Review of Economic Insights' Report *Electricity Distribution Productivity Analysis: 1996-2013*

Pacific Economics Group, LLC
Economic and Litigation Consulting

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1. INTRODUCTION AND SUMMARY

New Zealand's Electricity Network Association (ENA) engaged Pacific Economics Group (PEG) to: 1) prepare a study estimating total factor productivity (TFP), capital partial factor productivity (PFP), and operating expenditure (opex) PFP growth for New Zealand's electricity distribution businesses (EDBs); and 2) review and analyze the results of the productivity study prepared by Economic Insights (EI) on behalf of the Commerce Commission (the Commission). PEG's productivity research is summarized in our June 2014 report *Productivity Trends for New Zealand Electricity Distributors*. This report presents our review and analysis of the EI productivity study *Electricity Distribution Productivity Analysis: 1996-2013*.

EI has presented results for six different TFP specifications and five different opex PFP specifications. These specifications differ primarily in how output is measured, although results are also provided for two different capital measures. EI recommends determining the EDBs' "long run" productivity growth over a relatively recent period because it "is of the view that a significant change in market conditions facing the (NZ) energy supply industry has occurred since around 2007 with a reduced growth rate in demand…this change has also been observed in Australia, Canada, and the US."[1]

For the 2004-2013 period, EI estimates that TFP for NZ's 17 non-exempt EDBs grew between 0.09% and -1.03% per annum, depending on the specification. The analogous results for opex PFP growth are between -0.12% and -0.82% per annum. TFP growth over the 2004-2013 period was negative in five of the six TFP specifications that EI investigated and in all five opex PFP specifications.

While the EDBs' productivity has generally declined, EI says several experts expect energy demand to pick up in coming years, and "this is likely to contribute to a return to positive TFP growth in the electricity distribution industry in the medium term."[2] Given this expected upturn in output growth, EI believes zero is a reasonable value for the EDBs' long-run trends in both TFP and opex PFP.

[1] Lawrence, D. and J. Kain, *Electricity Distribution Industry Productivity Analysis: 1996-2013*, Report Prepared for the Commerce Commission, 24 June 2014, p. 39.

[2] Lawrence, D. and J. Kain, *op cit*, p. 39.

EI also estimates that EDBs' input prices are growing about 1% more per annum than input prices in NZ's overall economy. As a result, EI finds that an input price differential of 1% is appropriate. EI recommends a -1% value for the X factor in a rate of change formula, which is equal to the difference between its recommended productivity differential of zero and the input price differential of 1%.

Although EI investigated a wide range of output measures, none of its output specifications are consistent with the outputs the Commission plans to use when forecasting the EDBs' opex over the 2015-2020 period. The Commission will forecast opex using a formula that utilizes information on opex input price inflation, opex PFP growth, and output growth. The algebra behind this formula shows the same output specification should be used to measure opex PFP and output growth. If EI used the same outputs as the Commission plans to use in the opex projection formula, its estimated TFP and opex PFP growth would decline by as much as 0.72% per annum, depending on the specification.

The same input prices should also be used when measuring opex PFP and input price inflation in the Commission's opex projection formula. While EI's choices for input prices are defensible, they are not consistent with those the Commission plans to use when projecting the EDBs' opex. The Commission says it will use a weighted average of the producer price index-all industries (PPI-all) and the labor cost index-all industries (LCI-all) when forecasting opex. EI uses PPI-all and the Labor Cost Index for the Electric, Gas, Water and Waste sector (LCI EGWW) to deflate opex and estimate the quantity of opex inputs. EI's measured opex price inflation is higher than inflation in the opex input price index the Commission intends to use. If EI used the same input price indices as the Commission, measured growth in opex input quantities would increase and EI's estimated growth in opex PFP would decline in all five of its specifications.

In addition to the lack of consistency with the Commission's broader ratemaking framework, PEG believes one of EI's output specifications – Specification #1 – is not appropriate. This specification includes what EI calls a "supply-side dimension of system capacity," equal to the product of the EDBs' installed distribution transformer kVA capacity and total km of EDB lines (excluding street lighting and communications lines). PEG disagrees with using this variable as an output measure because, by definition, the “supply side dimensions” of any marketplace focus on production costs and *inputs*. Productivity measures the relationship between outputs and inputs. It is therefore critical for measured inputs and outputs to be clear and distinct, because if these metrics are blurred together and/or conflated then the relationship between inputs and outputs – and hence estimated productivity – is also obscured and distorted. EI does, in fact, use kVA of installed transformer capacity and km length of line (weighted by a capacity factor) to measure both outputs and inputs in productivity Specification #1, and PEG believes this is conceptually problematic.

PEG also finds output Specification 1 empirically problematic. EI emphasizes that electricity distribution demand is declining in several Western countries. This view influences EI’s recommended period for estimating TFP as well as its recommended values for long-run TFP and opex PFP growth. This view should also, logically, be reflected in the empirical evidence that is used to support these policy recommendations.

However, output Specification 1 actually grows *more* rapidly in recent years than in the first part of the sample period. This result is due entirely to relatively rapid growth in EI’s system capacity measure, which is a proxy for demand. Output Specifications 2 through 5 are consistent with EI’s finding that output growth has slowed in electricity distribution industries; output Specification 1 is not. PEG therefore believes output Specification 1 is not empirically compatible with EI’s finding that there have been “significant changes in underlying market conditions (that) may lead to a change or “break” in the achievable rate of productivity growth.”[3] We accordingly recommend that the Commission not rely on output Specification 1 when determining long-run TFP and opex PFP trends.

PEG also has concerns with EI’s use of physical capital measures in its TFP analysis. Although EI presents one TFP specification using monetary rather physical capital metrics, the two specifications put forward as the basis for the industry’s recommended long-run TFP trend (Specification 1 and Specification 4) both utilize physical capital metrics. PEG has previously discussed its concerns with physical capital metrics in some detail, and we will not repeat those arguments here.

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[3] Lawrence, D. and J. Kain, *op cit*, p. 37.

It is worth noting, however, that EI's physical measures of capital show capital inputs growing at nearly the same rate between 2004 - 2013 period as in 1996-2004. In contrast, EI's monetary measure of capital grows more than four times faster in the 2004-2013 period than in 1996-2004. ENA members have indicated to PEG that the EDBs have undertaken more capital replacement expenditures in recent years than in the 1996-2004 period.

One of PEG's fundamental concerns with physical capital metrics is that they do not reflect the costs of capital replacement spending. A pattern of increasing capital replacement expenditures over time is evident in both EI's monetary capital measures and PEG's measured capital stock, but not in EI's preferred physical capital measures. Assuming EDBs' capital replacement spending has in fact been increasing over time, the fact that physical capital measures do not capture this important trend illustrates PEG's concerns with these metrics. We therefore recommend that the Commission rely on EI's monetary-based capital measures rather than its physical capital metrics when reaching determinations on the EDBs' long-run TFP and opex PFP trends.

Overall, PEG believes the EI and PEG productivity studies strongly support negative values for the EDBs' long-run TFP and opex PFP trends. In the EI study, five of six TFP specifications register negative TFP trends. The exception uses output Specification 1 and, contrary to EI's conclusion that demand has been declining in the electricity distribution industry, this specification exhibits increasing demand over time. When the suspect results from output Specification 1 are excluded, EI's estimated TFP trends range from -0.34% to -1.03%, with an average value of -0.62%. Similarly, when the results using output Specification 1 are excluded, EI's estimated opex PFP trends range from -0.55% to -0.82% with an average value of -0.73%.

EI's TFP and opex PFP trends would be even lower if they used the same output specification and input prices the Commission intends to use when projecting the EDBs' opex. PEG's two-output specification is internally consistent with the Commission's opex projection formula. With this specification, PEG finds the EDBs' TFP and opex PFP growth has been systematically negative over the 2001-2012 period. TFP growth averaged -1.80%, and opex PFP growth averaged -2.04%, over these years.

Following this summary, Section Two reviews EI's evidence on the EDBs' opex PFP growth. Opex PFP plays a critical role in the 2015-2020 default price-quality paths, because the Commission is projecting EDBs' 2015-2020 opex using a formula that includes a forecast of the industry's opex PFP growth. Section Three turns to EI's TFP and capital PFP estimates. Section Four then discusses recommended values for long-run opex PFP and TFP trends.

2. OPERATING EXPENDITURE PFP

2.1 The Opex Projection Formula

2.1.1 Overview of Formula

In the Commission's *Default Price-Quality Paths from 1 April 2015 for 17 Electricity Distributors: Process and Issues Paper*, Box A1 on page 59 presents the following formula for calculating operating expenditure for the 2015-2020 period:

Operating expenditure $_t$ = operating expenditure$_{t-1}$ *

(1 + due to network scale effects

- operating expenditure partial productivity

+ input prices)

A footnote to Box A1 (footnote 95) says that, other than one submission which argued for adjustments to the opex projection formula, "no other submitter raised an issue with the specification of the formula, and there is regulatory precedent for a similar specification." However, neither the *Process and Issues Paper* nor the November 2012 report *Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors* presents further details on the mathematical rationale for this specification or the supporting regulatory precedent(s).

PEG supports the opex adjustment formula in Box A1 of the *Process and Issues Paper*. In fact, we have developed and used identical formulae when projecting opex growth. EI personnel referenced PEG's previous work on this issue in a 2007 report for gas distributors in the Australian state of Victoria. On page 1 of the March 26, 2007 report *Victorian Gas Distribution Business Opex Rate of Change*, EI personnel say that "PEG (2004) showed that the appropriate formula for rolling forward starting year real opex is given by:

(1) Real Opex = Opex Price - Opex Partial Productivity + Output Quantity - CPI"[4]

In this formula, "real opex" is the growth rate in opex relative to the growth in CPI. Accordingly, the change in real opex plus the change in CPI is equal to the change in nominal opex. It is easy to show that formula (1) above is identical to the formula presented in Box A1, although it is expressed somewhat differently.

The Victorian energy regulator did, in fact, use the formula above to project the gas distributors' opex over the term of their 2008-2013 price controls.[5] It is also worth noting that EI personnel found "this (PEG) approach is conceptually correct and consistent with practice in several North American jurisdictions listed in PEG (2004). PEG (2004) gives a lengthy theoretical justification for formula (1) which we repeat below…the PEG (2004) approach to calculating the roll-forward of opex can, thus, be seen to be well grounded in economic theory."[6]

However, there is a difference in terminology between Box A1 and the PEG formula described above. The Commission's formula refers to a 'scale effects' term as one factor contributing to the change in opex; the PEG formula refers to the change in output quantity. It might be argued that 'scale effects' are not synonymous with measured output quantity and, as a result, the specific outputs used to implement a scale effects adjustment can in principle differ from the outputs used to measure opex PFP. This argument would conflict with the opex adjustment formula that EI personnel found to be "well grounded in economic theory" and "conceptually correct" for projecting opex, as we demonstrate below.

Let nominal opex cost be given by C^{OM}, an index of the quantity of opex inputs by X^{OM}, and an index of opex input prices by W^{OM}. Because cost is equal to input quantity times input price, it follows that:

$$C^{OM} = W^{OM} \cdot X^{OM} \qquad [1]$$

[4] Lawrence, D. (2007), *Victorian Gas Distribution Business Opex Rate of Change*, Report prepared for Envestra, Multinet, and SP AusNet, p. 1.

[5] PEG advised the Victorian regulator during this gas distribution price review and of course supported the same formula.

Taking the natural log of both sides and differentiating with respect to time, we have

$$\Delta C^{OM} = \Delta W^{OM} + \Delta X^{OM} \qquad [2]$$

Where Δ refers to the percent change in a variable. By definition, the growth rate in a partial factor productivity index used in a cost-based, indexing formula is equal to:

$$\Delta PFP^{OM} = \Delta Y^{\varepsilon} - \Delta X^{OM} \qquad [3]$$

Here Y^{ε} is the change in a cost-elasticity weighted output index, in which selected output subindexes are weighted by their respective cost elasticities (i.e. shares of the outputs' respective contributions to cost). Re-arranging the terms of [3], we have

$$\Delta X^{OM} = \Delta Y^{\varepsilon} - \Delta PFP^{OM} \qquad [4]$$

Substituting equation [4] into [2] yields:

$$\Delta C^{OM} = \Delta Y^{\varepsilon} + \Delta W^{OM} - \Delta PFP^{OM} \qquad [5]$$

Equation [5] is equivalent to what EI personnel call "the appropriate formula for rolling forward starting year" opex, when opex is presented in nominal rather than real terms (relative to CPI inflation). The change in opex is equal to the change in output quantity, plus the change in opex input prices, minus the change in opex PFP.

Moreover, the explicit output quantity term in this formula *must* be consistent with the output quantity index used to measure PFP. Indeed, the change in output quantity is introduced as a term in the opex adjustment formula *only* because this same output quantity is used to compute opex PFP growth. Equations [4] and [5] show that the change in output quantity term has been separated out from the measured change in opex PFP. If different output subindexes are used in the ΔY^{ε} and the ΔPFP^{OM} terms, then equation [4] is not satisfied. If equation [4] is not satisfied, then neither is equation [5], which is equivalent to the formula the Commission intends to use to forecast opex.

This analysis shows the outputs used to measure the scale effects and opex PFP terms must be identical. Any inconsistency between these outputs undermines the mathematical derivation of, and underlying rationale for, the opex projection formula. More practically, any inconsistency in output choices within this formula will lead a

[6] Lawrence, D., *op cit*, pp. 1 – 3.

formula calibrated with historical data either to over-compensate or under-compensate EDBs for their projected opex going forward.

This can be seen by considering a simple example. Suppose the data below show the measured, historical trends (percent per annum) in the relevant variables, and suppose all these trends are expected to continue for the following five years:

Output index 1	1%
Opex input quantity index	1%
Opex input price index	2%

By definition, the change in operating expenditures is equal to growth in the opex input quantity index plus the growth in the opex input price index. Therefore, the measured operating expenditures consistent with the data above must be growing by 3% per year. These data also show historical opex PFP growth, equal to measured output growth of 1% minus measured growth in opex input quantities of 1%, is equal to 0.

If the Commission's opex projection formula was calibrated using historical data, it would forecast continued opex growth of 3% per year. In other words:

$$\Delta C^{OM} = 2\% - (1\% - 1\%) + 1\% = 3\%$$

This, of course, is the expected and intended result, because all of the underlying trends in output growth, opex input price inflation, and opex PFP are expected to continue for the next five years. Since those trends led to opex growth of 3% per annum historically, a formula projecting those same trends going forward should lead to ongoing opex growth of 3% per year. The Commission's formula generates that expected and intended result.

However, consider an alternate example where the Commission uses output index 1 to project the impact of 'scale effects' going forward, but an opex PFP study uses a different output index 2 to measure opex PFP (and makes no other methodological changes that would impact measured opex input prices or quantities). Assume output index 2 has been growing by 2% per year. This means a PFP study using this output specification will lead to measured opex PFP growth of 1% per year (i.e. 2% - 1% = 1%). When this estimate of industry opex PFP growth is integrated into the Commission's opex projection formula, the result is

$\Delta C^{OM} = 2\% - (2\% - 1\%) + 1\% = 2\%$

Using output index 2 instead of output index 1 to measure opex PFP reduces allowed opex growth from 3% per annum to 2% per annum. This results entirely from the fact that different output quantity indices are used for the scale effects and PFP terms of the formula, not from using output index 2 *per se* to measure PFP. If the Commission modified its scale effects term so that it was consistent with the PFP output measure – in other words, if the Commission used output index 2 to measure scale effects when this index was used to measure opex PFP – the formula would again project opex of 3% per annum going forward *i.e.*

$\Delta C^{OM} = 2\% - (2\% - 1\%) + 2\% = 3\%$

Again, this is the intended and expected result.

The same logic applies to input prices. The Commission's formula includes an input price inflation term. An opex PFP study will select opex input prices to "deflate" operating expenditures and thereby develop measures of opex input quantities. If the opex input prices used in the productivity study differ from the input price inflation term in the formula, the formula will again systematically under- or over-compensate EDBs for their expected growth in operating expenditures.

This can be easily seen by returning to our original example with the following, measured historical trends that are expected to continue going forward:

Output index 1	1%
Opex input quantity index	1%
Opex input price index	2%

Suppose, however, that instead of using the input price index used in the productivity study, the Commission chose an alternate input price index that was growing by 1% per year. This would lead to the following opex projection:

$\Delta C^{OM} = 1\% - (1\% - 1\%) + 1\% = 2\%$

Using a rate of input price inflation that is 1% below what is reflected in the productivity study causes projected opex growth to decline by 1%, from 3% to 2% per annum. But if the productivity study was also modified to be consistent with the Commission's input price choices, the input prices used to deflate opex now grow by 1% rather than 2% per year. Since it was previously determined that historical opex was growing by 3% annually, this choice for input prices would lead to 2% measured annual growth in opex input quantities rather than 1%. Given the 1% annual growth in output quantity index 1, measured opex PFP growth is now (1% - 2%) = -1% instead of the (1% - 1%) = 0 value computed using the previous input price indices. When the same input prices are used in the input price inflation term and the productivity study, the opex projection formula therefore yields the following:

$$\Delta C^{OM} = 1\% - (1\% - 2\%) + 1\% = 3\%$$

This is, again, the expected and intended result.

These examples show that outputs and input prices appear, implicitly or explicitly, in different terms in the Commission's opex projection formula, and the outputs and input prices selected for the formula should be identical across these terms. If this is not the case, the formula will not work properly. Indeed, inconsistencies in outputs and input prices are likely to over- or under-compensate the EDBs for their projected opex. This does not mean that any particular output specification or input price index must be used to calibrate the terms of this formula. But it does show the terms of the opex projection formula are inherently inter-related, and it is critical for these terms to be internally inconsistent for the formula to work as intended.

2.1.2 Choices for Input Prices and "Scale Effects"/Outputs

In the *Process and Issues Paper,* the Commission says (p. 64) it intends to use customer numbers and km of line to measure the impact of scale effects when projecting opex. Since the outputs used for scale effects and opex PFP should be internally consistent, PEG believes this decision by the Commission means customer numbers and km of line are the appropriate output measure to use when projecting opex PFP growth. PEG has accordingly used customer numbers and km of line in our productivity analysis. To ensure consistency across the opex projection formula, we also recommend that these same two outputs be used to construct the output index that is used to estimate opex PFP growth.

EI has investigated a wide range of output measures, but none of its output specifications are consistent with the outputs the Commission plans to use when forecasting the EDBs' opex over the 2015-2020 period. EI presents results for five different output specifications, constructed as follows:

Specification 1: Energy (23%); kVA*kms (47%); customer nos (20%)
Specification 2: Energy (28%); max. demand (10%); customer nos (62%)
Specification 3: Energy (24%); ratcheted max. demand (23%); customer nos (53%)
Specification 4: Energy (15%); ratcheted max. demand (18%); customer nos. (26%); circuit length (40%)
Specification 5: Energy (68%); max. demand (17%); customer numbers (15%)

The estimated growth in each of these specifications over the entire sample period (1996-2013) and for the 1996-2004 and 2004-2013 sub-periods is presented below:

	Spec. 1	Spec.2	Spec. 3	Spec. 4	Spec. 5
1996-2013	1.85%	1.42%	1.60%	1.34%	1.65%
1996-2004	1.84%	1.71%	1.81%	1.54%	2.10%
2004-2013	1.85%	1.16%	1.42%	1.15%	1.26%

As noted, none of these output specifications are consistent with the customers-km of line specification the Commission plans to use when projecting opex. PEG did investigate this specification, however. It is referred to as the "Two Output Specification" in our June 2014 report and was constructed by applying a 57% weight to customers and a 43% weight to km of line; these weights were derived from PEG's November 2013 TFP and benchmarking study for the Ontario Energy Board. For comparison purposes, our June 2014 report also presents data on the same "Three Output Specification" used in our 2009 TFP report for the ENA, although the current three-output specification uses cost elasticities rather than revenue shares to weight outputs, as is appropriate in a building block incentive regulation plan.

As reported in Table Two of our June 2014 Report, PEG estimates that the two-output specification grew at an average annual rate of 1.13% over the 2001-2012 period. Output growth averaged 1.38% per annum over the 2001-2006 period, but slowed to 0.92% per annum in 2006-2012. PEG recommends using the 2001-2012 sample period to estimate output and opex PFP growth.

There is some similarity between changes in PEG's two-output index and output growth in some of the EI specifications. EI output specification 2 grows by 1.16% per annum over the 2004-2013 period, and output Specification 4 grows by 1.15% over this period. These rates are nearly identical to the 1.13% measured rate of growth in PEG's two-output specification.

There is, however, a notable discrepancy between EI's Output Specification 1 and PEG's two-output specification. Output specification 1 grows by 1.85% per annum over the entire 1996-2013 period, as well as over the 2004-2013 period. These rates are 0.72% above PEG's weighted average growth in customer numbers and km of line. The inconsistency between Specification One and the outputs the Commission plans to use in the opex projection formula therefore increases measured opex PFP growth by about 0.72% per annum. PEG addresses output Specification 1 in more detail in Section 2.2.

EI's input prices are also not consistent with the input prices the Commission plans to use when projecting the EDBs' opex. The Commission has said it will use a weighted average of the producer price index all industries (PPI-all) and the labor cost index all industries (LCI-all) when forecasting opex, with a 40% weight applied to PPI-all. EI uses PPI-all and the Labor Cost Index for the Electric, Gas, Water and Waste sector (LCI EGWW) to deflate opex and estimate the quantity of opex inputs. EI's measured opex price inflation is higher than inflation in the opex input price index the Commission intends to use. The more rapid opex input price inflation in EI's study will, in turn, decrease measured growth in opex input quantities; raise EDBs' measured opex PFP growth; and thereby reduce the values for 2015-2020 opex generated by the Commission's formula. While EI's choices for opex input prices are defensible, the inconsistency between these input prices and those to be used in the Commission's opex forecasting formula are likely to under-compensate the EDBs for their expected changes in opex.

2.2 Output Specification

2.2.1 The Distinction Between Inputs and Outputs

In addition to its lack of consistency with the Commission's intended ratemaking approach, PEG believes one of EI's output specifications – Specification #1 – is not appropriate. This specification includes what EI calls a "supply-side dimension of system capacity," equal to the product of the EDBs' installed distribution transformer kVA capacity and total km of EDB lines (excluding street lighting and communications lines). PEG disagrees with using this variable as an output measure because, by definition, the "supply side dimensions" of any marketplace focus on production costs and *inputs*. Productivity measures the relationship between outputs and inputs. It is therefore critical for measured inputs and outputs to be clear and distinct, because if these metrics are blurred together and/or conflated then the relationship between inputs and outputs – and hence estimated productivity – is also obscured and distorted. EI does, in fact, use kVA of installed transformer capacity and km length of line (weighted by a capacity factor) to measure both outputs (system capacity) and inputs (capital) in productivity Specification #1, and PEG believes this is conceptually problematic.

EI has previously supported using system capacity as an output by likening energy networks to roads. EI argues that energy networks are like roads since both provide underlying infrastructure that is sized to meet the expected maximum demand for the assets, but they have no control over the "traffic" that goes down the road itself. Accordingly, EI has claimed that some measure of the capacity of the underlying infrastructure itself is an appropriate measure of the "system capacity" output being provided.

PEG believes that, on closer inspection, this analogy does not accurately describe the outputs provided either by roads or energy networks. Consider a private toll road operator. While the underlying asset owned by this operator is the road itself, this does not mean the road is the output the operator is providing to the public or that customers are demanding and paying the toll operator to use. These customers are demanding access to the road, at a given point in time, and for a certain distance. These are also the services that customers would be paying for; a flat fee for access, plus (perhaps) a mileage rate depending on the point of entry and the exit point. These access and mileage fees could be differentiated by time, which would constitute an additional service of being allowed use of the road during a peak period.

The road infrastructure, taken in totality, is therefore an input only. While this input is clearly necessary to deliver outputs to customers, it does not become an output itself. The outputs depend on gaining access to specific "pieces" of the infrastructure at distinct times and for defined intervals of time. This may be a subtle distinction, but it is an important one. It also demonstrates the difference between the demand side of the marketplace (which pertains directly to the outputs customers are demanding) and the supply side (the inputs companies procure and use to produce those outputs).

This analysis extends naturally to energy networks. Certainly infrastructure assets are necessary to provide service to customers, but this does not mean this infrastructure becomes an output itself. Customers demand access to this infrastructure and for kW to be delivered into their premises at any time desired (including peak periods). Again, the infrastructure is needed to deliver the electrons that customers are ultimately demanding, but the infrastructure taken as a whole does not become an output itself.[7]

In sum, PEG believes system capacity is a conceptually problematic output. There is a distinction between the entire infrastructure a utility purchases and manages and customers' demands for access to, and utilization of, that infrastructure. It is critical to keep measured inputs and outputs distinct, particularly in productivity studies that (by definition) explicitly attempt to measure the relationship between inputs and outputs. PEG believes EI's system capacity output blurs these distinctions, and classifying km of line (even when different classes of lines are adjusted by capacity factors) and kVA transformer capacity as both inputs and outputs is likely to obscure and distort productivity measures.

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[7] This analogy can, in fact, be extended to a large number of private sector firms that size their capacity to meet expected peak demand for their outputs. For example, printers have large print press assets that are "sized" to meet expected maximum demand for their printing services, but their customers are not demanding the printing presses themselves, but rather the printed material that comes off the presses. These are also the outputs that they are paying for.

2.2.2 Cost and Revenue Implications of Functional Outputs

A related issue is whether "billed" or "functional" outputs should be used to measure output quantities. Billed outputs are items that an EDB actually charges its customers for. Functional outputs are all those services EDBs provide to customers which are valued by customers (of which billed outputs are a subset).[8] EI has argued that "outputs in a TFP study should cover the main things the EDB produces which are valued by customers."[9] Moreover, "in the case of building blocks, it will be important to measure output in a way that is broadly consistent with the output dimensions implicit in the setting of EDB revenue requirements."[10]

In PEG's opinion, it is conceptually problematic to include unbilled, "functional" outputs in a productivity study used to set utility rates.[11] The reason is cost-based utility ratemaking involves two distinct but related tasks: 1) determining a utility's overall cost of service; and 2) setting prices that recover the estimated cost of service. Both of these elements are certainly evident in "building block" applications of CPI-X regulation.

EI's arguments in favor of functional outputs do not appropriately consider the second of these tasks, *i.e.* setting prices to recover the cost of service. EI says (correctly) that distributors do not explicitly bill for all services they provide which "are valued by customers." These unbilled services can also be important drivers of EDB costs. Thus, when EI claims "it is important to measure output in a way that is broadly consistent with the output dimensions implicit in the setting of EDB revenue requirements," it appears to be arguing that since the costs of functional outputs show up on the cost/input side of a TFP study, it is only natural for the functional outputs driving these costs to be included as an output in the same analysis, even though customers are not billed for the services.

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[8] These definitions for both billed and functional outputs were presented on slide 16 of the *Productivity Analysis of Electricity Distribution* presentation given by Denis Lawrence at the May 2, 2014 Commerce Commission Productivity Workshop.

[9] *Productivity Analysis of Electricity Distribution* presentation, *op cit*, slide 16.

[10] *Productivity Analysis of Electricity Distribution* presentation, *op cit*, slide 18.

[11] In the PEG productivity study, we have recommended customers and km of line in our preferred output specification, and one of those outputs (km of line) is not explicitly billed to customers. We included km of line as an output to align our output specification with the Commission's draft decision to use this variable when projecting opex. In order to achieve consistency within the rate setting process, we believe this draft decision by the Commission constrains the appropriate choice of output for measuring opex PFP.

While this approach may have merit in some applications, it is typically not appropriate for TFP studies used to set utility rates. Including unbilled, functional outputs in TFP measures can drive a wedge between the costs of utility services and a utility's ability to recover those costs through its billed revenues. All else equal, including unbilled outputs in TFP studies will likely cause changes in EDB revenues to fall short of changes in EDB costs, as we illustrate below.

Consider the case of investments in transformer capacity, designed to boost the security and reliability of the distribution system. The costs of these transformer investments would increase EDB revenue requirements and therefore the overall cost to be recovered from customers. The distribution service provided to customers is also likely to be more secure and reliable, which certainly is a source of customer value.

However, EDBs would not recover the costs of providing enhanced security and reliability through a charge for this functional output unless a separate, unbundled price was established for this service and the costs of the relevant assets and operations explicitly allocated to this charge. EI and PEG agree that this is rarely the case, and customers are typically not billed on an explicit, unbundled basis for valued enhancements in distribution services. Distributors can obviously only recover their costs through the charges they actually bill customers, and in practice this means the costs of distribution enhancements (for nearly all customers) are recovered through customer, volumetric usage (per kWh), and demand (kW) charges to those customers. Effectively, enhanced quality is "bundled" into the existing distribution service, and prevailing prices for the distribution service are increased to recover the costs of providing improved quality.[12] Customers do get "more" output than before, but EDBs recover their costs of providing the additional output through higher charges on their billed outputs.

Distributors would not recover the costs of providing this additional (*i.e.* enhanced) service if the Commission allocated these costs to a new "functional output" but did not allow EDBs to charge customers for this new functional output. In other words, assigning the costs of functional outputs to unbilled services will not allow EDBs to recover their entire cost of service. This is clear, because if some costs are assigned to unbilled outputs, then less than 100% of costs are assigned to billed outputs. Revenues can only be generated through billed outputs, so billed outputs in this scenario necessarily generate revenues that are not sufficient to recover all of the EDBs' cost of service.

This is essentially what happens when a TFP-based rate of change formula adds the growth in unbilled, functional outputs to billed outputs when computing changes in industry TFP. Adding a new, functional output will make measured output quantity grow more rapidly than billed outputs. Higher measured output quantity growth will, all else equal, lead to higher measured TFP growth and less rapid growth in allowed prices. But this less rapid price trajectory results from the fact that the output quantity measure is being impacted by the change in "outputs" that will not, in fact, be available to generate EDB revenues.

This can perhaps be clarified through an example. In any year t, let R_t = revenue, P_t = price, C_t = cost, W_t = input prices, Y_t = output quantity, and X_t = input quantity. Let all of these variables be computed as indexes, and in year zero, normalize all of these index levels at a value of 1.

Assume companies are subject to a five-year incentive regulation plan, where inflation is equal to the change in industry input prices and the X factor is equal to the ten-year average growth in industry TFP. Furthermore, assume that there is regular five-year cycle in which all of the following are true:

- There is no growth in billing determinants, which means revenue growth is due entirely to price growth, or

  - $\Delta R = \Delta P$ [6]

- There is no growth in input prices *i.e.*
  - $\Delta W = 0 \quad \forall t$ [7]

- In year one of every five-year cycle, there is investment providing an "unbilled output" but there is no other change in investment or opex in years 1 through 5 of the cycle:

  - $\Delta X_1 = \Delta \text{Unbilled output}$ [8]

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[12] This also happens frequently in competitive markets *e.g.* any time a company develops "new and improved" versions of existing products.

- $\Delta X_t = 0$ t=2, 3, 4, 5 [9]

- With $W_0 = 1$, it follows that

$$\Delta C_1 = \Delta \text{Unbilled output} \qquad [10]$$

$$\Delta C_t = 0 \qquad t=2, 3, 4, 5 \qquad [11]$$

- Let there be two possible specifications of the output quantity index that is used to measure industry TFP growth:
  - Option One: Billed outputs only are used as outputs
  - Option Two: Billed outputs plus the "Unbilled output" referenced above are outputs

- The change in prices (and therefore revenues, from [6]) is equal to

$$\Delta P = \Delta W - \Delta TFP = -\Delta TFP \text{ since } \Delta W=0 \qquad [12]$$

Although this is a highly simplified example, it focuses directly on the impact of the output specification on measured TFP growth, changes in costs and changes in revenues. Nothing substantial is sacrificed by the simplifying assumptions, but they do make the relationships between measured TFP growth, cost changes and revenue changes more clear.

The following two tables trace out the changes, in each of the five years, in measured output quantity in the TFP index; measured input quantity; prices (and revenues); and costs. The tables also show the average annual rate of change in each of these variables. The first table shows these results under Option One, when billed outputs only are used to measure the output quantity in the TFP index. The second table shows these results in Option Two, when both unbilled and billed outputs are used to measure output quantity in the TFP index.

Implications of Output Specifications on TFP, Prices, Revenues and Costs

Option One: Billed Outputs Only in TFP Measure

Year	ΔY	ΔX	ΔTFP= ΔY- ΔX	ΔP	ΔC
1	0	ΔUnbilled output	- ΔUnbilled output	ΔUnbilled Output	ΔUnbilled Output
2	0	0	0	0	0
3	0	0	0	0	0
4	0	0	0	0	0
5	0	0	0	0	0
Average Annual Change	0	$\frac{\Delta Unbilled Output}{5}$	$\frac{-\Delta Unbilled Output}{5}$	$\frac{\Delta Unbilled Output}{5}$	$\frac{\Delta Unbilled Output}{5}$

Since $\Delta P = \Delta R$,

$$\Delta R - \Delta C = \frac{\Delta Unbilled Output}{5} - \frac{\Delta Unbilled Output}{5}$$

$$= 0$$

In Option One, it can be seen that the change in the unbilled output causes TFP to decline in year one. This leads to positive price and revenue growth in that year. The change in revenue is just sufficient to recover the costs of providing the unbilled output.

Option Two: Billed and Unbilled Outputs in TFP Measure

Year	ΔY	ΔX	$\Delta TFP = \Delta Y - \Delta X$	ΔP	ΔC
1	ΔUnbilled output	ΔUnbilled output	0	0	ΔUnbilled Output
2	0	0	0	0	0
3	0	0	0	0	0
4	0	0	0	0	0
5	0	0	0	0	0
Average Annual Change	$\frac{\Delta Unbilled Output}{5}$	$\frac{\Delta Unbilled Output}{5}$	0	0	$\frac{\Delta Unbilled Output}{5}$

Since $\Delta P = \Delta R = 0$

$$\Delta R - \Delta C = -\frac{\Delta Unbilled Output}{5} < 0$$

In Option Two, the unbilled output is reflected on both the output and input side of the TFP calculation. Measured TFP change and revenue change is therefore zero in year one and every other year of the plan. Without any revenue growth, the utility is unable to recover the costs of providing the unbilled output in year one.

Again, while these examples are simplified, they do illustrate the potential adverse consequences from adding unbilled outputs to the output specification used to measure TFP growth. Doing so increases the probability that the resulting price changes will not be sufficient to recover EDBs' cost changes. This risk is exacerbated if functional outputs are proxied by asset measures (such as transformer capacity), which would cause at least some assets to appear on both the output and input sides of the TFP computation.

2.2.3 Empirical Issues

PEG also finds output Specification 1 empirically problematic. EI's recommendations put considerable emphasis on its view that electricity distribution demand has been declining since 2007 in several Western countries. For example, EI writes:

> "…significant changes in underlying market conditions (that) may lead to a change or "break" in the achievable rate of productivity growth. There is some evidence from a range of comparable countries that a significant change in market conditions facing the energy supply industry has occurred recently. In New Zealand electricity throughput grew at an average annual rate of 2.4 per cent between 1996 and 2007 but since 2007 it has grown at less than 0.5 per cent. While the global financial crisis reduced demand for electricity in 2009, it recovered in 2010 but has remained virtually static since then. In Australia, electricity demand reversed in 2008 and has fallen at an average annual rate of 1.1 per cent since then. A similar pattern has been observed in Ontario (PEGR 2013a,b). Maximum demand also peaked in Australia in 2009 and has fallen in New Zealand in 2013"[13]

These trends impact EI's recommended sample period for estimating TFP. EI says

> "We are of the view that a significant change in market conditions facing the energy supply industry has occurred since around 2007 with a reduced growth rate in demand which has now lasted for 6 years and which seems to be separate from the short term effects of the global financial crisis. This change has also been observed in Australia, Canada, and the U.S."[14]

These changing market conditions, and potential "break" in the achievable rate of productivity growth, lead EI to place more emphasis on recent as opposed to longer-term experience when recommending values for long-run TFP and opex PFP growth. As noted, five of EI's six estimates for recent TFP growth are negative, and all five estimates for recent opex PFP growth are negative. However, because several experts expect output growth to pick up a bit in coming years, EI has recommended values of zero for the long-run TFP and opex PFP trends, on the expectation that output gains will increase productivity from the currently observed negative trends.

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[13] Lawrence, D. and J. Kain, *op cit*, p. 37-38.
[14] Lawrence, D. and J. Kain, *op cit*, p. 39.

While EI presents a number of data points in the quotes above to support its opinion that electricity distribution demand has slowed, one would also expect this trend to be evident in EI's broader, measured output indices. After all, these are the most comprehensive measures of EDB outputs. They are also the output measures that are used directly to estimate TFP and opex PFP growth. It would be surprising if any of the output index specifications EI investigated were not consistent with the significant and widespread industry trend of declining output that is observed internationally in electricity distribution industries.

Four of EI's output specifications are in fact consistent with this conclusion, but output Specification 1 is not. In fact, output Specification 1 actually grows slightly more rapidly in recent years than in the first half of the sample period. This is evident in Table 3 of the EI 2014 Productivity Report. Below we replicate the estimated growth in all five of EI's output specifications over the entire sample period (1996-2013) and for the 1996-2004 and 2004-2013 sub-periods:

	Spec. 1	Spec.2	Spec. 3	Spec. 4	Spec. 5
1996-2013	1.85%	1.42%	1.60%	1.34%	1.65%
1996-2004	1.84%	1.71%	1.81%	1.54%	2.10%
2004-2013	1.85%	1.16%	1.42%	1.15%	1.26%

It can be seen that, between 1996-2004 and 2004-2013, average output growth declined by 0.55% in Specification 2 (*i.e.* from 1.71% to 1.16%), by 0.39% in Specification 3 (from 1.81% to 1.42%), by 0.39% in Specification 4 (from 1.54% to 1.15%) and by 0.84% in Specification 5 (from 2.10% to 1.26%). Output growth therefore declined in four of EI's five output specifications, with the average rate of output decline on these four output indices equal to 0.54% per annum. Output Specification 1, on the other hand, moves in the opposite direction and increases very modestly from 1.84% to 1.85% growth per annum.

Table 2 of the EI Productivity Report provides further details on this result. Output Specification 1 is a weighted average of energy, customer numbers, and system capacity, which is equal to the product of km of line and kVA of transformer capacity.

Between 1996-2004 and 2004-2013, customer and energy growth both declined (from 1.40% p.a. to 1.05% p.a., and from 2.28% p.a. to 1.20% p.a., respectively). However, the growth in system capacity increased from an average of 1.95% per annum in 1996-2004 to 2.65% per annum in 2004-2013. The more rapid growth in Output Specification 1 is therefore due entirely to relatively rapid growth in EI's system capacity measure, which is a proxy for demand.

2.2.4 Conclusion

In PEG's opinion, conceptual and empirical analysis both suggest that output Specification1 is anomalous and inconsistent with the rest of EI's research, including its broader conclusions and policy recommendations. Conceptually, it is problematic to include assets as both outputs and inputs in a TFP study, as output Specification 1 does. Including functional outputs in TFP analyses (as in output Specification 1) can also lead to price changes that are not sufficient to recover cost changes.

Empirical analysis also shows that output Specification 1 is problematic. Output Specifications 2 through 5 are consistent with EI's view that output growth has recently slowed in electricity distribution industries, but output Specification 1 is not. PEG therefore concludes that output Specification 1 is problematic and recommends that the Commission not rely on this output index when determining values for the EDBs' long-run TFP and opex PFP trends.

3. TOTAL FACTOR PRODUCTIVITY AND CAPITAL PFP

3.1 Output Measures

TFP growth is equal to the growth in comprehensive output quantity minus the growth in comprehensive input quantity. The comprehensive output measure used in a TFP index and an associated opex PFP index are identical. Accordingly, all of the output-related discussion from Section Two regarding EI's opex PFP research applies equally to its TFP work. This includes the analysis of why output measures used in productivity studies for the 2015-2020 default price-quality paths should be consistent with the outputs used in the Commission's opex projection formula. TFP estimates integrated into a rate of change formula should also use customer numbers and km of line as outputs because: 1) these outputs should be used to estimate the associated opex PFP index; and 2) if different outputs were used to estimate TFP, the industry TFP index would not decomposable into associated opex and capital PFP indices, as it should be.

3.2 Physical vs. Monetary Capital Measures: Conceptual Issues

TFP differs from opex PFP because the productivity measure includes capital as well as opex inputs. EI constructs both physical and monetary-based measures of capital inputs, but the report devotes little attention to the monetary capital measure. The two specifications that EI puts forward as the basis for the industry's recommended long-run TFP trend (Specification 1 and Specification 4) both utilize physical capital metrics. We accordingly confine our remarks here to EI's physical capital estimates.

PEG has concerns with EI's use of physical capital measures in its TFP work. We have previously discussed our conceptual concerns with physical capital metrics in some detail. Because we have little to add to those previous discussions, we will not repeat them here. A comprehensive statement of PEG's assessment of the merits of physical and monetary capital measures in presented in Appendix Two of PEG's April 2011 Concept Paper prepared for the Ontario Energy Board.[15]

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[15] Kaufmann, L. (2011), *Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper*, Report to the Ontario Energy Board.

3.3 Physical vs. Monetary Capital Measures: Empirical Issues

Table 4 of EI's Productivity Report presents data on the values of the physical and monetary capital metrics it constructed. The physical capital measures is labeled simply "Capital." The alternate, monetary-based measure is titled "Cons. price asset value."

It can be seen that, over the entire 1996-2013 sample period, these two measures display similar growth trends. The physical capital measure grew at an average annual rate of 1.62% over this period. The monetary-based capital metric grew only somewhat more slowly, at 1.53%.

However, there are significant differences in the growth of these capital measures in the 1996-2004 and 2004-2013 sub-periods. The physical capital measure grew by 1.57% per annum in the first half of the sample period and accelerated somewhat modestly to 1.67% in the latter, 2004-2013 period. The monetary measure, in contrast, grew by only 0.52% per annum in 1996-2004 but then increased at a far more rapid, 2.43% annual rate over the 2004-2013 period. The differences in these measures across time are material, in part because EI places more weight on the EDBs' recent experience when making productivity recommendations.

EI estimates that its physical measure of capital grows at nearly the same rate in 2004-2013 as in 1996-2004. EI's monetary-based capital measure grows more than four times faster in the 2004-2013 period than in 1996-2004. ENA members have indicated to PEG that the EDBs have undertaken far more capital replacement expenditures in recent years than in the 1996-2004 period.

One of PEG's fundamental concerns with physical capital metrics is that they do not reflect the costs of capital replacement spending. A pattern of increasing capital replacement expenditures over time is evident in both EI's monetary capital measures and PEG's measured capital stock, but not in EI's preferred physical capital measures. Assuming EDBs' capital replacement spending has in fact been increasing over time, the fact that physical capital measures do not capture this important trend illustrates PEG's concerns with these metrics. We therefore recommend that the Commission rely on EI's monetary-based capital measures rather than its physical capital metrics when reaching determinations on the EDBs' long-run TFP and opex PFP trends.

4. RECOMMENDATIONS

4.1 Overview

Overall, PEG believes the EI and PEG productivity studies strongly support negative values for the EDBs' long-run TFP and opex PFP trends. In the EI study, five of six TFP specifications register negative TFP trends. The one exception uses output Specification 1 which, contrary to EI's conclusion that demand has been declining in the electricity distribution industry, exhibits increasing demand over time. When the suspect results from output Specification 1 are excluded, EI's estimated TFP trends range from -0.34% to -1.03%, with an average value of -0.62%. Similarly, when the results using output Specification 1 are excluded, EI's estimated opex PFP trends range from -0.55% to -0.82% with an average value of -0.73%.

EI's TFP and opex PFP trends would be even lower if they used the same output specification and input prices the Commission intends to use when projecting the EDBs' opex. PEG's two-output specification is internally consistent with the Commission's opex projection formula. With this specification, PEG finds the EDBs' TFP and opex PFP growth has been systematically negative over the 2001-2012 period. TFP growth averaged -1.80%, and opex PFP growth averaged -2.04%, over these years.

4.2 Negative Productivity Factors

There are precedents for negative X factors in energy utility regulation. For example, a number of indexing plans approved for transmission utilities in Australia have had large negative X factors. These utilities were subject to a building block approach to incentive regulation, and all were undertaking extensive capital investment programs. Capital spending for transmission service is especially lumpy, and these utilities were entering a phase of their investment cycles that required large increases in capital spending just as their incentive regulation plans were being approved. More recently, many electricity distributors in the UK now have negative X factors in their RPI-X rate adjustment plans.

In principle, it can be appropriate to have a negative TFP or opex PFP trend embedded in price controls *if* industry-wide input quantity (overall inputs or opex inputs, depending on the productivity measure) is systematically growing more rapidly than industry-wide output quantity and that trend is expected to persist. A negative productivity trend in a utility sector is *not* necessarily evidence that efficiency is declining in that sector. A variety of factors can cause input quantity to grow more rapidly than output quantity and thereby lead to negative, measured productivity trends.

PEG has on several occasions undertaken decompositions of productivity change into different components. One such analysis is referenced in the March 2007 report for Victoria's gas distributors, which EI personnel found was "well grounded in economic theory." This analysis decomposes opex PFP change into five components, only two of which reflect efficiency: the change in management efficiency at an individual enterprise; and industry-wide "technical change," often interpreted as exogenous changes in efficiency throughout the industry. The three other factors that can impact opex PFP growth are: 1) changes in economies of scale resulting from changes in output growth; 2) changes in the operating environment that are independent of output; and 3) changes in opex PFP stemming from capital investment (*i.e.* changes in the capital stock).[16] The formula cited by EI personnel therefore shows the EDBs' measured opex PFP can be impacted by changes in output growth, changes in capital investment, and changes in the broader operating environment.

While PEG has not undertaken a detailed examination or decomposition of the EDBs' TFP or opex PFP growth, the productivity analysis we did undertake identifies several factors which, in our opinion, indicate that industry-wide input quantity is systematically growing more rapidly than industry-wide output quantity and this trend is expected to continue. Most importantly:

- In both the three-output and two-output specifications, industry TFP growth has been negative for the last 10 sample years (2003 through 2012 inclusive); the last year in which industry TFP growth was positive was

[16] PEG has also performed many decompositions of TFP change into various components, the results of which are very similar to the analysis cited in 2007 by EI personnel. A prominent example is

2002. This experience certainly qualifies as "industry-wide input quantity systematically growing more rapidly than industry-wide output quantity." Given this systematic evidence of negative TFP growth, PEG believes it would not be reasonable for the Commission to use a zero or positive estimate of the industry TFP trend reflected in a rate of change formula.

- Opex PFP is usually more volatile than TFP, but PEG's three-output specification registered negative opex PFP growth in nine of the last 10 years, and our two-output specification had negative opex PFP growth in eight of the last 10 years. Moreover, the opex PFP trends in the first- and second halves of our sample period were quite stable: in the three-output specification, opex PFP declined by 1.44% per annum between 2001-2006 and by 1.69% per annum between 2006-2012; for the two-output specification, opex PFP declined by 1.88% per annum over the 2001-2006 period and by 2.18% per annum in 2006-2012. Again, given this systematic evidence of negative productivity growth, PEG believes it would not be reasonable for the Commission to use a zero or positive estimate of opex PFP change when projecting the EDBs' opex over the 2015-2020 period.
- One of the factors that can give rise to persistent, negative productivity growth is slow output growth. The data show that EDB output has slowed between the first and second halves of the sample period, by 0.41% per annum for the three-output specification (from 1.82% p.a. to 1.41% p.a.) and by 0.46% per annum in the two-output specification (from 1.38% p.a. to 0.92% p.a.). Slowing output quantity growth is, with rare exceptions, a universal trend in utility industries in advanced Western economies. PEG also believes policy is widely expected to put further downward pressure on energy usage in the years ahead. PEG therefore believes current output trends will persist and may even slow further in coming years.

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presented in our April 2011 Report to the Ontario Energy Board, *Defining, Measuring and Evaluating the Performance of Electricity Networks: A Concept Paper*.

- Another factor that can lead to slower TFP trends is more rapid capital investment. The EDBs' growth in capital input essentially doubled between the first half (1.82% growth per annum) and second half (3.55% per annum) of the sample period. Communication with the EDBs indicate that much of this investment was driven by the need for greater capital replacement expenditures, and this trend is expected to continue for the next several years.
- It may be argued that greater capital investment will lead to opex savings, thereby accelerating opex PFP growth, as newer capital assets reduce maintenance expenditures that would otherwise be necessary on relatively aged infrastructure. While this is plausible in theory, there is little evidence that capital is actually substituting for opex inputs among the EDBs. As the rate of capital investment doubled between the first and second halves of the sample period, the growth in opex inputs declined by only 0.16% per annum (from 3.26% growth per annum in 2001-2006 to 3.10% per annum in 2006-2012). Much if not all of this decline can likely be attributed to a decline in the rate of output growth of more than 0.40% across these periods. While capital replacement may eventually lead to greater savings on maintenance, PEG cautions against simply assuming this will take place. We also believe rigorous, tested evidence must be put forward to support any such projected opex savings, particularly given the lack of apparent efficiencies from capital-opex substitution over the 2001-2012 period.

In sum, PEG believes that the productivity evidence and broader industry environment indicate that TFP and opex PFP trends will continue to be negative for the EDBs in the 2015-2020 period. Indeed, there would have to be a significant reversal of long-term trends for the EDBs to register positive TFP or opex PFP growth over the next five years since they have systematically exhibited negative productivity growth in the last 10 years. Important factors giving rise to that productivity decline are expected to continue, and may even be exacerbated, in the future.[17]

[17] In 2012-2013, PEG advised the Ontario Energy Board on productivity trends and appropriate X factors in an incentive regulation plan for electricity distributors and ultimately recommended a productivity factor of zero for those plans. We were originally asked to compute industry TFP trends for the 2002-2011 period, but 2012 data became available during the assignment, so we were asked to update the study to include these data. When the new data were added, the industry's TFP trend went from being slightly positive (about 0.2% growth per annum for 2002-2011) to slightly negative (about -0.3% per annum for 2002-2012). Unlike New Zealand, the negative TFP estimate in Ontario was driven by the experience of a single, anomalous year rather than systematically negative TFP change. In addition, a number of factors unique to Ontario's regulatory environment, and not relevant to the EDBs, argued against a negative X factor in Ontario. The fact that the 2012 experience was an outlier, as well as the broader regulatory environment in Ontario, led PEG to recommend a zero rather than negative productivity factor for the Ontario incentive regulation plans. For the record, here is a complete statement of my reasons for not recommending a negative X factor for the Ontario EDBs from the November 2013 PEG report (one footnote suppressed):

> Notwithstanding the theoretical possibility that negative X factors may be appropriate in some circumstances, there are several reasons why PEG finds a negative productivity factor would not be appropriate in Price Cap IR. First, the Board is currently examining the application of revenue decoupling to electricity distribution. Not to prejudge the outcome of this Board examination, but it should be noted that a decoupling mechanism would largely address the impact of declining output on industry TFP and, by extension, industry revenue change. Furthermore, as discussed in PEG's May 2013 report, the main reason electricity distributors' TFP has slowed and become negative in recent years is because of the decline in distributor output, and a revenue decoupling mechanism would counter this trend.
>
> A decoupling mechanism effectively breaks the link between distributors' revenues and the kWh volumes that are delivered to customers. Under current regulation, all else equal, distributor revenues fall when kWh deliveries decline. Revenue decoupling would sever (or at least greatly weaken) this relationship, so that revenue would remain constant when distributors' kWh output declines. Recall that revenue is, by definition, equal to price multiplied by output. Because decoupling allows revenues to remain constant even when output falls, decoupling effectively raises prices on distribution services to recover the revenues that would be lost when kWh decline.
>
> Second, there may also be concerns associated with the rate riders and related rate recovery mechanisms that exist in Ontario. Some costs transferred to the 2012 Trial Balance data may have been previously reflected in and recovered by a rate rider. If this is true, it would not be appropriate for costs previously recovered through rate riders to be reflected in the TFP trend, and therefore the rate adjustment mechanism, that will apply during the term of Price Cap IR. Doing so would mean increasing future customer rates to pay for costs that have already been recovered in previous customer rates.
>
> Finally, it is not clear that the negative 2002-2012 TFP trend is in fact industry-wide rather than the experience of a relatively small number of distributors. As previously noted, the Board's Renewed Regulatory Framework for Electricity (RRF) provides multiple ratemaking options to distributors. One of these options is designed to be "custom" to distributors with especially rapid capital investment needs. Although it is not clear which distributors will elect to file custom IR proposals, it is conceivable that distributors with historically high capital spending could depress industry-wide TFP trends, and thereby reduce the X factor in Price Cap IR, and later choose to opt out of this ratemaking approach precisely because of their atypical capital requirements. This would lead to higher price adjustments under Price Cap IR than are warranted for distributors with more typical capital requirements.

In sum, the implications of a negative productivity factor are troubling given the Ontario regulatory environment. The possibility of revenue decoupling, the potential concerns associated with rate riders, and the multiple ratemaking options in the RRF create a significant probability that a negative productivity factor would either double-count costs that are being recovered elsewhere, or reflect the experience of a small number of distributors with atypical investment needs who elect to opt out of Price Cap IR altogether. The latter result would be counter to the Board's intended purpose of Price Cap IR, which is to be appropriate for most distributors in the Province who do not have high or variable capital requirements. Because of these concerns, PEG recommends that the productivity factor in Price Cap IR be set at zero.

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