YOUR CURRENT CONNECTION

April 14, 2008

Ms. Kristen Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, ON M4P 1E4

Re: 3rd Generation Incentive Regulation for Electricity Distributors
Comments on the Board Staff Discussion Paper and Consultant's Report
Board File No.: EB-2007-0673

The Coalition of Large Distributors (CLD - Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc.) and Hydro One Networks are pleased to provide comments to the Board Staff Discussion Paper on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. The submission also provides comments to the Board staff's expert consultants report entitled "Calibrating Rate Indexing Mechanism for the 3rd Generation Incentive Regulation in Ontario".

The CLD and Hydro One have retained a consultant to provide expert advice and assist them in developing alternative ideas and proposals. The affidavit of Ms Julia Frayer of London Economics International is attached as Appendix A to the submission and this contains supportive evidence to the body of the report.

Please find enclosed three paper copies of the submission and accompanying affidavit. We have also sent an electronic copy of each in searchable/unrestricted PDF format through the Board's web portal.

As indicated during the Board's March 26th workshop, the CLD and Hydro One would be pleased to reconvene before the Board at any time to discuss our recommendations.

Yours truly,

Original signed by

Paula Conboy

Director of Regulatory and Government Affairs

PowerStream Inc.
161 Cityview Boulevard, Vaughan, ON L4H 0A9 Tel: 905-417-6900 Fax: 905-532-4505 www.powerstream.ca

EB-2007-0673
3rd Generation Incentive Regulation for Electricity Distributors
Coalition of Large Distributors and Hydro One Networks Comments
On Board Staff and PEG Reports

Executive Summary

The CLD and Hydro One are pleased to note the direction which the Board Staff and its consultant Pacific Economics Group ("Consultant") have taken with respect to the development of 3rd Generation IRM ("3GIRM"), specifically:

- The added flexibility in the process that allows utilities to file alternative rate setting proposals if circumstances warrant this approach;
- The comprehensive price cap index model with flexibility to recognize capital investment needs during the IRM period;
- The use of indexing method to develop the industry wide Total Factor Productivity ("TFP"); and
- The use of industry specific Inflation Price Index ("IPI").

The CLD and Hydro One also wish to commend the Board Staff and its Consultant on the cooperative and open approach in which the Working Group was allowed to function. We firmly believe that as a result of this approach we were able to move forward on a number of the key issues that helped to formulate ideas for the core plan put forward by the Board Staff and its Consultant. However, the timeline in which all stakeholders have been given to fully understand and access the complex issues and implications of the proposed 3 GIRM has been significantly tight for such a critical initiative. The regime approved by the Board will lay the foundation of the safety, reliability, viability and quality of the distribution sector for the foreseeable future. Distributors and other stakeholders must be able to fully understand the practical implications of the regime in order for it to be a success.

A considerable amount of work has been done in developing the 3GIRM core model and the CLD and Hydro One believe that the proposed concepts are sound to move forward with. The CLD and Hydro One recognize that despite some concerns pertaining to data quality and availability associated with the development of the model parameters this should not hold up the implementation of the 3GIRM core model in the context of evolving and adjusting the model as we gain more information and experience. It is imperative that the Board approve the core model so that utilities subject to 3GIRM rate adjustments starting in 2009 are afforded the required time to prepare and file their submissions in a timely manner. In this respect the CLD and Hydro One provide the following recommendations which we believe will assist the Board in making its decision.

ELEMENTS OF CORE MODEL

FORM

Recommendation # 1 The CLD and Hydro One agree with the Board Staff proposal and recommend the use of a comprehensive price cap index-based adjustment mechanism for electricity distributors. Distributors which need to depart from the core model could file an alternative proposal, e.g. a revenue cap or a cost of service, and would submit a rationale as to the circumstances for alternative treatment.

TERM

Recommendation # 2 The CLD and Hydro One recommend 5 years as the normal period for 3GIRM. Those utilities that request a longer or shorter period than 5 years would provide a rationale as to the circumstances for the need to depart from the norm.

INFLATION FACTOR

Recommendation # 3 The CLD and Hydro One recommend that the Board and stakeholders continue with the development of an IPI for future implementation during the 3GIRM period.

The CLD and Hydro One agree with the use of an industry specific Input Price Inflation factor as an appropriate measure for tracking inflation for electricity distributors. However, there is considerable concern with a lack of a readily available index results in the calculation of an index from other publicly available price information, and with respect to the reasonableness and consistency of the sub-indices that pertain to labour costs, utility capital costs and material costs and how these would reflect utility costs going forward.

Recommendation # 4 In the interim, and to help implement 3GIRM, the CLD and Hydro One recommend the Board adopt the use of a macroeconomic index such as GDPIPIFDD.

PRODUCTIVITY FACTOR – Total Factor Productivity

Recommendation # 5 The CLD and Hydro One recommend a TFP of 0.55% this being the mid point of a range of values estimated by our consultant London Economics International.

The CLD and Hydro One are concerned that too much reliance has been placed by the Board's Consultant on US data. Relying on US data as presented by PEG to derive TFP trends for Ontario's utilities may produce misleading results, or at a minimum, results that do not reflect Ontario's recent history of distributor operations or the negative TFP growth over the recent years. By correcting the long term PEG estimate for Ontario with the recent negative TFP growth the historical long term TFP would be expected to be reduced from the proposed Productivity factor to 0.4%-0.7%.

PRODUCTIVITY FACTOR – Stretch Factor

Recommendation # 6 The CLD and Hydro One recommend that the use of Stretch Factors be deferred until such time as an appropriate comparison of utility costs has been completed.

The CLD and Hydro One are concerned with the proposal to use a Stretch Factor based on incomplete analysis of distributor cost comparison. The design of a Stretch Factor needs to reflect the trends in productivity changes and circumstances under which the utilities have and will be operating under during the IRM. The proposed peer classification is insufficient. Therefore whether the productivity levels of firms within each peer group are consistent cannot be determined.

TREATMENT OF UNFORESEEN EVENTS – "Z"Factors

Recommendation # 7 The CLD and Hydro One recommend that the Board issue a consultation in the appropriate level and rules governing a "Z"-factor adjustment rather than applying an arbitrary 3% threshold level.

OFF-RAMPS

Recommendation # 8 The CLD and Hydro One recommend the use of off-ramps be determined on a case-by-case basis where a distributor brings forward an application that proposes the Board should make modifications to the adjustment mechanism or whether the distributor is seeking a cost of service re-basing.

EARNINGS SHARING MECHANISM

Recommendation # 9 The CLD and Hydro One accept the use of Earnings Sharing Mechanism with IR plans submitted by utilities for longer than the normal 5 year period associated with the core plan. For longer plans, if the achieved return on equity from regulated activities is more than 300 basis points different from the Board's allowed ROE, then the CLD and Hydro One recommend that the computed overage/underage be shared equally (i.e.,50/50) between the distributor and its customers.

LOST REVENUE DUE TO CHANGES IN CONSUMPTION

Recommendation # 10 The CLD and Hydro One believe that in the short term utilities can make use of existing lost revenue adjustment processes in connection with unforecasted CDM impacts, and that revenue-oriented IRM alternatives can accommodate broader concerns around reductions in load and customer numbers.

CAPITAL INVESTMENT DURING 3GIRM

Recommendation # 11 The CLD and Hydro One recommend that the Board reconvene the Working Group to develop a Capex factor that should be incorporated directly into the price cap formula.

A capital investment module needs to be based on the premise that it funds capital requirements that are anticipated, predictable, and form part of a distributor's large scale integrated capital programs. Based on this, the proposed Z factor mechanism is not appropriate. A capital expenditure module through a Capex factor would be able to accommodate the diversity among the LDCs while providing a mechanistic approach that streamlines the regulatory process. We believe that there is sufficient time to develop this factor during April-June period so that this element is incorporated in the 3GIRM.

REGULATORY AND LEGISLATIVE REQUIREMENTS

Recommendation # 12 The CLD and Hydro One recommend the availability of variance accounts to assist with tracking the differences between revenues earned and costs incurred with respect to Smart Meter projects that are not in base rates, and other material incremental revenue requirement impacts associated with annual capital and operating expenditures resulting from new regulatory and legislative requirements imposed on distributors.

1. INTRODUCTION

The Coalition of Large Distributors ("CLD") and Hydro One Networks ("Hydro One") is supportive of the Board's effort to move forward with incentive regulation for the electricity distributors in the form of the 3rd Generation IRM ("3GIRM"). In theory, a multi-year incentive regulatory process has the potential to benefit all parties through:

1. Making the regulatory process more efficient;
2. Providing incentives for the utility to improve performance, and
3. Allowing the benefits to be shared equitably between the utility and its customers.

As proposed, 3GIRM will focus mainly on regulatory efficiency. No explicit incentives for distributors to enhance customer service quality and reliability are proposed. Hydro One and the CLD also question whether the financial benefits will be shared equitably with distributors. Thus in essence this regulatory framework for setting distribution rates from 2009 onwards is a means of cost control through use of price caps and as such this concept is not new. Electricity distributors in Ontario have been exposed to a variety of cost control mechanisms comprising of price caps (1GIRM RP-1999-0034, 2GIRM EB-2006-0089) or rate freezes that date back to the former Ontario Hydro. Rate freezes and other constraints over the past decade and longer have acted as a surrogate price cap mechanism in a time where distributors have faced expanding obligations and mandates. Consequently the introduction of 3GIRM does not constitute a major shift in rate making from Cost of Service to Incentive Regulation that is typically the case in other jurisdictions that first embark on incentive regulation. Rather, we have experienced incentive regulation in different forms that have affected utility performance and caused utilities to manage cost pressures accordingly. Therefore, it is important to take into account the impact of past cost containment regimes on utility productivity and cost efficiency when setting expectations around future productivity gains to be achieved either at the firm level or from the distribution sector as a whole. However, the development of 3GIRM is different from other previous implicit or explicit price cap mechanisms in that this time around the Board's direction is to develop a comprehensive, sustainable IRM that relies on more quantitative analysis and objective measures.

We do not expect to solve all issues in developing a comprehensive, sustainable price cap mechanism in the first round. We need to approach the development of 3GIRM in a practical and reasonable way recognizing the diversity of electricity distributors and their respective needs going forward. In this respect the CLD and Hydro One are pleased to note that Board Staff has recognized that a "one size fits all" approach to developing a 3GIRM framework is not practical. The variety of distributors in Ontario warrants a flexible approach that allows those utilities that choose not to adopt the core model because of their particular circumstances to submit alternative proposals. All of this points to the fact that we need to:

- Put in place a mechanism that can evolve with time
- Identify priority issues to start with because these impact LDCs in the near-term
- Allow adjustments to be made as we gain experience with IRM and avoid drastic changes to regulatory framework which introduce uncertainty
- Recognize there are limitations which need to be addressed but which need not prevent starting down the 3GIRM path
- Recognize that utilities experience cost pressures moving forward that may not be amenable to simple indexing proposals for adjusting rates.

We believe that the ultimate goal should be the use of performance based regulation to set distributors rates with rewards and penalties for performance – as demonstrated by effectively and efficiently delivering services to customers at reasonable rates.

At this time the CLD and Hydro One propose to focus their comments on the matters listed below, and in so doing provide recommendations which are aimed at assisting the Board in formulating its decision.

- Core Model
  - Form
  - Term
  - Inflation factor
  - Productivity factor
    - Total Factor Productivity
    - Stretch Factor
  - Treatment of Unforeseen Events – “Z” factor
  - Off-ramps
  - Earnings Sharing
- Lost revenue due to changes in consumption
- Capital investments during term of 3GIRM
- Data requirements
- Regulatory and Legislative Requirements
- Implementation

We discuss each of these in more detail below. The CLD and Hydro One have retained a consultant to provide expert advice and assist them in developing alternative ideas and proposals. The affidavit of Ms Julia Frayer of London Economics International (LEI) is attached as Appendix A to the submission and this contains supportive evidence to the body of the report.

2. GENERAL OBSERVATION ON TIMELINES AND RECOMMENDATION FOR FURTHER WORK

Notwithstanding the general familiarity with the concepts of Total Factor Productivity, Inflation and Stretch Factor that may have been acquired as a result of developments in 1GIRM, 2GIRM and the Natural Gas IRM, there is a need for a cautious approach with setting the parameters for 3GIRM in the light of the continual changes in the industry, the circumstances in which utilities have operated since market opening in 2002, the government directives in respect of Smart Meters, the supply mix and conservation and demand management to ensure that the choices we make for establishing the fundamentals of 3GIRM are reasonable and sustainable. Care must be taken to ensure that the 3GIRM parameters are reasonable and balanced in encouraging productivity growth while recognizing the sector's obligations to provide quality service and maintain financial soundness. A sustainable and vibrant distribution sector is in the best interest of consumers.

While much valuable work has been performed by the Board's consultant, Board Staff, the Working Group, the EDA and other utilities there is still considerable work to be done in some areas of the core model. The utilities are certainly doing their own analysis with assistance from experts and to the extent practicable the CLD and Hydro One provide concrete recommendations at this time for those elements of the core model for which we believe there is sufficient supporting material from the said analysis to do so. However, progress in other elements of the model is taking more time and the analysis is not complete at the time of this submission, or may not in fact be practicable to complete in time for the implementation of 3GIRM.

However, that is not to say that the whole process for implementing the 3GIRM should be delayed, and the CLD and Hydro One are certainly not proposing any delays. Rather, the CLD and Hydro One identify in their recommendations where additional work is required in the next two months and where further work needs to continue beyond the start of 3GIRM. This in no way reduces the validity of moving forward as planned with the implementation of 3GIRM.

3. CORE MODEL

3.1 Form

The CLD and Hydro One understand that the Board deliberated on different forms of incentive regulation in 1st Generation PBR and in the Union Gas proceeding (EB-1999-0017) and adopted a price-cap index-based adjustment mechanism. Indeed a price cap mechanism is more commonly understood and easier to administer when dealing with a large number of regulated entities. However, given the diversity in the industry and the Government's mandate to promote a conservation culture the Board should be mindful that viable alternative mechanisms may be more appropriate. For example, where distributors are encountering loss of customers and/or load, through circumstance other than CDM, a revenue cap approach may be the appropriate approach to an incentive regulation application. Alternatively, a cost of service may be better suited to some distributors. In either case, the distributors should be allowed to make the appropriate application with the appropriate supporting documentation and evidence.

Recommendation # 1 **The CLD and Hydro One agree with the Board Staff proposal and recommend the use of a comprehensive price cap index-based adjustment mechanism for electricity distributors. Distributors which need to depart from the core model could file an alternative proposal, e.g. a revenue cap or a cost of service, and would submit a rationale as to the circumstances of alternative treatment.**

3.2 Term

The CLD and Hydro One support the concept discussed by the Working Group in allowing flexibility in the term of the plan. We agree that the choice of term should be made in application of the first year of the plan and that the rates of the distributor would not be subject to rebasing before the end of the plan term other than through eligible off-ramps. We would suggest however that the Board consider terms longer than 5 years. This recommendation is based on the core motivational features of incentive ratemaking caps: holding all else constant, a utility's incentive for efficiency-enhancing initiatives will simply be much stronger the longer the term of the price cap. The power of the incentives increases with time because of both practical and financial implications. With a longer term, the utility will have the necessary time to operationalize its cost reduction plans and more effectively make trade-offs and realize cost gains from optimizing short-term operating cost (OM&A) strategies versus longer term capital-intensive business strategies. Financially, the utility will also be more motivated with a longer term, because it can realize the returns to efficiency investments that take longer to materialize but are nevertheless very significant.

Alternatively a LDC may propose a term shorter than five years as a result of local circumstances such as internal corporate planning cycles that have already been set. Furthermore, if the Board does not adopt the recommendation of including an appropriate capital adjustment model as part of 3GIRM, many LDCs will have no option but to shorten the term of 3GIRM and move to a cost of service approach to rate regulation.

The regulatory complexity of moving distributors onto a comprehensive 3 GIRM over the next few years should not be underestimated. We appreciate the challenges faced by the Board and intervenors in adjudicating 30 cost of service applications and to approving the mechanistic price adjustments of 2 GIRM applications in addition to other regulatory obligations. In May 2009 the Board and other stakeholders will be faced with adjudicating cost of service applications, approving the mechanistic price adjustments of 2 GIRM applications in addition to approving the price adjustments of 3 GIRM applications which despite best efforts may not run as smoothly as originally planned. This is evidenced by the difficulty the industry has had in approving the 2008 EDR applications and the 2 GIRM applications. This workload might be made smoother if distributors were given an option of proposing differing terms.

Terms longer than 5 years are already possible given the implications of the Board's report on Rate-Making Associated with Distribution Consolidation (EB-2007-0028) that gives distributors an option to defer rebasing for a term of up to 5 years after the closing date of a consolidation.

Recommendation # 2 **The CLD and Hydro One recommend 5 years or shorter as the normal period for 3GIRM. Those utilities that request a longer period than 5 years would provide a rationale as to the circumstances for the need to depart from the norm.**

3.3 Inflation Factor

The CLD and Hydro One concur with the proposal that using an Input Price Index (IPI) is conceptually the best option for an inflation index designed to directly reflect the changes in prices of inputs that are used by utilities to carry out their distribution business. However, the issue is that such an index is not readily available in the public domain and must be calculated from other publicly available price information. In their discussion document Board Staff have provided an illustrative example of how an IPI might be constructed from publicly available sub-indices that pertain to labour costs, utility capital costs and material costs[1]. However, there was considerable debate at the March 25, 2008 Stakeholder Workshop with respect to the assumptions around the capital price index and what that contained[2] which casts some doubt as to its applicability in the utility context. One significant concern is whether these indices have been checked for reasonableness and consistency with actual cost trends experienced by utilities in the past. Are other indices better proxies? For example, as noted by Ms Frayer at the proceeding in respect of the capital input price index there is an incorrect presumption of continuous refinancing of the entire capital asset base, rather than an attempt to accurately capture what happens in terms of financing costs of new capital additions versus sunk investments[3]. We know that in reality that is not the case as utilities do not refinance on an annual basis their entire portfolio of assets. Typically, utilities may only refinance that portion of long term debt that comes up for renewal. In addition, utilities also add new assets on an annual basis that must also be factored into the equation. Obviously care must be taken in the calculation methodology that best reflects the way utilities manage their financing of capital.

As discussed by Ms. Frayer in section IV of her affidavit in Appendix A to this document, the representativeness and therefore validity of the proposed labour and material sub indices is also questionable given recent experience of Ontario LDCs. To some extent that issue of representativeness of the *Statistics Canada* indices arises because of survey formats and sample size. For the materials subindex, the problem escalates because no appropriate *Statistics Canada* index exists which effectively represents the unit price of contracted services in the electricity distribution sector. Indeed, in the discussion at the March 26, 2008 workshop, it became apparent that PEG and OEB Staff are employing different input price indices in their respective calculations of the Productivity factor and Inflation index, which raises concerns of consistency[4].

The CLD and Hydro One also have some serious concerns about the validity of the sub-indices that can be used to construct the IPI, as well as the assumptions employed for combining the indices. In addition, the CLD and Hydro One are concerned that application to future prices of the index smoothing methodology illustrated by Board staff may lead to unintended volatility in actual utility returns, since actual costs would not be smoothed. By definition, increased volatility in utility ROE entails increased risk for utilities.

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[1] Staff Discussion paper on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors; February 28, 2008; Section 4.3
[2] EB-2007-0673, Calibrating Rate Indexing Mechanisms for 3rd Generation Incentive Regulation For Electricity Distributors, Stakeholder Meeting, March 25, 2008, Transcript pages 13 through 37.

[3] *Ibid*, pages 29-37
[4] *Ibid* , pages 27-31

An alternative approach to an IPI is to use a macroeconomic price index such as GDPIP which the Board is familiar with since it has been used in 2GIRM and is to be used in the Natural Gas IRM[5]. This index is readily available from public sources, is transparent and is stable. The disadvantage of using this index is that it does not specifically track actual industry cost trends.

Notwithstanding the concerns raised to date with the IPI approach, the CLD and Hydro One are of the view that the preferred approach is to account for inflation trends on industry inputs and that more work needs to be done to research the appropriateness of the sub-indices that would be better proxies for tracking trends in labour, materials and capital inputs that utilities are faced with using, and that the methodology of using the sub-indices to calculate the IPI be refined to better reflect utility practices. Some concrete proposals from the CLD and Hydro One include:

- Adjustment of the financing component of the price of capital input index – which is proxied by the long term bond rate in the price of capital index (where Pk = (bond rate + depreciation rate)*Construction Cost Index). The financing component should be re-formulated to take into account the partial refinancing over time of the capital asset base. Concretely, the financing component should be the rolling average of bond rates over a 10 year period of time.
- The Board should also investigate the use of actual industry-level data from Ontario LDC filings under the RRRs. For example, LDCs typically file in their annual rate applications or in cost of service studies average wage rates or wage settlements, which on an aggregate basis can provide a very accurate measure of industry trends in the price of labour.
- The same material price index proxy sub-index should be used in both the TFP calculation and the inflation index on an interim basis. In the medium term, a survey on the costs of contacted services can be instrumental in building a more precise materials sub-index.
- The Board should update the elasticity cost shares used to combine the three sub-indices into a single input price index regularly using Ontario data.

The above indicates that this effort would require considerable analysis and that such an effort could not be completed in time for implementation of 3GIRM.

Recommendation # 3 **The CLD and Hydro One recommend that the Board and stakeholders continue with the development of an IPI for future implementation during the 3GIRM period.**

[5] EB-2007-0606 ; Union Gas Settlement Agreement, January 3, 2008, and EB-2007-0615;Enbridge Gas Distribution Settlement Agreement, February 4, 2008

Recommendation # 4 **In the interim, and to help implement 3GIRM, the CLD and Hydro One recommend the Board adopt the use of a macroeconomic index such as GDPIPIFDD.**

3.4 Productivity Factor

3.4.1 Total Factor Productivity

As a general comment the CLD and Hydro One concur with PEG regarding the general choice of methodology for measuring industry average Total Factor Productivity (TFP) growth. However, we believe a number of improvements in the technical analysis and design of the price cap components can be made to best reflect the potential for productivity expectations for the electric utilities in Ontario.

The major concern which the CLD and Hydro One have regarding the proposed TFP developed by PEG is that it is entirely reliant on data from US utilities. Productivity is a measure of the physical output produced from the use of a given quantity of inputs. For the price cap formula, we seek an estimate of productivity growth – rather than productivity levels. In other words, we need to understand how productivity changes over time in the industry, and specifically how we expect productivity to grow over the term of the incentive ratemaking regime, in setting the Productivity factor.

All enterprises use a range of inputs including labour, capital, land, fuel, materials and services, and the electricity sector is no exception. Although the general type of inputs are the same across jurisdictions in the electric distribution industry, the cost drivers may be different between utilities, which impacts the pace with which productivity changes over time. If the enterprise is not using its inputs as efficiently as possible then there is scope to lower costs and increase profitability through productivity improvements. This 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.

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 the Total Factor Productivity. TFP measures total output relative to all inputs used. Output can be increased by using more inputs, making better use of the current level of inputs and by exploiting economies of scale. The TFP index measures the impact of all the factors affecting growth in output other than changes in input levels. Given the diversity of utilities in Ontario, the CLD and Hydro One are concerned that circumstances under which the US utilities operated over the period considered by PEG in the analysis may be quite different from those under which Ontario utilities operated, leading to different historical measures of TFP growth and, more importantly, different expectations regarding TFP growth in the future. Ontario has seen significant changes in the past 10 years, especially since the restructuring of the industry following the proclamation of the *Energy Act, 1998*. For example, we know that the Ontario utilities have been subject to rate freezes as a result of government directives in the period 2002-2004. Prior to that there were prolonged rate freezes under the previous regime. Also, most LDCs in the province are either government or municipally owned and as a result may have different obligations than might be the case with investor owned utilities in the US. All of these differences impact on the operations of the distribution systems thus leading to potentially different expectations in terms of productivity and cost efficiency. Therefore relying solely on US data to derive TFP trends for Ontario's utilities may produce misleading results, or at a minimum results that do not reflect Ontario's recent history of distribution operations. Relying on data that does not readily reflect the immediate past history to set expectations for the future is inappropriate.

As discussed by Ms Frayer in Section V of her affidavit in Appendix A, and based on PEG's own analysis, all indicators suggest that a TFP growth is slowing down, both in the US and in Ontario. As noted on page 17 of the Board Staff report[6], the utilities in Ontario have been under cost pressures due to price cap regimes or effective rate freezes for some time and therefore efficiency improvements have been made. More importantly, we are now embarking on a period of replacement of aging assets and demographical shifts in labour that are likely to show up in input increases without commensurate output increases. The bottom-line is that PEGs' recommendation for a 0.88% basic Productivity factor is too high and ignores recent trends in Ontario. If PEG's average TFP growth analysis for the period 1995-2006 was recalibrated with a more accurate analysis for Ontario for the period 2002-2006, we expect that the historical long term TFP would be reduced to the range of 0.4% to 0.7% per annum. In addition, if the Board's precedent-setting approach from 1GIRM is employed, and more weight is given to recent trends in Ontario in combination with recalibrated 11-year average trends calculated by PEG, we approach an even lower productivity target.

No further analysis can be undertaken at this time to narrow down further this range of expected values. However, in the interest of moving forward with implementing 3GIRM, the CLD and Hydro One believe that making an assumption of a mid-range value for the TFP is not unreasonable at this time. As the distribution industry gains experience with 3GIRM and as more comprehensive data is accumulated there will be opportunities to undertake further analysis to refine the TFP trends. In the

[6] Staff Discussion Paper on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, February 28, 2008

meantime a decision has to be made as to what value we should start off with and in our opinion the analysis performed by LEI suggests a lower value for the TFP than proposed in the Consultant's report.

Recommendation # 5 **The CLD and Hydro One recommend a TFP of 0.55% being the mid point of a range of values estimated by London Economics International.**

3.4.2 Stretch Factor

We have calculated so far an industry average growth rate in TFP, so by definition, some LDCs will have growth rates that are lower and some will have growth rates that are higher than this industry average. The Board Staff and PEG propose that a stretch factor is included to complement the industry average TFP measure in the establishment of an industry "X"-factor that would be used to set rates on a prospective basis.

We must first recognize that we are not discussing the commonly accepted definition of a stretch factor, as described by Professor Yatchew at the workshops[7], as Ontario utilities are not just moving to IRM from cost of service. Rather that transition was effectively made years ago when the rate freezes and various price cap regimes were initiated. Therefore Ontario LDCs have been making productivity gains and effectively sharing those gains with consumers for a substantial period of time.

The purpose behind the use of the "stretch factor" in the current context is therefore to create a measure that recognizes diversity amongst Ontario utilities, and therefore aligns the utility or peer-specific Productivity factor so that the potential for additional productivity gains during the IRM period could be shared immediately with consumers rather than waiting for rebasing.

Diversity has two dimensions in Ontario's electricity distribution sector. First of all, heterogeneity among Ontario distributors is partially a function of exogenous factors. Some utilities may face business and environmental conditions outside management's control that may hinder or accelerate productivity growth vis-à-vis its peers. Recognition of this 'exogenous' diversity will therefore mean that some firms may need to have higher or lower Productivity factors than the industry average, as discussed by Dr. Yatchew at the workshop. Another dimension of diversity is a function of differences in achieved productivity improvements to date (effectively, efficiency gains on costs that are within management's control). Distributors that have been performing at superior levels historically and

[7] EB-2007-0673; 3rd Generation Incentive Regulation for Ontario's Electricity Distributors Presentation on behalf of the *Electricity Distributors Association;* Adonis Yatchew March 26t 2008 Stakeholder Meeting

achieving efficiency gains will eventually remove most inefficiencies and therefore will not be able to maintain the same pace of productivity growth as those distributors that have not been making the same level of productivity improvement, as discussed by Ms. Frayer at the Board's March 26th workshop[8]. Firm-specific Productivity factors should therefore be tailored to what can be reasonably achieved in the future - utilities will not be moving along the same trend (rate of change) line, given historical productivity improvements and relative differences in the level of productivity and/or efficiency today. This is an important consideration that should reflect the reality of the Ontario LDCs which is that some utilities are very efficient compared to the average productivity trend whilst other are less efficient and still have some ways to go to meet the average trend.

While the CLD and Hydro One agree with the concept of using a stretch factor to make a first approximation adjustment for differences in cost drivers, it is necessary to recognize that the design of such a factor is crucial to creating the appropriate incentives for utilities under an IRM. In all respects, the design of the stretch factor should be grounded in facts that appropriately reflect the trends in productivity changes that reflect the circumstances under which the utilities have and will be operating during the IRM. In addition, on an interim basis the CLD and Hydro One are not opposed to the use of peer groups to categorize utilities with similar kinds and degrees of exogenous cost drivers, in order to approximate a more thorough and exact analysis of cost driver differences. The use of such groupings would provide some measure of protection from the possibility that unjustified outcomes could be produced through inappropriate comparisons of utilities with very different sets of cost drivers. Again, it is crucial that the selection of peer groups reflect close similarities in costs drivers and not arbitrary and irrelevant features that do not have a demonstrable connection to costs. Additionally, in a sector as heterogeneous as the electricity distribution sector within any peer group established there will remain a variety of utility specific productivity levels.

As explained by Ms Frayer in Section V of her affidavit in Appendix A, a peer approach to using multilateral TFP analysis would be the most practical method for establishing an understanding of the diversity of performance between groups and determining group "diversity factors". We prefer the use of "diversity" rather than "stretch" factors because we feel that the industry is not yet at a level of understanding of the relative status of productivity trends and achievements by all utilities in Ontario to adopt the concept of "stretching" performance. Such an approach can only come about after we have (1) gathered sufficient data and experience of performance under an incentive regime , (2) performed a rigorous analysis of productivity growth and the relative standing of utilities thereof, and, on the basis of the analysis, (3) determined whether we need to "stretch" performance targets or not.

[8] EB-2007-0673, Calibrating Rate Indexing Mechanisms for 3rd Generation Incentive Regulation For Electricity Distributors, Stakeholder Meeting, March 26, 2008, Transcript pages 75 through 85.

Multilateral TFP (MTFP) is a rigorous approach for calculating the necessary inputs to such diversity factors. It is an index based approach that measures TFP for the industry and cross-sectional analysis of TFP levels across firms, producing reliable rankings of firms relative to industry average. But we lack the data to do a robust MTFP for Ontario's distributors. The peer classification created by Board staff is insufficient because it is based on an analysis of distributor's efficiency that has been limited to the use of OM&A costs to date and as such is inadequate for analyzing TFP or setting rates for a comprehensive price cap. As a result we cannot determine whether the productivity levels of firms within each peer group are consistent. To date the Board's consultant has relied solely on the use of OM&A data which on its own does not tell the true story of utility performance. The combination of OM&A and capital is the proper measure by which to establish utility performance on a level playing field. But we are not there yet as witnessed by the work done under proceeding EB-2006-0268, Cost Comparison of Electricity Distributors.

Given the status of analysis at this stage, the CLD and Hydro One recommend that the Board defer the use of stretch factors until such time as the comparison of utility costs has been completed taking into account capital costs. To do otherwise could result in a stretch factor set for an LDC that is completely contrary to that LDC's efficiency. This should be done at the earliest opportunity but the absence of this information at this time should not be a barrier for moving forward with setting the "X"-factor to equal the TFP developed taking into account industry aggregate Ontario data.

Recommendation # 6 **The CLD and Hydro One recommend that the use of Stretch Factors be deferred until such time as an appropriate comparison of utility costs has been completed.**

3.5 Treatment of Unforeseen events

Z factors provide for non-routine rate adjustments intended to safeguard customers and distributors against the unexpected costs that are outside management's control.

Board staff is proposing that the materiality threshold for Z-factor claims be increased from 0.2% of either distribution expenses or net fixed assets, depending on the type of costs under consideration to 3%. Using PowerStream's 2006 financial data (as presented in RP-2005-0020/EB-2005-0409/0410/0411) as an illustration, the materiality threshold would translate to $10.5 million and 1.8 million of net fixed assets or distribution expenses respectively. Similarly, using Hydro One's 2006 financial data (RP-2005-0020/EB-2005-0378) the respective materiality thresholds would translate to $102.7 million and $12.7 million of net fixed assets or distribution expenses respectively. Please see table below for details.

For 2006	$ Million	Threshold - 0.20% $ Million	Threshold 3% $ Million
PowerStream Net Fixed Assets	350	0.7	10.5
Hydro One Next Fixed Assets	3423	6.85	102.7
PowerStream Distribution expenses	60	0.12	1.8
Hydro One Distribution Expense	423	0.845	12.7

This is a significantly higher threshold than that calculated for Union Gas (EB-2007-0606) and Enbridge Gas Distribution Inc (EB-2007-0615) where Z factors generally have to meet the threshold of a cost increase/decrease of $1.5 million annual per Z factor event which undoubtedly is much lower than 3%.

Most of the consultation in 3GIRM (and in 2GIRM) has been focused on the key areas of productivity, inflation and capital. The rules governing Z factor treatment are important and merit a separate consultation. Proceedings such as the storm damage proceeding (EB-2007-0514, EB-2007-0595, EB-2007-0571, EB-2007-0551) are intended to be adjudicative hearings and should largely be restricted to circumstances where fact finding is required to support an order. As noted in the Report with Respect to Decision-Making Processes at the OEB where possible, policy matters should be addressed in codes, rules or guidelines. The CLD and Hydro One note that all parties to the proceeding agreed that the current threshold of 0.20% is likely too low, but we would submit that the Board issue a consultation on the appropriate level and rules governing Z factor treatment rather than arbitrarily choosing 3%.

Recommendation # 7 **The CLD and Hydro One recommend that the Board issue a consultation in the appropriate level and rules governing a "Z"-factor adjustment rather than applying an arbitrary 3% threshold level.**

3.6 Off ramps

An off-ramp is typically designed as a pre-defined set of conditions under which the IRM plan would be terminated or modified before its end date, usually because of some unforeseen event not addressed through Z-factor treatment.

The CLD and Hydro One are supportive of the use of off-ramps where a distributor would file an application with supporting evidence with the Board for a prospective review of the adjustment mechanism but would suggest that in the current context that they not be limited to a pre-defined set of conditions. There are still several government and regulatory initiatives that may affect the rate adjustment mechanism in the near term. In fact, the Board has directed some distributors in their 2008 EDR decision to make adjustments to the rates annually so that revenue to cost ratio increases are kept within certain bands (e.g. Barrie Hydro Distribution Inc. EB-2007-0746 Hydro and Oshawa PUC Networks Inc EB-2007-0710). The treatment of distributed generation may also require adjustments to the rate adjustment mechanism beyond what might be captured "outside the core model" or Y factor.

The CLD and Hydro One suggest that a distributor should be able, without prohibitive evidentiary burden, bring forward an application that would propose the Board should make modifications to the adjustment mechanism or whether the distributor is seeking a cost of service re-basing. This flexibility would allow the Board to determine the best course of action rather than automatically moving to a cost of service application by default.

Recommendation # 8 **The CLD and Hydro One recommend the use of off-ramps be determined on a case-by-case basis where a distributor brings forward an application that proposes the Board should make modifications to the adjustment mechanism or whether the distributor is seeking a cost of service re-basing.**

3.7 Earning Sharing Mechanism

In the development of 2GIRM, Dr Yatchew noted that the theoretical literature on incentive regulation provides a simple and clear argument on the role of productivity savings in creating incentives for cost minimization[9].

Earning Sharing Mechanism (ESM) also provides a degree of rate predictability and potentially help to avoid the possibility of unscheduled regulatory interventions. However in designing ESM, regulators need to be mindful that ESM when applied to deviations above targeted ROE can weaken incentives to reduce costs and increase the costs of administration. ESM have the potential to take a company's short term focus away from cost reductions, to the 'management' of finances, and produce even shorter claw backs of efficiency gains than that provided for at the time of rebasing cost of service applications. In effect, an ESM can neutralize the price cap.

[9] EB-2006-0089 "Incentive Creation as the Key to Incentive Regulation" Presentation by Dr Adonis Yatchew

Currently the electricity distribution industry in Ontario is in a time of consolidation and rationalization and the OEB has already recognized that distributors shareholders are permitted to retain the savings realized through Mergers, Acquisitions, Amalgamations and Divestitures (MAAD) applications by allowing distributors to remain on the IRM regime for up to 5 years from date of MAAD. The use of an ESM in the electric industry at this time in the Incentive Rate Mechanism is contrary to the goals of MAAD and should be deferred to a future IRM once the electricity distribution industry has been rationalized – which could be within the 3 GIRM period and therefore not coincident with a re-basing year.

The CLD and HYDRO ONE however would suggest that there is merit in the use of ESM for rate plans of longer duration (5 or more years). It is important that the ESM be symmetric in application so that regulatory risks implicit in the current ROE calculation are not increased.

Recommendation # 9 The CLD and Hydro One accept the use of Earnings Sharing Mechanism with IR plans submitted by utilities for longer than the normal 5 year period associated with the core plan. For longer plans, if the achieved return on equity from regulated activities is more than 300 basis points different from the Board's allowed ROE, then the CLD and Hydro One recommend that the computed overage/underage be shared equally (i.e.,50/50) between the distributor and its customers.

4. LOST REVENUE DUE TO CHANGES IN CONSUMPTION

In broad terms there are three types of Conservation & Demand Side Management programs that will impact customer usage:

- Distributor Delivered C&DM programs – A distributor can file for recovery of lost revenue through an LRAM program.
- Third Party Delivered C&DM programs – A distributor cannot file for recovery of lost revenue due to reduced unforecasted energy consumption and demand from these programs.
- Customer initiated C&DM programs – Customers are becoming more educated and implementing their own measures to use less and save money. These programs reduce energy consumption and a distributor’s ability to earn their Board Approved Revenue Requirement if the reduction is unforecasted. A distributor cannot file for recovery of this.

A Price Cap will not enable some Distributors to earn their regulated return since forecast billing determinants are not factored into the Price Cap calculations. The Price Cap Mechanism uses the rates established in the rebasing year as the starting point to calculate distribution rates for the IRM years and does not adjust rates for billing determinant forecasts. The experience of some distributors in Ontario is that irrespective of the degree of customer growth in their service territory, the average customer usage is falling and these distributors are disadvantaged from other distributors whose average customer usage is increasing even with downward C&DM pressures and environmental impacts on customer usage. In this case a Revenue Cap Mechanism may allow a utility to deal more appropriately with the circumstances.

Most utilities are in the early stages of the CDM programs which started in earnest in 2006. Utilities are still gathering data and information that will help them to examine the impacts of programs put in place and how well the results match expectations that were forecast at the outset of implementing the programs. Consequently for those distributors using a price cap there may be merit to move forward under 3GIRM with existing lost revenue adjustment processes. Utilities would still have the option to determine their base demand for setting rates at rebasing.

Recommendation # 10 The CLD and Hydro One believe that in the short term utilities can make use of existing lost revenue adjustment processes in connection with unforecasted CDM impacts, and that revenue-oriented IRM alternatives can accommodate broader concerns around reductions in load and customer numbers.

5. CAPITAL INVESTMENT

In the Discussion Paper issued in February 2008, the Board Staff asked for comments on two basic issues related to capital investment: is an incremental module for capital expenditures (capex) necessary and if so, what kind of module?

The Board Staff have already recognized that depreciation (amortization) included in rates is not necessarily sufficient to fund capital additions[10]. Indeed, even if we consider a steady state business with only ‘normal’ replacement needs, we can expect that capital requirements for replacement will exceed depreciation, because the depreciation amount is based on historical cost levels from 20 to as much as 40 years ago. Although technology improvements and efficiency gains may offset, to some degree, the shortfall in depreciation it is not clear that this would be adequate in any specific case.

[10] EB-2007-0673; Staff Discussion Paper on 3rd Generation incentive regulation for electricity distributors, February 28, 2008, page 17

The reality for Ontario LDCs is that many have aging networks that were built in stages and will soon be nearing the end of their physical lives. Replacement, in order to maintain reliable service, will therefore require substantial and "lumpy" Capex. LDCs also face expanding capital additions programs as a result of other exogenous factors, such as customer and volume growth as well as policymaking initiatives (for example, Distributed Generation). The Board has confirmed that it aims to ensure financial viability of the electricity distribution sector. Financial viability should be defined to include the opportunity to earn the Board-approved rate of return on prudent capital expenditure. As Ms. Frayer documents at section III of her affidavit in Appendix A in analysis of actual LDC's financial position under hypothetical, but likely, future circumstances, even a relatively "good performer" can experience suboptimal returns because of the inadequacy of depreciation alone to fund capital investment requirements.

For many LDCs, a simple inflation and productivity target price cap is unlikely to be sustainable. Rather than forcing LDCs down the path of cost of service filings, the Board should build in a Capex module as a default component of the core model. Unlike the Board's Staff proposal for a Z factor-like incremental capital investment module[11], we believe that the capital investment module should be based on the premise that the capital investment module fund Capex requirements that are firmly anticipated, relatively predictable, and large scale integrated programs (but perhaps composed of many individual elements). On these grounds, a Z factor mechanism is not the appropriate conceptual basis. The Working Group considered a number of options that would be 'additive' to an 'Inflation minus Productivity factor' price cap. Given the diversity of circumstances for LDCs in Ontario, we believe it is appropriate and ideal for the Board to allow all these options. Each utility would then make a showing for a particular plan given its specific circumstances. However, the CLD and Hydro One also understand that the Board realistically may not be able to accommodate this multivariate approach because of the regulatory burdens on the Board and Board staff in reviewing diverse 3GIRM applications.

In lieu of the ideal, we believe that a capital expenditure module through a K factor would be able to accommodate this diversity among LDCs while also providing a mechanistic approach that streamlines regulatory processes. The K factor would be incorporated directly into the price cap formula, and therefore rates would change year-to-year based on inflation less the Productivity factor plus the K factor. In terms of implementation, LDCs would defend the appropriateness of the K factor at the time of entering 3GIRM if a K factor is necessary.

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[11] *Ibid*, pages 65-68

The K factor would accommodate diversity of conditions among LDCs by virtue of how it is set. We recommend that two approaches are taken to setting the K factor. Ms. Frayer lays out the fundamental approaches in her testimony at section III in Appendix A. In summary, utilities would have the option of formulating a K factor through filing of a forward looking capital expenditure schedule for the term of their 3GIRM. We understand that some LDCs will not be able to prepare such a forward looking plan. Therefore, the second option for formulation of the K factor will be based on other known criteria, such as age of network and volume growth. In effect, we envision that the Board (through a working group process over the short term) would develop a matrix of K factors that is based on the combination of various levels of volume growth and network age. The K factor would then be selected for a given LDC given the proximity of a particular firm's conditions to a specific combination in the matrix. As described in Ms. Frayer affidavit at Section III in Appendix A, such an analysis would be done on the basis of actual financial analysis of actual data across LDCs (or a sample thereof) and the estimation of the level of K factor that would have been necessary under certain inflation and Productivity factors parameters to accommodate capital investment targets under different growth and network age profiles.

At the workshop on March 26, 2008, the Board staff and their consultant, Larry Kaufmann of PEG, asked whether a K factor approach would be consistent with an incentive-based scheme involving a comprehensive price cap where an inflation index and Productivity factor is set to represent total costs. At first it may appear that a K factor, especially when tailored to the revenue requirements of a forward schedule of capital expenditures, is more "cost of service" than incentive-based, but in fact, the incentives for efficient capital investment are preserved. The utility has very strong incentives to limit cost overruns. Furthermore, as noted above, the addition of a K factor, by construct of the K factor itself, will only complement the other components of the comprehensive price cap, as it will be created to target financial viability assuming efficient operations.

A K factor has many advantages: it will ensure financial viability and sustainable capital funding practices, and provide for stability in regulation by maintaining the long term applicability of 3GIRM design in the face of various stages of investment by utilities and across the industry. A K factor that provides revenues to accommodate Capex requirements will also smooth out rate patterns in the longer term, and therefore provide the rate predictability that is important to both utility planners and customers. The rate predictability is achieved through the bridge that the K factor creates between rebasing. Typically, when rates are re-set to include capital additions made either over the previous term of IRM or during the test year, the revenue requirement will jump up and base rates will increase, sometimes dramatically. The K factor, on the other hand, provides for a gradual evolution of rates and therefore there is no need for dramatic increases at rebasing. Ms Frayer illustrates this characteristic of the K factor in her affidavit at section III in Appendix A through the pro forma financial modeling.

It is important to note that the capital investment module within the price cap would deal not with capital expenditures mandated by government policy, such as the capital spending required to install smart meters, or additional capital expenditures for achieving government's policy priorities for CDM and targeted renewable resource mix. Because of the nature of these particular cost drivers we agree with Board's Staff proposal to deal with such capital addition requirements through existing rate riders or rate adder processes[12], outside the rate adjustment formula. The benefit with maintaining the current established process is that it would capture both OM&A and Capital related costs whereas the capital investment module described above would only capture the capital related costs.

Recommendation # 11 **The CLD and Hydro One recommend that the Board reconvene the Working Group to develop a Capex factor which could be incorporated directly into the price cap formula.**

6. DATA REQUIREMENTS

It is imperative that we develop an incentive-based ratemaking regime that is based on the direct experiences, existing business conditions, and reasonably expected opportunities for efficiency gains in Ontario in the electricity distribution sector. The Ontario Energy Board, key stakeholders, and electricity distributors have expended effort to develop an industry-wide data set for evaluating Ontario LDC productivity growth.

We agree that there are shortcomings with the existing data. For example, the Ontario data set only covers the period 2002 through 2006 currently. This limited timeframe has important implications for the productivity analysis. For example, the short timeframe of data means that there may be distortions in the analysis of productivity trends because of assumptions made on the quantity of capital inputs. This same issue also makes benchmarking of distributors on a total cost basis difficult, and partial productivity metrics will be inconclusive on establishing the relative performance of LDCs because of the relative importance of capital (it is estimated to be over 60% of the cost structure on average for Ontario LDCs) and the variability in capital utilization policies across distributors. In spite of these limitations, the existence and relevance of this data should not be ignored. Productivity analysis using alternative measures of capital can overcome some of these shortcomings in the data

[12] A variance account would also need to be included so utilities could track revenue - cost differences for future recovery.

and provide useful insight into recent trends. As the Board recognized in 1GIRM, recent experience is very important indicator of what is achievable in the short- to medium-term (and the 3GIRM is likely to encompass this short- to medium-term).

In this respect we see a need to make improvements in the data as we move forward and focus on building up a database for future applications but as far as implementation of 3GIRM is concerned we move forward with what is currently available. Looking into the future, data should be improved on along these considerations:

- the existing data variables in the data set need to be more clearly defined by the Board and industry stakeholders and the industry needs to make a concerted commitment to report data that is comparable across firms based on industry-developed guidelines;
- additional data variables should be reported that would allow for more accurate firm-to-firm comparison in benchmarking and overall productivity analyses.

We need to make a committed effort to make the Ontario LDC data reliable for comparative analysis. Although the LDCs have diligently provided the data required per the Reporting and Record Keeping Requirements (RRRs) and have certified the accuracy of that data, discrepancies in what is filed remain because of the lack of 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. The CLD and Hydro One are committed to developing such guidelines and working with industry stakeholders to improve the data set in such a way.

As Ms Frayer discusses in her testimony at Section VI of her testimony in Appendix A, that analysis of historical productivity relies on capturing accurately the total 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, electricity networks are not simply vehicles for throughput of the commodity. 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. Any output measure needs to reflect both the quantity and quality of the access being provided to customers. 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 engineering measures are possible. For example, customer number concepts can and should be better defined and better related to the areas in which they drive costs – number of bills for customer care costs versus number of connections in operations. Instead of metered peak demand, it would be preferable to have a measure of network capacity that is not dependent on consumption patterns. Such a 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 depends not only on the voltage of the line 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 making this conversion. With the availability of such information, a more rigorous and robust comparative analysis can be done on industry TFP as well as relative productivity of firms.

7. REGULATORY AND LEGISLATIVE REQUIREMENTS

There are a number of known requirements which utilities will face during 3GIRM period that will require consideration from a cost recovery perspective. Consequently these should not be considered as “Z”-factor type adjustments since they are clearly on the horizon and the associated costs may be forecast to some extent. Provisions should be made for utilities to expect recovery of these costs incurred while under the 3GIRM. That is they should be treated outside the price adjustment formula.

Smart Meters

The Board Staff Discussion Paper acknowledges on page 16 that the costs associated with the implementation of Smart Meters during 3GIRM will need to be dealt with. Under the 2GIRM costs are being recovered through Board approved rate riders and as such these are outside the core 2GIRM model. The CLD and Hydro One expect that similar treatment should be accorded during 3GIRM.

Utilities will incur significant costs as they ramp up to implement Smart Meters to meet the government targets set for completion of the projects by 2010. It is expected that the costs incurred will included elements of OM&A and capital expenditures. As for 2GIRM, utilities should bring forward proposals for including costs in rate riders which the Board will approve and any variances between revenues recovered and costs incurred should be tracked in variance accounts. That approach is consistent with current processes associated with implementation of Smart meters.

Other regulatory and legislative requirements

The same would hold true for other material incremental revenue requirement impacts associated with annual capital and operating expenditures resulting from regulatory and legislative requirements imposed on distributors. These would include but are not limited to:

- material cost increases resulting from mandated changes as a result of the Board's proceeding on Customer Service, Rate Classification and Non-payment Risk (EB-2007-0722),
- the move to the International Financial Reporting Standards (IFRS). This could have a significant impact on the finances of utilities that must be considered in the regulatory process.
- anticipated reforms in tax law and legislation and distributor's allowance for taxes.
- implications of the Board's initiative to formalize Service Quality Regulation (SQR) for the electricity distributors through amendments to the Distribution System Code (EB-2008-0001). Both the CLD and Hydro One will be submitting its respective comments in that proceeding. However it is an important to note that consideration in this respect is the recovery of costs driven by compliance with new or more stringent SQR requirements during the 3GIRM period.

Recommendation # 12 **The CLD and Hydro One recommend the availability of variance or deferral accounts as appropriate to assist with tracking the differences between revenues earned and costs incurred with respect to Smart Meter projects that are not in base rates, and other incremental revenue requirement impacts associated with annual capital and operating expenditures resulting from regulatory and legislative requirements imposed on distributors.**

8. IMPLEMENTATION ISSUES

- The CLD and Hydro One have provided a set of recommendations pertaining to the core model which are aimed at assisting the Board to make its decision on the 3GIRM core model. In doing so we have recommended alternative approaches for setting the Total Factor Productivity, deferring the implementation of a Stretch Factor until such time as the Distributor Cost Comparison project is completed, and using a macroeconomic index for setting the Inflation Factor while work continues to develop the industry specific IPI. We have also recommended that the Board reconvene the Working Group to develop the Capital Investment Module so that can be implemented with the 3GIRM core model.

- These recommendations will require the Board to make decisions in the light of the evidence submitted. The key is that a decision is needed soon so that the core model is ready in time for implementing the 3GIRM in a timely manner so that those utilities that will be subject to 3GIRM rate setting for 2009 have ample time to understand the requirements and file their submissions. The utility regulatory agenda is full and with all of the case files under way utilities need timely decisions to effectively manage their workload.

- The CLD and Hydro One recognize that the proposed 3GIRM core model is designed to meet requirements of the majority of the LDCs in the province and that there maybe some utilities for whom this model will not work because of their particular circumstances. The Board currently has approved, in addition to the price cap mechanism, the cost of service methodology and a revenue cap concept as in the gas industry and should take some comfort this may provide sufficient flexibility with the 3GIRM proposal that allows those utilities to file alternative proposals and that those would be exceptions rather than the norm.

- The CLD and Hydro One would recommend that changes to regulated specific service charges should be treated outside the price cap mechanism. If a distributor proposes any changes to the regulated specific service charges during the term of the IR Plan, it will provide the Board with evidence that supports the change. The same principle that was adopted in the Natural Gas proceeding that the specific service charges should not generate incremental revenue in excess of any related incremental costs would equally hold in this case. Specific service charges account for approximately 4% to 6% or more of an LDCs revenue requirement. The current Board approved Specific Service Charges, provided in Chapter 11 of the 2006 EDR Handbook were calculated based on LDC costs available at the time. As LDC costs, applicable to these charges, will likely increase over the 3GIRM period, the Board might also consider updating the current specific service charges provided in the 2006 EDR handbook.