but markedly different capital and line loss shares. The difference in total cost share attributed to line losses is 14.8 percent for Utility A versus 21.8 percent for Utility B.

Exhibit 5.2 shows that 2005 line losses was 2.1 percent for Utility A and 2.9 percent for Utility B. Utility A's customers are benefitting substantially from a loss factor which is 28 percent lower than Utility B.

Given the high price of power in 2005 (0.1013 per kWh), the substantially lower loss factor for Utility A translates into about $80 savings per customer. And, note in Exhibit 5.1 that Utility A and Utility B also have markedly different costs per customer: $381 versus $634 in total costs; and, $56 versus $138 in line loss costs.

Line losses vary greatly over time depending on regulatory incentives and prices of electricity as well as other factors such as investment and OM&A.

Let's look at some actual LDC data on costs and losses.

Exhibit 5.2 shows line loss data for three Ontario utilities over the 1988 to 2011 period.

Exhibit 5.2. Line Losses (Percent) for Three Ontario Utilities: 1988 - 2011

	Utility A		Utility B		Utility C		kWh Price
1988	3.7		4.8	$91	3.7		0.0411
1997	2.3		3.1		2.3	$55	0.0581
2005	2.1	$56	2.9	$138	2.9	$119	0.1013
2009	3.3		3.1		3.8	$116	0.0830
2010	3.5	$66	3.0		3.5		0.0861
2011	3.3		3.2		3.5		0.0935

Line losses vary greatly over time depending on regulatory incentives and relative prices (e.g., prices of electricity versus labour or capital). For example, in the exhibit above the cost of losses for Utility C varies by as much as $64 per year per customer (i.e. $55 to $119) or 116 percent in an 8 year period.

LDC line loss management can materially impact TFP performance.

Exhibit 5.3 shows that with improvements in line losses TFP for Utility A increases:

- In the 1988-1997 period, TFP inclusive of losses increases from 0.6 percent per year to 1.0 per year
- In the 1993-1997 period, TFP inclusive of losses increases from 2.1 per year to 3.7 per year
- In the 2000-2001 period, TFP inclusive of losses increases from 0.3 per year to 0.6 per year

Exhibit 5.3. 3-Factor and 4-Factor Total Factor Productivity by Period

	Utility A		
	3-Factor	4-Factor (with Line Losses)	
1988-1997	0.6	1.0	(improved losses)
1993-1997	2.1	3.7	(improved losses)
2000-2011	0.3	0.6	(improved losses)

As seen in Exhibit 5.4, with line loss improvements in the 1988-1997 period Utility B's TFP increases and with the line loss degradation post 2000 its TFP decreases.

- In the 1988-1997 period, TFP inclusive of losses increases from -1.3 per year to -0.9 per year
- In the 1993-1997 period, TFP inclusive of losses increases from 1.6 per year to 1.9 per year
- In the 2000-2011 period, TFP inclusive of losses decreases from 1.9 per year to 1.2 per year

Exhibit 5.4. 3-Factor and 4-Factor Total Factor Productivity by Period

	Utility B		
1988-1997	-1.3	-0.9	(improved losses)
1993-1997	1.6	1.9	(improved losses)
2000-2011	1.9	1.2	(degraded losses)

We see from Utility A and Utility B's actual line loss performance that including this cost input's in TFP analysis can materially affect their respective TFP performance.

This analysis confirms that losses are a critical input. Utilities use information on relative prices, regulatory incentives, and their own understanding of utility operations to make their decisions. These include the composition of the inputs they use in both capital additions and OM&A.

With the Ontario electricity industry structure's lack of incentive for line loss reductions distributors should be given regulatory incentives consistent with the size, the significance, and the consequential impact of these losses. Potential gains should be optimized. As was the intent of the 1st Generation, distribution losses need to be brought into the 4th Generation IR. This would be the preferred outcome from a consumer-centric and a green perspective. It would also reduce future infrastructure requirements.

5.2 Incorporating Service Reliability into TFP

A number of Ontario LDCs have experienced a ***deterioration*** in reliability. I have documented this finding in prior research.[26] I also have proposed incorporating reliability performance in assessments of TFP performance. Many regulators have included reliability standards or

[26] EB-2010-0249. PWU Submission. Service Reliability and Regulation in Ontario. October 29, 2010. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2010-0249&sortd1=rs_dateregistered&rows=200

financial consequences as part of their PBR frameworks. These include both the UK regulator Ofgem, and the Norwegian regulator, NVE.

In fact, for some years now, Ofgem has included side conditions/consequences within its PBR. Ofgem based their service guarantees (i.e., financial penalties) on WTP surveys. NVE has incorporated a statistical, yardstick-benchmarking formulation within the allowed revenue ceiling. These specifications included customer class WTP results from their own surveys.

An alternative approach to embedding service reliability within the PBR framework would be to include reliability performance within the TFP calculation. It would be helpful for the OEB in doing so to have TFP estimates with customer valuations therefore I am providing this information. To understand this, it is informative to document the associated issues surrounding reliability. Specifically:

- How has reliability degraded?
- How can we incorporate this performance in TFP?
- How does this adjustment affect TFP?

This approach would be analogous to the incorporation of line losses in TFP above. Except instead of modifying the factor inputs, we would be modifying utility outputs. But, in general, the procedure would be similar.

SAIDI Performance for Selected LDCs: 2005-2011

Let's look at the actual performance of a sample of five Ontario distributors and focus only on the period 2005-2011. In this analysis, we are focusing on the performance from mid-decade onward, i.e., 2005-2007 to 2011. We are not comparing early post-2000 results or mid-1990s with the most recent past.[27] We will present these results broken into three groups: large, medium-sized, and small LDCs.

We will calculate a baseline based on each LDCs three-year mean of reported System Average Interruption Duration Index (SAIDI). For each group we will report a table of actual means and annual observations. Following that exhibit for each group, we will present a chart depicting each LDCs annual deviation from its mean.

Exhibit 5.5 presents annual SAIDI performance for a select sample of five small LDCs relative to their 2005-2007 mean.

[27] Were we to present data for earlier periods, the degradations would in general be more pronounced. So 2002-2004, would indicate better performance than 2005-2007. 2000-2002, would indicate better performance than 2002-2004. And, 1994-1997, would indicate better performance than 2000-2002.

Exhibit 5.5. SAIDI Performance for Selected Small Ontario LDCs: 2005-2011

Distributor	2005	2006	2007	2008	2009	2010	2011	2005-2007 Average Baseline
A	5.36	4.34	6.50	7.54	9.86	15.86	13.69	5.40
B	0.36	0.78	2.46	10.00	1.65	1.63	9.75	1.20
C	1.24	0.42	2.41	4.08	0.33	0.06	15.39	1.36
D	1.25	4.99	2.19	6.56	3.20	0.71	10.69	2.81
E	4.45	2.48	3.28	2.23	2.14	2.11	8.44	3.40

Blue is < Mean
Brown = 10% > Mean
Red = 25% > Mean
Green = 50% > Mean
Purple = 100% > Mean

Note the preponderance of purple shaded results (100 percent or more above the baseline) in 2011. In fact 9 out of 20 entries (45 percent) between 2008 and 2011 are shaded purple. We also note three entries in red and one in green. So 65 percent of entries over 2008-2011 indicate that SAIDI was 25, 50, or 100 percent higher than the three-year average baseline. Note the predominance of blues in the first three years of the time series, 2005-2007.

Exhibit 5.6 presents the same SAIDI data as in Exhibit 5.5 but expressed as deviations from the three-year mean for each of the five distributors by year. Note the preponderance of smaller deviations in the first three years. Starting in 2008 and especially in 2011, we see deviations that are many times greater than we see in the earlier period. In fact, in 2011 all the distributors have very large positive deviations indicating a substantial decline in service reliability.

Exhibit 5.6. SAIDI Performance Relative to 2005-2007 Mean Select Small LDCs

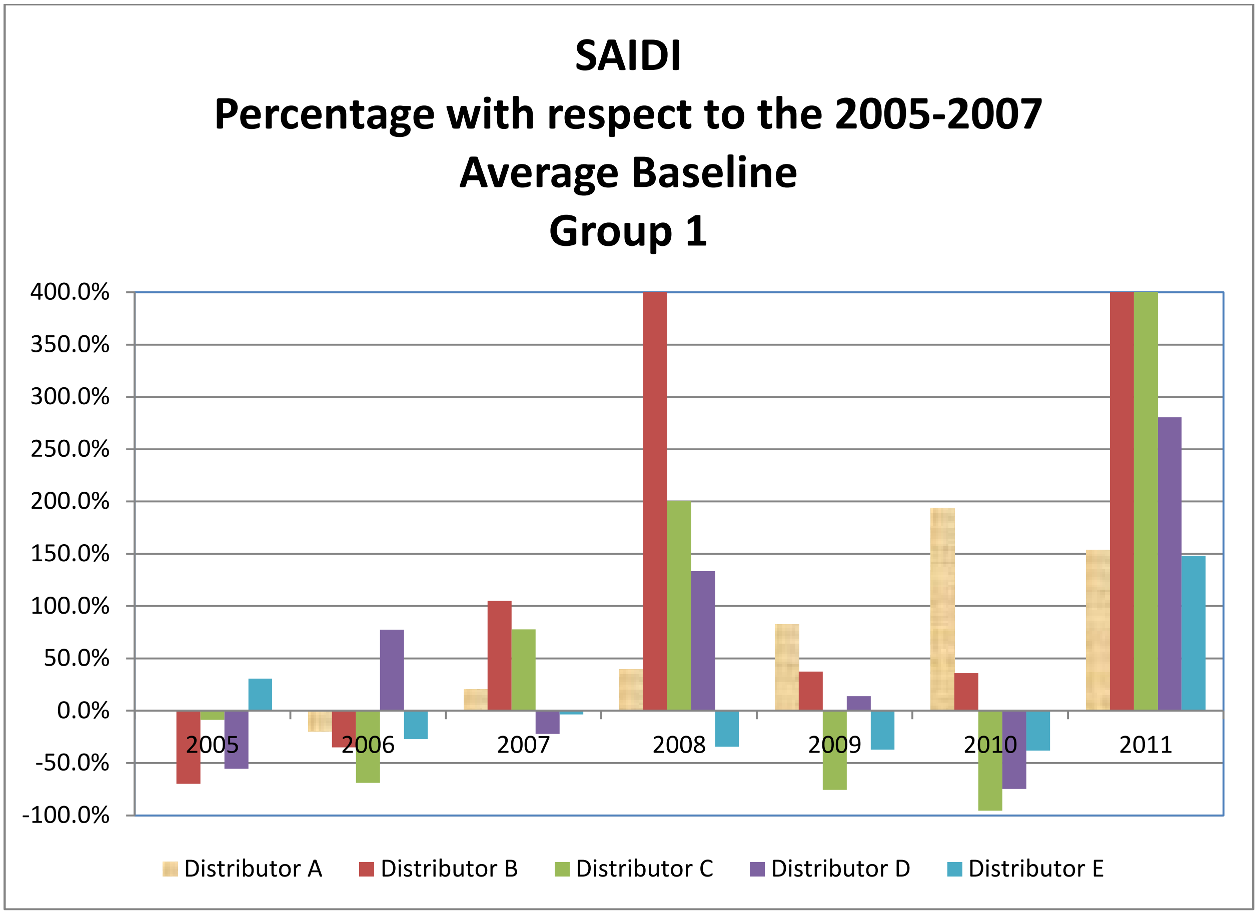


Exhibit 5.7 presents annual SAIDI performance for a select sample of five medium LDCs relative to their 2005-2007 mean.

Exhibit 5.7. **SAIDI Performance for Select Medium Ontario LDCs: 2005-2011**

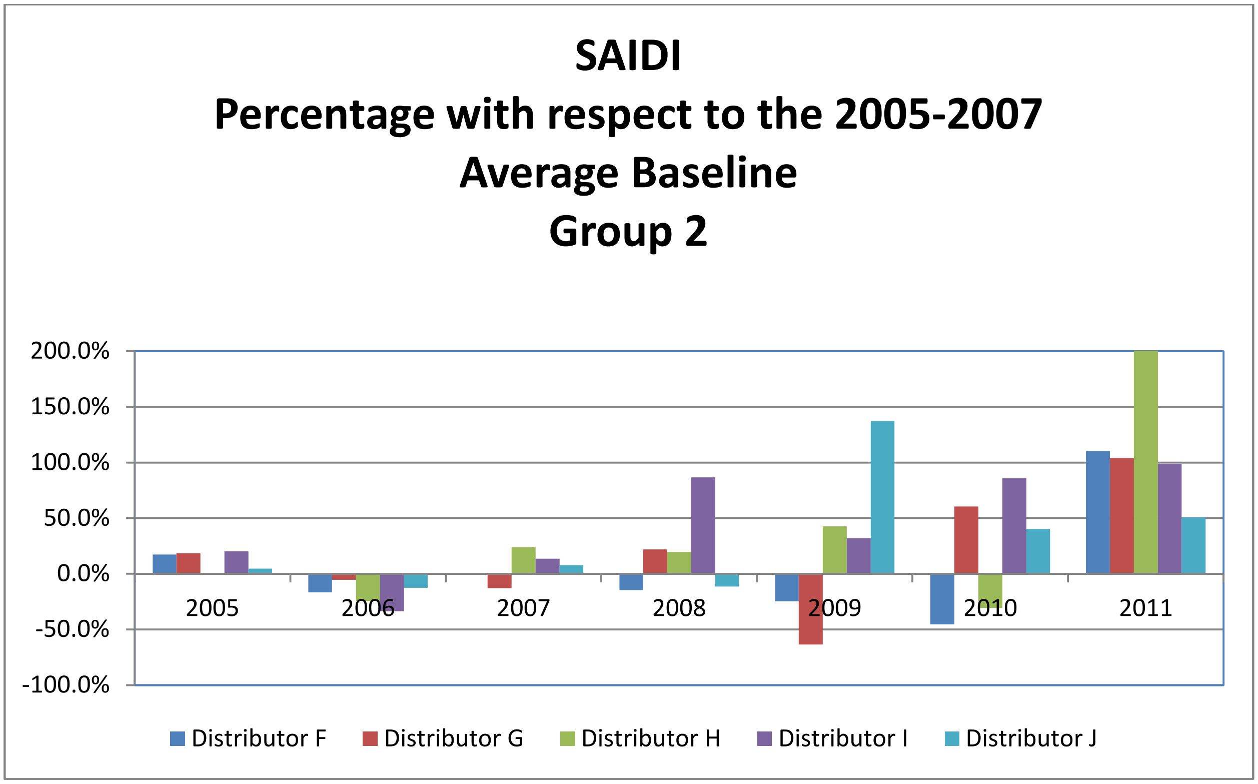
Distributor	2005	2006	2007	2008	2009	2010	2011	2005-2007 Average Baseline
F	3.25	2.31	2.76	2.37	2.09	1.51	5.83	2.77
G	2.08	1.66	1.53	2.14	0.64	2.82	3.58	1.76
H	0.48	0.36	0.59	0.57	0.68	0.33	2.02	0.48
I	1.76	0.97	1.66	2.73	1.93	2.72	2.91	1.46
J	1.94	1.62	2	1.64	4.4	2.6	2.79	1.85

Blue is < Mean
Brown = 10% > Mean
Red = 25% > Mean
Green = 50% > Mean
Purple = 100% > Mean

Again note the preponderance of purple shaded results (100 percent or more above the baseline) in 2011. Four out of the five entries are purple and the last is green (50 percent or more above the baseline). In fact 11 out of 15 entries (73 percent) between 2009 and 2011 indicate that SAIDI was 25, 50, or 100 percent or larger than the three-year average baseline. Note the predominance of blues and browns in the first half of the time series, 2005-2008, with only one green over this period.

Exhibit 5.8 presents the same SAIDI data as in Exhibit 5.7 but expressed as deviations from the three-year mean for each of the five distributors by year.

Exhibit 5.8. SAIDI Performance Relative to 2005-2007 Mean Select Medium LDCs



In Exhibit 5.8 again note the preponderance of smaller deviations in the first three years. Starting in 2008 we see an almost monotonic worsening of performance deviations. In 2008, 2009, 2010, and 2011, we see deviations that are many times greater than we see in the earlier period. Note in particular the magnitude of the degradation. In fact, in 2011 all the distributors have very large positive deviations indicating a substantial decline in service reliability.

Exhibit 5.9 presents annual SAIDI performance for a select sample of six large distributors relative to their 2005-2007 mean.

Exhibit 5.9. SAIDI Performance for Selected Large Ontario LDCs: 2005-2011

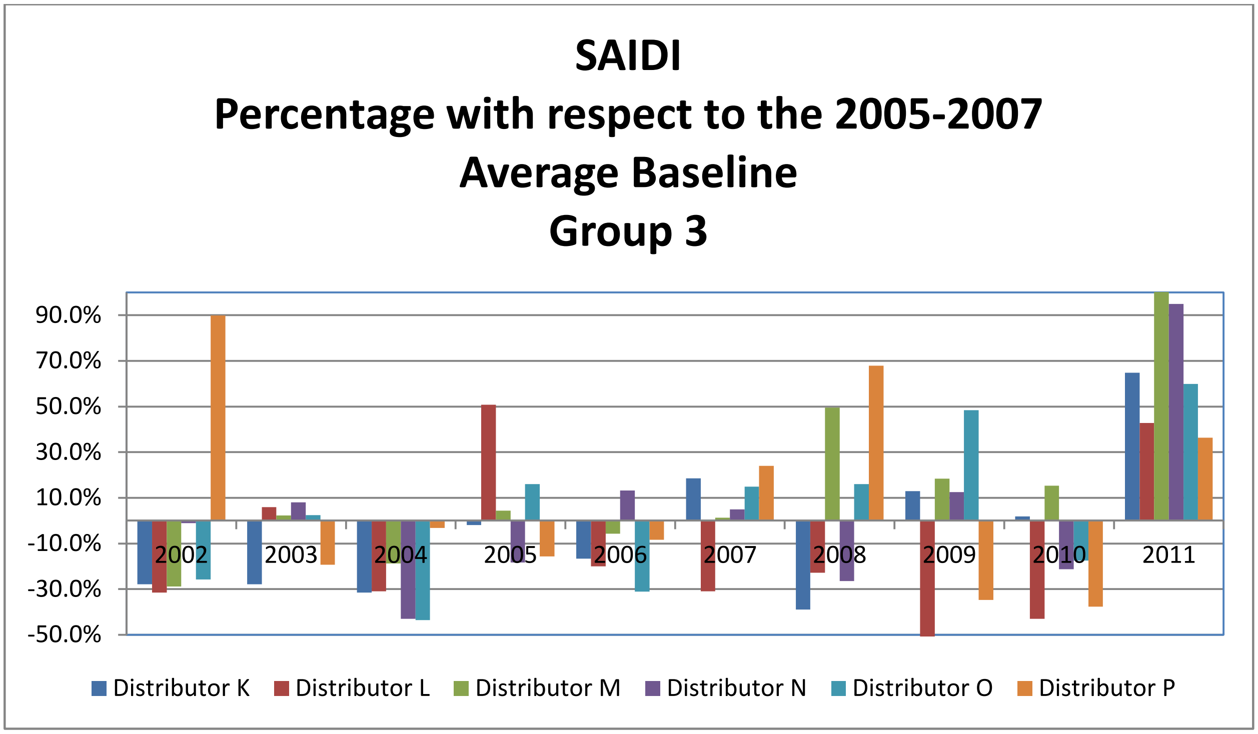
Distributor	2005	2006	2007	2008	2009	2010	2011	2005-2007 Average Baseline
K	0.53	0.45	0.64	0.33	0.61	0.55	0.89	0.54
L	2.62	1.39	1.2	1.34	0.55	0.99	2.48	1.74
M	1.04	0.94	1.01	1.49	1.18	1.15	2.25	1.00
N	1.09	1.51	1.4	0.98	1.5	1.05	2.66	1.33
O	1.11	0.66	1.1	1.11	1.42	0.79	1.53	0.96
P	1.15	1.25	1.69	2.29	0.89	0.85	1.86	1.36

Blue is < Mean
Brown = 10% > Mean
Red = 25% > Mean
Green = 50% > Mean
Purple = 100% > Mean

Note the degradation across the board in 2011. We see two results at 100 percent or more above the baseline, two results at 50 percent or more above the baseline, and two results at 25 percent or more above the baseline. Note in fact that 14 out of 24 entries (58 percent) between 2008 and 2011 are 10, 25, 50 or 100 percent above the mean. On the other hand, note the predominance of performance less than or 10 percent above the mean in the first three years of the time series, 2005-2007. Over the 2005-2007 period, only six out of 18 (33 percent) are above the mean indicators. And, over this period we also note not a single entry 100 percent above the mean and only one entry at 25 percent and one 50 percent above the mean.

Exhibit 5.10 presents the same SAIDI data as in Exhibit 5.9 but expressed as deviations from the three-year mean for each of the six distributors by year.

Exhibit 5.10. SAIDI Performance Relative to 2005-2007 Mean Select Large LDCs



In Exhibit 5.10 we again note the preponderance of smaller deviations in the earlier years, 2002-2006 (note in this chart we are starting in 2002). In fact, note the preponderance of negative deviations in the first three years denoting performances better than the mean for most of the distributors. Starting in 2007 (and except for 2010) we see an almost monotonic worsening of performance deviation. In 2008, 2009, and 2011, we see deviations that are many times greater than we see in the earlier period. Note in particular the magnitude of the degradation. In fact, in 2011 all LDCs have very large positive deviations indicating a substantial decline in service reliability.

Developing a More Customer-centric Measure of Utility Output

<u>Utilities, IR, and Reliability</u>

The potential adverse impact of IR on utilities' operations and ultimately on reliability has been known for some time.

The OEB's 1st Generation PBR Stakeholder Implementation Task Force (Implementation Task Force) dealt at length with these issues. Its Final Report is quite instructive. The implementation Task Force concluded that utilities would face increased profit motives under IR. It would not be unreasonable to expect the Ontario utilities to react to these increased incentives. Ultimately the OEB implemented PBR.

The Implementation Task Force noted the dilemma involved in moving to PBR.[28] While a utility would face greater incentives to eliminate embedded inefficiencies likely accumulated under COS, the regulator could not easily quantify the potential level of allocative inefficiency (i.e. cost allocation between OM&A and capital).[29] Some participants pointed to the "yardstick competition" being implemented in the UK, Europe, and Australia and argued that such models should be adopted.[30]

In fact, the Board noted its own concerns and cautions regarding the implementation of First Generation PBR as follows:[31]

> *Any reduction in the quality and/or reliability of a service represents a reduction in the value of that service. Therefore, as part of its function in regard to approving or fixing just and reasonable rates, the Board has a responsibility to oversee that service quality is preserved and improved… the Board favours the minimum standards proposed in the draft Rate Handbook for first generation PBR. The Board notes that these standards represent the minimum acceptable performance; a utility should continue to establish its operating performance at any level better than the minimum standard, taking into consideration the needs and expectations of its customers and of cost implications.*

However, it seems apparent that the OEB's standards, monitoring, and reporting requirements were not sufficiently robust to mitigate lowered reliability.

Researchers and regulators have looked at this issue.

In fact, research on US LDCs has confirmed that what happened in Ontario also happened in similar situations in the US. IR induced imprudent curtailments in OM&A have been shown to significantly lower LDC reliability. Ter-Martirosyan (2003) examined the effects of IR on electricity distributors' OM&A and service quality.[32] The author uses 1993 – 1999 data from 78 major US electric utilities from 23 states. Ter-Martirosyan finds that IR is associated with a reduction in OM&A expenditures and that reduced OM&A activities are associated with an

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[28] See Report Of the OEB, *PBR Implementation Task Force*, May 1999, at: http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/implemnt.pdf

[29] Because they were not for profit the earned returns were reinvested to avoid debt, rather than returned as rebates to customers. That was the decision of local commissions who took pride in having a debt-free utility. Commissioners were either publicly elected reps or appointed by the city**.**

[30] Subsequently, we examined PBRs implemented in the U.K., Australia and Europe. These PBRs generally benchmark on partial costs and examine only a minority of inefficiency. They create sizeable distortions in efficiency rankings: *individual utilities could experience errors in rankings of 20, 30 or even 40 percent.* See F.J. Cronin & S.A. Motluk, "Flawed Competition Policies: Designing Markets with Biased Costs and Efficiency Benchmarks," *Review of Industrial Organization*, Vol.31, No. 1, Aug 2007.

[31] OEB Decision on PBR for Electricity Distributors, RP-1999-0034, January 18, 2000, pp.50-53.

[32] Ter-Martirosyan, A., *The Effects of Incentive Regulation on Quality of Service in Electricity Markets*, George Washington University Dept. of Economics Working Paper, Presented at International Industrial Organization Conference, North Eastern University, Boston, 2003.

increase in SAIDI. Importantly Ter-Martirosyan's analysis concludes that the incorporation of strict reliability standards with financial penalties into IR can offset the tendency of plans without standards and penalties to result in imprudent cuts in critical OM&A activities.

Dr. Kwoka, who also published work with Ter-Martirosyan depicting the adverse consequences of IR, has also done his own research. He also stresses the clear danger of IR incentives on reliability.

> *One neglected issue in these evaluations of restructuring is any possible effect on service reliability... Such effects would not be surprising, as restructuring has replaced the vertically integrated utility's "obligation to serve" with contractual arrangements and information… This altered structure and incentives indisputably can affect outcomes, as is evidenced …by studies of the quality effects of incentive regulation in electricity and other markets…*[33]

European regulators have undertaken extensive work in this area. For example, the Council of European Energy Regulators (CEER) noted in its 3rd Benchmarking Report on the Quality of Electricity Supply (2005):

> *…Price-cap regulation without any quality standards or incentive/penalty regimes for quality may provide unintended and misleading incentives to reduce quality levels. Incentive regulation for quality can ensure that cost cuts required by price-cap regimes are not achieved at the expense of quality….The increased attention to quality incentive regulation is rooted not only in the risk of deteriorating quality deriving from the pressure to reduce costs under price-cap, but also in the increasing demand for higher quality services on the part of consumers…. a growing number of European regulators have adopted some form of quality incentive regulation over the last few years.*[34]

Recent research in the U.K. and Poland found allocative inefficiency increased under IR, utilities were simply not reacting to the correct price signals, e.g., under valuing the loss of load to customers.[35] It is not surprising then, that the Ontario IR experience worsened the allocative inefficiency (see section 6 below) as well as reliability of the distributors.

Indeed, Ontario's large distributors have warned the Board for some time about the "aging infrastructure and the significant increases that would be required in capital spending in the next

[33] Kwoka, J. "Restructuring the U.S. Electric Power Sector: A Review of Recent Studies, Review of Industrial Organization, (2008), p.193.

[34] CEER, Third Benchmarking Report of Quality of Electricity Supply, 2005, p.31.

[35] Cullmann., A. & Hirschhausen., C.V., (2006), From Transition to Competition – Dynamic Efficiency Analysis of Polish Electricity Distribution Companies, Working paper, Dept. of International Economics, DIW Berlin, May 24, 2006. Yu, William, et al, "Incorporating the Price of Quality in Efficiency Analysis: the Case of Electricity Distribution Regulation in the UK," July 2007.

decade."[36] These LDCs have been explicit in their warnings: "*The Board must address this situation or the ability of LDCs to maintain reliable and cost effective distribution systems will be impaired*."[37] The largest LDCs in Ontario filed evidence detailing the aging infrastructure and the capital budgets necessary to sustain their networks.

For example, defective equipment was responsible for 27 percent of Hydro One's System Average Interruption Frequency Index (SAIFI) for the period 2005-2008.[38] According to Hydro One, this performance could be improved by improving programs and increased funding[39]. Hydro One has indicated that it has deferred large numbers of system defects since 2005 and that while this "has not, to date, resulted in an increase to equipment caused outage levels" Hydro One is of the view that this situation cannot be sustained indefinitely.[40]

Clearly, the degradation we have seen in Ontario's composite SAIDI is consistent with such deficits in LDC capital budgets.

<u>Utilities, IR, and Regulatory Responses to Bad Incentives</u>

Regulators have put in place long-standing policies to deal with the reliability problem under IR.

Ofgem

Six years ago Ofgem noted its own IR-financial incentives program for service quality had been running for five years. In an October 2007 report on Electricity Distribution Quality of Service, Ofgem states:

> *Ofgem considers quality of service to be one of its key priorities in network regulation…2006/07 was the fifth year that the DNOs [Distribution Network Operators] faced financial incentives on their quality of service performance…*[41]

For many regulators, customer-based surveys, especially of WTP, have been the foundation of their IR-incentive programs on service reliability.

In Great Britain, earlier data from 1999 was used to set some of the initial values for penalty payments. This was the Accent Report on WTP.[42] More recently Ofgem updates on customer

[36] For example, Coalition of Large Distributors, "*Incentive Regulation-Business Considerations*," Presentation to OEB Technical Conference, EB-2006-0089, September 21, 2006.
[37] Ibid.
[38] EB-2009-0096, Exhibit A, Tab 4, Schedule 1, p.20, Figure 5.
[39] Ibid, Exhibit H, Tab 6, Schedule 1, p.2.
[40] Ibid, Tab 1, Schedule 21.
[41] Ofgem, 2006/07 Electricity Distribution Quality of Service Report, Oct 31, 2007, p.1.
[42] Ofgem, Consumer Expectations of DNOs and WTP for Improvements in Service Report, Prepared by Accent Marketing & Research, June 2004.

reliability valuations were used to revalue the payments[43]. For example, under standard GS2, a distributor who failed to restore power within 18 hours under normal conditions would face a penalty of 50 pounds for residential customers and 100 pounds for non-residential customers. This penalty would increase by 25 pounds for each additional 12 hours of non-service. Similarly for standard GS2A, a customer that experiences four or more interruptions each lasting three or more hours that occur in any single year (1 April – 31 March) , would be eligible for a payment of 50 pounds. In this way, the regulator tries to induce the distributor to factor in the customers' costs and consequences from lessened reliability.

Besides, Ofgem, regulators in Norway, Italy and Sweden among others have conducted various studies to ascertain customers' satisfaction with distribution performance or the value placed on reliability. These regulators have used WTP studies to gauge the value customers place on reliability and the amount they would be willing to pay for service improvements. Some of these regulators have taken this WTP information and explicitly incorporated the values into their distribution price regulation.

NVE

NVE recent developments with its supply quality benchmarking are discussed in "Quality of Supply Regulation – Status and Trends," by Kjell Sand, Knut Samdal, and Helge Seljeseth, researchers at SINTEF Energy Research. The authors note:

> *Recent deregulation of electricity markets around the world and subjection of electricity networks to economic Performance-Based- Regulation regimes pose a challenge to assure efficient provision of quality of supply by the regulated network monopolies. Absence of explicit regulatory framework for assuring quality of supply creates perverse incentives for the regulated network monopolies to reduce quality to meet the budgetary constraints implicit in the performance based regulatory regimes. This can over time lead to declined quality of supply.*
>
> *To counteract such consequences, the network companies are being increasingly subjected to regulatory regimes that explicitly take into account the quality of supply to the consumers. One example is the Norwegian regulation scheme CENS (Quality adjusted revenue caps), where the network companies' revenue caps are adjusted in accordance with the customers' interruption costs… (Sand, et al, p 1)*

NVE found that aggregate WTP values typically exceeded the total OM&A budgets of the LDCs. And, the WTP totals were about 60 – 75 percent of investments.

What we find, then, is that a broad and deep body of work has been compiled on IR-incentive programs and WTP. Some of the WTP research for LDCs goes back decades. Much of it has been conducted in North America.

[43] Ofgem, RBA/DPCR4/GOSP 10/22/04 "Open Letter on Ofgem's Proposal to Implement Revised Standards of Performance Arrangements for Electricity Distributors"

OEB

And, in fact, the OEB has undertaken a WTP survey of its own. I will refer to this as the Pollara report.[44] I have commented on this report previously.[45] Here, I will just note the critically important findings contained in the Pollara regarding WTP and customers' extreme aversion to degradations in their service reliability.[46]

Yes, Pollara reports that 58 percent of residential customers are unwilling to pay more for better service. But, Pollara also reports that 42 percent of customers are willing to pay more. Among these latter, respondents are willing to spend $16.20 on a monthly basis for improved reliability.

It would be surprising if respondents were not cost conscious; I am not sure this is telling the Board and stakeholders anything new. More to the point, about 2 million customers are willing to pay more for improved reliability. The average of this increase would be about $194.40 per year. Should the preferences/experiences of these 42 percent or 2 million customers be ignored?

In a study I conducted in 1982 for the US EPA on the benefits of improved water quality (Cronin, 1982), I examined the presence and extent of Strategic Bias among a 2000-household survey of water quality.[47] I found that Strategic Bias is statistically significant in that analysis. The size of the bias ranged from about 10 to 25 percent.

Now let's look at what we can make out of the OEB's WTP survey.

The Pollara and Ofgem WTP Studies

The Pollara (2010) study results are generally quite similar to the results reported by Ofgem (2004) with respect to customers' WTP. However, with respect to outage experience, we should note that a much greater percentage of residential and business customers in the UK reported no

[44] Pollara, Electricity Outage and Reliability Study Consumer Component, September 2010; Electricity Outage and Reliability Study Business Component, September 2010.

[45] Cronin, F., Service Reliability and Regulation in Ontario, October 29, 2010.

[46] Three important issues were unexplored in the Pollara report (really a presentation): 1) the WTP and WTA questions were badly phrased and undefined; 2) are the expressed WTP's correlated with the customers' outage experience About 40 percent of respondents experienced four or more outages a year. No information on respondents' locations was provided; 3) another question that is not addressed in Pollara's results is whether respondent gaming and the free rider problem has been addressed. Fundamental to the survey results is the lack of any reported attempt to deal with Strategic Bias or respondent gaming. Economists with experience in WTP studies are aware that some respondents will explicitly understate their actual WTP in the expectation that that response might affect decision makers. Distribution service is similar to a "common good"; upgrades can benefit many customers simultaneously and some respondents may hope for a "free ride". Some economists have labeled "0s" and other extreme bids as protest bids and conducted research accordingly.

[47] F. Cronin, *Valuing Nonmarket Goods through Contingent Markets,* Pacific Northwest Laboratory (a US DOE National Energy Lab) for the US Environmental Protection Agency, September, 1982.

outages than the percentage of customers in Ontario without cuts in power. Customers in the UK also reported both fewer outages and shorter outages. For example:

Customers in the UK had many fewer outages.

- **Ofgem: number of outages**
  - **62%** of urban households had experienced no outages;
  - for the 38% with outages: 53% had only one outage, 25% had two outages;
  - **40%** of rural households had no outages; for those with outages, 36% had only one outage, 29% had two
- **Ontario: number of outages**
  - **30%** of total households had experienced no outages;
  - for the 68% with outages, the mean number of outages is 4.78

Customers in the UK had much shorter outages than did customers in Ontario.

- **Ofgem: length of outage**
  - Urban household outage length is 1.35 hours;
  - Rural household outage length is 2.27 hours
- **Ontario: length of outage**
  - Household Survey response is 2.79 hours
  - OEB Yearbook statistics is higher: 3.96 hours (2009), 3.44 hours (2010), 7.19 hours (2011)

For businesses in the two jurisdictions, the experience is similar.

The Ofgem survey reports that 54 to 60 percent of businesses (by size class) had experienced no outages. For those with outages, the average number of outages is 2.9 with an average length of 2.6 hours. In Ontario, only 35 percent of businesses had experienced no outages. For those with outages, the average number of outages is 4.8 with an average length of 3.6 hours.

Now what about the WTP findings?

Pollara finds 42 percent of residential customers would pay for improvement. Among yes respondents, the average is $16.20 per bill or $194.40 per year. The average across all Ontario customers is $82, or about $7 per month. Ofgem finds 46 percent of residential customers would pay for improvement. Ofgem finds WTP per customer is $93 to $138 (for 1 hour improvement in 2002 depending on the exchange rate). The Ofgem finding would translate into an $8 - $12 per month increase. Clearly the OEB and Ofgem WTP findings are very consistent.

Ofgem reports business customers value such an improvement at 7 percent to 10 percent of their distribution bill, or $8,888 across all classes.

What about the WTA findings?[48]

Of critical importance, Pollara finds 57 percent of residential customers in Ontario would be unwilling to accept any compensation in return for degraded service. For the small proportion of respondents willing to accept compensation for degradation, the average value offered was $27.90 per bill or $334.20 per year. *This would be the minimum value in converting to an overall residential customer average since value for customers unwilling to accept compensation would by definition be higher but is otherwise not known.*

Note that the average LDC distribution bill amount in Ontario is $28.38 per month (2009). We can see from the Pollara survey results that customers' value degradation loss as equivalent to what they pay for distribution. Customers have little regard for the artificial "boundaries" drawn by policymakers and regulators which now separate generation, transmission, and distribution. It is clear that customers do not value the lines, only the power (contrary to LDCs which have costs whether power is being supplied or not). On the other hand, regulators seem engrossed in the exact opposite; questioning infrastructure investments because they "seem" high relative to the historical costs allocated to distribution in the restructuring.

Some comments have been offered that the WTP/WTA findings seem too high, especially in the aggregate. Two comments are worth noting.

First, NVE reports that aggregate WTP is slightly higher than aggregate O&M costs; WTP is about 60 - 75 percent of investment. Based on aggregate Ontario data using OM&A or capital budget, numbers would imply that WTP equaled $25 per customer per month, i.e., 75 percent of Ontario LDCs' investments would equal $25 per customer per month. Basically, identical to the results reported in the OEB's WTP survey.

Second, distribution rates in Ontario are significantly lower than those in the UK and the US. Recall the average distribution bill is $28 per month. This is significantly less than the UK or a sample of US "peers". UK monthly distribution costs are about $50 - $60 or about double those in Ontario.[49] US distribution rates are quite similar, typically being around $50+ per month.[50] Let's call the US rates in the vicinity of 60 percent higher than Ontario, with some notably more than that. So, the expressed WTP in Ontario may appear high because the distribution rates are so low. Again, customers' WTP/WTA have nothing to do with distribution costs or rates. The WTP/WTA is a reflection of customers' values for continued (reliable) service and what uses it is applied to.

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[48] Ofgem reports that WTA results were similar to WTP results.

[49] UK residential distribution costs are reported as 376 pounds per year in the report. Approximately $600 - $700.

[50] Of the 10 U.S. LDCs examined, only 1 LDC has rates in the $30s per month, 5 LDCs are in the $40s per month, and 4 LDCs are in the $50 per month. The high rounds to $60 per month.

Pollara finds Ontario customers place a very high value on the maintenance of service. Pollara finds Ontario business customers place an even higher value on the maintenance of distribution service*. 62 percent of business customers in Ontario would be unwilling to accept any compensation in return for degraded service.* For the small proportion of respondents willing to accept compensation for degradation, the average value offered was $125.1 per bill or $1501.2 per year. *This would be the minimum value in converting to an overall business customer average since the value for customers unwilling to accept compensation would by definition be higher but is otherwise not known.*

Developing a More Customer-centric Measure of Utility Output

Traditionally, researchers have characterized the output of LDCs by such measures as number of customers, kWh, and in the case of PEG, available peak capacity. But these features convey little regarding the value that end-users place on the continued delivery of power. What we stress is that the standard treatment of output in TFP tends to be LDC-centric. The traditional research and the regulation associated with it place no value on the very items most valued by customers. That is, customers place no value on, say, line connections; they place value on the continued delivery of power.

Researchers, regulators, and utilities in North America and in Europe have used WTP and WTA studies for decades. For electricity distributors, these survey-based analyses gauge the value that different classes of customers place on service improvements, degradations, number of outages, length of outages, time of outage, etc. Ofgem and NVE have both employed WTP and/or WTA for a decade to value service not supplied and gauge the efficiency of O&M and capital. Pollara finds Ontario customers place a high value on service reliability. We have employed these results as inputs to an adjusted TFP estimate.

The treatment of output in TFP needs to be customer-centric. In fact, reliability-adjusted TFP is one approach to more accurately reflect LDCs' performance from the *perspective* of the rate-payer.

Supplementary TFP Estimates with Customer Valuations

In section 5.2 we presented data on a sample of sixteen distributors and find reliability has declined significantly over 2007/8 to 2011 relative to a baseline of 2005-2007. However, these declines are not reflected in the Board's IR performance rankings or any other measure of performance. LDCs therefore have no incentive to improve reliability. In the past they have had incentives to degrade reliability. This is a critical gap in the IR's framework.

Let's examine the consequences of incorporating information on reliability performance within a TFP calculation.

In adjusting TFP for reliability, we used reported changes in service reliability together with the Pollara reported WTP and WTA for improvements and degradations. These "customer valued" improvements/decrements were then weighted with changes in the reported LDCs' outputs.

In Exhibit 5.11 we consider four examples of TFP estimates adjusted for degradations in reliability.

Exhibit 5.11. TFP Growth Estimates Adjusted for Changes in SAIDI[a] : 2002 – 2011

Utility A		Utility B		Utility C		Utility D	
w/	**w/out**	**w/**	**w/out**	**w/**	**w/out**	**w/**	**w/out**
-3.4	**-0.2**	**-0.9**	**-0.6**	**-1.9**	**-0.3**	**-3.1**	**0.2**

[a] **w/** means TFP has been adjusted; **w/out** means no reliability adjustment

And, indeed, we find that the incorporation of customer valued service changes can have a significant effect on the calculated growth or decline in average annual TFP from 2002 - 2011.

6. Estimating Efficiency with DEA

A plethora of studies have used DEA to estimate the relative efficiency of electricity distribution systems (Weyman-Jones, 1991 and 1992; Førsund and Kittelsen, 1998, and Kumbhaker and Hjalmarsson, 1998). Such yardstick approaches have also been employed by regulators in the design of regulatory mechanisms. The Norwegian regulator NVE (Grasto, 1997), the Dutch regulator DTe (DTe, 2000) and the NSW Australia regulator (IPART, 1999) have all employed DEA to benchmark electric distribution utilities and establish parameters of alternative regulatory frameworks. The California Public Utility Commission relied upon a DEA benchmarking to evaluate Pacific Gas and Electric's (PG&E) efficiency. The U.K. regulators in the UK have also examined and employed DEA.

6.1 Benchmarking Techniques: External, Fixed Benchmarks

As part of electric sector restructuring, regulators have employed two broad approaches *to externally establish fixed performance benchmarks* for utilities under IR. 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.

Second, implementations in Europe and Australia and some later North American IR implementations have often relied on peer-based, “yardstick” techniques, both nonparametric and stochastic. Production frontier (i.e., best performance) techniques like DEA have been used in New South Wales, the United Kingdom, Finland, and the Netherlands, among numerous other jurisdictions. DEA studies have been filed in regulatory proceedings in California and Maine. Stochastic techniques have been used in the United Kingdom and Ontario.

6.2 Yardstick Benchmarking Techniques

During the past decade, a number of studies have used peer group benchmarking to estimate the relative efficiency of electricity distribution systems. These studies have been done primarily in Europe and Australia. Indeed, peer group benchmarking, often employing DEA, has been used by regulators worldwide to establish performance targets as part of electric sector restructuring.

DEA is a non-parametric approach to estimating production frontiers using linear programming techniques. It has been widely adopted by regulators to estimate efficiency. Parametric or stochastic techniques can also be applied in benchmarking. These include standard regression analysis like ordinary least squares (OLS), “corrected” OLS, and stochastic frontier analysis (SFA).

DEA estimates a production frontier by constructing a non-parametric piecewise linear convex hull on outputs and inputs, and then calculating efficiencies relative to the frontier. The approach was originally developed in the 1950s and further extended in the 1970s and 1990s.

Input-Oriented Technical and Allocative Efficiency

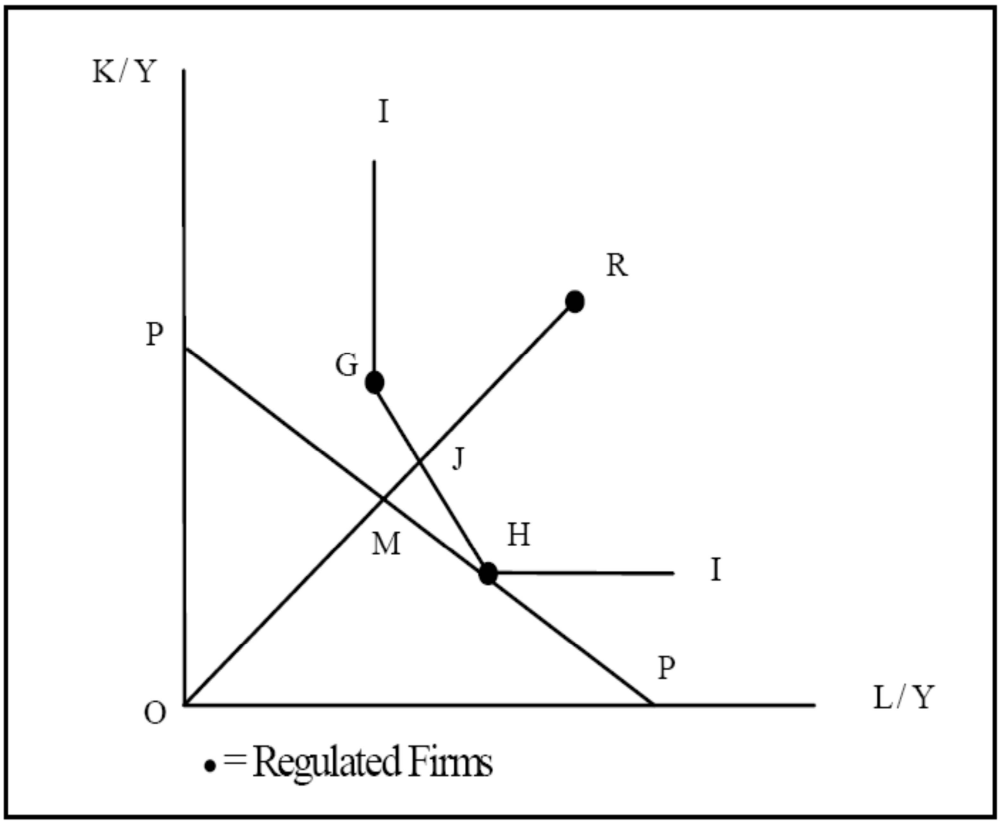
Exhibit 6.1 presents an input-oriented model with constant returns to scale. Three firms (G, H, R) use two inputs (capital K, labour L) for a given output Y. The vertical and horizontal axes represent the capital and labour input per unit of output respectively and the line PP shows the relative price of the two inputs. Firms G and H form the efficient frontier that envelops the less efficient firm R.

The technical and allocative efficiencies of firm R relative to the frontier can be calculated from OJ/OR and OM/OJ ratios respectively. Technical efficiency measures the ability of a firm to minimize inputs to produce a given level of outputs. If TE = 1, the firm is fully technically efficient and is producing on the isoquant II′[51] (for example, point J). Allocative efficiency reflects the ability of the firm to optimize the use of inputs given the price of the inputs; and the allocative inefficiency represented by the distance MJ, which is the savings the firm could realise if it produced at point H. Obviously, the measurement of allocative efficiency requires information on relative input prices.

[51] II′ represents the unit isoquant of the efficient firm(s). Regulators have estimated these from samples of firms in the industry using an input-oriented constant returns to scale (CRS) DEA model.

The firm is both allocatively and technically efficient, if it produces at point H. The overall efficiency of firm R is measured from OM/OR.

Exhibit 6.1. DEA Frontier Benchmarking



Factor Prices, Allocative Efficiency, and Frontier Stability

I note that we have calculated factor input prices for the Ontario distributors. The fact that many prior studies lacked factor prices restricted their research to examining technical efficiency. Thus, the potentially critical issue of optimal input selection was unexplored. Yet, earlier research (Fare, et al., 1985) concluded that allocative inefficiency is especially important for regulated utilities facing non-market price signals.

Finally, little research has examined the question of benchmarking stability: over time does the set of "efficient" firms exhibit stability? One study, possibly due to data quality issues, found the frontier unstable with firms cycling on and off the frontier (Weyman-Jones, 1992). We can examine the stability of the frontier for the Ontario distributors over almost a twenty five-year period, i.e., 1988 – 2011.

6.3 DEA Regulatory Applications

As noted above, numerous regulators have employed DEA to guide the design of regulatory mechanisms.

Advocates of DEA point to numerous advantages. The firms are judged relative to the most efficient, not the average. There is the ease of incorporating multiple outputs and inputs. There is no requirement to specify a functional form for the production function. Mechanisms exist for standardising for environmental factors. There is no requirement to specify a behavioral assumption such as cost minimisation. There are limited data requirements (i.e., in the limit, one year for the firms or utilities in the sample). There is the ability to determine peer groups that define a reference point of potential efficiency for each firm and thus a calculated level of relative efficiency. In addition there is the ability to decompose efficiency into component elements such as technical efficiency, allocative efficiency and scale efficiency. And finally, the ability to calculate efficiency without the incorporation of prices.

Criticism of DEA include that it uses "extremes" of performance rather than "average" (as with many stochastic approaches). This implies that DEA-calculated efficiencies could be sensitive to sample selection (e.g., outliers), data definitions and problems, model specification, and period of performance. Further, data errors in outputs or inputs could potentially artificially inflate the efficiency of firms defining the frontier or the inefficiency of those deemed off the frontier. Another source of criticism relates to the fact that several mechanisms exist for standardising for environmental factors. The latter two are hardly unique to DEA however.

6.4 Main Findings from DEA Analysis

Unfortunately, we have not had quite enough time to fully develop our research on benchmarking. This is particularly true with respect to our review of PEG's benchmarking of the Ontario LDCs. Therefore, our comments in general and with regard to PEG's benchmarking in particular, are limited.

DEA Results on the Performance of Ontario LDCs

Let's first look at what we can say about the performance of Ontario LDCs using the DEA.

<u>Frontier Composition</u>

Very little research has been done on frontier composition: is the set of firms defining efficiency stabile? One earlier research study found their frontier composition to be unstable with firms cycling on and off the frontier. However, we find that for the Ontario distributors over a ten-year period "efficiency" is defined by a consistent set of distributors. We have similarly stable results over a longer 20 and even 24-year period.

<u>Frontier Shifts</u>

Based on DEA, I find that the pre-restructuring Ontario electricity industry frontier has degraded. Technical efficiency for the pre-restructuring frontier distributors has fallen consistently. This degradation tends to make frontier LDCs less distinguishable from the interior LDCs that operated off the frontier. Allocative efficiency for these pre-restructuring frontier firms has also degraded. This degradation is significant, falling by more than 20 percent. These findings are consistent with the incentives offered by OM&A-only benchmarking.

These findings are at variance with the findings of the Norwegian regulator. NVE concluded that the frontier improved between 1 and 1.5 percent per year. This expectation was embedded in its first two generations of PBR. Similarly, my research over the 1988-1997 period with Ontario distributor data concluded that the improvement in the frontier was indeed close to what NVE had found.

Overall, Ontario LDCs 2011 efficiency has fallen from 1997. Efficiency in 2011 has also fallen from 2000 and from 2002 levels. Technical efficiency has remained essentially flat, in the low 90s percent. So we continue to see less than 10 percent technical inefficiency among the distribution sector in Ontario. Allocative efficiency, which was always lower than the corresponding technical efficiency, has declined precipitously, falling by more than 20 percent. Again, these findings are consistent with the incentives offered by OM&A-only benchmarking.

Comparing My DEA with PEG's Benchmarking Results

The PEG analysis misidentifies the firms comprising the frontier. Furthermore, PEG's analysis underestimates the efficiency of the most efficient Ontario LDCs. These LDCs have consistently formed the efficiency frontier in the span of time from 1988-2011 that we examined. By and large, the same set of the most efficient LDCs that formed the frontier in 1997 and 2000 form the frontier in 2011.

PEG understates each distributor's efficiency by more than 10 percent. In addition, PEG's extremes of inefficiency are substantially broader than my results. That is, the distribution of PEG's results has a much wider variance than the variance of my results distribution:

- PEG's least efficient LDC is at + 85.4 percent (85.4 percent inefficient)
- PEG's most efficient LDC is at - 49.8 percent (49.8 percent efficient)

What about my results distribution? For the distributors included my analysis the extremes go from +39 to -32.

- my least efficient LDC is at + 39 percent (39 percent inefficient)
- my most efficient LDC is at - 32 percent (32 percent efficient)

PEG's results have appeared to change substantially between the first and second versions of their work. PEG's benchmarking model appears to be unstable. Furthermore, PEG's estimated benchmarking coefficients are almost certainly biased based on their sample and specification.

PEG's efficiency results and rankings for individual LDCs appear in a number of cases to be significantly and substantially different from those I obtain with DEA. Recall that my estimates have the full span of necessary data covering decades and decades of information. Exhibit 6.2 compares PEG efficiency estimates with my estimates for a sample of seven LDCs. Note that in this exhibit negative numbers convey efficiency and positive numbers convey inefficiency. There are consistent, wide differences between PEG's and my estimates.

We can see that the estimates differ on the low end by over 10 percentage points and on the high end by over 23 percentage points. In some cases PEG's evaluation finds the LDC is below its average cost while I find the same LDC to be above its average cost. Conversely, in some cases PEG's evaluation finds the LDC is above its average cost while I find the same LDC to be below its average cost.

Exhibit 6.2. Comparing PEG Efficiency (Percent) Estimates with My Estimates

	PEG	**Cronin**
Distributor 1	-18.3	-30
Distributor 2	-11.2	6
Distributor 3	-7.3	-17
Distributor 4	-3.5	20
Distributor 5	3.1	-7
Distributor 6	6.5	23
Distributor 7	54.7	39

I find the most efficient of PEG's estimates in this sample to be notably biased downward and not properly conveying the magnitude of the relative efficiency, i.e., understating the magnitude of the relative efficiency by 39 percent. I find the most inefficient of PEG's estimates in this sample to be notably biased upward, i.e., overstating the magnitude of the relative inefficiency by 40 percent.

The following are some observations on PEG's data samples that will have impacted the outcome of its analysis. PEG has used confusing and inconsistent sample combinations in its analysis. It included Toronto Hydro and Hydro One in benchmarking but not the TFP analysis. The inclusion of Toronto Hydro and Hydro One in the benchmarking would tend to bias the estimated coefficients which would lead to inaccurate predicted LDC costs and inaccurate rankings. Indeed, PEG's estimated LDC inefficiencies and rankings often differ substantially from the results of the DEA analysis. There are further inconsistencies with PEG including Toronto Hydro and Hydro One in the TFP capital analysis (e.g., the depreciation rate calculation) even though they are not included in the final TFP calculations; and, PEG includes Toronto Hydro and Hydro One in the cost elasticities from the benchmarking (which are then used in the TFP analysis as cost shares) even though they are not included in the final TFP calculations.

Appendix 1. Output Price (Rate) Change Analysis - Methodological Notes

The rate change analysis calculates the average rate increases for the following Ontario electricity LDCs:

- Bluewater Power Distribution Corp.
- Cooperative Hydro Embrun Inc.
- Enersource Hydro Mississauga Inc
- ENWIN Utilities Ltd.
- Guelph Hydro Electric Systems Inc.
- Horizon Utilities Corporation
- Hydro One Networks Inc.
- Hydro One Brampton Networks Inc.
- Hydro Ottawa Limited
- Kitchener-Wilmot Hydro
- London Hydro Inc.
- PowerStream Inc.
- Toronto Hydro-Electric System Limited

Based on the OEB's *2011 Yearbook of Electricity Distributors*[52], the distribution revenue (i.e. distribution revenue is defined as Power and Distribution Revenue minus Cost of Power and Related Costs as reported in line 9 of sheet "IS" contained in the OEB's *2011 Electricity Yearbook*) for this group of LDCs is about $2.6 billion. The total 2011 distribution revenue for all electricity LDCs is $3.2 billion. Accordingly, the distribution revenue of the LDCs covered in this rate change analysis represent about 80 percent of the total Ontario electricity distribution LDCs.

The rate change analysis covers the period 2006-2011.

The following is a description of the calculation of the average rate increases for each LDC:

I. Calculation of the monthly distribution bill that results from applying rates and charges, as set out in Board's approved rate schedules, to the typical usage for each customer class (i.e. residential, General Service < 50 kW, General Service > 50 kW and Large Use customer classes).
    - The typical usage for each customer class is as follows:
        - Residential: 800 kWh per month
        - GS < 50 kW: 2,500 kWh per month

[52] http://www.ontarioenergyboard.ca/OEB/_Documents/RRR/2011_electricity_yearbook.pdf

    - GS > 50 and Large Use: based on actual usage per customer (i.e. kW-month per customer) using data provided in the most recent cost of service applications.
- Rates and charges were used for determining the monthly distribution bill:
    - Monthly Service Charge, excluding the component related to the smart meter cost
    - Volumetric Rate (i.e. $/kWh or S/kW)
    - Loss Revenue Adjustment Mechanism (LRAM) and Share Saving Mechanism (SSM) Recovery Rate riders
- The data sources are the distributors Board approved Rate Orders

II. Monthly distribution bill (i.e. $ per kWh/kW) for each customer class for the period 2006-2011
- Year over year change of the monthly distribution bill (i.e. $ per kWh/kW) for each customer class
- Year over year average rate increase for the LDC based on the average monthly distribution bill increase weighted by the share of the revenue requirement by customer class as reported in the most recent cost of service application.