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THIRD GENERATION INCENTIVE	§	ONTARIO ENERGY BOARD
REGULATION FOR ELECTRICITY	§	
DISTRIBUTORS	§	
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Written Comments on Board Staff and PEG Report

Prepared by Julia Frayer, London Economics International LLC

for the Coalition of Large Distributors and Hydro One Networks, Inc.

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I. Introduction

Q1. Please state your name and business address.

A1. My name is Julia Frayer, and I am one of the partners and a Managing Director of London Economics International LLC ("LEI"). My business address is 717 Atlantic Avenue, Unit 1A, Boston, MA 02111.

Q2. Please briefly outline your professional qualifications.

A2. As Managing Director of LEI, I direct many of the company's engagements involving market analysis and economic analysis, including tariff design, financial modeling, asset valuation, benchmarking and productivity analysis, price forecasting, market-power analyses, and market design issues with respect to market mechanisms, information disclosure policies, competition, investment, and regulation.

Performance-based ratemaking (PBR), the subject matter at the heart of this consultation, is an area that I have specialized in with respect to tariff design. I have extensively studied regimes involving PBR in other jurisdictions and advised utilities, regulators, and investors on best practices with respect to institutional design and implementation.

Moreover, I have been actively working with Ontario power sector participants since prior to restructuring and re-regulation of the electricity distribution sector, and have in fact worked with both generators, transmission owners, distributors, power marketers, Ontario Energy Board and other Ontario government agencies. The diversity of past clients and their perspectives gives me an in-depth, and unique, appreciation of policy issues in the Province, and a particular interest in improving on and ensuring a vibrant energy sector in the future. I have testified on a variety of issues before US state and Canadian provincial regulators, and the Federal Energy Regulatory Commission (FERC) in the U.S., and have also served as an expert in litigation and arbitration proceedings. Appendix A to this testimony contains more details of my credentials.

Q3. On whose behalf are you testifying in this proceeding?

A3. I am testifying on behalf of Hydro One Networks, Inc. ("HONI") and the Coalition of Large Distributors ("CLD"), whose members include Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited, and Veridian Connections Inc. This group of distribution companies represents over 65% of the industry in Ontario, based on energy volumes (as of 2006). Within this group, there is a variety of business conditions represented. Although many of the CLD members are located in Southern Ontario, HONI's distribution system extends over many areas of the Province. Among the CLD members and HONI, both new and relatively old distribution systems are represented, as well high growth and low growth customer profiles, underground and aerial networks, distribution systems with and without high voltage transformers, etc. Although a small group in number, the CLD members and HONI represent the diverse situations of all utilities in the industry at large.

II. Purpose of Testimony and Recommendations

Q4. What is the purpose of your testimony?

A4. The purpose of my testimony is to outline an alternative set of recommendations for the rate adjustment mechanism ("RAM") for third generation incentive ratemaking regulation ("3GIRM") in Ontario.

Q5. What are your recommendations?

A5. First, I would recommend that a capital investment module be introduced into the structure of the RAM. A capital investment module would be included in the price cap formula as an additional term.

Second, I would recommend that the input inflation index be restructured and reformulated to be more consistent with Ontario utilities' actual experiences with changes in input prices. More specifically, I would recommend that the Board staff work with the utilities to refine the data series that Board would rely on to compile the labour, capital, and material sub-indices. These sub- indices should also be consistent with the input price indices used in calculating historical total factor productivity growth and deriving the X factor. In addition, the price of capital sub-index needs to be reformulated to recognize actual refinancing policies. Lastly, the elasticity shares that the Board employs for combining the three sub-indices into a single input price index need to be updated for 3GIRM, and thereafter on a regular basis. In the event such improvements are not possible to achieve within the timeframe for implementing 3GIRM, I would recommend continued use of a macroeconomic indicator of inflation (like the GDP deflator used in 2GIRM).

Lastly, I would recommend modifying the historical estimates of TFP growth in Ontario to reflect the data available in Ontario, and employing the recent trends explicitly in setting the X factor for 3GIRM. More concretely, in contrast to Board staff's consultant's proposed 0.88% industry average X factor based on US trends, my analysis suggests that a reasonable industry-wide productivity target for 3GIRM should lie in the range of 0.4% to 0.7%, after taking into account recent Ontario trends. Therefore, I recommend an X factor of 0.55% (which is the mid-point of the above range). Due to the lack of reliable measures of relative firm productivity, I propose that the Board dispense with additional firm-specific adjustments to this industry average X factor for 3GIRM. For future generations of IR, and once data refinements are realized, a robust multilateral total factor productivity-based benchmarking analysis can be used to develop reasonable firm-specific X factors.

Q6. What type of rate adjustment mechanism is being considered for 3GIRM?

A6. The Board staff has proposed a comprehensive price cap regime for 3GIRM in the Staff Discussion Paper issued on February 28, 2008 (referred to herein as the "Staff Discussion Paper"). Following convention, the comprehensive price cap would have two basic components, an X factor and an inflation index. Distributors' rates would increase year-on-year by the inflation factor less the X factor. For example, if the inflation factor is determined to be 2%over the previous annual period and the X factor is set at 0.5%, then rates will increase by 1.5% from the previous year.

Q7. What adjustments would you make to the RAM?

A7. I agree with the general "price cap" approach, but would recommend that the rate adjustment mechanism also incorporate a capital investment module as part of the core model, under which rates would increase year-on-year by the inflation factor less the X factor plus a CAPEX factor, as described in Figure 1 below. This capital investment module is necessary because of the specific circumstances facing Ontario local distribution companies (LDCs) in the short to medium-term where the growth in rate base is significantly greater than growth in depreciation with respect to capital investment needs, and because of the lumpiness of investment due to volume growth and aging asset base. In contrast to the basic assumption underpinning price cap regulation, the amortization (depreciation) profile (based on historical costs) of Ontario LDCs is significantly less than current costs of capital replacement. This is exacerbated even further because of the timing of initial investment – similar to experiences in other jurisdictions; many LDCs have clustered investments over the years. Going forward replacement of aging assets will further strain the situation given the clustering of initial investment. Furthermore, the lumpiness of capital investment, and the fact that there are initial periods when new capital is typically underutilized, also signifies that even growth-driven capital may not be sufficiently remunerated in the basic price cap formula.

Figure 1. Proposed addition of the capital investment module to the RAM

$\Delta P = 1 + I - X$ (as proposed by the Board staff)

I would propose an additional term, such that:

$\Delta P = 1 + I - X + CAPEX$, such that $P_t = P_{t-1} * (1 + I - X + CAPEX)$

where P = Price (ΔP = change in Price)

I = inflation index

X = productivity target in % terms

CAPEX = capital investment module in % terms

I will describe the premise of the CAPEX factor, as well as some concrete recommendations about how to implement this module, further below.

Q8. How should the inflation index in the RAM be developed?

A8. Conceptually, the inflation index in a price cap regime should track the costs of the industry being regulated with the price cap. Therefore, a customized input price index

("IPI"), which measures the change in prices of all inputs used by firms in the industry, would be optimal. However, practically, there are a number of obstacles for developing an accurate IPI, which stem from the lack of robust measures of unit price trends for industry inputs.

The staff of the Ontario Energy Board ("OEB Staff") has put together a proposal for an IPI based on the formulation used in 1GIRM. The formulation makes some unrealistic assumptions on how utilities deal with capital financing costs. Re-formulation of the capital input price index is necessary to account for the fact that typically LDCs only re-finance a fraction of the long term debt borrowed to finance the asset base. Furthermore, based on a review of the historical values for the component sub indices in the IPI and investigation of actual cost trends for a sample of utilities, I am suspicious of the trends profiled by the proposed labour, materials, and capital sub-indices. I discuss these concerns further below.

I would recommend that prior to any decision regarding implementation of an IPI, the Board with the support of key industry stakeholders, critically re-examine the methodology and input information required for calculating the IPI. If there is insufficient time to make the necessary improvements, I would then recommend that the Board continue employing the macroeconomic GDP deflator that was used in 2GIRM (and has been approved under settlement for the natural gas distribution IR regimes).

Q9. What changes do you propose for developing an X factor for 3GIRM?

A9. My recommendation for the industry average X factor is based on Ontario-specific data, with a TFP measure that attempts to do the best possible analysis given the available data. Specifically, I propose a lower X factor than that which was developed and proposed in the report dated February 28, 2008[1] prepared by Dr. Lawrence Kaufmann of

[1] Kaufmann, Larry. *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation In Ontario* February 2008, Report to the Ontario Energy Board, Pacific Economics Group, LLC. ("February 2008 PEG Report").

Pacific Economics Group ("PEG"), on behalf of the OEB Staff. Instead of an industry average X factor of 0.88%, as proposed by PEG, I would recommend an X factor of 0.55% for 3GIRM, which is the mid-point of the range 0.4% to 0.7% that I had calculated in my assessment. My recommendation is based on Ontario-focused analysis of total factor productivity (TFP) growth. I have taken into consideration the results of previous studies; for example, the work of Cronin and King for 1GIRM, which spanned the period of 1988-1997,[2] as well as PEG's interpolated TFP estimates for the period 1998 – 2002,[3] and combined it with the independent analysis I performed of TFP growth trends among Ontario electricity distributors for the period 2002-2006.

All indicators suggest that there is a deceleration – in fact – a reversal – in TFP growth for Ontario LDCs. Even PEG's analysis conforms to this observation: Larry Kaufmann notes that annual average TFP growth in Ontario was measured at 2.05% for the 1993-1997 periods. He then posits that it was likely in the range of 1.09% to 1.68% for the 1997-2002 period and his own analysis of Ontario data results in a TFP growth rate of 0.01% between 2002 and 2006.[4]

This slowdown (reversal) will likely continue through the medium-term given generally accepted, verifiable, and escalating cost pressures for LDCs, such as:

- Sustainment of aging assets and increasing emphasis on cyclical, preventative maintenance activities to extend the life of plant and offset reliability impacts from aging plant.

[2] Cronin, F.J., M. King, and E. Colleran, *Productivity and Price performance of Electric Distributors in Ontario*, Report prepared for OEB Staff, July 6, 1999 (addendum dated September 10,1999)

[3] Specifically Ontario 2 and Ontario 3 models that PEG developed through scenario analysis and in relation to US trends, see page 54-56 in February 2008 PEG Report. Scenario 2 assumes that Ontario TFP growth matched that of US distributors over the 1997-2002 period and therefore averaged 1.09% per annum. Scenario 3 assumes that the relative relationship in TFP growth between US and Ontario observed from 1993 to1997 would continue through 2002, which yields an annual average TFP growth estimate for Ontario of 1.68%.

[4] February 2008 PEG Report, pg. 57 (Table 12).

- Expanding focus on service quality and safety has already pressured operating costs and will continue to raise operating costs in the future. The implementation of mandatory service quality standards, for example, is likely to increase costs in areas like emergency response and corrective maintenance (i.e., more frequent vegetation management, etc.). Similarly, rising thresholds for ensuring employee safety, will mean that LDCs will need to spend additional funds to ensure satisfactory compliance with such requirements, including increased testing, preventive removal (for example, of asbestos contaminants), and purchasing of advanced equipment (like fire retardant clothing).

- Increased government initiatives i.e., conservation programs, TOU, smart meters[5], RPP, bill presentment changes, rebates, renewable generation programs, which are expected to only continue to escalate costs across many operating areas of the LDC, including the field services, information technology, customer service/interface, regulatory support, and financial reporting functions.

- Increase in stakeholder interface and corresponding administrative burdens – As the electricity industry structure has evolved, so has the number of industry stakeholders and institutions (such as the OPA, IESO, MDMR, competitive retailers, etc.). LDCs have been required to build up the capacity to interface with many more entities and agencies than they have had to deal with historically, and such interactions will continue in the future.

- In complement to the increased stakeholder interactions, compliance requirements have also increased in volume and depth. Instituting and maintenance of compliance program with OEB, OPA, IESO, ESA, and environmental regulators, have increased costs, including, in some cases actual

[5] Although, it is important to recognize that some of these initiatives and their cost implications will likely be dealt with outside the price cap regime.

costs of operations in addition to administrative costs. Compliance programs are likely to only become more complex and demanding, therefore further expanding administrative costs.

- As an extension of general trends of compliance and government policy initiatives, regulatory costs have also risen and are unlikely to contract through the medium term – rather, they are likely to expand. LDCs have had to grow their regulatory departments or increase regulatory outsourcing to tackle the numerous regulatory and policy initiatives. These costs are expected to increase significantly as many LDCs re-base and respond to various regulatory consultations. In addition, OEB fees are rising and there is an observable increase in the overall level of cost awards related to OEB initiatives.

- Labour demographic shifts – due to substantial demographic change in the labour pool across the industry – are requiring extensive hiring and training of new staff. Indeed, because of the magnitude of upcoming retirements, LDCs have had to initiate extensive apprenticeship and workforce planning programs, do that new hires can be adequately trained before current staff depart. Notably, such apprenticeships typically increase the quantity of labour (and expenditures on labour) without commensurate increase in productivity or output, and therefore negatively impacts TFP growth. Other effects of the demographic shift – like increases in sick days, vacation time - are also likely to pressure costs.

- Increased security needs – given local as well as global events, LDCs have had to substantially increase security operations and spending. Some LDCs have experienced increased costs related to theft of copper and resulting cost outlays for repair and replacement of damaged plant. Many LDCs have also had to institute new security plans and activities, cyber-security measures, and anti-terrorism protocols, and will continue to spend substantial funds in this general area.

- Outsourcing and external cost pressures – for example, when the market first opened, Hydro One began exiting the meter service provider business as meter reseal dates came up for renewal and many LDCs that had previously relied on Hydro One then had to contract with third-parties or develop in-house capabilities. Such meter service contracts and resulting OM&A cost increases will be part of the going forward status quo, and may in fact expand with the smart meter initiative and expanding customer requirements (for example, individual metering in condominiums buildings and time of use billings). Example of other external cost pressures include, for instance, rising vehicle fuel costs.

In order to achieve a sustainable, effective, and practical rate regime, recent trends in productivity among Ontario LDCs must be taken into account in setting the productivity target for the 3GIRM. PEG, in contrast attempts to disregard recent trends, claiming that the results are "biased" by "one time cost pressures." [6]

PEG's recommendation of 0.88% X factor for Ontario LDCs in 3GIRM stems from historical productivity analysis of a sample of US utilities, without any customization to the Ontario sector or consideration of business conditions in the province, or future trends in demand growth and other requirements on the businesses. In addition, the US sample includes utilities that have been operating under different conditions from the Ontario sector, and face different cost drivers because of the type of service they provide (i.e., bundled electric and gas distribution services or vertically integrated generation, transmission, and distribution services).

I recognize that a TFP growth estimate should be completed over a period that extends through a sufficiently long timeframe such that long run trends are represented.

[6] In the February 2008 PEG report, Larry Kaufmann asserts that some of these are transitory costs and may be to blame for the low TFP growth estimate for 2002-2006 but are not relevant for the next three to five years (page 45), but these costs, simply because of their make-up, are unlikely to disappear or even shrink in the course of 3GIRM.

Nonetheless, there needs to also be some accounting or understanding of business cycles and fundamental shifts in costs, and how they relate to future ratemaking. For example, the 0.88% average TFP growth estimate relied upon by PEG is associated with the period of 1995-2006, although if one were to look at a longer (20-year) period, the estimated TFP growth is in fact lower (0.72% per annum[7]), and recent US utility TFP growth rates (over the last four years) are even lower, averaging 0.41% per annum[8].

Although a long term analysis of TFP growth gives the Board an important historical perspective, looking at data that is too old may also be deceiving as it represents business conditions that are no longer relevant and unlikely to be relevant in the future.[9] The Board rightly recognized the importance of recent trends in making forward-looking policy decision in 1GIRM.

On this basis, I believe recent productivity trends in Ontario are critical to setting the X factor. PEG documents an average TFP growth of 0.01% per annum for 2002-2006.[10] As I discuss further below, I believe that this is an overstatement of actual TFP growth for Ontario LDCs for this period, and that productivity growth has in fact been negative. However, in either case, the implications are self-evident: the Ontario electricity distribution sector has been experiencing a substantial slowdown in productivity growth and perhaps even a reversal in trends.

Taking into account recent experience with TFP growth deceleration (reversal) is not only good statutory policy (given precedents from 1GIRM), but also good regulatory

[7] February 2008 PEG report, page 57 (Table 12). The 0.72% annual average TFP growth estimate for US distributors was estimated over the 1988 – 2006 timeframe.

[8] February 2008 PEG report, page 54.

[9] Larry Kaufmann concurs and notes that the "sample should not be so long that it includes information that is 'stale'." (February 2008 PEG report, page 31).

[10] February 2008 PEG report, page 42 (Table 6), page 43.

policy. Regulators need to be wary about regulatory risks that they, perhaps unintentionally, apply to regulated entities. Regulatory risk effectively gets passed through to customers because it is not a risk that can be diversified or hedged. And the reason that it is not diversifiable is because it is typically one-sided or asymmetric. Selection of an X factor does not need to be yet another example of this asymmetric, undiversifiable regulatory risk. In 1GIRM, Board acknowledged the ramp up in productivity and established productivity targets consistent with then recent trends. The Board should now recognize the slow down in productivity growth and set an X factor that similarly recognizes recent industry experience.

PEG also proposes a range of adders to the industry average X factor for setting firm-specific productivity targets. I disagree with PEG's proposal on several grounds. First, practically speaking, the adders that PEG developed are arbitrary and run the risk of distorting incentives because they are based on a flawed analysis of relative productivity using only partial productivity measures of OM&A (the attempts to include capital were unsuccessful and the proxy variable for system age is in fact representing volume growth rather than capital stock).

Moreover, although PEG aims to be 'scientific' in their approach, the actual level of stretch factors (scale) and how it is applied to firms (position of scale) is completely ad hoc. As I discuss further below, PEG is mixing apples and oranges by developing stretch factors that are adopting a 'frontier approach' and combining that with an industry-wide X factor. Furthermore, PEG's recommendations are conceptually flawed, as the suggested firm-specific adders are not properly addressing the diversity among LDCs. In effect, one can interpret PEG's position on stretch factors to imply that all Ontario LDCs are inefficient (or at best, just average) and therefore require an additional "push" to get more efficient. While this is possible, PEG has produced no evidence to support this. And such a position is counterintuitive to the historical record – LDCs in Ontario have been operating under explicit IR schemes or related rate freezes for years. A more reasonable starting position would be to assume that some LDCs are relatively efficient, some are of average efficiency and some are inefficient. Under such conditions, the stretch factors would have to be both positive and negative and centered around the industry average X factor.

In the aim of developing an effective rate regime for 3GIRM, I would recommend that the Board dispense with the PEG proposed consumer dividends until more data becomes available. Once additional data becomes available, robust relative productivity analysis can be completed on a comprehensive total cost basis, and the results of that analysis methodically applied to develop firm-specific adjustments for the industry average X factor.

Q10. Would your recommendations result in a delay in implementation of 3 GIRM?

A10. No, I do not believe that my recommendations would necessitate a delay. Although Board staff and PEG noted that they may be getting and employing slightly different data for the "final" TFP analysis,[11] a revision of the TFP index calculations per my specifications is easy and quick to implement. Nevertheless, the Board may want a working group of stakeholders to work through and confirm the analysis, with the ultimate aim of providing the Board with a consensus-built TFP. The design of the IPI will take a concentrated effort on behalf of a working group, but will benefit from the fact that the problems with the current IPI are generally identifiable, historic cost experiences of the LDCs can be useful as sanity checks, and actual industry data can be a good candidate for constructing substitute industry price indices in lieu of *Statistics Canada* data series. As a backstop, to the extent that an IPI design is taking longer than

[11] The Board's Chief Regulatory Auditor noted at the March 26, 2008 Workshop that the Board has undertaken a data recovery exercise of 1989-1997 data, which is targeted to be complete at the end of May. The Chief Regulatory Auditor noted that the Board staff "anticipate[s] having the data available for further use… [and] hopefully, [in] this exercise." March 26, 2008 Transcript, pg. 174, lines 15-17. In addition, Dr. Larry Kaufmann noted later on that data that due to the Board's position on data confidentiality and the need for transparency, PEG would be re-modeling the TFP figure using publicly available data, noting "since we have all agreed that we're going to use the more aggregated data as the basis for the TFP trends, we will be re-computing the TFP trends on the basis of those data." March 26, 2008 Transcript, pg. 190, lines 5-8.

anticipated, the Board can continue to use on an interim basis the GDP-IPI (which was used in 2GIRM as the inflation index in the RAM and will be used in the next generation of IR for natural gas distributors). A working group of key stakeholders, supported by expert consultants, would also be well-positioned to propose a strawman on the particular details of a capital investment module.

Q11. Do you have any additional recommendations for the Board in connection with incentive ratemaking?

A11. The value of incentive ratemaking is that it should lessen the regulatory burden on all parties by eliminating the need for the Board to delve into the details of annual cost of service reviews and therefore it hands operating control back to the utilities. However, the efficacy of such regulation lies in having access to good data to measure accurately the historical performance of distributors, be able to identify cost drivers and trends, and therefore be well-positioned to set up challenging, yet achievable productivity targets. The annual data that the utilities provide needs refinement so that it can be used with confidence for such benchmarking analysis. Indeed, additional data that describes the distribution networks and improvements in data consistency across utilities, which I discuss further below, can also improve measures of industry average productivity growth.

I would therefore recommend that the Board expressly condition approval of the 3GIRM scheme on establishing more concrete guidelines on reporting requirements and getting better data from LDCs, which will eventually be used to refine the RAM components in future generations of incentive ratemaking. The data should be improved in terms of timeframe coverage (given the Board's access to historical statistical yearbooks and 1GIRM data) and data coverage. The data set should be expanded to include other characteristics of the distribution system and specifically output produced, and overall LDC-to-LDC comparability, where appropriate, need to be improved through better guidelines.

III. Adding a Capital investment module to the RAM

Q12. In the Staff Discussion Paper, Board staff asked whether an incremental module for capital investment is necessary. Why do you believe a capital investment module is necessary?

A12. I believe that many LDCs in Ontario will need a capital investment module to remain financially viable, e.g., achieve their allowed rate of return, even if they are reducing costs in line with the productivity target. Financial viability is in fact a core objective identified by the Board at the outset of the 3GIRM consultation, "effective" regulation that "provides for prudent capital investment".[12] In addition, a capital investment module will ensure that the Board's other criteria are met, such as predictability (which "facilitates planning"), as well sustainability (which the Board defined as "flexible and reasonably able to handle changing and varied circumstances facilitates planning by consumers and LDCs").[13]

Q13. Isn't some level of capital investment already embedded in the rates and price cap mechanism?

A13. Yes, some level of capital investment is represented in the basic price cap formula or inflation less an X factor. However, the heart of the issue is that the basic price cap formula cannot warrant that capital investment needs will be met completely, because it makes implicit assumptions about the pattern of capital investment: namely that capital investment has been smooth and consistent with the pace of depreciation (also referred to commonly as amortization), such that the rate base (net book value) remains stable over time.

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[12] *See* Ontario Energy Board, 3rd Generation Incentive Regulation for Electricity Distributors. Staff Scoping Paper. EB-2007-0673. August 2, 2007 and Ontario Energy Board, Staff Discussion Paper on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, February 28, 2008, pg.10. ("Staff Scoping Paper").

[13] Id.

It is important to recognize that capital investment is effectively not discretionary in the electricity distribution sector. Ontario LDCs are required to maintain a reasonable quality of service so that their connected customers do have access to the transmission network and the energy being transmitted and distributed. Capital expenditures are therefore necessary to meet basic business requirements, and cannot be avoided or substantially delayed.

Furthermore, it is also important to recognize that capital investment is lumpy and cyclical. In fact there have been periods of heavy investment in the industry, as well as periods of low investment.

Although the base rate, on which the RAM is applied, includes a return component and some return of capital invested (through the depreciation allowance), the value of this depreciation allowance is based on *historical costs of the original capital investment* and may be substantially below current market prices for replacement capital. And although the X factor is a comprehensive measure of productivity, it is calibrated to observed *historical* levels of productivity growth achieved, which, again, may not be representative of current or future needs. We therefore have the issue the Board staff acknowledged in the Staff Discussion Paper, "amortization is not a good predictor of future capital expenditure needs".[14]

Q14. For growth-related capital investment, will additional demand be sufficient to cover the costs of such investment?

A14. Even for growth-related capital investment, a price cap based on I – X may be insufficient. Capital investment is lumpy, which may lead to periods of time, after the initial investment, when the new capital is underutilized. Therefore, the increased

[14] Ontario Energy Board. Staff Discussion Paper on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. February 28, 2008, pg. 17.

volume is not sufficient to fully recoup investment costs. In addition, if the current price includes a return of capital component (i.e., depreciation allowance) that is out of synch with current capital prices, then the revenues may not be sufficient to cover the costs of this investment.

Q15. Can you provide an example illustrating the situations you describe above?

A15. I created a financial model using approximately actual data for an Ontario LDC with some hypothetical assumptions on going forward X factor and inflation, cost reductions, capital expenditure requirements, and volume growth. The input assumptions are documented in the figure below. The main objective of the model is to demonstrate the implications of the price cap mechanism on an LDC's revenues, profits, and rate of return.

Figure 2. Assumptions used in financial model

tariff (base year)	$17.5	per MWh
Inflation	2.0%	
X factor	0.5%	
electricity volume (base year)	6.75	million MWh
Volume Growth	1.0%	
OM&A (base year)	$40	million
OM&A cost reduction (p.a.)	0.5%	
Implied tax rate	35.0%	
rate base (base year)	$575	million
annual capex	$45	million
interest rate	6.1%	
leverage	60.0%	
amortization rate for pre-existing rate base	4.0%	
amortization rate for new capital additions	7.0%	
allowed ROE	8.60%	

The figure on page 21 shows the build up of revenues from projected rates and volumes, with rates growing based on the adjustment formula of I - X. Even with rate increases due to inflation exceeding the target X factor, and despite operating cost gains that keep pace with the productivity target, and growth in demand, operating profits are outpaced by rising interest expense and amortization. Amortization and interest expense are growing because of the necessary capital expenditures. ROEs fall precipitously below allowed levels, averaging 7.3% over the five-year term. In reality, this degradation in allowed rates of return would likely lead to scaling down of capital investment (with possible service quality ramifications) or a request for cost of service rates by this firm, although this firm is a good performer and is achieving productivity gains.

The deteriorating financial conditions are in fact prevalent under a variety of assumptions regarding both the inflation and X factor, as well as the level of capital expenditures. I performed a sensitivity analysis, where I analyzed the average five-year returns for the LDC under a range of inflation, X factor assumptions and capital expenditure levels. I assumed a range of I – X from -3% (i.e., rates would decline annually by 3%) to +3% (i.e., rates would rise by 3% annually). I also tested annual capital expenditure levels ranging from $25 million to $60 million (for simplicity, I retained the constant capital expenditure profile over the five years that I had modeled previously). The results of the sensitivity are documented in the table in Figure 4 on page 22. Notably, of the 72 combinations presented below, 62 cases resulted in a five-year average ROE less than the allowed rate of return of 8.6%.

Figure 3. Results of financial model, with I - X price cap

		Base Year (T)	Year T+1	Year T+2	Year T+3	Year T+4	Year T+5
Distribution Rates	*$/MWh*	**$17.5**	**$ 17.76**	**$ 18.03**	**$ 18.30**	**$ 18.57**	**$ 18.85**
Rate Adjustment Mechansim	*1 + (I -X)*		*101.5%*	*101.5%*	*101.5%*	*101.5%*	*101.5%*
Volume Served	*MWh*	6,750,000	6,817,500	6,885,675	6,954,532	7,024,077	7,094,318
Revenues	*$ millions*	$ 118.1	$ 121.1	$ 124.1	$ 127.3	$ 130.5	$ 133.7
OM&A Expenses	*$ millions*	$ 40.0	$ 40.6	$ 41.2	$ 41.8	$ 42.4	$ 43.1
Earnings Before Interest, Amortization, Taxes	*$ millions*	**$ 78.1**	**$ 80.5**	**$ 82.9**	**$ 85.4**	**$ 88.0**	**$ 90.7**
Amortization of capital invested	*$ millions*	$ 26.2	$ 29.3	$ 32.5	$ 35.6	$ 38.8	$ 41.9
Interest expense	*$ millions*	$ 21.4	$ 22.0	$ 22.5	$ 22.9	$ 23.2	$ 23.4
Earnings Before Taxes	*$ millions*	**$ 30.6**	**$ 29.2**	**$ 28.0**	**$ 26.9**	**$ 26.0**	**$ 25.4**
Payment in lieu of taxes	*$ millions*	$ 10.7	$ 10.2	$ 9.8	$ 9.4	$ 9.1	$ 8.9
Net Income	*$ millions*	**$ 19.9**	**$ 19.0**	**$ 18.2**	**$ 17.5**	**$ 16.9**	**$ 16.5**

		Base Year (T)	Year T+1	Year T+2	Year T+3	Year T+4	Year T+5
Rate Base (rolled into Distribution Rates)	*$ millions*	$ 575.0	$ 575.0	$ 575.0	$ 575.0	$ 575.0	$ 575.0
Book Value - Opening Balance	*$ millions*	$ 575.0	$ 593.9	$ 609.6	$ 622.1	$ 631.5	$ 637.8
Capex	*$ millions*	$ 45.0	$ 45.0	$ 45.0	$ 45.0	$ 45.0	$ 45.0
Amortization	*$ millions*	$ 26.2	$ 29.3	$ 32.5	$ 35.6	$ 38.8	$ 41.9
Book Value - Closing Balance	*$ millions*	$ 593.9	$ 609.6	$ 622.1	$ 631.5	$ 637.8	$ 640.9
Mid-year Book Value	*$ millions*	**$ 584.4**	**$ 601.7**	**$ 615.8**	**$ 626.8**	**$ 634.6**	**$ 639.3**

		Base Year (T)	Year T+1	Year T+2	Year T+3	Year T+4	Year T+5
Net Income	*$ millions*	**$ 19.9**	**$ 19.0**	**$ 18.2**	**$ 17.5**	**$ 16.9**	**$ 16.5**
Mid-year Book Value	*$ millions*	$ 584.4	$ 601.7	$ 615.8	$ 626.8	$ 634.6	$ 639.3
Debt	*$ millions*	$ 350.7	$ 361.0	$ 369.5	$ 376.1	$ 380.8	$ 383.6
Equity	*$ millions*	$ 233.8	$ 240.7	$ 246.3	$ 250.7	$ 253.9	$ 255.7
Return on Equity		**8.50%**	**7.88%**	**7.38%**	**6.98%**	**6.67%**	**6.45%**

Figure 4. Five-year average ROE under different combinations of inflation, X factor, and capital expenditure assumptions

Annual Capex	-3.0%	-2.25%	-1.50%	-0.75%	0.00%	0.75%	1.50%	2.25%	3.00%
	Inflation - X factor								
$25	5.9%	6.6%	7.2%	7.8%	8.5%	9.2%	9.8%	10.5%	11.3%
$30	5.4%	6.0%	6.6%	7.2%	7.8%	8.5%	9.2%	9.8%	10.5%
$35	4.8%	5.4%	6.0%	6.6%	7.2%	7.9%	8.5%	9.2%	9.8%
$40	4.3%	4.9%	5.5%	6.1%	6.7%	7.3%	7.9%	8.5%	9.2%
$45	3.8%	4.4%	4.9%	5.5%	6.1%	6.7%	7.3%	7.9%	8.6%
$50	3.4%	3.9%	4.4%	5.0%	5.6%	6.2%	6.8%	7.4%	8.0%
$55	2.9%	3.4%	4.0%	4.5%	5.1%	5.6%	6.2%	6.8%	7.4%
$60	2.5%	3.0%	3.5%	4.0%	4.6%	5.1%	5.7%	6.3%	6.9%

Q16. Under what conditions will a comprehensive price cap with only an inflation index and productivity target adequately remunerate an LDC?

A16. Economic theory claims that under a "steady state," the basic price cap regime (with an inflation index and X factor) should be sufficient. Only under some very limiting conditions will the price cap with an inflation index and X factor provide for sufficient profits to maintain operations. For example, if a utility has a relatively new asset base, then the discrepancies between historical cost-based depreciation (amortization) and replacement cost of new capital should be muted. Alternatively, if an LDC is not making substantial investments because of its current investment cycle, then over that period of time, cashflow pressures should be minimized and returns stabilized so long as the firm is achieving efficiency gains. In general, an "I – X" price cap regime is sufficient only when annual rate base growth is in line with the annual change in depreciation expense. Such circumstances are not likely to hold for many LDCs in Ontario over the proposed term of 3GIRM.

Q17. How pervasive are the discrepancies between capital investment and depreciation in Ontario's electric distribution industry?

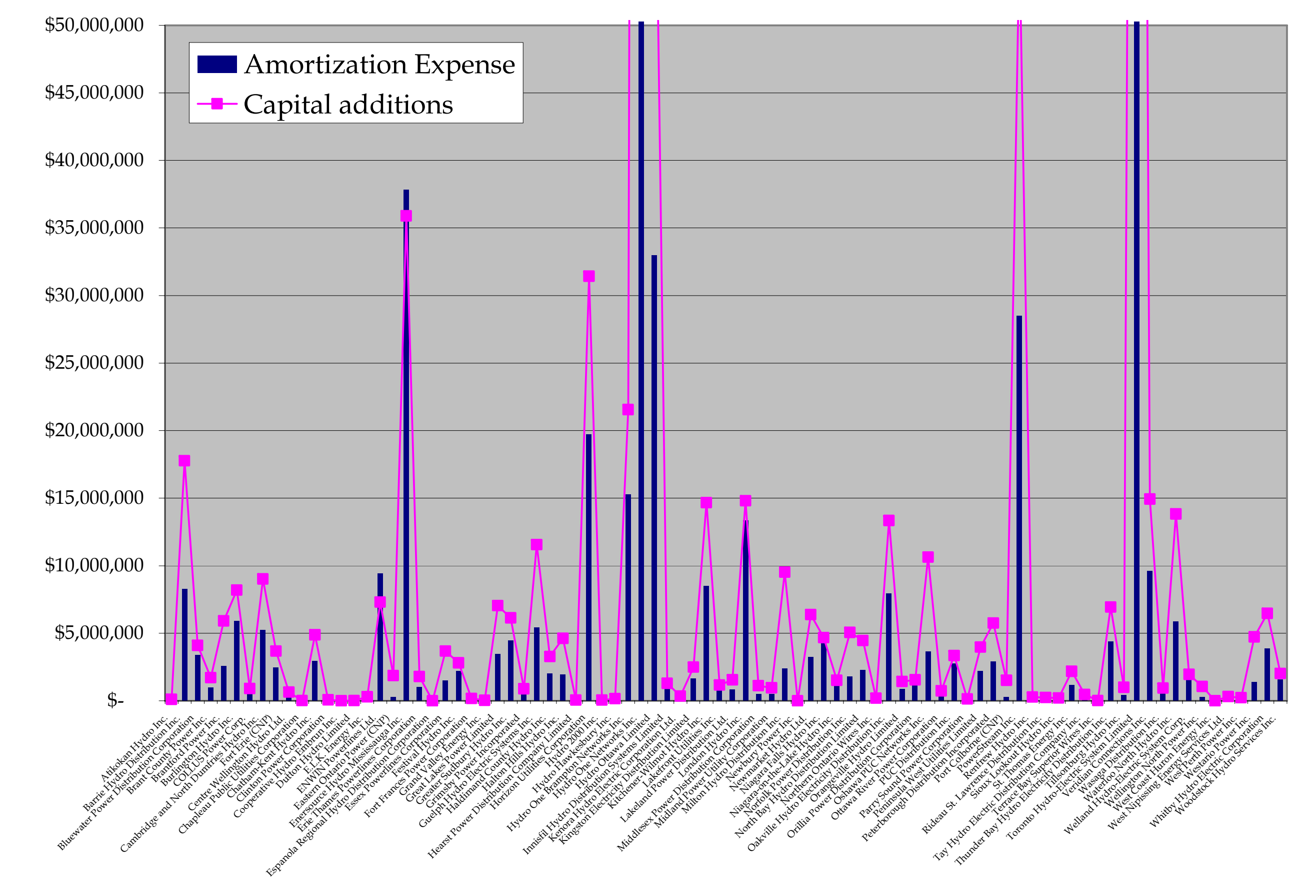
A17. Without analyzing each utility's pro forma financials, I cannot give a definitive answer, but a cursory review of 2006 data filed under the Reporting and Recordkeeping Requirements (RRRs) and presented in the September 7, 2007 Cost Comparisons Database of Ontario Electricity Distributors (CCM Database),[15] shows that 65 of the 86 firms listed had capital expenditures in 2006 that exceed their amortization expenses (for example, in Figure 5 below, every time the pink line rises above the blue bar, then that firm represented by the blue bar experienced a shortfall between amortization and capital spending in 2006). On average, the shortfall between capital spending and

[15] Source: http://www.oeb.gov.on.ca/documents/cases/EB-2006-0268/spreadsheet_ontarioelectricitydistributorscosts_20070907.xls.

amortization expense in 2006 was over $6.1 million for these 65 firms, but for some, the shortfall between amortization and capital spending was as much as $128 million in that year (Figure 6 contains a complete list of data for each LDC from the CCM Database). Although this is a snapshot in time, and the capital expenditure figure may include expansion-related spending as well as replacement, it is indicative of the problem arising from the disconnect between depreciation and capex.

Growth pressures and the need to renew major portions of the network will inevitably exaggerate the lumpy investment profile and this disconnect in depreciation and capex, putting further strain on a utility's financials. For example, half of the 86 electricity distributors have an asset base that is 50% or more depreciated as of 2006, based on reported data on gross book value and accumulated depreciation in the CCM Database, (see Figure 7 below).

Figure 5. Divergence between capital additions and amortization expense (2006)



Note: Y-axis values are intentionally cutoff at $50 million, to allow for a view of the situation for majority of LDCs. Therefore, for completeness, the table below has the underlying data for each LDC in Ontario.

Figure 6. Tabular data underlying Figure 5

LDC	Capital additions (2006)	Amortization Expense (2006)	Does capex exceed amortization expense?	How big is the shortfall in amortization vis-à-vis capex?
Atikokan Hydro Inc.	$109,897	$181,721	No	
Barrie Hydro Distribution Inc.	$17,769,650	$8,279,871	Yes	$9,489,779
Bluewater Power Distribution Corporation	$4,097,888	$3,394,877	Yes	$703,011
Brant County Power Inc.	$1,701,477	$969,174	Yes	$732,303
Brantford Power Inc.	$5,905,835	$2,556,008	Yes	$3,349,827
Burlington Hydro Inc.	$8,196,416	$5,920,601	Yes	$2,275,815
COLLUS Power Corp.	$904,081	$767,646	Yes	$136,435
Cambridge and North Dumfries Hydro Inc.	$9,021,293	$5,234,187	Yes	$3,787,106
Fort Erie (CNP)	$3,684,687	$2,464,724	Yes	$1,219,963

LDC	Capital additions (2006)	Amortization Expense (2006)	Does capex exceed amortization expense?	How big is the shortfall in amortization vis-à-vis capex?
Centre Wellington Hydro Ltd.	$640,611	$488,770	Yes	$151,842
Chapleau Public Utilities Corporation	$24,291	$37,370	No	
Chatham-Kent Hydro Inc.	$4,884,102	$2,970,412	Yes	$1,913,690
Clinton Power Corporation	$78,211	$49,806	Yes	$28,405
Cooperative Hydro Embrun Inc.	$0	$112,741	No	
Dutton Hydro Limited	$15,498	$21,904	No	
E.L.K. Energy Inc.	$302,763	$642,658	No	
ENWIN Powerlines Ltd.	$7,313,900	$9,417,063	No	
Eastern Ontario Power (CNP)	$1,859,166	$275,906	Yes	$1,583,260
Enersource Hydro Mississauga Inc.	$35,886,428	$37,852,492	No	
Erie Thames Powerlines Corporation	$1,788,589	$1,023,655	Yes	$764,935

LDC	Capital additions (2006)	Amortization Expense (2006)	Does capex exceed amortization expense?	How big is the shortfall in amortization vis-à-vis capex?
Espanola Regional Hydro Distribution Corporation	$1,234	$188,561	No	
Essex Powerlines Corporation	$3,677,870	$1,497,416	Yes	$2,180,454
Festival Hydro Inc.	$2,804,029	$2,190,695	Yes	$613,334
Fort Frances Power Corporation	$174,355	$384,100	No	
Grand Valley Energy Inc.	$30,073	$41,915	No	
Great Lakes Power Limited	$7,052,228	$3,464,633	Yes	$3,587,595
Greater Sudbury Hydro Inc.	$6,137,566	$4,465,185	Yes	$1,672,381
Grimsby Power Incorporated	$884,091	$809,449	Yes	$74,642
Guelph Hydro Electric Systems Inc.	$11,569,000	$5,423,227	Yes	$6,145,773
Haldimand County Hydro Inc.	$3,275,338	$2,026,392	Yes	$1,248,946
Halton Hills Hydro Inc.	$4,617,056	$1,930,209	Yes	$2,686,847

LDC	Capital additions (2006)	Amortization Expense (2006)	Does capex exceed amortization expense?	How big is the shortfall in amortization vis-à-vis capex?
Hearst Power Distribution Company Limited	$57,943	$97,698	No	
Horizon Utilities Corporation	$31,425,369	$19,729,625	Yes	$11,695,744
Hydro 2000 Inc.	$51,362	$44,364	Yes	$6,998
Hydro Hawkesbury Inc.	$150,888	$162,043	No	
Hydro One Brampton Networks Inc.	$21,563,451	$15,278,462	Yes	$6,284,989
Hydro One Networks Inc.	$378,500,000	$250,671,600	Yes	$127,828,400
Hydro Ottawa Limited	$70,722,819	$32,979,486	Yes	$37,743,333
Innisfil Hydro Distribution Systems Limited	$1,298,789	$1,550,134	No	
Kenora Hydro Electric Corporation Ltd.	$344,391	$367,748	No	
Kingston Electricity Distribution Limited	$2,501,729	$1,646,429	Yes	$855,300
Kitchener-Wilmot Hydro Inc.	$14,663,461	$8,510,357	Yes	$6,153,104

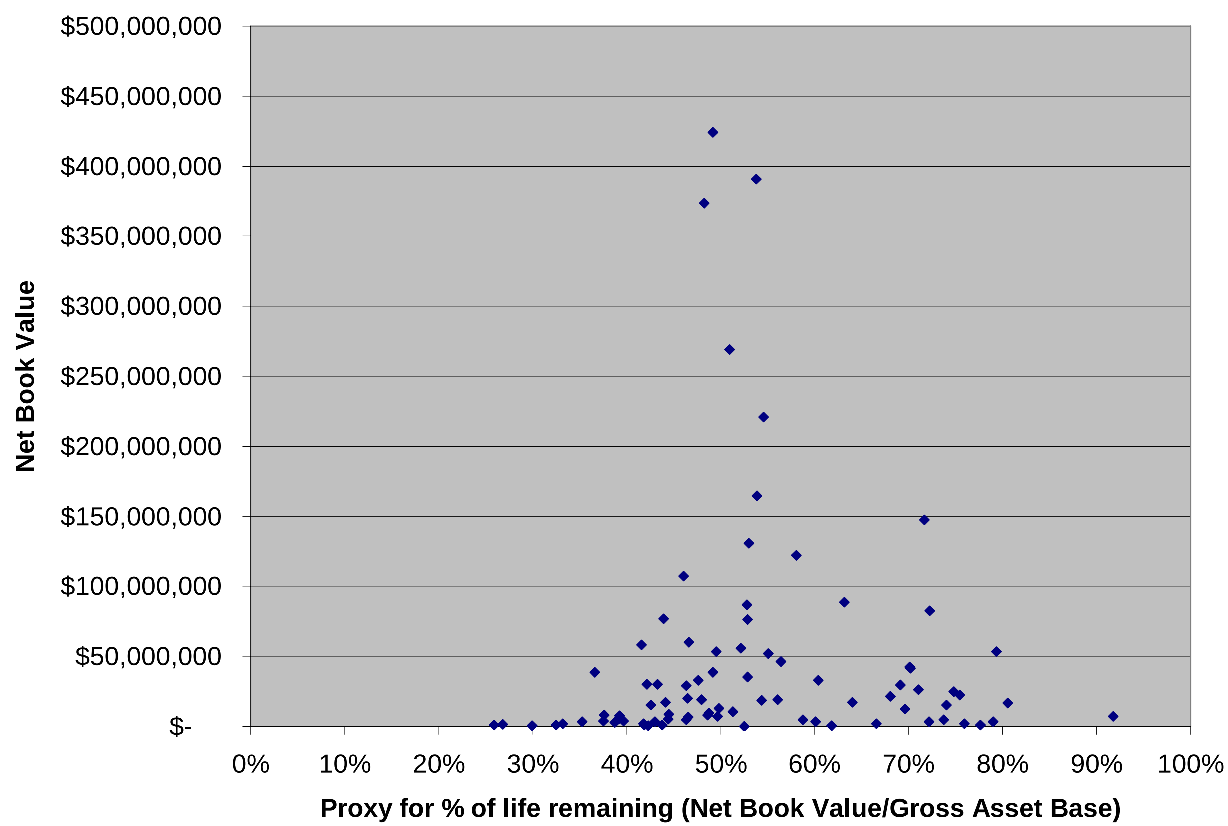
LDC	Capital additions (2006)	Amortization Expense (2006)	Does capex exceed amortization expense?	How big is the shortfall in amortization vis-à-vis capex?
Lakefront Utilities Inc.	$1,173,063	$824,816	Yes	$348,247
Lakeland Power Distribution Ltd.	$1,543,831	$834,432	Yes	$709,400
London Hydro Inc.	$14,799,324	$13,351,523	Yes	$1,447,801
Middlesex Power Distribution Corporation	$1,118,084	$481,992	Yes	$636,092
Midland Power Utility Corporation	$953,561	$497,831	Yes	$455,730
Milton Hydro Distribution Inc.	$9,527,762	$2,381,999	Yes	$7,145,763
Newbury Power Inc.	$0	$13,086	No	
Newmarket Hydro Ltd.	$6,389,729	$3,259,164	Yes	$3,130,565
Niagara Falls Hydro Inc.	$4,672,285	$4,354,697	Yes	$317,588
Niagara-on-the-Lake Hydro Inc.	$1,517,368	$1,247,363	Yes	$270,005
Norfolk Power Distribution Inc.	$5,049,756	$1,817,777	Yes	$3,231,979

LDC	Capital additions (2006)	Amortization Expense (2006)	Does capex exceed amortization expense?	How big is the shortfall in amortization vis-à-vis capex?
North Bay Hydro Distribution Limited	$4,459,906	$2,283,832	Yes	$2,176,074
Northern Ontario Wires Inc.	$184,228	$317,223	No	
Oakville Hydro Electricity Distribution Inc.	$13,350,051	$7,943,770	Yes	$5,406,281
Orangeville Hydro Limited	$1,423,060	$885,464	Yes	$537,596
Orillia Power Distribution Corporation	$1,552,615	$1,359,080	Yes	$193,535
Oshawa PUC Networks Inc.	$10,634,423	$3,659,116	Yes	$6,975,307
Ottawa River Power Corporation	$736,154	$697,057	Yes	$39,097
PUC Distribution Inc.	$3,356,036	$2,764,612	Yes	$591,424
Parry Sound Power Corporation	$133,809	$380,084	No	
Peninsula West Utilities Limited	$3,968,771	$2,222,119	Yes	$1,746,652
Peterborough Distribution Incorporated	$5,752,245	$2,900,527	Yes	$2,851,718

LDC	Capital additions (2006)	Amortization Expense (2006)	Does capex exceed amortization expense?	How big is the shortfall in amortization vis-à-vis capex?
Port Colborne (CNP)	$1,525,495	$269,269	Yes	$1,256,226
PowerStream Inc.	$56,197,851	$28,500,487	Yes	$27,697,365
Renfrew Hydro Inc.	$286,661	$359,870	No	
Rideau St. Lawrence Distribution Inc.	$252,819	$192,866	Yes	$59,952
Sioux Lookout Hydro Inc.	$208,644	$232,779	No	
St. Thomas Energy Inc.	$2,184,234	$1,187,635	Yes	$996,599
Tay Hydro Electric Distribution Company Inc.	$469,807	$282,724	Yes	$187,083
Terrace Bay Superior Wires Inc.	$20,923	$90,479	No	
Thunder Bay Hydro Electricity Distribution Inc.	$6,936,925	$4,384,439	Yes	$2,552,486
Tillsonburg Hydro Inc.	$996,413	$409,940	Yes	$586,473
Toronto Hydro-Electric System Limited	$198,056,369	$124,560,191	Yes	$73,496,178

LDC	Capital additions (2006)	Amortization Expense (2006)	Does capex exceed amortization expense?	How big is the shortfall in amortization vis-à-vis capex?
Veridian Connections Inc.	$14,935,375	$9,619,991	Yes	$5,315,384
Wasaga Distribution Inc.	$940,822	$616,862	Yes	$323,960
Waterloo North Hydro Inc.	$13,835,703	$5,858,566	Yes	$7,977,137
Welland Hydro-Electric System Corp.	$1,954,654	$1,541,359	Yes	$413,295
Wellington North Power Inc.	$1,064,041	$253,460	Yes	$810,581
West Coast Huron Energy Inc.	$0	$207,686	No	
West Nipissing Energy Services Ltd.	$317,177	$170,323	Yes	$146,854
West Perth Power Inc.	$221,249	$186,551	Yes	$34,698
Westario Power Inc.	$4,717,752	$1,382,224	Yes	$3,335,528
Whitby Hydro Electric Corporation	$6,468,970	$3,896,884	Yes	$2,572,086
Woodstock Hydro Services Inc.	$2,030,837	$1,581,823	Yes	$449,014

Figure 7. Asset base (net book value) versus % of asset base depreciated (2006)



Q18. Are there jurisdictions that have successfully implemented price caps without a capital investment module?

A18. The UK distribution industry has never had a CAPEX factor explicitly, and one could argue that the performance based ratemaking regime has been successful. There have been substantial efficiency gains made, customers have benefited from rate decreases, and distribution companies have fared well under that regime.[16] But keep in mind that the distribution companies began the price cap with a lot of "fat", the starting position allowed them to meet their profitability targets even in the face of extensive cost cuts. In addition, the UK system's form of price cap regulation is substantially different from what is being contemplated in Ontario for 3GIRM. The UK regulator has used an approach known as the "building block" method, where (some level of) forecasted capital investments are taken into account in the derivation of the price cuts at the start of the generation (referred to as P_0) and X factor. Therefore, one can posit that the X factor – to some degree – reflects capital needs in the UK price cap regime for electricity distribution businesses.

Although most US utilities under price cap regimes have also not required an explicit capital investment module, that is not to say that they will not need one in the future. Indeed, part of the reason why the "I – X" price cap has worked for some US utilities is related to the underlying circumstances and US utilities' position in the investment cycle. Over the last 10-15 years, distribution investments, similarly to other 'wires' investments like transmission, have been lagging behind other infrastructure investments, such as generation development. In other words, many US utilities have probably been operating close to a 'steady state' paradigm.

[16] Goulding, A.J., Julia Frayer, Jeffrey Waller "*X Marks the Spot*: How UK Utilities Have Fared Under Performance-Based Ratemaking" *Public Utilities Fortnightly*, July 15, 2001.

In addition, for some US utilities, a price cap regime involves a structure very similar to the UK's building block approach, where capital investment is scheduled on a forward basis, reviewed (by technical consultants) and then rationalized; the X factor in combination with the price cut at rebasing then forms the glide path for rates taking into account efficient operating costs and scheduled capital investment needs. In other words, a capital investment outlook – and surety of cost recovery - is embedded in the X factor.

In New Zealand, some of the electricity distributors will in the medium term (possibly at some point in the next generation of the price control regime) enter periods of extensive asset replacement – also referred to as the "wall of wires" problem. To date, the New Zealand price control regime for distribution businesses has not explicitly accommodated capital investment, although the price path threshold included some factoring of profitability. The Commerce Commission, however, has acknowledged the need to incorporate additional mechanisms for incentivizing efficient investment in the future, including possibly an "I factor" which would "allow [distributors] additional revenue to invest in their networks."[17] The Commerce Commission is currently in the process of enlisting stakeholder comment on this and other aspects of its resetting of the thresholds for 2009 through 2014.

In effect, although we have had over two decades of experience with (different flavors and forms of) PBR across a number of jurisdictions, those two decades have likely encompassed a period of low investment, therefore presenting policymakers with the 'steady state' presumptions discussed above and obviating the need for consideration of a capital investment module for the time being.

[17] Commerce Commission. Regulation of Electricity Lines Businesses: Targeted Control Regime, Threshold Reset 2009, Discussion Paper. December 19, 2007, pg. 55.

Q19. What kind of capital investment module would you recommend?

A19. The 2007 Working Group, as summarized in the Staff Discussion Paper, considered a number of approaches with respect to investment modules and investment incentive mechanisms. And I believe each proposal has individual merit. Ideally, it would be preferable to have each utility choose the option that best suits its circumstances. However, that would inevitably increase the regulatory burden on the Board in setting 3GIRM rates.

Consistent with the spirit of simplifying and 'automating' rate applications, while also retaining some level of flexibility, I would recommend that the comprehensive price cap formula include a third term, a CAPEX factor, which would be added to the "I – X" components and would therefore result in a rate increase, holding all else constant. For example, going back to my simple example from earlier, if the inflation factor is determined to be 2%over the previous annual period and the X factor is set at 0.5% and the CAPEX factor is set at 1%, then rates will increase by 2.5% from the previous year (2% inflation – 0.5% X factor + 1% CAPEX factor).

Q20. What does the CAPEX factor represent?

A20. The CAPEX factor provides a means for rates to increase in order to allow the LDC to finance capital investment. From a tariff design perspective, the CAPEX factor would represent a true-up to the notional allowed revenue requirement (to achieve the allowed rate of return), assuming adequate (good) performance by the utility. In effect, it will be the additional revenue requirement that a utility needs to receive above and beyond that which is already embedded in rates (i.e., beyond the depreciation (amortization) allowance already in rates) in order to maintain its allowed ROE, taking into account targeted productivity gains (and resulting profits), the impact of volume growth, etc.

Similarly to the IPI and X factor, the CAPEX factor would be denominated in percentage terms, so that it can be simply incorporated into the mechanistic RAM.

Q21. How do you propose to calculate the CAPEX factor?

A21. There are a number of ways to estimate the CAPEX factor. If the utility is willing to provide a multi-year forward capital investment schedule for the term of the IR, then that capital additions schedule can be used to determine rate trajectory and therefore an annual adjustment factor (in % terms) to sufficiently fund such capital expenditure (capex). This approach would require some ex ante prudence review, as well as financial modeling to isolate the CAPEX factor against other financial parameters. Although the CAPEX factor would set the trajectory for rates, as does the X factor and inflation index, financial statements and regulatory accounts will reflect only that capital that was placed in service, so this method does not attempt to increase ratebase for fictitious (not yet in service) capital.

Alternatively, a CAPEX factor based on observable relationships between business variables (such as volume growth and asset age) and financial viability of an LDC could be developed. Note that these business variables – asset age and volume growth – are linked to the need for a capital investment module and are therefore implicitly representing capex. Based on analysis of actual Ontario data, quantitative relationships would be developed that would identify the typical level of CAPEX factor necessary if an LDC has, for example, volume growth of 2% per annum and an average system age of 28 years (or, as proxy for system age, a net book value that is 40% of the gross book value). Different combinations of such parameters would be tested and related to a CAPEX factor value, so that eventually LDCs would simply indentify the most similar combination of parameters to their circumstances and be presented with a CAPEX factor.

Q22. The Board has stated that it will allow individual utilities to propose alternative mechanisms if the core model is not sufficient for a particular utility's needs. Why should the CAPEX factor be part of the standard price cap mechanism for all utilities in 3GIRM?

A22. As discussed above, the capital investment "problem" associated with the insufficiency of historical based depreciation is pervasive. It should not be treated as an issue effecting a limited subgroup of LDCs or arising 'unexpectedly' (like a Z factor). The capital investment aging and replacement problem is substantial, highly anticipated by most utilities in the Province, and will only become more substantial over time, as a result of government directives, growth-driven expansions, and replacement programs of aging assets. The Rate Adjustment Mechanism (RAM) – to be sustainable into future regimes – should define how the capital investment module will work. If a utility does not need a capital investment module, given its circumstances, then that utility would simply ignore (or zero out) that element of the price cap.

Q23. Can you demonstrate how the CAPEX factor would alleviate the concerns of financial viability and improve rate stability?

A23. If we return to the financial model example that I previously described, I can use that model to illustrate the impact of the CAPEX factor. Assuming the same assumptions as outlined in Figure 2 on page 19, I have simply inserted a CAPEX factor of 1% per annum into the RAM. The utility continues to make operating efficiency gains and volume grows by 1% per annum. I have retained my previous assumption of annual capex in the range of $45 million.

The CAPEX factor allows rates to climb at a slightly higher pace than in an "I – X" regime (2.5% per annum versus 1.5% per annum). Net income is boosted such that the five-year average ROE is over 8.1% (in contrast to the 7.3% under the "I – X" formula). Figure 8 on the next page highlights the rate differences under a price cap with and without this 1% CAPEX factor, as well as the implications for ROE.

I also extended the financial model to a second generation of price caps for five more years, taking into account re-basing, with updates in revenue requirement from ratebase increases as a result of capital additions made in previous period and operating cost gains. I assumed also that the X factor would increase to 1 % in the second generation. I then projected rates with and without a CAPEX factor. Without a CAPEX factor, rates need to rise by 9% to get to the allowed ROE at re-basing. With a CAPEX factor, rates only need to rise by less than half of that amount. The rate smoothing characteristics of the CAPEX factor is illustrated in Figure 9 on page 41.

Figure 8. Comparing financial results for an LDC: with and without a CAPEX factor

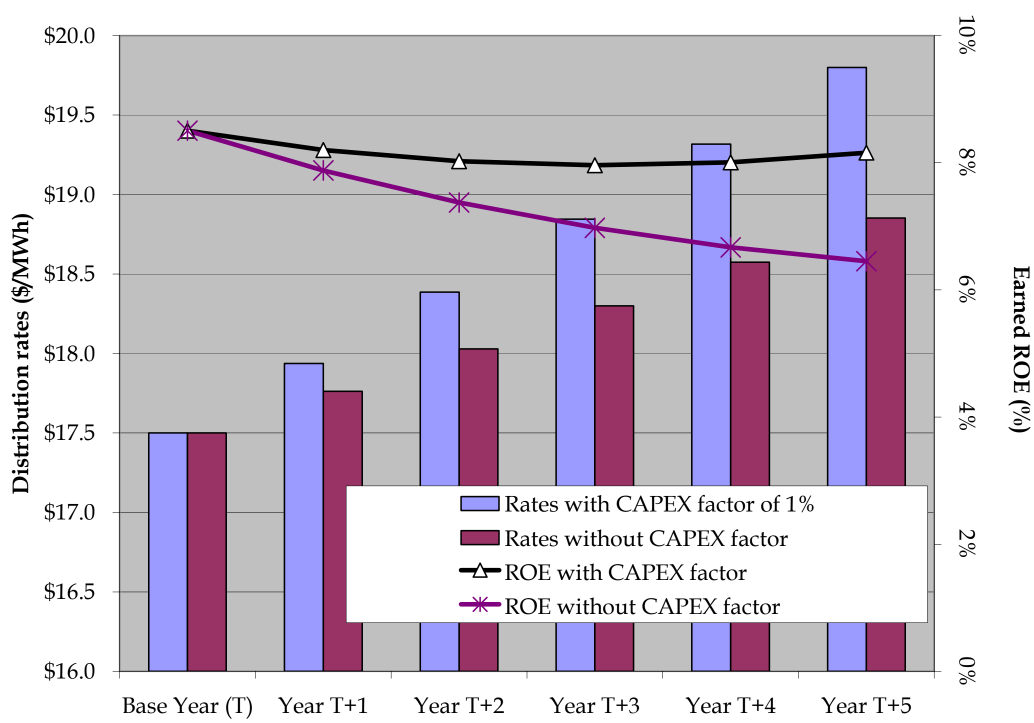
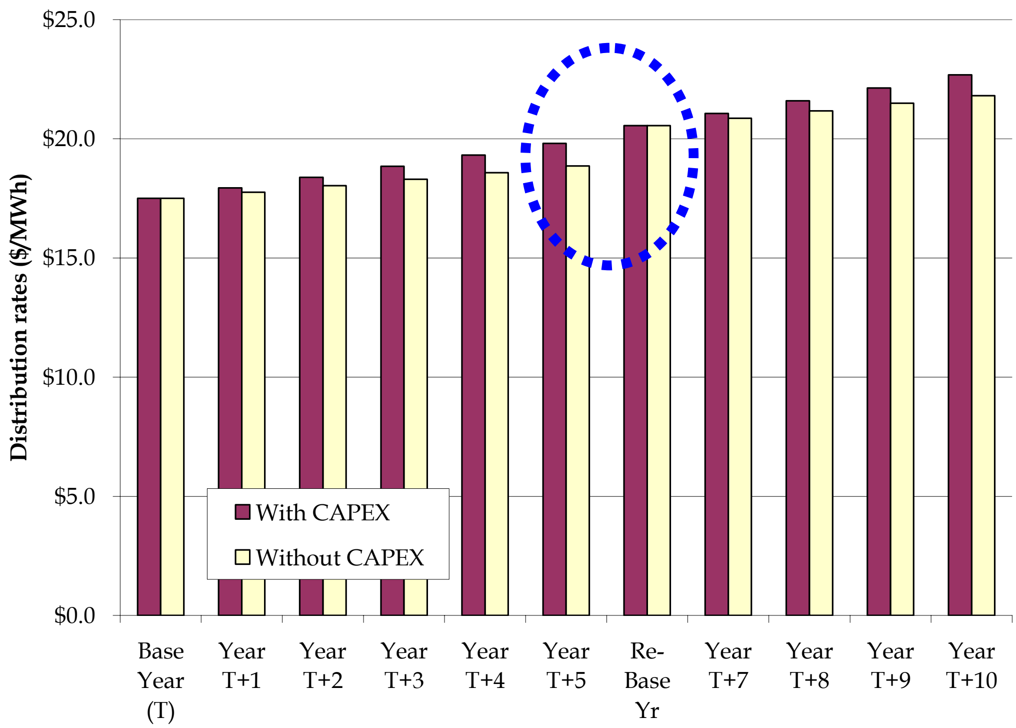


Figure 9. CAPEX factor minimizes rate shock at re-basing



Q24. How complicated would the analysis be to determine a CAPEX factor with a multi-year capital expenditure schedule?

A24. It would not be too difficult. The primary requirements would be a forward capital expenditure scheduled, and a pro forma financial model with the price cap RAM, based on some assumed inflation rate and Board-approved X factor. Operating costs would be pegged to the X factor, so that we are consistent with the presumption that the utility is performing well and meeting the productivity target. Then, the model could be set up to automatically generate annual CAPEX factors that allow the LDC to achieve the allowed ROE set by the Board. I have employed the financial model that I had briefly discussed above to illustrate how this would work (I have again retained all the same assumptions that I had described previously in Figure 2 on page 19 (e.g., 2% inflation rate, 0.5% X factor (with 0.5% real cost gains), 1% volume growth, and $45 million in capital expenditures forecast for each of the five years). An annual CAPEX factor ranging from 2.2% (in first year) to 0.5% (in fifth year) would be appropriate, in order to allow the LDC to maintain an 8.6% ROE. It is instructive to contrast the financial schedule in Figure 10 against the projected financials for this LDC without the CAPEX factor, in Figure 3 on page 21).

Figure 10. Deriving a CAPEX factor from a forward schedule of CAPEX

		Base Year (T)	Year T+1	Year T+2	Year T+3	Year T+4	Year T+5
Distribution Rates	*$/MWh*	**$17.5**	**$ 18.15**	**$ 18.69**	**$ 19.20**	**$ 19.64**	**$ 20.03**
CAPEX factor			*2.2%*	*1.5%*	*1.2%*	*0.8%*	*0.5%*
Volume Served	*MWh*	6,750,000	6,817,500	6,885,675	6,954,532	7,024,077	7,094,318
Revenues	*$ millions*	$ 118.1	$ 123.7	$ 128.7	$ 133.5	$ 137.9	$ 142.1
OM&A Expenses	*$ millions*	$ 40.0	$ 40.6	$ 41.2	$ 41.8	$ 42.4	$ 43.1
Earnings Before Interest, Amortization, Taxes	*$ millions*	**$ 78.1**	**$ 83.1**	**$ 87.5**	**$ 91.7**	**$ 95.5**	**$ 99.0**
Amortization of capital invested	*$ millions*	$ 26.2	$ 29.3	$ 32.5	$ 35.6	$ 38.8	$ 41.9
Interest expense	*$ millions*	$ 21.4	$ 22.0	$ 22.5	$ 22.9	$ 23.2	$ 23.4
Earnings Before Taxes	*$ millions*	**$ 30.6**	**$ 31.8**	**$ 32.5**	**$ 33.1**	**$ 33.5**	**$ 33.7**
Payment in lieu of taxes	*$ millions*	$ 10.7	$ 11.1	$ 11.4	$ 11.6	$ 11.7	$ 11.8
Net Income	*$ millions*	**$ 19.9**	**$ 20.7**	**$ 21.1**	**$ 21.5**	**$ 21.8**	**$ 21.9**

		Base Year (T)	Year T+1	Year T+2	Year T+3	Year T+4	Year T+5
Rate Base (rolled into Distribution Rates)	*$ millions*	$ 575.0	$ 585.8	$ 585.8	$ 585.8	$ 585.8	$ 585.8
Book Value - Opening Balance	*$ millions*	$ 575.0	$ 593.9	$ 609.6	$ 622.1	$ 631.5	$ 637.8
Capex	*$ millions*	$ 45.0	$ 45.0	$ 45.0	$ 45.0	$ 45.0	$ 45.0
Amortization	*$ millions*	$ 26.2	$ 29.3	$ 32.5	$ 35.6	$ 38.8	$ 41.9
Book Value - Closing Balance	*$ millions*	$ 593.9	$ 609.6	$ 622.1	$ 631.5	$ 637.8	$ 640.9
Mid-year Book Value	*$ millions*	**$ 584.4**	**$ 601.7**	**$ 615.8**	**$ 626.8**	**$ 634.6**	**$ 639.3**

		Base Year (T)	Year T+1	Year T+2	Year T+3	Year T+4	Year T+5
Net Income	*$ millions*	**$ 19.9**	**$ 20.7**	**$ 21.1**	**$ 21.5**	**$ 21.8**	**$ 21.9**
Mid-year Book Value	*$ millions*	$ 584.4	$ 601.7	$ 615.8	$ 626.8	$ 634.6	$ 639.3
Debt	*$ millions*	$ 350.7	$ 361.0	$ 369.5	$ 376.1	$ 380.8	$ 383.6
Equity	*$ millions*	$ 233.8	$ 240.7	$ 246.3	$ 250.7	$ 253.9	$ 255.7
Return on Equity		**8.50%**	**8.59%**	**8.58%**	**8.59%**	**8.58%**	**8.58%**

Q25. What analysis would be required to build the CAPEX factor around other variables, such as system age and volume growth?

A25. We would need to calibrate a set of relationships between the system age and volume growth proxies and capital needs. I would recommend that we take a sample of Ontario utilities and insert their historical data on revenues, costs, capital expenditures into a financial model, similar to what I have been describing so far. We can then pinpoint the average CAPEX factor that would have been needed if these utilities were under the price cap regime contemplated for 3GIRM, assuming good operations and targeting the allowed rate of return. Then, we would relate that CAPEX factor to system age. We would re-calibrate the model with different age profiles so that we had a distribution of CAPEX factors to different circumstances.

That analysis could be extended easily to include another parameter, such as volume growth. One would then have a two dimensional table or matrix that will specify for a given level of volume growth and system age, a target CAPEX factor. I have included an illustration of such a matrix below, note that the CAPEX factor values are notional (for illustration purposes only).

Figure 11. Illustrative CAPEX factor matrix

		Average System Age (based on % of gross book value depreciated)						
		20%	**30.0%**	**40.0%**	**50.0%**	**60.0%**	**70.0%**	**80.0%**
Volume Growth	**-1.0%**	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	2.0%
	-0.5%	1.0%	0.0%	1.0%	1.0%	1.0%	3.0%	3.0%
	0.0%	0.0%	0.0%	1.0%	1.0%	2.0%	3.0%	3.5%
	0.5%	0.0%	0.0%	1.5%	2.0%	3.0%	3.0%	4.0%
	1.0%	1.0%	0.0%	1.5%	2.0%	3.0%	3.0%	5.0%
	1.5%	1.0%	1.0%	2.0%	2.0%	3.0%	4.0%	5.0%
	2.0%	1.0%	1.0%	2.0%	2.0%	3.0%	4.0%	4.0%
	2.5%	1.0%	1.0%	2.0%	2.0%	2.0%	4.0%	4.0%
	3.0%	1.0%	1.0%	1.5%	1.5%	2.0%	4.0%	4.0%

Q26. Would the use of a projected capital expenditure schedule and recovery of the revenue requirement shortfall associated with capital investment through such a CAPEX factor negate the premise of a comprehensive price cap regime?

A26. If we are effectively determining the CAPEX factor based on revenue requirement calculations, then the CAPEX factor would involve some element of cost of service regulation. However, there is still some incentive properties to this approach – the utility must keep within the bounds of its forward looking capital expenditure schedule in order to achieve the allowed rate of return. Therefore, the utility has strong incentives to control capital cost over-runs.

A CAPEX factor based on a matrix schedule, as described above, would be very much incentive-compatible. There is no cost-of-service element, because the CAPEX factor would not be directly related to a firm's capital investment projections, but to the underlying drivers of such investment. Taking the X factor and CAPEX factor as a given, the firm would have strong incentives to create efficiency gains in both operating costs and capital programs so that it can improve its profitability.

Q27. How do these proposals for setting the CAPEX factor reflect LDC diversity?

A27. The determination of the CAPEX factor, and just as importantly, the implementation process, gives the LDCs multiple avenue for accommodating their diverse circumstances. Each LDC would - as part of rate filing - "check the box" on whether they require a capital investment module at the start of their individual 3GIRM. The LDC would then provide the Board a multi-year forward capex schedule and financial model to justify a firm-specific CAPEX factor or identify the average age of its system and expected volume growth characteristics for supporting the determination of a CAPEX factor from a pre-set matrix. For those LDCs that do not need the module, a zero value would be set for the CAPEX factor.

I do not anticipate that the Board would be swamped by LDCs applying to use the CAPEX factor, but if there is a subgroup of LDCs seeking to trigger the CAPEX factor contemporaneously, the relatively straightforward matrix approach will ease regulatory burden. I do expect that a few LDCs will have the capacity and necessity to file a multi-year forward capital expenditure schedule. Although more complex and burdensome from a regulatory process perspective (because of the prudence review that would be required), a multi-year forward capex schedule approach can provide for a more accurate CAPEX factor, tailored to a firm's circumstances.

Q28. Have any other jurisdictions used a similar concept to a capital investment module or CAPEX factor?

A28. Yes, explicit capital investment modules have been used in performance-based ratemaking regimes in several industries/jurisdictions. For example, a "K factor" was explicitly employed in setting rates for the network business in the Republic of Ireland.[18] Ireland's Commission for Energy Regulation (CER) has authorized K factor implementation for tariffs for electricity distribution businesses since 2000.[19] The approach adjusted allowed revenues in accordance with changes in inflation, unit growth, a productivity (X) factor and a parameter reflecting the impact of new investment for system expansion (K factor). In practice, the K factor component of the formula corrected for any unrecovered allowed revenues from year to year.

K factors are also prominent in the tariff design for water utilities in the United Kingdom. Ofwat, UK's regulator of the water supply sector, has been employing a K factor in its benchmarking-oriented ratemaking to accommodate financing of capital investments since 1994. The RAM for water rates uses the following formula: RPI +/- K + U, where RPI is Retail Price Index (UK's equivalent to the consumer price index), K is adjustment factor for capital investments (determined at the price review), and U is the value of K not taken up in the previous years.[20] The K factor is set according to benchmark performance based on the principle of efficiency frontier analysis, where the most efficient company's performance becomes the benchmark for the industry.[21] K

[18] Commission for Energy Regulation. 2006-2010 ESB Price Control Review. September 2005

[19] A similar rate structure, with a K factor, also applies to the natural gas distribution sector, which is under CR regulation.

[20] Ofwat. Future Water and Sewage Charges, 2005-2010. Final Determinations

[21] The single company or the group of the companies to be considered a benchmark must account for at least 2% of the industry turnover.

factors are also annually adjusted according to the performance of capital maintenance efficiency.

Additionally, there are jurisdictions, such as electricity sector in UK, Australia, US, and Norway where X factors were set at negative levels in order to accommodate recovery of capital investment costs. In its most recent price control review of the distribution sector, IPART (the distribution regulator in New South Wales, Australia) approved price increases of 5% to 7% and negative X factors of -1.5% to -2.5% per annum for the 2004/05 through 2008/09 period, in recognition of the need to make increased demand related expenditures.[22] In another example, Transgrid (the transmission company in New South Wales) was allowed to receive revenues according to the RPI-X formula, where its X factor was set in 2000 to be negative 1.3%,[23] so to allow it to complete an extensive capital expenditure program. [24] Queensland's Powerlink was allowed to set an X factor of negative 6.37% to accommodate an even more extensive capital expenditure program. [25]

The initial round of the price cap regime in the United Kingdom for the electricity distribution sector included negative X factors for all but one utility.[26] One of the primary reasons for setting initial X factors at negative levels was the belief (at that time) that the industry needed to make extensive capital investments over the coming years, and thus utilities needed a secure cash flow. More recently, in the November 2004

[22] Independent Pricing and Regulatory Tribunal of New South Wales (IPART) (2004), *NSW Electricity Distribution Pricing, 2004/05 to 2008/09, Final Report*, Sydney

[23] Australian Competition and Consumer Commission, Transgrid Revenue Cap Decision (January 2000), p. iv

[24] The reference is to transmission system operator in one of the states in Australia, the regulatory regime was to set revenues caps, rather than price caps.

[25] Australian Competition and Consumer Commission, *Powerlink Revenue Cap Decision* (November 2002), p. 82

[26] Thomas Weyman-Jones, "Problem of Yardstick Regulation in Electricity Distribution," *The Regulatory Challenge*, eds. Matthew Bishop, John Kay, Colin Mayer (Oxford University Press: London, 1995), p. 429.

distribution price review, Ofgem approved zero X factors for the 14 distribution network operations (DNO) businesses, commenting that, "in coming to a decision," they considered "the financial profile of companies and the longer-term trend of prices."[27] Ofgem also allowed for a negative X factor of 2% per annum, 2007 through 2012, coupled with a price increase at rebasing in 2007 of 8% for National Grid, the UK transmission utility, to encourage investment in its most recent price control review.[28]

The Norwegian Water Resources and Energy Directorate (NVE) is responsible for monitoring grid management and operations, and among other things, it determines an income cap for each network company in Norway (transmission and distribution). The income cap reflects factors that influence area-specific costs, such as climate, topography and settlement patterns. This system is intended to ensure that grid companies do not make unreasonable monopoly profits and that cost reductions also benefit the grid customers. Price regulation has recently been revised so that there will be annual updates to the income cap, based on benchmarking analysis, starting from January 2007 onward (originally the caps were set for a five year term). This modification to rate design was instituted in order to "improve the incentives for new investments", among other reasons.[29]

In the US, another example of an embedded or implicit capital investment adjustment factor is highlighted in the case of San Diego Gas & Electric's revenue cap in its 1994 PBR plan.[30] Analysis suggests that the revenue cap – with an X factor of negative 4.23% -

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[27] Ofgem. Electricity Distribution Price Control Review, Final Proposals. November 2004.

[28] *See* http://www.ofgem.gov.uk/NETWORKS/TRANS/PRICECONTROLS/TPCR4/Pages/TPCR4.aspx

[29] *See* http://www.regjeringen.no/en/dep/oed/Subject/Energy-in-Norway/The-transmission-and-distribution-grid.html?id=444385

[30] G.A. Comnes, S. Stoft, N. Greene and L.J. Hill. Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource-Planning Issues (Volume I). Lawrence Berkeley National Laboratory. November 1995 (p. 35).*See* http://eetd.lbl.gov/EA/EMP/reports/37577.pdf

was set at levels higher than historical performance would otherwise indicate, in order to create a "generous allowance for electrical network distribution additions."[31]

UK's Civil Aviation Authority (CAA) and Competition Commission (the Commission) are the regulatory bodies that determine airport charges. The Commission recommends the maximum price levels, which are then formally (often with modification) approved by CAA. The price regime for the 2003-2008 period specifies price controls that allow a 6.5% increase of prices in addition to inflation, i.e. PRI + 6.5%, for Heathrow airport .[32] The increase in prices is meant to enable the BAA (operator of Heathrow airport) to implement a £7.4 billion, 10-year investment program to meet the growing demand for airport capacity. [33] Notably, the other airports in BAA's British portfolio (Gatwick and Stansted) are allowed to increase their prices by the inflation rate only.

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[31] Id., pg. xvii.

[32] Civil Aviation Authority. Economic Regulation of BAA London Airports (Heathrow, Gatwick, and Stansted) 2003-2008 CAA Decision, February 2003

[33] Including recently opened Terminal 5 at Heathrow

IV. Selecting an Inflation factor

Q29. What is the purpose of an inflation index in the RAM?

A29. The objective of the inflation index is to allow the utility to recover changes in the unit costs of inputs in a timely manner. It is presumed that the utility is a price taker and has no control over the price of the inputs it purchases, consistent with the definition of a competitive firm. In combination with the X factor, the inflation factor simulates the cost pressures of a competitive industry.

Q30. What has been typically used by regulators in other jurisdictions for an inflation index?

A30. The Consumer Price Index (CPI) has been commonly used in performance based ratemaking regimes abroad, because of its transparency and relative ease of application. CPI measures explicit changes in the price levels for a fixed set of goods and services, with a focus on consumer goods and services.

The conceptual weakness of using the CPI is that it does not incorporate any indicators for the price of capital, as it represents consumer goods, rather than cost of inputs to production processes.[34] In addition, the CPI implicitly includes the impact of average productivity improvements across all economic sectors because it is representing the final price of outputs (rather than inputs). Therefore the CPI is not an accurate representation of the (isolated) input cost changes for the firm. Because of this discrepancy in representation, a CPI may skew a price cap. For example, let us assume the CPI is 2% and the X factor is 0.5%. Rates will therefore increase by 1.5% from the previous year. However, if the actual price of inputs to the utility rose by 4%, then the

[34] For the Canadian economy, there are two commonly used CPI estimates: one produced by *Statistics Canada* (traditional definition of CPI) and CPI Core, which is calculated by Bank of Canada and excludes volatile items such as fruit, vegetables, gasoline, fuel oil, natural gas, mortgage interest, inter-city transportation and tobacco products.

rate increase will be insufficient to cover the basic cost pressures that the utility faces and will therefore under-compensate the utility. Alternatively if unit costs increased by only 1%, the CPI will over-compensate the utility.

Q31. Are there other alternatives to the CPI?

A31. Yes, there are other macroeconomic inflation indices that can be used, like the GDP deflator (also referred to as the GDP Implicit Price Index, "GDP-IPI").[35] As the name implies, the GDP-IPI estimates the price change component in Gross Domestic Product (GDP) from the previous period. The GDP-IPI measures changes in price levels, but also continuously accounts for changes in the economy, i.e. changes in consumption patterns of goods and services. The GDP-IPI for Canada was used in the 2GIRM and is being employed in the gas distribution sector's recently negotiated price cap and revenue cap regimes. However, similar to the CPI, because it does not track actual costs to electricity distributors, it may over- or under-compensate a utility within a price cap regime. Figure 12 graphs the historical year-on-year trends in the report *Statistics Canada* indices for CPI and GDP-IPI.

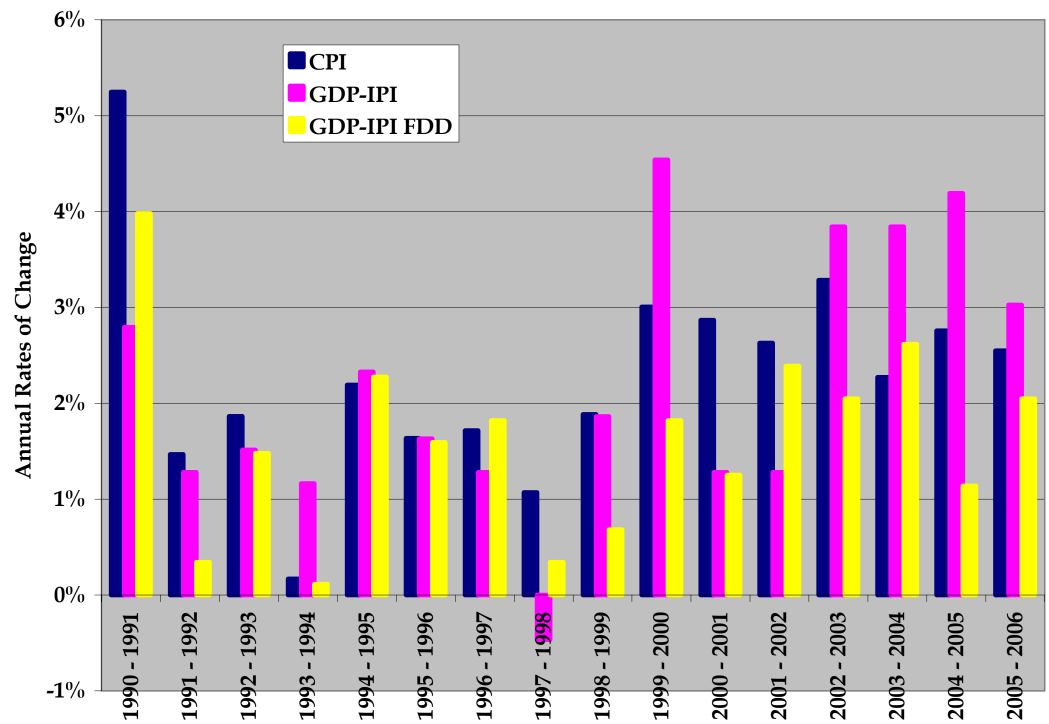
In addition, California regulators, Maine regulators (in the Central Maine Power PBR plan), and the Board (in 1GIRM), have employed a tailored input price index (IPI) for the inflation index. An IPI should ideally represent the cost trends for all inputs used in the production process for that industry. By definition if it is properly constructed, an IPI will not over or under-compensate a utility for its increased costs. Therefore, conceptually, an industry IPI[36] would be the preferred inflation index for 3GIRM.

[35] *Statistics Canada* produces two variations of GDP IPI index: GDP IPI (includes overall economy) and GDP IPI Final Domestic Demand (GDP IPI FDD), which excludes net exports of goods and services.

[36] One can even estimate a firm-specific IPI, but that would raise concerns of endogeneity, specifically whether the utility affect and manipulate the price of the inputs it buys?

However, in practice, not all inputs can be accounted for; the goal should be to account for a subset comprising a substantial portion of the cost structure of a business.

Figure 12. Macroeconomics inflation indicators (CPI and GDP-IPI)



Q32. What are the components of an IPI for the electricity distribution industry?

A32. The most basic components of an electricity distribution sector IPI include:

- unit cost of labour - which is primarily unionized labour in this industry;
- unit price of capital – which implicitly will include the opportunity cost (financing cost) of capital as well as the construction cost (for example, the engineering costs of capital programs, as well as raw materials used in constructing distribution assets, such as copper and steel, etc.);

- materials – which should include the unit costs of contracted services and interim products and services not covered by labour and capital.

Q33. Can a macroeconomic indicator be adjusted to adequately represent unit cost changes for the electricity distribution sector?

A33. Theoretically yes, we can add an input price differential (IPD) and an economy-wide TFP measure to the RAM, which will isolate then the appropriate inflationary changes for the electric distribution sector. However, the IPD is difficult to measure and becomes a controversial component of the RAM. Typically, in other jurisdictions, the IPD is assumed to be zero. Proxy measures for the TFP for the economy are available, but there may be imperfections (for example, *Statistics Canada* publishes a multifactor productivity growth measure that covers all business sectors of the economy, but ignores the government sector).

Figure 13. Business Sector MFP and GDP Implicit Price Inflator Final Domestic Demand

	MFP Business Sector	MFP Index	MFP Annual rate of change	Canada GDP IPI FDD	GDP-IPI FDD Index	GDP-IPI FDD Annual rate of change	Rate Adjustment, assuming X factor of 0.55%, IPD of 0%
1997	94.9	1.0000		94.3	1.0000		
1998	95.6	1.0074	0.74%	94.6	1.0032	0.3%	0.5%
1999	97.5	1.0274	2.00%	95.2	1.0095	0.6%	2.1%
2000	99.7	1.0506	2.32%	96.8	1.0265	1.7%	3.5%
2001	99.3	1.0464	-0.42%	97.9	1.0382	1.2%	0.2%
2002	100	1.0537	0.74%	100	1.0604	2.2%	2.4%
2003	99.5	1.0485	-0.53%	101.8	1.0795	1.9%	0.8%
2004	99.1	1.0443	-0.42%	104.1	1.1039	2.4%	1.5%
2005	99.3	1.0464	0.21%	105.1	1.1145	1.1%	0.7%
2006	99.1	1.0443	-0.21%	106.9	1.1336	1.9%	1.1%
Average, 1997-2006			**0.49%**			**1.48%**	**1.43%**

Source: Statistics Canada

Note: Index, 2002=100

Q34. Are there are any disadvantages associated with an IPI?

A34. There are no theoretical disadvantages, but many exist in the realm of practical implementation. An IPI requires compilation of a single index (from a number of sub indices) that reflects changes in all production costs. Actual sub-indices that could be used are likely to be less liquid, less robust, and more volatile. In many cases, the regulator will need to choose between sub-optimal sub-indices or create proxies. In reality, it will be impossible to build a perfect IPI, but the constructed IPI may be robust enough that the benefits of using an IPI outweigh the known and potential distortions.

Q35. Please summarize the Board staff's proposal for an IPI

A35. The Board staff is proposing to create an IPI based on a composite of three factor inputs: capital, labour and materials. The formulaic representation of the index has the following form (consistent with the 1GIRM IPI):

$$IPI_t = \left\{ \frac{P_{Kt} \cdot w_K + P_{Lt} \cdot w_L + P_{Mt} \cdot w_M}{P_{K0} \cdot w_K + P_{L0} \cdot w_L + P_{M0} \cdot w_M} \right\} \cdot 100$$

where P_K denotes price of capital, P_L price of labour and P_M, the price of materials, with W_K, W_L, W_M representing the weights of these three factors in the formula. In calculations of the inflation index for a typical utility, OEB Staff is proposing to use the following fixed weights for 3GIRM: W_K (capital) = 63%, W_L (labour) = 26%, and W_M (materials) = 11%, based on cost shares from 2002 – 2006 utility cost data, as calculated by PEG.[37]

The percentage change of the IPI index on an annual basis would provide the estimate of the inflation index for a utility's costs. The same index (and same fixed weights) would be applied to all distributors.

[37] Staff Discussion Paper, pg. 52

The price of capital is based on three components of (1) cost of acquiring capital, (2) opportunity cost of making the capital investment and (3) cost of using the capital. The cost of acquiring a capital is represented by *Statistics Canada's* Price Index for Electric Utility Construction Price Index (EUCPI) in the Board staff proposal. The opportunity cost of making the capital investment was defined as yield of long term (10 years plus) Canadian Bonds (r_t). The cost of using the capital was measured as the depreciation rate (d) of a typical distribution utility (fixed at 5.67%). Taking these three parameters, the formula for the price of capital sub-index is as follows:

$$P_{Kt} = (r_t + d) \cdot EUCPI_t$$

Notably, PEG has constructed a different implicit cost of capital index for use in the TFP analysis.[38] These discrepancies between the Board staff's proposal for the IPI and PEG's method in developing the TFP needs to be studied further.

Given the volatility of the price of capital sub-index, OEB decided to limit the effect of this price of capital sub-index to 50% of the observed rate of change in 1GIRM, and therefore only half of the observed changes were accounted for in the IPI formula. Distributors were responsible for absorbing the other half of the year-on-year trend in capital costs. In the Board staff's current proposal, volatility adjustments would be made by calculating a three-year average of the P_K sub-index within the IPI.

For the labour sub-index, the OEB staff recommends using either the construction union wage rate index for Ontario from *Statistics Canada* or wage adjustment in base rates from Human Resources and Social Development Canada (HRSDC). Notably, the former index is based on collective bargain negotiations with 500 or plus employees,[39] which is distinctly not representative of the LDCs. The latter – the construction union

[38] March 25, 2008 Workshop Transcript, pg. 13-14, starting at lines 16 on pg.13, and pg. 19, lines 21-27.

[39] Staff Discussion Paper, pg. 50.

wage rate index - covers many trades that are not relevant to electricity distribution. There is a third index for labour costs that the Board staff did not contemplate – the *Statistics Canada* index of weekly earnings in utilities (which is available at the national and provincial level), but the trends in that index for the Ontario data set appear to be counterintuitive, as I discuss further below.

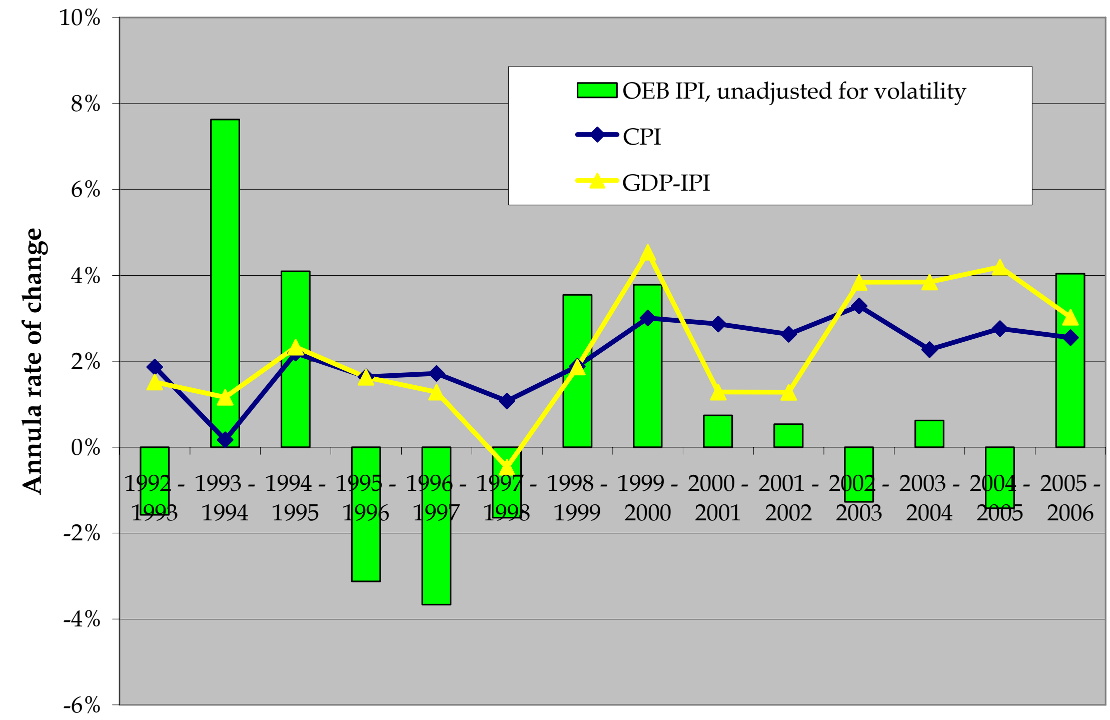
The price of materials in the Board staff's current IPI proposal is represented by the All Finished Goods Industrial Producer Price Index (IPPI) published by *Statistics Canada*, consistent with the 1GIRM. However, notably PEG used the GDP-IPI as the input price for the materials component of OM&A in doing the TFP calculations.[40] This apparent inconsistency needs to be resolved.

Q36. Historically, what have the differences been between macroeconomic indicators and the Board staff's proposal for an IPI?

A36. The figure below illustrates the Board Staff's IPI proposal on a historical backward looking basis, 1992 – 2006), along with the CPI and GDP-IPI. The Staff's proposed IPI has been more volatile than the CPI or GDP-IPI. Moreover, the IPI growth rate has been negative, most recently in 2002-2003 and 2004-2005 periods. The CPI and GDP-IPI have oscillated between 2% and 4% in recent years.

[40] February 2008 PEG Report, pg. 37.

Figure 14. Comparing the Board staff's IPI with macroeconomics inflation indicators



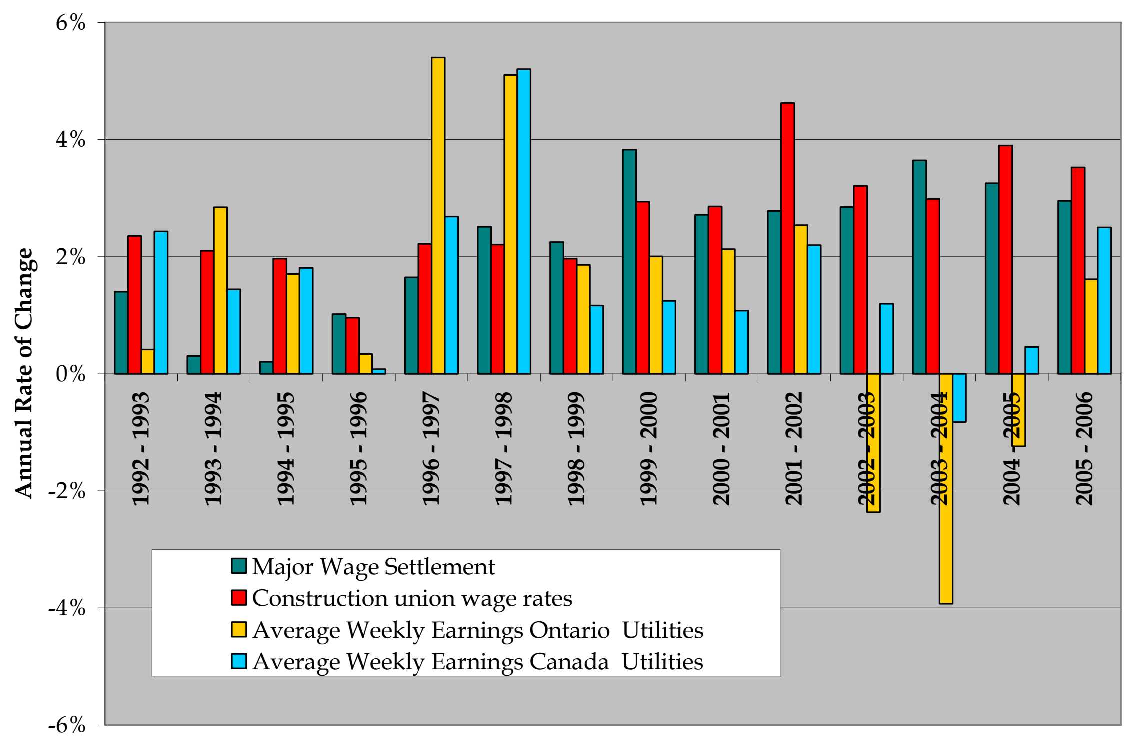
Q37. Are these differences reasonable?

A37. On a first principles basis, I did expect different trends between an IPI and a GDP-IPI or CPI. And my hypothesis would have been a more volatile trend from the IPI, which is what we observe. However, I was surprised with the repeated negative trends given the anecdotal evidence I had heard about rising costs for the industry over the last four to five years. This suggests to me that there may be some issues with the formulation of the IPI and/or the selected sub-indices.

Q38. Have you investigated the reasonableness of the labour and materials sub-indices?

A38. I have reviewed the historical data for the values of all three sub-indices with the members of the CLD and HONI and I am concerned that the sub-indices are not representative, at least historically, for the unit cost pressures actually experienced. Figure 15 identifies the historical trends for four different labour price sub-indices.

Figure 15. Various labour sub-indices



As I discussed already, there are sampling problems for the labour sub-indices proposed by Board staff, with only large utilities included or a number of superfluous labour pools included. Other data series may also be flawed. For example, in some years, the *Statistics Canada* index for weekly earnings in the Ontario utility sector suggests that labour costs have actually decreased from the preceding year, which is contrary to observed trends for LDCs. I have collected data on average annual wages (for unionized labour) from the CLD members and HONI, and a review of this data (summarized in Figure 16), suggests that labour prices have in fact grown at an average annual rate of 3% for this sample group as a whole over the 2002-2004 period, and generally with no year-on-year decreases.

Figure 16. Average annual wages reported by a sample of Ontario LDCs

Annual Yearly Base Wage for Unionized workers

Company		2002		2003		2004	CAGR (2002-2004)
Enersource	$	55,136	$	59,316	$	59,632	4.0%
Hydro Ottawa	$	50,304	$	51,352	$	54,493	4.1%
Veridian	$	56,359	$	58,042	$	60,255	3.4%
Toronto Hydro	$	62,397	$	62,127	$	63,079	0.5%
Powerstream	$	52,959	$	57,519	$	55,705	2.6%
Horizon	$	45,069	$	46,583	$	48,457	3.7%
Total for Sample	**$**	**322,224**	**$**	**334,939**	**$**	**341,621**	**3.0%**

Source: Section 3.4.8 - Employee Total Compensation from 2006 EDR Model

Given that the Board has accurate utility data for Ontario LDCs on average wages, from the RRRs and cost of service studies, it may be more appropriate to design a labour price sub-index using the aggregated LDC data, similarly to the 1GIRM design concept (which relied on surveyed data from the LDCs).

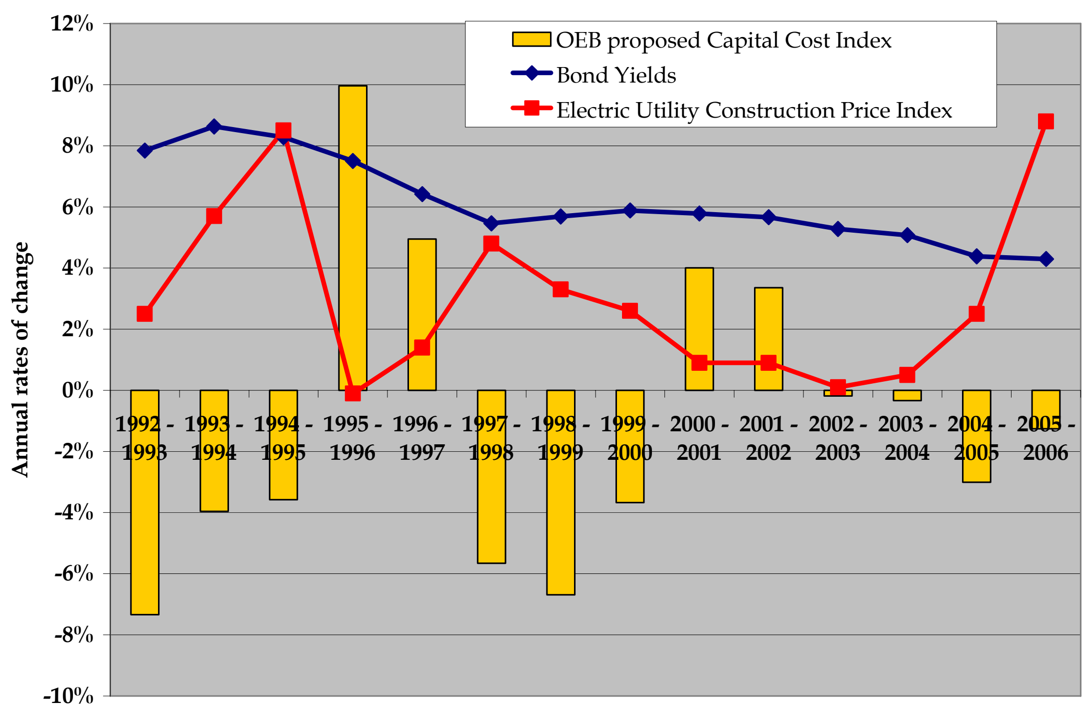
The materials index poses a different kind of problem. As I discussed above, the materials cost category represents interim services and products that the LDC procures that are not captured under the labour or capital categories. Ideally one would want a materials sub-index that evaluates the unit cost of legal services, accounting, public relations, IT, and other contracted services, etc. It is difficult to compute independent measures of these costs because one needs to decompose price changes from quantity changes. For example, expenditures on legal services may be rising for an LDC, but is that due to volume of services procured or to the price of the services? *Statistics Canada* does not currently publish any suitable proxies. I would therefore recommend that the Board consider how to solicit this information from distributors through some sort of annual survey.

It is also notable that PEG uses one measure of a material sub-index in their estimate of TFP and Board staff use another in the IPI formulation – this inconsistency needs to be resolved.

Q39. If capital construction costs are rising, why is the capital sub-index declining then?

A39. The capital input price sub-index is composed of several elements in the Board staff's proposal: a bond rate trend, a depreciation rate (which is actually held constant), and construction cost trends. The formula for the capital price sub-index presumes that utilities will continuously and completely refinance their entire debt in response to decreasing bond rates. As can be seen in Figure 17 below, bond rates have been slowly declining. And although the construction costs of capital have increased, the decline in the bond rates outweighed those construction cost increases for some time.

Figure 17. Components of the Price of Capital Index, as proposed by Board staff

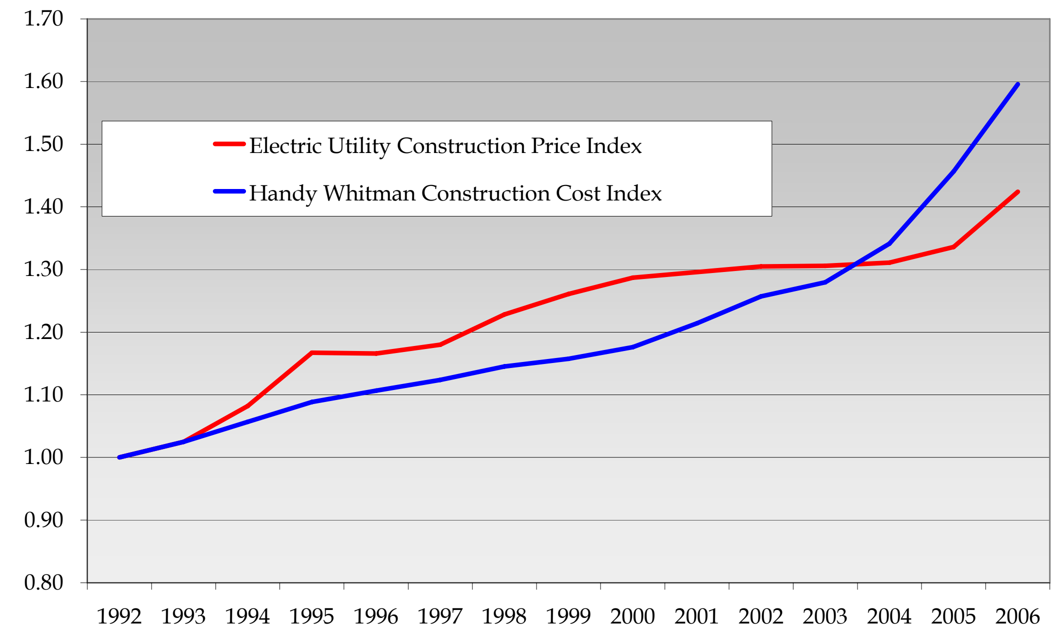


The presumption of continuous re-financing is inconsistent with actual experience. Typically LDCs borrow on a long term basis and seek refinancing when the debt reaches maturity. One could hypothesize that approximately 3% (assuming 30 year maturity) to 10% (assuming 10 year maturity) of overall debt level turns over annually. Because of the improved rates that can be achieved with larger volume debt offerings, LDCs may wait to tap the long term debt market until they have a significant volume and therefore will not refinance each year. Other LDCs have long-term promissory notes with their municipal shareholder(s). Such trends need to be incorporated into the capital sub-index in order to properly account for business practices of LDCs.

In addition, I observe that the construction index proposed by the Board staff appears low given anecdotal evidence about skyrocketing raw materials (copper and iron ore) and double-digit increases in equipment costs. Instead of relying on *Statistics Canada* construction cost indices, which may be biased given survey sample size, I would recommend exploring use of third-party construction cost indices tailored to the distribution sector, such as the Handy Whitman Index.[41] As illustrated in Figure 18, the cumulative trend in the Handy Whitman Index has outpaced that of the EUCPI.

[41] The Handy Whitman Index of Public Utility Construction Costs is published by Whitman, Requardt & Associates, LLP.

Figure 18. Construction Cost Indices: Handy Whitman versus EUCPI



Q40. The staff also proposed a three-year moving average adjustment to the capital sub-index to deal with volatility. What is you opinion on this adjustment?

A40. There are three basic types of capex for LDCs that are distinguished primarily by their purpose: capex in the normal course of business, expansion capex (for growth), and emergency-related capex. Typically utility planners have some discretion over timing for the planned maintenance capex (replacement of aging assets), but generally no discretionary for emergency capex or growth-related capex (because of the statutory requirement to interconnect consumers).

I would recommend that smoothing adjustments be generally limited, in recognition that LDCs have limited scope in shifting the timing of capex, and the fact that the asset base is not refinanced 100% in every period.

Q41. How does the staff combine the capital, labour, and materials sub indices into the IPI?

A41. They use weights from previous empirical analysis, for example, the Board staff in the Discussion Paper relied on PEG's cost analysis of 2002-2006 data. Similarly, in 1GIRM, the weights were estimated using 1993 data and were held fixed for the remainder of the generation. Notably, Board Staff recognize that cost shares have changed, as they document the substantial difference in weights reported by PEG as compared to the estimates used in 1GIRM: capital cost share has risen from 51% to 63%, while the labour share has decreased from 35% to approximately 26%.[42]

Q42. Do you have concerns with the use of fixed cost elasticity shares?

A42. The above changes in estimated weights personify my concerns. I am worried that discrepancies can arise between the fixed parameters and actual industry trends, which would then undermine the ultimate purpose of the IPI (e.g., to track actual unit costs in a timely manner). In pursuing efficiency, utilities can re-allocate their resources, from capital to labour or labour to materials, etc., in order to achieve higher productivity. This re-allocation is continuous and using fixed parameters for a five-year IRM term will ignore such changes. I would recommend that the Board update these weights regularly (at least annually), based on industry average cost shares observed in the most recent data submitted by LDCs in their annual PBR reports.

Q43. What are your conclusions regarding the Board staff proposal for the IPI?

A43. The IPI needs to be redesigned and the formula adjusted to take into account actual observed trends and situations in the sector. Moreover, the Board needs to investigate whether there are more reliable sources of data for the sub-indices. The Board needs to make a commitment to regularly update the cost shares. Use of smoothing should be

[42] Staff Discussion Paper, pg. 52 (Table 2).

limited as it is likely to create distortions and undermine the "timely cost tracking" principles that led to the selection of the IPI as a superior inflation measure.

I can also recommend the following concrete improvements to the Board Staff's proposed IPI:

- in lieu of *Statistics Canada* series, construct a labour sub-index using actual wage rate data collected by OEB;
- in the near term, switch the materials sub-index to the GDP-IPI as a proxy, in order to be consistent with TFP analysis (or vice versa);
- explore the potential to design a cost reflective sub-index for materials prices from a survey of electricity distributors;
- switch the capital sub-index calculation to use a more widely recognized capital construction cost sub-index like the Handy Whitman (reflecting the global nature of construction equipment and raw materials markets); and
- reformulate the capital price sub-index to represent the longer timeframe for refinancing.

If a more robust IPI cannot be found in time for the 3GIRM implementation, then the Board can proceed with a GDPI-IPI on an interim basis.

V. Establishing the X factor

Q44. What is the purpose of an X factor in a comprehensive price cap regime?

A44. The X factor represents the ***productivity growth*** target that is imposed on the firm to provide it with the discipline of competition by proxy. In the competitive market, competition motivates firms to improve their cost basis through productivity improvements. Incentive ratemaking aims to instill that same motivation in regulated businesses that technically have no direct competition.

Productivity growth is defined as the change over a period of time in productivity levels. Productivity levels measure how much physical output a firm produces given a particular quantity of inputs. If a firm is not using its inputs as efficiently as possible, then there is scope to lower costs and increase profitability through productivity improvements.

Q45. What drives productivity growth in this industry?

A45. Productivity improvements can be realized through a number of means. For example, improved efficiency may come about through the use of better quality inputs including a better trained workforce, adoption of technological advances, removal of restrictive work practices and other forms of waste, and better management through a more efficient organizational and institutional structure. Economies of scale can also improve the productivity of a firm, by allowing it to produce more output given a certain level of input(s).

Q46. How does one measure productivity growth for developing a productivity target under a comprehensive price cap regime?

A46. Because we are aiming to develop a comprehensive price cap that will apply to all tariffs and cover all costs, the measure of productivity that we are seeking to replicate is known as Total Factor Productivity (TFP), which measures total quantity of output relative to total quantity of all inputs used. The change in TFP levels from year to year - TFP growth - is defined as the proportional change in total output divided by the proportional change in total inputs used between two time periods. The formulaic representation is as follows:

TFP growth = $\mathbf{\Delta Q/\Delta I}$,

where ΔQ is the proportional change in the quantity of total output between the current period and the base period, and ΔI is the corresponding proportional change in the quantity of total input.

TFP growth measures inform the setting of the X factor in price cap regimes like the one proposed for 3GIRM in Ontario.

In complex industries, like electric distribution, there are multiple inputs to the production process and multiple outputs. Implementing TFP requires combining changes in these diverse outputs and inputs in order to measure changes in ***total*** outputs and ***total*** inputs. To that end, index number methodology is very useful and practical. Index methods essentially take a weighted[43] average of changes in component outputs relative to a weighted average of changes in component inputs and to produce a measure of annual TFP growth.

Q47. Will TFP growth always be positive?

A47. No, TFP growth can be negative over certain periods. In fact, negative TFP growth rates are likely during specific segments of a utility's business cycle, because of the lumpiness

[43] Either revenue or output cost shares are used as output weights and cost shares as input weights to calculate the weighted averages.

of capital expenditures and demographic shifts.[44] Negative TFP growth occurs when one or more inputs increase without a measureable increase in output quantity.

One concrete example of such situation in the utility sector is the result of capital investment which is initially underutilized. Capital inputs have increased but there may be no impact on the quantity of output produced. Another likely cause of negative TFP growth in the electric distribution sector is labour increases – for example, as a result of apprenticeship programs – which do not necessarily result in immediate increases in higher network capacity or ability to deliver more MWhs of electricity.

Q48. Please describe PEG's recommendation for the 3GIRM X factor.

A48. PEG recommends that the Board adopt an industry-average X factor of 0.88% plus annual stretch factors ranging from 0% to 0.3%, resulting in firm-specific X factors that range from 0.88% to 1.28% per annum, and a mean value of 1.16% across the LDCs.[45]

Q49. What are your concerns with PEG's proposed X factor?

A49. PEG's recommended industry average X factor of 0.88% is completely unrelated to Ontario utilities and observed trends in Ontario – it is based entirely on TFP estimates for a sample of US utilities. The sample of US utilities includes a variety of firms, including vertically integrated firms with generation and/or transmission assets, as well as electricity distribution companies with natural gas distribution businesses. US utilities under a variety of regulatory frameworks are represented in the sample, including many utilities under cost of service, firms under rate freeze arrangements, and utilities under

[44] Larry Kaufmann also confirmed agreement on this point at the march 25, 2008 Workshop; see March 25, 2008 Workshop Transcript, pg. 46, lines 8-11.

[45] February 2008 PEG Report, pg. 77.

various forms of PBR.[46] In summary, I do not believe that the US peer group has been carefully selected to represent Ontario LDC structures or Ontario business conditions. US utilities, over the study timeframe, have also faced very different cost pressures than Ontario LDCs. We cannot be certain that US-based estimate of historical productivity is in fact accurate for describing the circumstances in Ontario – PEG does not provide any concrete evidence suggesting representativeness of underlying US business drivers to the Ontario LDC environment. The only evidence PEG provides in support of the US versus Ontario gap is that directional TFP movements in the US and Ontario have been in synch.[47] However, directional movements do not inform on the level of X factor that should be applied. Without further evidence, US experience cannot be accepted as a reasonable basis for what can be achieved in the future in Ontario.

Larry Kaufmann, himself, notes this point in a 2007 report prepared for the regulator in Victoria, Australia, "[B]enchmarking is designed to obtain an inference on the efficiency of the management of an enterprise. Such an inference can only be obtained by examining metrics that reflect the impact of management decisions, … **Only data that reflect the actual operations, and hence management decisions of the companies themselves** will necessarily reflect the managerial efficiency of those companies" [emphasis added].[48] In a more recent companion report in this same rate setting case in Victoria, Australia, Larry Kaufmann also notes "[d]ata on gas distribution business' own operating expenses are simply **indispensable** for opex benchmarking studies"

[46] Larry Kaufmann conceded in fact that most of the utilities in the US sample were not under an incentive-based regime, see March 25, 2008 Workshop Transcript, pg. 72, lines 19-23.

[47] February 2008 PEG Report, pg. 57 (Table 12)

[48] Kaufmann, L. *Response to Meyrick and Associates Benchmarking Reports.* 2007. Prepared for the Essential Services Commission, pg. 12.

[emphasis added].[49] How is it that PEG is willing to dispense with analysis of Ontario data?

Q50. Did PEG run a TFP index for Ontario using 2002-2006 data?

A50. PEG did calculate a Törnqvist Index for Ontario LDCs (using a sample of firms rather than the entire industry pool) for the 2002 - 2006 period. PEG determined that TFP grew on average by only 0.01% per annum over this timeframe. Because this TFP growth was so small, (indeed, with all the references to US data, PEG gives the impression that it had another number in mind), PEG then simply dismissed the results as meaningless for setting the X factor for 3GIRM.

Q51. Do you agree with PEG's analysis of historical TFP growth in Ontario and implications for 3GIRM?

A51. I concur with the general index-based approach that PEG completed, but I do not agree with the specific model assumptions and techniques that PEG employed. And most importantly, I do not agree with Larry Kaufmann's dismissal of the Ontario results for developing an X factor for 3GIRM. PEG committed a number of errors in its analysis.

Rather than trying to develop the best possible model for Ontario LDC TFP analysis given the data, PEG simply took the US model and applied it to Ontario data.[50] More specifically, PEG knowingly ignored the fact that Ontario data included "peak distribution loads" because that information was not "available for US electric distributors."[51] As a result, PEG understated TFP trend reversals in Ontario by using a two-output model. At the minimum, PEG should have tested a three-output model that

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[49] Kaufmann, L. *Further Response to Meyrick and Associates and Worley Parsons Benchmarking Reports* January 2008. Prepared for the Essential Services Commission, pg. 5.

[50] February 2008 PEG Report, pg. 34.

[51] February 2008 PEG Report, pg. 32-33.

includes peak demand, since that is in fact a model specification that PEG has readily applied to electric distribution industries in other jurisdictions.[52]

I also believe that PEG's TFP results are biased because of the capital input measures used. PEG admits that its capital input quantity index was less than reliable because it was influenced by the relatively near term 2002 benchmark year.[53] Dr. Cronin testified at the March 26, 2008 Workshop that in fact he believes that PEG's capital proxies overstate the capital that the LDCs have on had, therefore biasing the productivity analysis.[54]

In spite of the short time dimension of the current Ontario data set and resulting TFP growth estimates, PEG should have not dismissed the results of Ontario analysis. The results, to the extent calculated properly, are indeed telling us something. Low or even negative TFP growth is possible, as I discussed above. Even a cursory review of the current situation for Ontario LDCs suggests that we are in just that type of investment cycle where we would expect to see productivity growth slowdown and reversals. This has relevance and bearing on future rates, especially given the evidence on the ground regarding cost pressures and the continuation of those cost pressures for the foreseeable future.

Q52. Have you performed any independent measures of TFP growth for Ontario?

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[52] Pacific Economics Group (2004), *TFP Research for Victoria's Power Distribution Industry*, Report prepared for the Essential Services Commission, and subsequent updates of this study released in 2006 and 2008.

[53] February 2008 PEG Report, pg. 44.

[54] March 26, 2008 Workshop Transcript, pg. 200, lines 25-27.

A52. Yes, in association with Dr. Denis Lawrence[55] of Meyrick and Associates, I calculated a TFP index for Ontario LDCs using the publicly available data for 2002-2006.

I used the 2007 data set from Comparison of Ontario Electricity Distributors Costs (EB-2006-0268), the "CCM Database," to run an industry TFP growth analysis for 2002-2006 using the Fisher Ideal Index method.[56]

The data is relatively good for standard metrics and appears to be comprehensive in covering all LDCs (with limited exception) at the aggregate OM&A cost and revenue level. There are some anomalies but nothing that cannot be reasonably adjusted. I prefer making some adjustments than simply excluding certain utilities from the analysis as PEG appears to have done. Therefore, in contrast to PEG's analysis based on a sample of firms, my TFP growth estimates cover the entire industry. Ideally, I would like to see improvements in the accuracy of the data and a longer time series (stretching further back in time), but I am also confident that the current data is useful for informing on future X factors.

I understand that PEG has not relied on this same data set in the results reported in the February 2008 PEG Report, and I have not had an opportunity to review their data set to

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[55] Dr. Denis Lawrence is Director of Meyrick and Associates. Dr. Lawrence has played a key role in the regulation, benchmarking and performance measurement of infrastructure enterprises. He has advised Australian and overseas regulators and utilities on a wide range of quantitative and strategic issues in the energy, telecommunications, postal and transport sectors.

[56] Since different index number methods produce different component weights, so selecting an appropriate index method is crucial. Among the various index number methods, the Fisher ideal index is increasingly preferred by practitioners and statistical agencies in calculations of productivity measurement. The Fisher ideal index is the geometric mean of the Laspeyres index, which multiplies the current and base period quantities by the base period price to form the weights, and the Paasche index, which multiplies the current and base period quantities by the current period price. By taking a geometric average of the two, the Fisher ideal index aims to resolve the classic "index number problem" suffered by both of these indexes, where the further one moves away from the set of prices used, the representative quality of the index declines (since prices change over time). PEG employed the more 'old-fashioned' Törnqvist index which satisfies fewer desirable properties than the Fisher index.

identify precise differences because of confidentiality issues.[57] However, I have some basic conjectures about the differences in results, which I will discuss later.

Q53. Please describe your TFP analysis.

A53. We began the TFP analysis by identifying the outputs of the Ontario LDCs. Ideally, it would be best to represent the output quantity of LDCs as the customer connected capacity of the network, because in effect distribution networks provides a certain quantity and quality of "access" to electricity supply. We do not have a measure like that currently. But we have three commonly accepted proxy measures of electricity distribution output: throughput, number of customers, and peak demand. Throughput represents the amount of energy supplied through the network or the amount of 'traffic' traveling the 'road' supplied by the LDC). Number of customers proxies for customer connections and therefore network coverage. Peak demand – which represents utilization of the system at peak - proxies for the capacity required of the underlying network.[58] It is quite typical to use these three measures to represent quantity of output

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[57] PEG had completed its TFP analysis using data from confidential Trial Balance Reports. Larry Kaufmann noted at the Workshop on March 26, 2008 that the result would differ but not dramatically if he used the publicly available data and that he was planning to modify his results to make sue of data that could be released. See March 26, 2008 Transcript, pg. 190, lines 5-8.

[58] At the March 26, 2008 Workshop, some stakeholders had questioned the source of the peak demand data. It is specifically the summer peak demand data reported by each LDC and then aggregated to an industry figure. The LDC data comes from the 2007 CCM Database, as I stated at the Workshop, and according to our research typically represents the metered (or calculated) peak load on each LDCs' system. The industry aggregate is in effect a non-coincident peak load measure. At first glance, some stakeholders may have not been able to reconcile the industry aggregates I had described in my presentation with the totals in the CCM Database, because one must apply some caution in totaling the raw data from the CCM Database. In completing the TFP analysis, we did have to edit some data for missing entries or reporting errors. These most commonly involved reporting of peak system demand figures in megawatts (MW) instead of the specified unit of kilowatts (kW) or a possible digit shift was identified (i.e., summer peak demand for a distributor in order of thousands of kW for four of the reported five years, but in order of hundreds of kW in the remaining one). In all of these instances, the remedy was simple and straightforward. On the other hand, certain other reporting inconsistencies or missing data items required backfilling or extrapolation (under conservative assumptions) in order to avoid otherwise exclusion of a distribution company from the calculations. Fortunately, these instances were relatively few and involved smaller distribution companies. As a result, we did not have to exclude any distributors from the analysis due to missing or bad data. In looking at the CCM Database, one also needs to be aware of instances of double counting due to M&As.

for an electric distribution business. The figure below summarizes the output quantity data we relied on.

Figure 19. Annual output quantity measures for Ontario electric LDC industry

Year	Throughput	Customer numbers	Peak demand
	kWh		*kW*
2002	113,257,605,034	4,303,716	27,803,678
2003	115,506,338,511	4,388,660	26,666,631
2004	116,695,981,455	4,460,842	25,464,011
2005	122,179,877,250	4,533,426	22,765,502
2006	119,082,477,315	4,592,124	23,996,250

In terms of quantity of inputs, the core elements are capital, labour, and materials. Labour and materials are represented by OM&A financial measures off the income statement, and once we adjust for the implicit price of labour and materials, we have an effective quantity of OM&A. I used *Statistics Canada's* average weekly earnings labour

The CCM Database not only reported the combined figures for the resulting merged entity (for all years, in other words, including those years preceding the transaction) but also retained and simultaneously included individual records of the individual firms. Hence, summation without removing either the individual records or the combined entity would lead to double counting. We, of course, had taken care of that in our analysis, but other parties may not be aware of this issue. One stakeholder also questioned the relationship between this peak demand metric and the peak demand reported at the wholesale level by IESO. The peak load figure one typically gets from IESO is coincident peak. IESO also has non-coincident peak load data, but that is also differently defined from that which the LDCs report in the RRRs. The IESO would consider each of the separate delivery points metered by each LDC in its non-coincident aggregation, while LDCs report in the RRRs the coincident peak of all the delivery points within their service area. Looking at the annual IESO non-coincident data against the CCM data, we observe that there are in fact different trends at the industry level. The CCM data, at the aggregate level, shows a declining trend in peak demand, while IESO peak demand figures are more stable (and even climbing) and higher than the LDC figure in recent years. One possible explanation for these differences is that the LDC data is not including large users who moved away from the LDC network and became members of IESO market and established a direct connection to the transmission system. The peak load figure that we are using in the TFP analysis from the CCM data would then effectively also represent utilization of the network, in addition to approximating 'capacity' of the network. In the future, it would be useful for the Board to revisit the filing guidelines for this data to concretely define the information being reported and perhaps to develop better measures of output for utilities to provide as part of the RRRs.

index (national level, utility sector) in combination with the GDP-IPI as the implicit input price index for OM&A.

Figure 20. Annual OM&A input quantity measures ($ millions)

Year	OM&A Costs *$ mio*	OM&A Implicit Input Price index
2002	975.32	1.0000
2003	1,006.75	1.0168
2004	996.34	1.0215
2005	1,041.54	1.0345
2006	1,121.84	1.0568

There are two basic methods for measuring the quantity of capital inputs in productivity theory – direct method, which looks at physical measures of capital, and indirect method, which looks at the deflated asset values (Larry Kaufmann referred to the indirect method as the "monetary value" approach during the March 2008 workshop). Larry Kaufmann had argued that the monetary approach is the only option for the rate adjustment mechanisms because the initial rate levels are set to include a monetary value for capital, and therefore any index should be developed with inputs denominated in monetary measures. He also criticized the direct method for not incorporating depreciation. Indeed, both of Larry's comments get to the heart of the reason why I decided to use the direct approach.

The direct approach does indeed incorporate physical depreciation, and the physical depreciation of distribution capital assets is critical for purposes of a TFP index which is looking at quantities as the primary driver. The deflated asset value approach PEG employs requires re-assessing historical accounting measures of asset value into real terms and adjusting for depreciation. However, any accounting measure of depreciation will not represent the physical depreciation of assets. Distribution lines, like a light bulb (for example), will continue to function (with only small deterioration in performance) until they one day simply fail (and presumably the LDCs would have performed preventive replacement before a failure occurs). A deflated asset approach that Larry Kaufmann recommends would have assumed that each year the distribution line would lose some portion of its functionality.

For example, let us assume a utility builds 10 kilometers of 4 kVA line and it is supposed to last 50 years. In its 20th year, there will still be 10 kilometers of line and it still will be able to carry close to 4kVA. By using the physical quantity proxy we can recognize this characteristic of the capital input. By using a deflated depreciated asset value approach, we would actually say that the carrying capacity of that 10 kilometer line has declined to say 1 kVA or lower (depending on what scrap value is built into the calculation, if any) by the 20th year. Which approach is more realistic? I believe that in practice, depreciation of utility capital is much closer to the light bulb characterization than to the accounting definitions of straight line depreciation or accelerated schedules.[59]

In answer to Larry Kaufman's concerns about the units, we must recognize that the rate adjustment mechanism – the price cap – is composed of trends – not levels. We must also recognize that the quantity of physical capital is directly related to the monetary value we assign it - if more kilometers of lines are deployed, the net book value increases. There is, thus, no disconnect then in using physical quantity measures in lieu of value measures. In fact, since we are trying to measure the change in quantity (and not the change in value), then the change in the physical capital held by a firm is logically the best (most direct) measure given the characteristics of the assets employed in electricity distribution.

[59] For further discussion see Denis Lawrence and Erwin Diewert (2004), 'Measuring Output and Productivity in Electricity Networks', Paper presented to SSHRC International Conference on Index Number Theory and the Measurement of Prices and Productivity, Vancouver, 1 July. Professor Diewert is from the University of British Columbia and is one of Canada's, and the world's, leading productivity analysts.

For representing the change in capital input quantity, I chose to use the change in the length of distribution lines.[60] I recognize that there are a few different physical assets employed by distributors in their business, including distribution lines, transformers, property, buildings and IT systems, vehicles, etc. However, if one were asked to describe the most critical capital asset for an electric distribution firm, the reply would certainly be distribution lines. Without distribution lines, there is no distribution business. I therefore used the reported kilometers of distribution line as the representative quantity measure of capital input employed.[61] This capital quantity measure can be refined in the future (for voltage comparability) and then other capital inputs can be integrated (such as transformers) on an apples-to-apples basis, as I discuss further below.

To form input weights for the indexing procedure we use the endogenous approach to measuring the annual cost of capital inputs. Under this approach the cost of capital inputs is taken to be the difference between total revenue and non–capital costs (in this case OM&A costs) for each year.

[60] I had to make corrections to the raw kilometers of line data in the CCM Database, after observing and verifying some anomalies for certain firms. The raw data exhibited a decline in line length from 2005 to 2006 for some firms. The magnitude of the reduction appeared implausible. I confirmed through discussion with some firms that this may be a data entry error and therefore to be conservative, we have adjusted these anomalous records by interpolating.

[61] Ideally, I would have preferred a MVA-km measure of capital input. This requires data on line length by voltage category, and then different engineering conversion factors would be used for each voltage category to calculate the MVA-km measure. However, using the total line length, which essentially assumes that the voltage composition of line length remained the same over this relatively short period, is a reasonable proxy when we are focusing on industry-wide TFP growth.

Figure 21. Annual capital input quantity and cost measures (kilometers and $ millions)

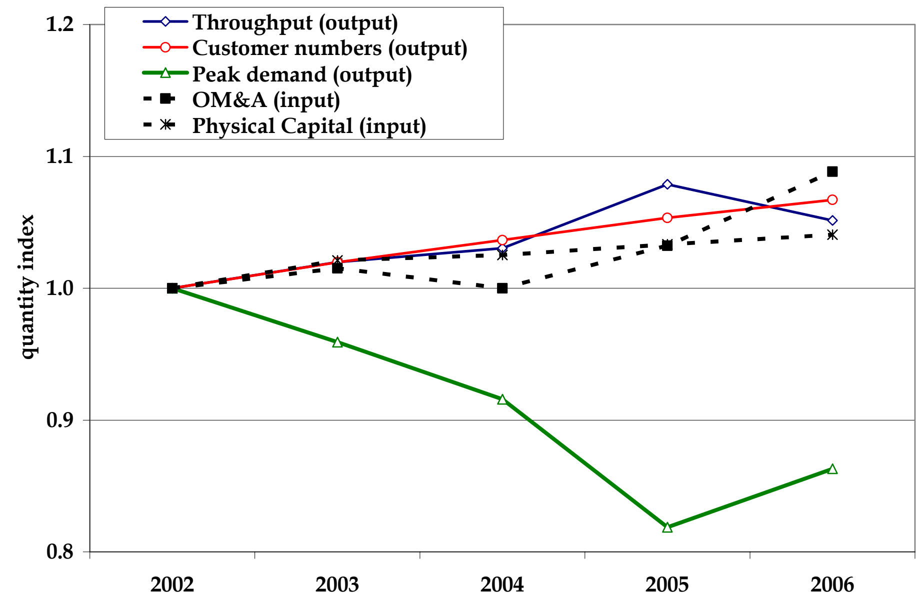
Year	Total distribution line length	Total Billed Distribution Revenues	OM&A Costs	Total Revenues - OM&A costs = Annual Cost of Capital
	km	*$ mio*	*$ mio*	*$ mio*
2002	193,974	2,508.45	975.32	1,533.14
2003	198,073	2,099.65	1,006.75	1,092.91
2004	198,870	2,097.80	996.34	1,101.46
2005	200,424	2,282.71	1,041.54	1,241.17
2006	201,837	2,408.98	1,121.84	1,287.13

Allocation of total revenue to the three outputs was the next step. For most industries which produce multiple outputs, these weights would be revenue shares, however in electric distribution, these outputs are not typically separately charged for (although the LDCs in Ontario file extensive cost of service studies that can be used to develop revenue shares in the future). In lieu of reliable data on revenue shares, the estimated output cost shares would be derived from an econometric cost function study completed for the industry in question. While ideally I would have liked to rely on such Ontario-specific empirical evidence, an econometric cost function study has not been completed for Ontario's electricity distributors. Thus, in consultation with Dr. Denis Lawrence at Meyrick and Associates, I decided to employ a range of reasonable output cost shares which were broadly consistent with the findings of cost function studies in other countries to each output, in order to illustrate the resulting variation in TFP estimates.

Q54. What were the results of your Ontario TFP analysis?

A54. Prior to calculating the TFP, we first calculated and graphed the quantity indices for the three outputs and two inputs (see the figure below), with a base year of 2002.

Figure 22. Quantity indices



Year	Throughput (output)		Customer numbers (output)		Peak demand (output)		OM&A (input)		Physical Capital (input)	
2002	1.000		1.000		1.000		1.000		1.000	
2003	1.020	*2.0%*	1.020	*2.0%*	0.959	*-4.1%*	1.015	*1.5%*	1.021	*2.1%*
2004	1.030	*1.1%*	1.037	*1.7%*	0.916	*-4.3%*	1.000	*-1.5%*	1.025	*0.4%*
2005	1.079	*4.8%*	1.053	*1.7%*	0.819	*-9.7%*	1.032	*3.2%*	1.033	*0.8%*
2006	1.051	*-2.7%*	1.067	*1.4%*	0.863	*4.4%*	1.088	*5.6%*	1.041	*0.7%*
Trend 2002-2006		**5%**		**7%**		**-14%**		**9%**		**4%**

On the input side, the OM&A quantity goes up by 9% and the capital quantity goes up by 4% over 2002-2006 study timeframe. The increase in OM&A quantity is a function of the increasing O&M expenditure (which is trending faster than the increase in the OM&A price index). On the output side, throughput increases by 5% and the number of customers increase by 7% over the four year period. However, peak demand declines by about 14%. On a combined basis, these observations indicate that any reasonable weighted average of the input quantities is likely to go up by more than that of the weighted average output quantity, which, in turn, means that TFP will be declining.

Over a range of output weights, the calculated average annual TFP trend over the 2002-2006 period is negative, as highlighted in the results table below.

Figure 23. Results of Ontario electric distribution industry TFP analysis, 2002 - 2006

Scenario 1: 33% (throughput), 33% (customer numbers), 33% (peak demand)

Year	Output index	Input index	TFP index	% Change
2002	1.000	1.000	1.000	
2003	0.999	1.019	0.981	-1.9%
2004	0.993	1.013	0.980	-0.1%
2005	0.976	1.033	0.945	-3.4%
2006	0.989	1.062	0.931	-1.4%
			average	-1.7%

Scenario 2: 25% (throughput), 50% (customer numbers), 25% (peak demand)

Year	Output index	Input index	TFP index	% Change
2002	1.000	1.000	1.000	
2003	1.004	1.019	0.986	-1.4%
2004	1.003	1.013	0.990	0.4%
2005	0.995	1.033	0.963	-2.7%
2006	1.008	1.062	0.949	-1.4%
			average	-1.3%

Scenario 3: 25% (throughput), 25% (customer numbers), 50% (peak demand)

Year	Output index	Input index	TFP index	% Change
2002	1.000	1.000	1.000	
2003	0.989	1.019	0.971	-2.9%
2004	0.973	1.013	0.960	-1.1%
2005	0.934	1.033	0.905	-5.5%
2006	0.956	1.062	0.900	-0.5%
			average	-2.5%

Scenario 4: 10% (throughput), 45% (customer numbers), 45% (peak demand)

Year	Output index	Input index	TFP index	% Change
2002	1.000	1.000	1.000	
2003	0.992	1.019	0.974	-2.6%
2004	0.980	1.013	0.967	-0.7%
2005	0.943	1.033	0.913	-5.4%
2006	0.968	1.062	0.912	-0.1%
			average	-2.2%

Q55. In summary, how did your Ontario TFP analysis differ from PEG's analysis?

A55. My analysis suggests that TFP growth has been negative in Ontario's electricity distribution sector over the last four years, while PEG's analysis shows a flat TFP profile (essentially zero TFP growth). My analysis of Ontario LDC industry average TFP growth relied on publicly available data for all LDCS (86 firms), while PEG employed a sample of firms (77 firms), as well as some confidential financial data from the Trial Balance reports.[62] My analysis customized an index model that best utilized the Ontario

[62] February 2008 PEG Report, pg. 31, pg. 37.

data. I used a three output model specification, consistent with industry practice, while PEG used a two-output model so that the Ontario results more closely matched its US analysis. PEG had weather normalized the throughput (volume) output measure, while I employed unmodified data.[63] Lastly, I used the direct method for estimating capital input quantities while PEG relied on the indirect method. I tested a number of potential output cost shares while PEG employed a single set of output cost shares (63% for customer numbers and 37% for kWh of throughput) developed from its US data.[64]

Q56. What do you believe are the key differences?

A56. I believe the primary difference is the output specification – the addition of the peak demand measure puts negative pressure on the TFP growth estimate, as I discuss below. By excluding this output measure, PEG overstated TFP growth.[65] In addition, the capital input quantity indices were designed using different methods. According to Dr. Frank Cronin's testimony at the March 26, 2008 workshop, PEG's reliance on short-lived capital additions data in its "monetary value" approach to estimating the quantity of capital inputs may have led to biases in the measurement of capital[66] over the study timeframe and therefore a bias in the TFP estimate.

[63] Although I do not have any issue with weather normalization models employed by PEG, for transparency, I prefer to estimate the TFP levels and growth rates without any weather normalization and then interpret the results given my knowledge of weather trends (for example, in Ontario, 2002 was a very hot summer, while 2006 was very mild).

[64] February 2008 PEG Report, pg. 36.

[65] I confirmed this hypothesis by actually re-testing the public Ontario data set, using PEG's output weights and excluding peak demand as an output measure. The resulting average annual TFP growth rate is -0.02%, closely approximating PEG's 0.01% result.

[66] March 26, 2008 Workshop Transcript, pg. 200, lines 25—28.

Q57. How would you interpret the results of your Ontario TFP study?

A57. A finding of TFP growth declines in recent years is not unique to Ontario, other jurisdictions are experiencing similar trends, so it cannot be dismissed as an 'inconvenient' outcome of unreliable data and assumptions.[67] TFP growth is not only decelerating but also negative. Given known operating cost pressures and business drivers, and the propensity for such conditions to remain or even expand in the future, such TFP growth results suggest that we should be pragmatically conservative in setting an X factor. An X factor that overextends the utilities will contradict the principles outlined by the Board staff in the Scoping Paper from July 2007.

In 1GIRM, Board recognized the importance of recent trends in setting the productivity factor. Five year estimated TFP trends were higher than the ten-year average, suggesting ramp up in productivity growth. The Board approved a final X factor of 1.25% for 1GIRM, with more weight on TFP growth in recent five years over the TFP growth over 10 years, in order to motivate the continuation of fast TFP growth.

Recent trends should again be considered in the X factor determination process. With a negative TFP growth over the last four years, and the potential for persistence of such trends due to exogenous factors, an 0.88% industry average X factor is simply not reasonable. Even without weighting the last four years more heavily, but simply

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[67] For example, based on PEG's 2005 Update for Victoria, there is a distinct slow down in annual TFP growth from 2001 onwards:

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	6.33%	6.78%	2.26%	3.11%	2.95%	-0.97%	-0.35%	1.53%	0.62%	-0.13%

Meyrick and Associates, in their work for the New Zealand Commerce Commission, also estimated significant productivity slow down and reversal in the electricity distribution sector: see Meyrick and Associates (2007), *Electricity Distribution Business Productivity and Profitability Update*, Report prepared for the New Zealand Commerce Commission.

correcting the long term PEG estimate for Ontario (under model 2 and model 3) with my results of negative TFP growth for the last four years, the highest calibrated X factor justifiable for the 1995 – 2006 period would be in the range 0.41% p.a. to 0.68% p.a. Furthermore, if I applied the same weighting concept that the Board applied in 1GIRM, then the recalibrated and re-weighted productivity target would approach 0%. I would conservatively recommend an X factor of 0.55%, which is the midpoint of the 0.4% to 0.7% range described above.

Q58. What is the significance of the difference between 0.55% and 0.88 X factor?

A58. Although at first blush, there is very limited difference in the numerical value of my recommendation as compared to PEG's for the X factor, the differences are material once you consider it from an LDC's perspective. For example, if we take the financial model I discussed earlier and overlay in the "I – X" price cap an X factor of 0.88% versus 0.55% on top of the other assumptions for that hypothetical LDC, we can see that the implications are quite meaningful for the LDC.

An 0.88% X factor, taking all the other assumptions as fixed (see Figure 2 on page 19), results in ROEs that are on average 7% over the five year IR generation - a whole 160 basis points below the allowed ROE of 8.6%. We can also consider the difference from management's perspective – how much cost gains must be realized in order to maintain LDC profitability at allowed ROE levels? An X factor of 0.88% requires almost a 20% decrease from base year OM&A costs as compared to a 14% decrease using a 0.55% X factor. Based on the experience of other utilities in the US, the 0.88% X factor establishes an unrealistic target for Ontario LDCs.

Q59. Would you recommend applying this single industry-wide X factor to all LDCs?

A59. In theory, no, I would not recommend a single industry-wide X factor for all LDCs in Ontario. A casual look at the publicly available data that describes the disparate LDCs and their operational profiles confirms that there is a lot of diversity in Ontario.

Customized firm-specific or group-specific X factors would better represent conditions and better align incentives. But in practice, we may be limited in the information we currently possess to adequately differentiate and set firm-specific productivity targets.

Q60. How would one go about in principle establishing firm-specific X factors?

A60. Conceptually, I would recommend measuring relative firm productivity through a Multilateral TFP (MTFP) analysis, which is an index method approach that allows for cross-sectional analysis of relative productivity of firms vis-à-vis each other and across time. The relative productivity differences can be converted into adjustment factors to the industry-average X factor.

Other productivity methods, such as econometric analysis and Data Envelopment Analysis, could also be employed to look at the underlying (exogenous) drivers for observed productivity differences. But, in any case, better data is required that will allow for comparative analysis on a total cost basis. Given the preference for a comprehensive price cap, it is vital that any such cross-sectional productivity analysis look at both OM&A and capital metrics, and allow the results to reflect capital versus labour and materials tradeoffs that should result in allocative efficiency gains.

Q61. Do you agree with PEG's proposed stretch factors?

A61. No, I do not agree with PEG's stretch factor proposal for several reasons. I disagree with the scale chosen as well as PEG's positioning of the stretch factors. Although PEG did attempt to analyze relative productivity levels of the LDCs, the scale of the stretch factors was chosen arbitrarily.[68] The incomplete benchmarking study was used by PEG simply to consolidate firms into groups for assignment of a stretch factor.[69] The level of

[68] The "particular values [for the stretch factors] obviously reflect a degree of judgment," writes Larry Kaufmann in the February 2008 PEG Report, page 77.

[69] February 2008 PEG Report, Section 4, pg. 64 – 79.

the stretch factor need not be based on ad hoc judgment. As discussed at the workshops in March 2008, empirical analysis can be applied to determine reasoned values for such adjustments.[70]

It is important to note that even the firm groupings are flawed, because the underlying productivity benchmarking is incomplete - it looks at only partial productivity and will inevitably result in substantial shifts in rank for some firms once a total factor productivity analysis is undertaken.

Indeed, PEG has criticized other consultants for proposing to develop rates on the basis of partial productivity measures. Just recently, in a January 2008 report issued in the gas distribution performance based ratemaking review in Victoria, Australia, Larry Kaufmann writes, "Because there can be tradeoffs among different [partial] performance indicators, it is extremely difficult to determine that a given set of indicators is consistent with good performance unless the partial benchmarking approach is able to quantify and evaluate the host of potential tradeoffs [capital-opex tradeoffs] that companies face and which can affect indicator performance. Since WP [the utility's consultant] did not put forward such a methodology, PEG did not believe that its partial indicator analysis… provided persuasive evidence one way or another on the [gas distribution business's] cost performance."[71]

But the most important concern from my perspective is PEG's positioning of the stretch factors. PEG has erroneously recommended stretch factors that are one-sided, with only positive stretch factors that will be added to the industry average X factor to form a firm's total productivity target. Although the price cap regime is being designed against an industry *average* target, PEG applies stretch factors associated with a *frontier* target

[70] *See* discussion from March 26, 2008 Workshop Transcript, starting on line 13 of pg. 134.

[71] Kaufmann, L. *Further Response to Meyrick and Associates and Worley Parsons Benchmarking Reports* January 2008. Prepared for the Essential Services Commission, pg. 1-2.

framework, with convergence of productivity growth for all firms to the growth rates of a "top tier" of firms rather than industry average.[72] In my opinion, this is mixing apples and oranges given that X factor component of the core model is being developed on the basis of an industry average TFP growth. In regards to the presence of diversity driven by exogenous factors, this is equivalent to disregarding business conditions that may make it difficult for some firms to keep pace with industry average TFP growth.[73]

From the perspective of diverse productivity targets to account for relative performance, PEG acknowledges that in principle diminishing returns are likely for productivity growth if productivity improvements had been achieved over previous periods[74], but then implicitly denies the possibility that some Ontario firms are indeed efficient in setting the stretch factors, despite the fact that many Ontario LDCs have been under pressure to restrain costs – because of explicit IR regimes or rate freezes – since the early 1990s.

Q62. How would you position the 'stretch factors'?

A62. I would position adjustments to the industry average X factor around the industry average X factor, in order to represent the diversity of firms.

Diversity is two dimensional. There is the diversity in firms' relative productivity that is a function of external and exogenous drivers, commonly referred to as business drivers.

[72] March 26, 2008 Workshop Transcript, pg. 132, lines 1-8.

[73] This issue was discussed at the March 25, 2008 Workshop. Although it was clear that Larry Kaufmann in principle agrees with the principles of diversity, noting that "even if that industry has been under incentive regulation for a while, that there still are differences in productivity among the firms. And therefore, there are differences in those firms' ability to make future productivity gains," (*see* March 25, 2008 Workshop Transcript, pg. 65, line 25-28), he did not recognize that such circumstances should be reflected in the stretch factor positioning around the industry average for Ontario.

[74] *See* March 25, 2008 Workshop Transcript, pg. 68, lines 9-13 and March 26, 2008 Workshop Transcript, pg. 87, lines 3-8.

Some firms may simply be incapable – given circumstances beyond their control – of achieving target productivity growths set on the basis of industry-wide trends. For example, given the customer mix (less dense customer base and therefore the need for higher expenditures per customer to interconnect), 'inherited' network topology (for example, ownership of transmission assets that have been deemed to be distribution assets, or more underground lines versus overhead lines), and local environment (harsh weather conditions requiring additional maintenance), some LDCs in Ontario may simply have a higher cost basis. Further, certain technological improvements that are driving productivity growth for their peers may not be applicable or accessible to them. The opposite may also be true for another group of LDCs that are well endowed to be good performers. So diversity factors that recognize these differences would naturally fall on either side of the industry average.

PEG attempted to accommodate some of these issues in the peer groupings but without any rigorous evidence sufficiently justifying the results. Indeed, PEG simply grouped firms on the basis of location, size, volume growth, and degree of undergrounding, but PEG did not fully test other business drivers.[75]

There is also diversity in productivity that is represented by endogenous choices made by management to become more productive. Some firms may already be relatively efficient and others less efficient. The less efficient firms may have more scope for greater efficiency gains, as noted by Larry Kaufmann at the March 25, 2008 workshop.[76] The more efficient firms are more likely to experience a slower growth over time as they will have already maximized their opportunities in many regards. Therefore, we expect that over time, an IR regime should motivate convergence of disparate firms' productivity to a narrower band around the long run industry trend. Notably, PEG's

[75] February 2008 PEG Report, pg. 66 – 71.

[76] March 25, 2008 Workshop Transcript, pg.63, lines 1-8.

own TFP evidence shows a slow down – rather than acceleration – in the US, Ontario, and other jurisdictions, which is direct support for the propensity for convergence and the fact that a high paced TFP growth is not sustainable indefinitely. Inexplicably, PEG has denied that such differences should be considered in the 3GIRM framework although in principle Larry Kaufmann has agreed that the purpose of the stretch factors is to "pick up the incremental TFP gains that a company, a given company, can be expected to make under a PBR plan relative to the industry standard."[77]

Q63. What data would you need to produce a robust MTFP?

A63. Engineering measures of carrying capacity of network would be vital to a MTFP study as would measures of transformer capacity, so that various capital inputs can be consolidated into a single index and accurately compared across firms on an apples-to-apples basis. I discuss data improvements in more detail in the next section of this testimony.

Q64. In recognition of the current data shortcomings, how would you recommend the Board proceed?

A64. I would recommend that the Board proceed with a single, industry-wide X factor and make commitments to improve data for future generations of IR. There is simply too much uncertainty in the existing benchmarking results – or indeed certainty with respect to flawed conclusions - to proceed with the PEG's recommended stretch factors.

[77] March 25, 2008 Workshop Transcript, pg.62, lines 12-15.

VI. Data issues

Q65. What kind of improvements would you recommend the Board make in the PBR data currently filed by LDCs?

A65. I understand that the Board has started the process of recovering the data employed in 1GIRM, spanning the period 1988 – 1997.[78] Although there will be some inconsistencies in data variables (definitions may have changed) and utility-level information (due to corporate structure changes, mergers, etc.), the data will nevertheless be useful in analyzing longer term trends. Additional effort should be expended by the Board staff filling in the missing years of 1998 – 2002, for such basic parameters like total revenues, total labour and material expenses (OM&A expenses), volumes of electricity served, metered peak demand or system carrying capacity, physical asset descriptions (kilometers of distribution lines by voltage level, number and voltage rating of transformers), ratebase, capital additions, etc.

In addition, at the March 26, 2008 workshop, the Board's Chief Regulatory Auditor discussed the possibility of transcribing data from prior to 1988 from the Ontario Hydro statistical yearbooks.[79] There is value in this for at least some variables, like capital additions, as it will improve the accuracy of the assumed methods in the TFP calculations. Although there are costs to such data mining, I believe those costs are substantially outweighed by the piece of mind that the Board and stakeholders will possess once the data improves the robustness of the quantitative analysis and therefore the rigor of the IR process.

I also believe that it is important to supplement the current data set in terms of the type of information collected. The accuracy of the results of the productivity analysis are tied

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[78] See footnote 11 on page 15.

[79] March 26, 2008 Workshop Transcript, pg. 173.

to how well we can measure the quantity of output produced and input employed. The output of an electricity distribution company is in fact a difficult metric to establish. Unlike a natural gas distribution company, or a highway, electricity distribution networks have a more complex output that is quality and quantity dependent. Electricity distribution networks - through carrying capacity and coverage –provide a service with some embedded level of quality. Ideally we would like to represent output of an LDC as the customer connected capacity because in effect the distribution company provides interconnection to the transmission system and access to energy. The volume of electricity delivered on the network, the number of customers served, and peak demand are conventional proxies for measuring the underlying service provided by the utility, with throughput and peak demand proxies for carrying load of the network and customer numbers describing the extent of network coverage. However, better measures – albeit engineering in nature – are possible. For example, customer numbers can and should be replaced with a more concrete measure of connections, as utilities may have different protocols in how they count or estimate the number of customers. Instead of metered peak demand, it would also be preferable to have a measure of network capacity that is not dependent on consumption patterns. An even better measure could be developed by aggregating the carrying capacity of the individual elements – distribution lines, transformers – that make up the system, recognizing that the effective capacity of an individual line or transformer depends not only on the voltage of the element, but also on a range of other factors, including the number, material and size of conductors used, the allowable temperature rise as well as limits through stability or voltage drop. This is a conventional engineering concept in the industry, and there are established methods for measuring the MVA-kilometers of line and MVA of transformation capacity. The availability of such information would allow for a more rigorous and robust comparative analysis of relative productivity of firms and industry TFP.

Finally, the existing data variables in the data set need to be more clearly defined by the Board and industry stakeholders and the industry need to make a concerted commitment to report data that is comparable across firms based on industry-developed guidelines; Certification by a firm is insufficient to prevent discrepancies in how firms individually interpret the information requirements. Currently, there are no guidelines and protocols for what the Board intended that the LDCs provide. Each LDC has used its best efforts and filed data per its interpretation of the RRRs; however, multiple (and sometimes conflicting) interpretations are possible. As an example, when kilometers of distribution line are reported, some LDCs may be reporting primary lines, while others may also be counting secondary lines. Elimination of such conflicts in the data is possible, especially for going forward data submissions, and would simply require a working group, composed of industry stakeholders, to review the RRRs and identify industry standards.

VII. Concluding remarks

Q66. OEB Staff asked whether "tradeoffs" exist in the selection of different components for the IRM regime. Please describe your views on these "tradeoffs."

A66. In any regulatory framework, we will have tradeoffs. The most common tradeoff that we make in policymaking is one of accuracy versus simplicity. Indeed, there will need to be tradeoffs made by the Board even in terms of the board objectives – no possible IRM design can maximize all the stated objectives in the Staff Scoping Paper. The goal is therefore to present policymakers with a clear understanding of the value of those tradeoffs and, perhaps more importantly, to make sure that we are presenting a framework that is internally consistent. The design of an IRM framework is challenging because there are in fact many such linkages that we need to be aware of and ensure are considered.

The notion of internal consistency and linkages between components of the core plan and the objectives of the 3GIRM is the driving force behind many of my recommendations. For example, a capital investment module is necessary given the Board's own stated objectives. A 3GIRM mechanism will not endure if it cannot properly remunerate prudent investment.

On the issue of linkages, the Board's intention to make service quality mandatory provides further impetus for a CAPEX factor. Mandatory service quality measures will require a management and operating shift for Ontario LDCs, and as part of that, capital life extension, replacement, and emergency response plans will need to be carefully adjusted so as to ensure adequate performance to mandatory service quality indicators.

Internal consistency also argues in favor of a single industry-average X factor, as PEG's recommended stretch factors are wholly inconsistent with the comprehensive price cap paradigm given that they were developed using partial productivity measures. At the same time, a CAPEX factor, buttressed with incentives schemes, can be compatible with a comprehensive price cap. The compatibility relies on how we implement the CAPEX factor. In contrast, ESM are not naturally compatible with price cap regimes, and therefore I would recommend that they not be included as part of the core plan. Consistency was also the theme raised in my recommended changes in the Board staff's proposed IPI. To the maximum extent possible, the IPI and TFP analysis (which underlies the X factor) need to utilize similar components and methods when it comes to looking at the input price indices.

VII. Exhibit: Resume for Julia Frayer

KEY QUALIFICATIONS:

Julia Frayer is a Managing Director with London Economics International LLC, specializing in economic analysis and evaluation of infrastructure assets, such as power plants, natural gas-related infrastructure, electricity transmission and distribution systems, and utilities. Julia manages LEI's quantitative financial and business practice area, and also specializes in market and organizational design issues related to the electricity sector. Sample projects include cost of capital estimation; rate-setting analysis; short- and long-term forecasting of wholesale power prices; valuation of generators and vertically-integrated utilities; productivity analysis and benchmarking; assessment of provider-of-last resort portfolios and contracts; advice on and design of energy sales agreements; and advisory on structuring request for proposals and sale processes for energy assets and derivative contracts.

Julia also leads many of the firm's market design engagements, spanning such diverse issues as cost-benefit analysis, tariff design, market power mitigation, auction design (including competitive solicitations for procurement), wholesale market rules design, and competitive market efficiency benchmarking. Julia has a unique perspective on key issues affecting the electricity industry given that she has worked both for private sector clients and government institutions (such as regulators and policymaking organizations). She has led and contributed to numerous projects at LEI involving tariff design, rate setting using performance based principles, cost-benefit analysis of regulatory regimes, the structure of market institutions, such as ISOs, power exchanges, transmission system operators, etc. These engagements involved substantial stakeholder consultation, and required tailored advice to the client on operational issues, funding questions, marketing protocols, and organizational/governance structures. Julia, as part of LEI, has been active in the Ontario market for over a decade, and has experience advising on incentive regulation, through work in North America, Eastern Europe, South America, and Asia. She understands the evolutionary nature of the Ontario market and appreciates from all dimensions how recent government initiatives are impacting stakeholders.

Prior to joining London Economics, Julia was working as an Investment Banker with Merrill Lynch in New York. At Merrill Lynch, she specialized in the financial sector, working closely with specialty finance companies, re-insurance firms, asset management and regional depository institutions, in both mergers and acquisitions aspect and strategic financing areas.

EDUCATION:

Graduate School of Arts & Sciences, Boston University, M.A. in Economics

College of Arts & Sciences, Boston University, B.A., Summa Cum Laude, in Economics and International Relations, member of Phi Beta Kappa

EMPLOYMENT RECORD:

From: February 1998 **To:** present

Employer: *London Economics International LLC,* United States

- ***Alternative supply and rate design:*** In response to new state legislation mandating change in policy towards renewables, conservation, and non-conventional generation sources, Julia was tasked with an investigation of how renewables, distributed generation and energy efficiency could be accommodated and encouraged by the KPSC, by virtue of rate design and other policy decisions. Julia conducted a stakeholder interview session and then prepared independent analysis documenting on impediments in current statute and potential recommendations for following through on legislative intent. Julia will be testifying at the KPSC in April 2008.

- ***Market advisory support in due diligence of new technology:*** In support of the Massachusetts Technology Collaborative, Julia led a team of economists that evaluated the market scope for a new flywheel technology being built by beacon Power for possible employment in the regulation markets, and other power products. LEI's analysis served as basis for project loan that the Commonwealth of Massachusetts granted to Beacon Power for the further commercial development of the application.

- ***Support to California Energy Commission ("CEC") on regulatory and market design changes:*** LEI was contracted by CEC to study the capacity products that have been traded in other jurisdictions, and more broadly examine trading platforms that may be useful models for California if a voluntary trading mechanism was implemented to assist market participants in trading capacity to achieve compliance with Resource Adequacy Requirements. Additionally, LEI produced a report to cover the functional requirements for a bulletin board posting and trading platform for bringing buyers and sellers together and allow trading of the various capacity products supported by RAR in California, such as System RA Capacity and Local RA Capacity, and possibly some form of Import RA Capacity. We also covered the functional requirements for a tracking system, including title tracking, certification of transactions, and possibly, compliance filing.

- ***Development of an Electric Resource Adequacy Plan in Maine:*** Julia is currently leading a team of economists in support of the Maine Public Utility Commission on a project evaluating the role of long term contracts for utilities to hedge wholesale market costs on behalf of ratepayers. As of March 2008, LEI has completed an assessment of the reliability of the bulk power system within the State and gave appropriate consideration to generation and transmission resources in order to maintain or enhance that reliability. The next phase of work will include the design of a competitive solicitation for long term contracts.

- ***Support to CEC on long-term planning and procurement policymaking:*** LEI is providing feasibility analysis for the potential application of "To Expiration Value at Risk" (TeVaR) analytical methods to long-term electric utility portfolio analysis and planning and procurement policymaking activities of CEC.

- ***Economic transmission valuation:*** On behalf of a transmission and distribution utility in New England, Julia led a team of economists in the analysis and detailed simulation of net benefits attributable to a proposed transmission line that would be built in New England to bring renewable resources from northern Maritimes into central New England. LEI's analysis was presented in stakeholder consultations at ISO New England.

- ***Transmission rate design best practices:*** On behalf of the Ontario Energy Board, Julia prepared a working paper series for the Board documenting theoretical best practices with transmission rate design, as well as case studies in how transmission rates are developed, specifically speaking to issues pertaining to uniform rate design.

- ***Advice on incentive rate structure for Alberta utility:*** Julia supported the LEI team and her partner, AJ Goulding, in the design of a proposed incentive based rate structure for a for a large metropolitan Alberta utility, specifically assisting on the preparation of a forecast of long term inflation trends that may be used by the utility in setting rates.
- ***Study of PBR designs employed in the world for a Caribbean electric utility:*** key issues included the tradeoffs between using RPI-X style formulations and revenue sharing techniques, accounting for the unique nature of island systems, impacts on employment, exploring issues related to calculation of an appropriate return on equity, the implications of different types of designs for key stakeholders. LEI culminated in workshops for the regulator, the leading utility, and government representatives.
- ***Analysis of ancillary services market designs:*** in support of large multinational utility, Julia led a six market case study of ancillary services market design elements, commenting on strengths and weaknesses of design and implications for opportunity cost reflective pricing. Traditional, market-based ancillary services, as well as nontraditional services were examined.
- ***FEOC Consultations in Alberta:*** In the role of expert advisor, Julia supported a large power producer in responding to Ministry's comments on new legislation defining a fair, efficient, and openly competitive market, and best practices with respect to regulatory design of generation market power rules and procedures.
- *Development of RFP for new generating or demand-side electrical capacity in state of Connecticut* - Julia served as the economic advisor to the Department of Public Utility Control in Connecticut , helping them design and implement an "all source" RFP for new capacity in the state in order to mitigate the exposure to ratepayers from Federally Mandated Congestion Costs. As economic advisor and RFP Coordinator, Julia and her team of economists, lawyers, and technical experts are responsible for managing all aspects of the RFP, including design of innovative financial contracts for capacity, administration of RFP process, and evaluation of bids submitted by project sponsors, and recommendation to the DPUC for selection of winning projects. The selection of projects is based on a proprietary set of models that LEI staff designed under Julia's guidance to estimate the cost-benefit to ratepayers from long term contracts with new capacity, based on reduction in wholesale market costs across three different ISO New England power markets.
- ***Monitoring of 5,500 MW RFP for energy services for standard offer contract issued by Connecticut-based utility:*** the Department of Public Utility Control of Connecticut retained the services of LEI to assist the DPUC in monitoring the power procurement processes for Connecticut Light & Power's (CL&P) Transitional Standard Offer auction in November 2004 for services in 2005 and 2006, and once again selected in September 2005 to monitor the November 2005 auction for services in 2006. Julia led and is currently leading LEI's team in providing advisory services to the DPUC, including guidance on communications protocols, design of sales contract agreement (between CL&P and winning bidders), and also valuation of final bids vis-à-vis the forward market alternatives available to the utility. In November 2004, Julia filed an affidavit after completion of the process which the Commissioners used to approve the process and the contracts between CL&P and the winning bidders.
- ***Economic analysis and expert testimony in front of the Public Utilities Commission of Texas on market power related issues:*** prepared and filed testimony and quantitative analysis on questions of market definition and market integration. In June 2005, Julia participated on panel discussing market monitoring issues, as well as market power safeguards for wholesale electricity markets. In 2004, she

also provided testimony on pricing safeguards proceeding, which looked at alternative market power testing procedures for market power, analyzed implications on investment, and discussed efficiency consequences of certain bidding behavior.

- ***Contract analysis and risk management:*** Julia led analysis of large market participants' collar contract positions within its overall portfolio-wide risk management strategy in Northeast market. Analysis and risk management recommendations will be presented to Board of Directors.

- ***Expert testimony on financial market theory with respect to competition and confidentiality of data release in auction setting:*** Julia Frayer provided expert witness support to the California Energy Commission staff in a proceeding before the Commission relating to confidentiality of data in the IERP 2005 process. Julia Frayer testified to the potential benefits that could arise as a result of the release of aggregated supply-demand data compiled from the IOUs' Long-term Resource Plans. She also worked alongside Energy Commission staff in analyzing the arguments laid out by the utilities in their appeals of the proposed release of the aggregated data. Her testimony spanned a number of issues, such as auction theory, market design, and power procurement in California, market power, and also availability of various historical data. The Commission ruled in September 2005 to reject the IOUs' appeals and to permit the release of the aggregated data.

- ***Provided oral and written testimony to the Quebec regulator on the potential design of an auction for transmission in the region:*** As part of HQTE's rate application in front of the Régie de l'Energie, Julia submitted evidence on behalf of Brascan Energy Marketing Inc. regarding demand elasticity of transmission services and market-based mechanisms for optimizing usage of transmission assets, including the practical aspects of designing and implementing an open auction for physical transmission rights. In addition, LEI staff provided oral testimony to the Régie on these topics.

- ***Economic advisor to large European power company in its acquisition of an electric distribution franchise in Eastern Europe:*** Julia, along with her team members, assisted a large European power company in its acquisition strategy in Romania. Project involved government and stakeholder consultations, proposed modifications to market design and regulatory structure, including the implementation of a performance based ratemaking regime. London Economics was also responsible for forecasting tariffs - which were an integral part of the overall financial model and supported the proposed purchase price.

- ***implications of 1st generation PBR in Ontario:*** LEI advised the Canadian subsidiary of an integrated US utility on its prospective acquisition of an Ontario municipal utility on all aspects of distribution company valuation, including implications of PBR in Ontario, determination of annual revenue requirements, potential for revenues from unregulated businesses, other revenue and profit drivers, and on financial and corporate structure.

- ***Development of a methodology for transmission planning for the CA ISO:*** on-going engagement, in which Julia is co-project manager. LEI, in association with Professor Robert Wilson of Stanford Business School, ECCO, and Dr. John Smalls, has been engaged by the California Independent System Operator (CA ISO) to construct a framework for the economic valuation of transmission investment. Though grounded in a cost-benefit analysis approach, the methodology is proposed to move beyond traditional valuation frameworks and to incorporate concepts from real options investment analysis and game theory, and include innovative techniques for forecasting market power implications for wholesale power markets. In the last phase, LEI demonstrate the practical application of the methodology to a real-world transmission investment. The work, completed jointly with the CAISO, was filed with the CPUC in late 2002. As a result of this work, LEI developed a linear program model, which combined with econometric techniques, helped resolve and evaluate the question of generation and transmission interdependence.

- ***Market analysis and forecasting for IPP developer in Ontario in response to Ministry of Energy's RFEI for 2,500 MW of clean energy:*** Julia directed the quantitative analysis and wholesale electricity price forecasting completed for an IPP. Projections were used to justify project sponsorship of a small gas-fired plant in front of the IPP's Board of Directors and led to project submission to RFEI. In addition, Julia and her team of economists designed a risk model for the client to evaluate the contract payment risks vis-à-vis actual dispatch.

- ***Analysis of LMPs in New England:*** using well-established econometric techniques, analyze location-based marginal prices in New England since inception of the new nodal system. Assess the node-specific marginal loss and congestion premiums for certain assets located in load pockets. Analysis integral to a valuation of a portfolio of generation assets and power supply agreements.

- ***Advisory support to the Government of Hong Kong in rate-setting:*** In preparation for 2008, when the contracts governing Hong Kong's electricity sector expire, LEI provided detailed briefing papers to the Government on a variety of topics ranging from the appropriate allowed rate of return, calculating the ratebase, establishing efficiency, performance, and environmental incentives, and assessing the merits of the Development Fund and the Fuel Clause Adjustment. Julia assisted the LEI team in a strategic advisory role. With regard to efficiency and performance incentives, LEI conducted an international assessment of different PBR programs in place in jurisdictions ranging from Australia to Canada to the US to Austria, identifying international best practices, and developing an appropriately tailored proposal that could be easily implemented in the Hong Kong context. The project culminated in a series of recommendations regarding the industry's regulatory structure, which were publicly issued as part of the Government's consultation process.
- ***Extensive economic support of a private client's acquisition of a New England-based generating portfolio:*** Julia assisted a large Canadian private client in its acquisition of a large New England generation portfolio. Julia and her team supported the client's valuation team, providing extensive forecasting and revenue modeling support for the bid development, due diligence, and cost-benefit analysis of key components of the portfolio (which contains an assortment of power plants, ranging from coal-fired facilities to hydro units, and other power sector-related assets, such as transmission rights contracts, power purchase agreements, and power supply obligations). London Economics, with Julia's support, is currently working on FERC filings in anticipation of the acquisition, which will assess the market power attributes of the transaction, per Section 203 requirements. In addition, London Economics'' quantitative and modeling analysis will be used to support securitization and credit rating efforts which may include the acquired assets.

- ***Review of PBR tariff structure of a large utility for a Latin American regulatory authority:*** Julia was a member of the consortium team (multi-firm consortium, led by LEI) that evaluated the performance of the utility in the 1992-2002 tariff period; advised the authority on international best-practice design of distribution tariffs; proposed a tariff setting methodology for the 2002-2007 tariff period; provided technical assistance in the analysis of information presented by the utility; proposed tariffs for the 2002-2007 tariff period; and, assisted the authority during public hearings on the proposed tariffs. The consortium has proposed that tariffs be set via an RPI-X approach employing Data Envelopment Analysis (DEA) for establishment of the X-factor.

- ***Support the Balancing Pool on economic issues related to the MAP II sale of dispatch rights associated with key generation assets currently controlled by the Balancing Pool:*** conducted an in-depth analysis of current and future market outcomes under a variety of ownership structures (required multi-year simulation modeling of strategic behavior using CUSTOMBid) for energy and ancillary services market in Alberta, quantitative analysis served as foundation for the design of efficient holding restrictions that would be applied to the sale of the Clover Bar, Sheerness, and Genesee contracts; consulted the Balancing Pool, MAP Committee, and associated parties on sale process and auction design principles; provided an independent valuation of the contracts using an options-based approach based on London Economics' proprietary spark-spread model.

- ***Economic feasibility study of a New York City cogeneration facility, a Western New York peaker, New York City CCGT (various clients)***: for a developer, prepared a ten-year revenue forecast for a proposed cogeneration facility, including a forecast of energy and capacity revenues (namely intrinsic revenues) and a volatility or real options-based adder (extrinsic revenues) for the New York City zone of the NY ISO. Analysis was used in support of board approval and aided in the design of the project (e.g., choice of technology and flexibility of such technology vis-à-vis expected market outcomes). For another private client, conducted a longer term projection (spanning 20 years) for a peaking power generation project in Western New York, producing a forecast for regional energy, installed capacity, options-based adders, and ancillary services revenues streams.

- ***Modeling of the future value of emissions reduction credits in regional, continental and global emissions trading markets:*** on behalf of large multinational client, Julia completed a study of the short to long term dynamics of the emissions trading markets. The majority of the focus was on greenhouse gas emissions and the potential for trade-able instruments in North America based on recent publicized transactions and pilot trading programs. However, discussion of current US emissions trading markets (for nitrogen oxide and sulfur dioxide) and their relative features was included in the report.

- *Financial analysis and portfolio review for a New York hedge fund* - Julia assessed the value of a client's international portfolio, consisting of generation assets in Asia and other utility assets across the Caribbean. The project involved the identification of possible purchasers of these assets and assessments of the current appropriate cost of capital for each asset.

- *Analysis of market-based discount rates:* Julia has overseen the preparation of a number of reports for various clients discussing discount rate issues, employing techniques ranging from Capital Asset Pricing Model to Arbitrage based principles and comparative analysis. The latter involved peer analysis and econometric techniques to estimate reference points in the energy markets for determining implied discount rates for generation projects at which buyers are willing to purchase contracted generation assets in today's markets.

- ***Review of innovative leasing deal for electric and gas networks:*** for set of investment banks, performed engagement reviewing ownership arrangements for network assets, revenue drivers, and contract structure, including implications on financial viability from performance based ratemaking regimes. Julia created detailed net benefit analysis for innovative swap structure, involving the cash flows from the network assets under performance-based regulatory regimes.

- ***Analysis of industry credit conditions and likelihood of bankruptcy:*** Julia and a team of financial experts prepared an opinion letter for a US investor in a cross-border acquisition analyzing the likelihood of bankruptcy and the occurrence of servitude events vis-à-vis certain trigger conditions in a big ticket lease transaction involving infrastructure assets, because of the time span between a negative event taking place and the timeframe for financial filings. Julia utilized industry-standard ratings criteria frameworks and rating migration methodologies.

- ***Financial and economic support for potential acquirer of hydroelectric capacity in New England*:** In the last quarter of 2005, Julia managed the initial due diligence and market analysis for New England market participant interested in acquiring a portfolio of small an larger hydroelectric facilities in New England in preparation of initial bid by potential acquirer, including baseline review of assets' market position, key revenue considerations, financial viabilities, survey of key risks, and initial analysis of regulatory hurdles at FERC for transfer of assets.

- ***Evaluation of a structured financial agreement (swap) or service contract with respect to district heating network in Austria:*** directed the economic analysis of the financial instrument which involved the quasi-securitization of the income streams of a district heating distribution business in Austria; supported the legal counsel in the due diligence process and contributed to the design of the transition structure with respect to the financial arrangement; analysis and final opinion provided backing for a US cross-border lease.

- ***Economic support of generation acquisition by investment funds in PJM:*** Julia is leading a due diligence team and assisting in the exclusivity negotiations with respect to an acquisition of a 400+ MW coal fired plant in the PJM market by a group of private investors. Julia's role included management of LEI's economic appraisal, coordination of preliminary technical due diligence, negotiations with third parties on possible of-take arrangements, and oversight over financial modeling.

- ***Valuation of coal-fired generation assets in the NYPP:*** forecast energy and capacity prices for the New York market on a sub-regional basis, rooted in transmission constraint parameters. Utilizing London Economics' proprietary pool simulation model, Julia composed detailed unit-by-unit performance, revenue and cost parameters over the next twenty years. In addition, she investigated the affect on market projections by varying key drivers and scenario assumptions, in an effort to bracket the perceived risks to clients. Julia studied the influence of several key market drivers, such as the implementation of various environmental programs, changes to system supply-demand profile due to various new entry/retirement profiles, modification of market rules, and shifts in key input markets (e.g. coal, natural gas and oil markets).

- ***Valuation of New England, PJM and Midwest generation assets:*** evaluated potential value of assets available under various regional auctions for a dominant IPP player. Julia worked with client in composing a bid proposal by assessing market risks posed by various factors, such as fuel price shifts, merchant plant construction scenarios, site conversion potential, and transmission constraints and through extensive production cost modeling.

- *Analysis of price-cost markup in PJM's wholesale energy market*– as part of studied funded by American Public Power Association, Julia led a team of economists and econometricians in a highly complex back-casting modeling exercise of hypothetical competitive pricing, and estimation of markups embedded actual locational marginal prices. This empirical analysis provides a cornerstone for policy discussions and consideration of the financial motivation for new investment in PJM's energy market, as well as other market design issues.

- ***Asset optimization for international generation-only company:*** Using application of methods and quantitative techniques from Modern Portfolio Theory, Julia participated on LEI team working on a first stage review of a multinational firm's generation asset holdings, scope for efficiency improvements, risk reduction, and identification of areas for increased diversification potential.

- ***Assessment of Austrian hydroelectric generation*: **Julia was asked to provide an economic opinion for a US-based investor involved in a cross-border acquisition of certain hydroelectric assets. Julia's opinion detailed the appropriate WACC and price forecast that should be used in the valuation, based on current and proposed structure of the power market, and provided an assessment of the marketability of the service contract involving an exchange of market-based revenues (energy and ancillary services) for a fixed cash payment between the owner of the assets and an independent counterparty. For this project, extensive financial analysis of reasonable costs of capital for generation-only investments was done, including adjustment factors for various risk factors unique to hydroelectric assets. In addition, LEI performed a multi-scenario financial analysis of the service contract based on projected exchange of funds.

- ***Valuation of a pumped storage facility:*** in support of an asset bid by a multi-national player, Julia and her team of economists and modelers completed a medium-term analysis of potential peak versus off-peak price trends in a key Eastern Interconnect market. The price forecast was based on both network simulations using marginal cost-based bidding and strategic bidding. The strategic biding analysis was based on an innovative algorithm, referred to as ConjectureMod, developed by LEI in consultation with a well-known game theorist in electric power markets.

- ***Determination of reasonable rates and subsidy payments for a water business in Germany, as part of US cross-border lease transaction:*** managed an economic valuation and forecasting exercise in support of a combined $1 billion plus transaction involving several wastewater and freshwater systems (treatment facilities and collection and distribution networks) in Germany. As part of the economic analysis, forecast reasonable rates for the water and wastewater businesses based on true cost recovery principles. In addition, provided industry expertise in the design of a subsidy mechanism, to overcome certain legal obstacles in local jurisdiction's laws with respect to return on investment vis-à-vis fair market value.

- ***Valuation of Mid-Atlantic utility:*** co-led economic aspect of valuation process for potential acquisition of Mid-Atlantic utility for international entity. Analysis included valuation of PJM-based generation portfolio through the use of production cost-based models and real options applications. Julia also coordinated evaluation effort for trading entity and regulated asset base (wires assets), including review of exposure due to provider of last resort obligations. Julia and her team of economists assessed contract portfolio and load growth parameters, as well as mitigation measures employed by target utility.

- ***Measurement of contract exposure under a series of PPA contracts and its effect on enterprise value:*** this study was done in conjunction with a due diligence process, where London Economics was part of team analyzing a potential merger between an international power producer and diversified US utility. In identifying key issues in merger between these two entities, London Economics was given the task of defining and quantifying the liabilities associated with the US utilities' power purchase agreements. Julia lead the analysis on behalf of London Economics in the due diligence process: constructing a theoretical framework and applying it to complex asset swap and power purchase agreements in order to measure the magnitude of the liability via current and forecasted market conditions.

- ***Valuation of distribution assets:*** quantified synergies and developed strategies for potential cross-border transaction between top Canadian distribution corporation and affiliate of Top 20 US utility, by performing in-depth analysis of diversified strategies available to global energy companies in energy generation, transmission, distribution, wholesale and retail marketing, energy services, and other infrastructure industries. Julia co-managed a team of economists and consultants, pursuing unique valuation approaches in this transaction, utilizing comparable analysis, examination of PRB mechanisms and other regulatory pricing designs, growth strategies, as well as the application of real options theory.

PUBLICATIONS AND SPEAKING ENGAGEMENTS

Frayer, Julia "Prepared Presentation of Julia Frayer for Market Monitoring and Surveillance in the context of Market Design." Panelist, *PUCT Workshop for Project #28500*, Austin, Texas, June 10, 2005.

Frayer, Julia "Written Statement of Julia Frayer for the January 27th 2005 Technical Conference in Docket RM04-7-000" Panelist, *FERC Technical Conference*, Washington D.C., January 27, 2005.

Frayer, Julia "Competitive procurement options for Ontario's LDCs" Speaker, *APPrO 2004 Conference*, Toronto, Ontario (Canada), November 24, 2004.

Frayer, Julia, Nazli Uludere, and Sam Lovick "Beyond market shares and cost plus pricing: designing a horizontal market power mitigation framework for today's electricity markets." *Electricity Journal,* November 2004.

Frayer, Julia "The World Changed on August 14th: the (Second) Great Northeast blackout." Chairman of Panel Session, *Electric Power Conference* 2004, Baltimore, Maryland, March 30, 2004.

Frayer, Julia "Alternative to LMP pricing for transmission: a case study of the ICRP approach used by National Grid Company in the UK." Speaker, *Electric Power Conference* 2004, Baltimore, Maryland, March 31, 2004.

Frayer, Julia "Big ticket leasing - what next for the future?" Panelist, *Big Ticket Leasing 2003*, London (United Kingdom), March 12, 2003.

Frayer, Julia "Evaluating the Electron Highway" Speaker, *IPPSO 2001 Conference*, Richmond Hill, Ontario (Canada), November 28, 2001.

Frayer, Julia and Nazli Uludere "What is it worth? Application of real options theory to the valuation of generation assets" *Electricity Journal,* November 2001.

Goulding, A.J., Julia Frayer, Jeffrey Waller "*X Marks the Spot*: How UK Utilities Have Fared Under Performance-Based Ratemaking" *Public Utilities Fortnightly,* July 15, 2001.

Frayer, Julia "How much is it worth? Applying real options valuation framework to generation assets" Speaker, *Electric Power 2001*, Baltimore, Maryland, March 22, 2001.

Goulding, A.J., Julia Frayer, Nazli Z. Uludere "Dancing with Goliath: Prospects After the Breakup of Ontario Hydro" *Public Utilities Fortnightly*, March 1, 2001.

Frayer, Julia and William Chapman "Improving price forecasting in wholesale power markets through the application of models of strategic bidding" Speaker, *EPRI International Pricing Conference 2000*, Washington, D.C., July 28, 2000.

COMMONWEALTH OF MASSACHUSETTS §
COUNTY OF Suffolk §
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BEFORE ME, the undersigned authority, on this day personally appeared Julia Frayer, who, having been placed under oath by me, did depose as follows:

My name is Julia Frayer. I am of legal age and a resident of the Commonwealth of Massachusetts. The foregoing testimony and the attached exhibits offered by me are true and correct, and the opinions stated therein are accurate, true and correct.

Julia Frayer

Julia Frayer

SUBSCRIBED AND SWORN TO BEFORE ME by the said Julia Frayer this 14th day of April, 2008.

Notary Public, Commonwealth of Massachusetts

GLORIA COLEMAN
Notary Public
Commonwealth of Massachusetts
My Commission Expires March 30, 2012