EB-2010-0379

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B, as amended;

AND IN THE MATTER OF a consultation by the Board with respect to Defining and Measuring Performance of Electricity Distributors.

SUBMISSIONS OF THE

SCHOOL ENERGY COALITION

June 27, 2013

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1 OVERVIEW

1.1 ***Background***

1.1.1 On October 27, 2010, the Board initiated a process called the Renewed Regulatory Framework for Electricity, which culminated after almost two years of extensive analysis and consultation in a Report of the Board dated October 18, 2012 entitled "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (the "RRFE Report").

1.1.2 The RRFE Report sets out the Board's policy direction in this area, but leaves a number of implementation issues to subsequent processes. The current process deals with one of those areas: establishing the details of the formula for 4th Generation IRM. This has included gathering significant data from the industry, a comprehensive analysis by experts retained by the Board, a working group representing a range of stakeholders, and a number of full stakeholder dialogues. Four expert reports have now been filed: one from the Board's experts, two from LDC groups, and one from the largest union of LDC employees.

1.1.3 The final part of this consultation is submissions from stakeholders. Letters from the Board dated May 3, 2013 and May 30, 2013 provided guidance on those submissions, including a series of fourteen questions the Board would like to see answered.

1.1.4 These are the submissions of the School Energy Coalition. They are organized as follows:

(a) Section 2 provides general comments on the conceptual underpinnings of the analysis, and the practical implications of the Board's decisions on the issues.

(b) Sections 3 through 6 deal with the four major areas in which the Board is seeking input relating to the formula.

(c) Section 7 deals with specific implementation issues, including in particular the need to re-set the ICM threshold formula.

(d) Section 8 provides answers to the Board's fourteen questions.

1.1.5 SEC has already provided input to the Board on a number of occasions throughout this process and the RRFE process, including active participation on the Performance and Benchmarking Working Group. Our submissions in this document are consistent in principle with our previous submissions. Except where in the context it is necessary, we have tried not to repeat our earlier comments.

1.1.6 The ratepayer groups involved in this process have worked together closely on the issues. This has included separate meetings to work through differing perspectives, and some exchanges of written materials as well. This has been of assistance to SEC in developing these submissions. While these submissions are the position of SEC, and do not purport to represent the positions of other ratepayer groups, open communication with other ratepayer groups has improved the result.

1.2 ***Process Issues***

1.2.1 Although the RRFE process was thorough and wide-ranging, and the followon process relating to Performance and Benchmarking was also thorough, we have been increasingly concerned with the disparity in the review of the experts' reports. Given that implementation issues in IRM are to some extent "expert-driven", it is in our view critical that the Board recognize the different levels of evidentiary value that have been presented to it by the experts.

1.2.2 ***Pacific Economics Group.*** The report of the Board's expert Dr. Kaufmann and his firm has been subjected to a very thorough review and testing. Initial material was provided for comment and input at the outset, and then as the PEG work progressed a Working Group provided regular guidance and feedback. As well, it challenged the direction PEG was taking on specific components of the analysis, causing PEG to modify its approach on a number of issues.

1.2.3 Subsequently, there was a draft report and a Q&A, plus the filing of all working papers for others to see. The Q&A was, to all intents and purposes, cross-examination of the expert by stakeholders and by the other experts. This included written discovery of PEG and their work.

1.2.4 Finally, PEG's report was provided in advance of the Stakeholder Conference, and then challenged extensively by the other experts over those two days. In fact, some of those challenges turned out to be clearly and obviously wrong, i.e. based on incorrect assumptions, now admitted by the challengers.

1.2.5 In the result, the work of PEG is thoroughly tested evidence before the Board.

1.2.6 ***Fenrick and Yatchew***. The same is not true of the work of Mr. Fenrick and Professor Yatchew. There was no Working Group review, nor Q&A, and when we came to the Stakeholder Conference, we did not have their reports and so had no chance to review their analysis and conclusions in any detail. Indeed, in the case of both experts the analysis presented at the Stakeholder Conference did not even include their final recommendations, which we just saw for the first time when their reports were filed on June 13th. (In the case of Professor Yatchew, we still don't have all of his recommendations. On inflation, we appear to have to wait for the EDA submissions on June 27th for that.)

1.2.7 In fact, we have never had an opportunity to challenge either of these experts on the contents of their reports.

1.2.8 ***Cronin.*** The situation is even more problematic with respect to Dr. Cronin's work. PWU elected not to put forward their expert at the Stakeholder Conference, so until June 13th we knew nothing about his analysis or recommendations. At no time has anyone had any chance to ask questions about his work (except briefly, on a preliminary basis, during the Working Group), much less challenge any of his assertions or findings.

1.2.9 In our view, this is particularly problematic in light of the fact the Dr. Cronin's analysis is not just further variations on the same analysis that Dr. Kaufman, Mr. Fenrick and Professor Yatchew have done. Dr. Cronin proposes a quite different approach to some of the issues, and that approach has not been discussed by the other experts, or by the stakeholders.

1.2.10 ***Impact.*** The reason SEC raises this is not to criticize the process. It is likely that this imbalance in the review of the experts' work is intrinsic to a policy consultation initiated or centred around the work of a firm of experts working for the Board.

1.2.11 But even if the process worked largely as one might have expected, that does not change the fact that the work of Mr. Fenrick, Professor Yatchew, and Dr. Cronin is essentially untested evidence.

1.2.12 In our submission, the result of this imbalance is that the Board should properly treat the report of Dr. Kaufmann differently from the reports of the other three experts.

1.2.13 In the case of Dr. Kaufmann's report, if the Board wishes to adopt all or any part of that analysis, or any of his recommendations, the Board would have a firm basis on which to do so. The work has evolved right out in the open, was guided by a great deal of stakeholder (and Board) input, and has been thoroughly tested and challenged. The Board has sufficient information to reach supportable conclusions about PEG's work on these issues.

1.2.14 Not so with the other three reports. At the current stage of the process, they are in some ways useful as challenges to the PEG Report, allowing the Board to see PEG's conclusions from a different perspective.

1.2.15 But, if the Board wishes to adopt all or any part of the analysis or recommendations in those reports, in our submission that is premature. The Board's practice is to make its decisions, including major policy decisions, based on a solid evidentiary foundation. It is one of the Board's important strengths. In the case of these three reports, that foundation does not yet exist.

1.2.16 Therefore, in the event that the Board is considering the adoption of any of the expert recommendations of Mr. Fenrick, Professor Yatchew, or Dr. Cronin, SEC submits that the Board should initiate a further process with respect to those recommendations under consideration. That process should include an opportunity for all stakeholders to get written discovery relating to that work, and to have oral questioning of the experts in the same manner as was provided to all of us with respect to Dr. Kaufmann.

1.2.17 ***Conclusion.*** In SEC's submission, the Board should not adopt any of the analysis or conclusions of any of the other three experts unless and until that analysis or conclusion is turned into a solid evidentiary foundation by being subjected to full testing and challenge by all parties.

1.3 ***Summary of Analysis and SEC Recommendations***

1.3.1 ***Principles vs. Practical Realities***. It is important that the Board follow its standard policy-making practice by determining the IRM formula on a principled basis. It is, though, also important that the Board be cognizant of the resulting overall rate adjustment level that flows out of the formula.

1.3.2 There is a narrow range of reasonableness and acceptability. If the result would otherwise not be within that range, the consequences could be severe. The Board should see anything outside of that range as having failed a "sanity check", and should identify why the apparently principled result is not within a reasonable range. The (rebuttable) presumption should be that a result outside of the range is incorrect, and not in fact consistent with the ratemaking principles being employed.

1.3.3 The formula that flows out of SEC's recommendations in these submissions would result, assuming a 2% GDP IPI FDD, in a range of rate increases from a high of 1.14% for those with the lowest stretch factor, to a low of 0.64% for the least efficient distributors. SEC believes that is within the reasonable range.

1.3.4 ***Inflation Factor.*** SEC does not believe there is an acceptable solution to the inherent volatility of an industry-specific inflation factor. Each proposed solution has material problems, and in every case the result is likely to be an inflation factor in any given year that could be very different from the actual inflationary pressures affecting LDCs in that year. SEC therefore proposes that, despite the Board's decision in the RRFE Report to go to an industry-specific inflation factor, the Board should retain GDP IPI FDD as the inflation factor for 4th Generation IRM.

1.3.5 ***Productivity Factor.*** What the experts' work revealed is that there is a wide range of individual productivity levels among the 73 LDCs. The productivity factor in the formula is the level of productivity that utilities are expected to achieve. It is, in effect, the Board standard. That standard should exclude the poorer performers.

Otherwise, the formula implicitly draws the best performers down to a lower level. SEC therefore proposes that the productivity factor be the simple average of the top half of the individual TFPs of the LDCs. Before being updated with 2012 data, that number appears to be +0.86%.

1.3.6 ***Benchmarking Method.*** The debate about business conditions to be employed in an econometric model demonstrates not only that it is contentious, but also that individual econometric results are very sensitive to the business conditions determined to be appropriate. Those conditions in turn can be considered significant or not depending on relatively small changes in data or model approach.

1.3.7 Meanwhile, unit costs are the method used by most businesses, including LDCs, to compare themselves, and are readily understood by the public. Assuming the peer group question can be solved, unit costs are, in our submission, the appropriate way of comparing LDCs.

1.3.8 ***Median vs. Mean***. SEC agrees with a number of other parties that, in order to minimize the distorting impact of outliers on the peer groups, individual LDCs should be compared to the median of the peer group, rather than the average or mean.

1.3.9 ***Peer Groups***. Since most LDCs have a very good idea of which other utilities are reasonable comparators for them, the Board's goal should be to find a reliable way to gather that information from all of the LDCs.

1.3.10 SEC proposes "crowd-sourcing" of the peer group selection, in which each LDC is required to provide a ranked list of ten other LDCs to whom they feel they are similar (with reasons if desired). Board Staff would then look at those lists, and remove any names that they felt were obviously not comparable (e.g. a high cost rural utility on the list of a predominantly urban utility). Utilities would be incented to provide fair lists because to seek to game the process would risk having their views not counted at all. Once the revised lists are prepared, they should be matched using normal computer software designed for this purpose, and the collective peer group lists thus created for Board approval.

1.3.11 ***Toronto Hydro Exception***. The CLD expert has proposed that Toronto Hydro not be compared to other Ontario LDCs. There is no evidence before the Board on which to reach this conclusion. If Toronto Hydro wishes to argue that the Board's ratesetting policy should not apply to them, they should do so on utility-specific evidence in their own rate case.

1.3.12 ***Stretch Factors.*** To avoid the problem of utilities not being able to move from one stretch factor to another, we propose a formula that assigns unique stretch factors to each LDC based on their performance relative to all other LDCs. Every utility could then improve their stretch factor by improving their peer-measured relative

performance. The stretch factors would follow the emerging consensus range of 0.0% to 0.5%.

1.3.13 ***ICM Threshold Formula.*** Changes to the IRM formula result in a different number level of capital additions being funded within the general formula. That level is the percentage that capital additions are of depreciation in the past data on which the formula is based. If that percentage has, over that period, averaged 150% of depreciation, then that much is being funded in the IRM formula. The ICM threshold should start at that point. The current growth factor and deadband should be added to that, to get the revised formula.

2 CONCEPTUAL BASIS

2.1 *Introduction*

2.1.1 Many people have commented throughout this process that they feel they are being overwhelmed with technical details. Clearly when a process is intended to deal with implementation details, "details" will be a key component. No surprise.

2.1.2 However, there is also a "forest and trees" problem that can arise. Deciding between particular solutions to each detailed issue must inevitably require analysis of those solutions in light of both the overriding principles at play, and the practical realities of the electricity distribution industry in Ontario today.

2.1.3 Therefore, in this section SEC proposes to summarize our understanding of those principles, and those practical realities. The remainder of our submissions will be based on this understanding.

2.2 *Principles*

2.2.1 There appear to be four main principles at work in this analysis:

(a) The basic structure of the IRM rate adjustment.

(b) The empirical basis of the components of the adjustment.

(c) The assumption that the future will be similar to the past.

(d) The methods of delivery of ratepayer benefits.

We will deal with each of these in turn.

2.2.2 ***IRM Structure.*** IRM flows from the basic assumption that a reasonable level of price adjustment for a typical utility can be achieved by taking price inflation, and adjusting it for the productivity of like companies relative to inflation. This creates a revenue envelope, in which prices are decoupled from costs. Utilities are thus incented to drive further cost reductions. IRM then has one or more mechanisms for sharing the benefits of those cost reductions between the utility owners and the ratepayers.

2.2.3 The first part of the structure, inflation, represents the changes in the prices of goods and services utilities need to operate. General inflation measures are available, like CPI and GDP IPI. However, prices for all goods and services don't increase at the same rate, so every inflation measure must assume a basket of goods and services to be purchased. Electricity distributors, being capital intensive businesses, generally need an assumed basket that has more capital than the average business. This is why the

Board, in the RRFE Report, determined that the inflation measure should be industry specific.

2.2.4 The second part of the structure, productivity, may be misnamed. Productivity captures things like unit cost reductions due to technological change, and unit cost reductions due to economies of scale. However, it will also normally capture things like changes in outputs due to economic and other factors (government CDM policy, for example), and changes in cost due to regulatory and other non-inflationary cost pressures. Because of the range of factors that potentially influence this component, productivity does not always have to represent unit cost reductions. Fewer outputs can mean unit cost increases, as can additional costs that do not have corresponding increases in outputs.

2.2.5 Properly calculated, the net of the inflation figure and the productivity figure should produce an overall revenue envelope that fairly represents the main cost drivers for a typical utility, before taking into account the impact of IRM itself (i.e. the "incentive" component).

2.2.6 ***Empirical Basis***. To get to the right numbers for both figures, regulators typically want to have a firm empirical basis for those numbers. The theory is that the inflationary cost pressures will be revealed if recent external data on prices is studied, and the productivity adjustment will be revealed by looking at how actual utility unit costs have varied in the past relative to those inflationary cost pressures.

2.2.7 In a perfectly stable environment, it is possible to argue that you can determine through past data the "normal" impact of all of those productivity factors (technology, economies of scale, CDM, etc.) on utility costs. If you then apply that to expected (which usually means most recent historical) inflation, you get a "normal" rate adjustment for a utility.

2.2.8 ***The Future Is Like the Past.*** Implicit in this empirical approach to the IRM formula is the assumption that the future period in which the formula will be applied will be similar, in all material respects, to the past period from which the empirical analysis is drawn. Or, at the very least, any differences between the future and the past will perfectly offset.

2.2.9 In reality, of course, there is no "perfectly stable environment", and no "normal" impact of all of the productivity factors. That is particularly true in periods of policy or regulatory change.

2.2.10 Therefore, the impact of the empirical analysis is not some kind of revelation of an external truth. Rather, the Board's task in setting the components of the formula is a forecasting exercise. As with all forecasting, it can be informed by analysis of past data and trends. However, the future is not predictable, and the Board's judgment and

expertise – not the opinions of the experts - is in the end the appropriate basis for the forecast of reasonable future revenue envelopes.

2.2.11 There is a measure of rough justice in this, as all regulators recognize. In any given future year, for any given LDC, the formula may not be the perfect revenue envelope for their particular needs. As in the competitive markets, the company has to adapt to the revenue available to it. Over time, all cost pressures will be recognized in a well-designed formula. In exceptional cases, the RRFE Report provides other regulatory options so that the rough justice of the IRM formula does not become unfair.

2.2.12 ***Ratepayer Benefit***. The last principle is the allocation of the ratepayer benefit. The theory is that, on rebasing, sustainable unit cost reductions by utilities will flow through to rates going forward. Some of this has been seen in the rebasing applications of the two gas utilities, who after a number of years have a mature and fairly stable regulatory structure. We have seen less of this in electricity distribution, perhaps because that sector is going through a continued period of change.

2.2.13 Prior to rebasing, IRM assumes there will be unit cost reductions. To ensure that some of those benefits flow through to ratepayers, there is normally a stretch factor in the formula, which allocates a certain amount to ratepayers as the assumed benefit of the IRM. This also ameliorates the problem of lack of actual cost savings in many rebasing applications.

2.2.14 The Board has a particular formulation of the stretch factor, in which it is assumed that more efficient LDCs have less room to achieve incremental unit cost reductions, so their stretch factor is lower. For the ratepayers of those utilities, the ratepayer benefit from IRM is lower because those ratepayers are already enjoying the benefits of the LDC's higher level of efficiency.

2.3 ***Practicalities***

2.3.1 As can be seen from the discussion of the principles, this process of implementing IRM is not capricious. The Board, like other regulators, is striving to get a "right answer", one that is fair and consistent with the evidence. SEC strongly supports the Board's principled approach to its ratesetting rules. In the long run, everyone benefits from that approach.

2.3.2 However, it would in our view be foolish not to recognize that the result of the formula will matter. Regardless of its principled basis, if it is too high or too low there will be consequences.

2.3.3 ***Rate Adjustment Too Low.*** Some of the formulations of the IRM adjustment that have been discussed in this process would lead to something akin to a rate freeze. The primary culprit appears to be the negative industry-specific inflation rate for 2012, on

which more later. It's impact may be to cause net adjustments of zero, or even rate decreases, for three years while it works through the smoothing mechanism.

2.3.4 The Board has heard, in the Stakeholder Conference, and in some of the expert reports (and will undoubtedly hear in the utility submissions) complaints about the unreasonableness of a rate freeze. The utilities – who were the ones who asked for an industry-specific inflation factor in the first place – don't like the result.

2.3.5 SEC is not sympathetic to those complaints. If the costs of the goods and services that utilities are using are in fact going down, then the formula for rates should be going down as well. That is only fair. (In our later discussion of inflation, we will propose a solution to this, but that does not take away from the practical implications if the data is simply followed.)

2.3.6 But there is a practical reality here as well. If there is no rate increase under 4th Generation IRM (and by extension under Annual IR), the Board is implicitly inviting all LDCs to file five year cost-of-service applications. This could have three impacts:

(a) Regulatory gridlock beyond anything the Board has seen before. This is not just a question of Board resources. It is also a problem for the availability of regulatory resources for the utilities, and the intervenors. The cost and timeliness of the regulatory process would be materially and adversely affected.

(b) An increase in the disparity between larger and smaller utilities. As the Board has already seen in the past, larger utilities can engage in more complex and extensive regulatory processes. Most small utilities could not. If the only way to get a rate increase is through Custom IR, then in general the larger utilities will get rate increases, and the smaller utilities will not. The "IRM rate freeze" will be for smaller utilities only, in effect.

(c) The increased regulatory pressure on smaller utilities could reduce their valuations, and force them to accept mergers or acquisitions that they would otherwise have refused, and on less than favourable terms.

Customers do not benefit from results such as these.

2.3.7 ***Rate Adjustment Too High.*** Some of the utilities and utility experts are proposing rate adjustments of 3% or 4% per year, year after year. This is, in our view, equally unrealistic.

2.3.8 While the LDCs are business corporations, they are almost all in the public sector, operating public monopolies. In a period in Ontario when

(a) There is significant pressure within the public sector to keep wages and other cost

increases to zero, or as close to zero as possible; and

(b) We already know of substantial bill increases from the commodity (e.g. Darlington refurbishment, increased renewables) and transmission sides that ratepayers will face in the next few years;

high increases in the distribution component of the bill will not be accepted by the public.

2.3.9 There is a risk – particularly in a period of political uncertainty in Ontario - that a Board formula that generates high increases in rates will be treated as a signal that a political, rather than a regulatory, response to distribution rates must be found**.** This has already happened once in the recent past, in 2002, and no-one benefited from that result.

2.3.10 ***Appropriate Board Response***. SEC is not proposing, in the case of either too low rate adjustments, or too high rate adjustments, that the Board simply jettison its principles and "pick a number". The Board's record of principled decision-making is something that it must guard jealously.

2.3.11 What we are proposing is that the Board use the reasonable expectations of the stakeholders as to a range of acceptable results as a type of sanity check. Proposed solutions that fall outside of that range should be looked on with greater skepticism and doubt.

2.3.12 That is, if the solution is not within a reasonable range, the assumption should be that there is a flaw in the solution. That flaw must be found and corrected. The "right answer" generally will not produce an unreasonable result.

3 INFLATION FACTOR

3.1 *Introduction*

3.1.1 The RRFE Report directs the use of an industry-specific inflation factor for 4th Generation IRM. GDP IPI FDD was used in 3rd Generation IRM, but the utilities complained – probably correctly – that it did not reflect the actual changes in the prices of the basket of goods and services utilities need to buy each year. The Board determined that it would move from GDP IPI to industry-specific to address that concern.

3.1.2 It has always been recognized that, in doing so, there would be a risk of calculation issues, and of volatility. Both of those risks have been realized.

3.2 *Issues That Emerge from the Experts' Analyses*

3.2.1 ***Labour and Non-Labour O&M.*** There appears to be general agreement between the experts on the inflation factors used for labour and non-labour O&M. To the extent that there are differences, they do not appear to be material.

3.2.2 ***Capital Component.*** The problem arises with the capital component, which for electricity distributors is the largest component of their annual costs. Calculating the increase in the capital component each year is not straightforward. For the vast majority of a utility's capital base the cost is actually going down each year, because the assets are depreciating. This is one of the advantages of a capital-intensive business, as many a real estate investor can attest. On the other hand, for a small part of the capital base (replacement assets), the cost is going up not by one year's cost increases, but many years'. A widget installed today may be replacing a widget installed 40 years ago, at a much much lower capital cost.

3.2.3 In theory, the annual cost associated with capital assets is calculated by multiplying the capital base for the year by the carrying costs of that capital (depreciation, interest, ROE, and taxes). The capital base for the year is in turn the capital base for the previous year, less depreciation, plus capital additions. Capital additions are, ignoring growth-related assets, the original cost of the assets being replaced, inflated over their lifetime by the net of annual price inflation less productivity for assets of that type.

3.2.4 Both Mr. Fenrick's Triangularized Weighted Average technique, and Dr. Kaufmann's Capital Inventory technique, are intended to model this capital cost calculation annually and produce a net rate of change. They produce different results, for two reasons. First, they structure the calculation differently. Second, Mr. Fenrick excludes changes in interest rates, and hence changes in ROE and taxes as well. Dr. Kaufmann adjusts for tax rate changes (which has the effect of increasing his inflation rate for capital), but not for tax costs driven by ROE changes.

3.2.5 ***Which Method?*** On the structure of each technique, while different they both have conceptual support. Professor Yatchew appears to accept Dr. Kaufmann's approach, and it appears clear to us that the Fenrick technique is not an accepted standard used by energy economists. And, as noted earlier, the TWA method has not been subjected to full testing before the Board, so in our submission does not yet have sufficient foundation to be adopted by the Board. It looks, at first glance, like it might make some sense, but like many other aspects of this analysis the devil is in the details.

3.2.6 ***Interest Rates/WACC.*** In any case, however, it would seem to us that the technique used is not the main difference here. The main difference is Mr. Fenrick's decision to exclude reductions in interest rates and related impacts from the capital component of his model. This, in our view, is simply wrong.

3.2.7 Mr. Fenrick is correct in saying that the capital component of Dr. Kaufmann's inflation factor is reduced significantly by reductions in interest rates. Since the annual cost of the capital base is mostly a multiplication of the annual capital base times the grossed-up WACC, then even if there are more capital assets being employed, the cost will be pushed downward by reductions in that WACC.

3.2.8 The error, though, is in assuming that one influence on a cost should be included, and not another. Mr. Fenrick includes the increases in capital assets prices, but not the reductions in interest rates, ROE and taxes on that ROE. This is cherry-picking of the worst kind. A result based on this kind of approach is not methodologically sound.

3.2.9 It has been pointed out, quite correctly, that interest rates (and therefore ROE and taxes) are not likely to continue to drop over the 4th Generation time frame, as they have in the past ten years. On this point, the future will not be the same as the past.

3.2.10 The problem with that argument is that it is only one of the obvious ways in which the future will not be the same as the past. For example:

(a) It is well understood that during periods of declining interest costs, the prices of capital assets tend to rise faster, since cheap financing spurs greater demand. The cost of ownership is reduced by interest rate reductions, so more people can buy. As interest rates level off, capital asset costs cannot rise as much, because those increases are no longer offset by interest reductions. Mr. Fenrick does not propose to include this impact in his inflation factor.

(b) We have now entered a period of public sector wage and cost restraint in Ontario. It is reasonable to expect that utility and general wage settlements will be affected by that restraint, and thus be less than in the recent past.

3.2.11 It is in fact true that inflation in the last few years has been lower than would otherwise

be the case due to declining interest rates. This has affected utilities more than the average in the economy, because utilities are more capital intensive. This particular influence on inflation is not likely to continue, but neither are other, opposing influences.

3.2.12 In our submission, if the Board seeks to create a forecast of future inflation, it can do so, but it should do so in a comprehensive way. If, instead, the Board wishes to use the most recent year's inflation as its forecast for next year, then it should use the past data as is, without cherry-picking adjustments to it.

3.2.13 In this regard, we note that all other IRM systems that have a comprehensive inflation factor, whether general or industry-specific, include changes in interest rates. This includes the Board's 3rd Generation IRM, which used GDP IPI FDD. That general measure, as with all general measures, includes the impact of interest rate and other WACC changes.

3.2.14 ***Volatility***. The other impact of the capital component is that it increases the volatility of the inflation index. Three different solutions have been proposed.

3.2.15 Mr. Fenrick proposes removing the impact of interest rates, which in our view is essentially saying "Let's calculate this wrong in order to reduce volatility." That is not a credible answer.

3.2.16 Dr. Kaufmann proposes averaging the last three years of his measure, to smooth the volatility over time. The disadvantage here is that the Board would be using increasingly outdated inflation data to forecast inflation for a future year. Given a volatile measure, outdated data is increasingly problematic.

3.2.17 Professor Yatchew suggests (this is not his proposal; he appears to agree with Dr. Kaufmann on inflation) a solution in which the inflation measure is the greater of the industry-specific number calculated as per PEG, and GDP IPI FDD. If GDP IPI FDD is higher, the difference between the industry specific number and the number used would be "banked". Then, in a subsequent year in which the industry-specific number is higher, it would be reduced by the banked total.

3.2.18 While intriguing, Professor Yatchew's suggestion guarantees higher rate increases than industry-specific in almost all scenarios. Any banked increases would, of course, have to disappear on rebasing, since rates on rebasing are based on approved forecast costs. Thus, in every case in which the banking system did not naturally resolve to zero from one rebasing to the next, the utility would have received higher increases. If industry-specific is generally high, that's what utilities will get. If industry-specific is generally low, they would get GDP IPI or something closer to it.

3.2.19 Thus, Professor Yatchew's suggestion ends up handling volatility by setting a floor on

inflation, but no ceiling. This is neither symmetrical nor fair.

3.2.20 In our submission, volatility is inherent in an industry-specific inflation factor, something the Board knew might be the case. Every method of adjusting this volatility ends up having significant disadvantages.

3.3 ***SEC Recommendation***

3.3.1 SEC submits that, notwithstanding the conclusion of the RRFE Report, the Board should retain GDP IPI FDD as the inflation factor for 4th Generation IRM.

3.3.2 We say this for two reasons:

(a) There is no reasonable way to reduce the volatility associated with the various approaches to industry-specific inflation. GDP IPI FDD has proven to be a stable measure of inflation, and with continued control of consumer price inflation within a narrow band by the Bank of Canada, GDP IPI FDD is also likely to remain stable and within a narrow band.

(b) The empirical work highlights the fact that any past calculation of industry-specific inflation is not likely to be reflective of actual inflation affecting the industry for the year in which the number is applied. The Board is not in a position to forecast next year's industry-specific inflation on a year by year basis, taking all of the changing factors into account. It is likely that, in any given year, the GDP IPI FDD will be closer to the actual inflation experienced by LDCs than an industry-specific calculation two or more years out of date.

4 PRODUCTIVITY FACTOR

4.1 *Introduction*

4.1.1 In this proceeding, the Board is seeking to implement a productivity factor based on total factor productivity, as determined in the RRFE Report. SEC is on record as saying, on more than one occasion, that TFP is fairer to LDCs and ratepayers alike, as it more correctly identifies the collective differences between the movement of utility costs and the movement of their price inputs.

4.1.2 PEG has done a very significant amount of work in developing a comprehensive data base from which TFP can be determined. Data limitations may still prevent the Board from making accurate determinations of the individual factors driving LDC TFP (e.g. technological change, economies of scale, CDM, changes in government and regulatory policies, etc.), but that is not fatal to this exercise. It is a future desirable improvement, not a current must have.

4.1.3 That aside, the foundation laid by the work of PEG does allow the Board to generate an overall TFP number, once the Board reaches its own conclusions on a small number of technical and policy judgments, of which the most important, in our view, is the nature of the productivity standard utilities should be expected to meet.

4.2 *Issues That Emerge from the Experts' Analyses*

4.2.1 ***Technical Issues.*** The experts appear to be in general agreement on the use of PEG's TFP data as is, subject to two technical issues.

4.2.2 First, some of the experts argue that the trend variable (-1.2%) in the econometric model is indicative of total factor productivity, and therefore it should either be used as the productivity factor, or it should be used as a check on whether the TFP figure arrived at from other means is reasonable.

4.2.3 It is our understanding that the trend variable in an econometric model is not a common and accepted method used to measure TFP, and that this proposal is an unusual one, particularly where TFP can be measured directly.

4.2.4 SEC has discussed earlier the difficulties the Board has in dealing with the expert evidence when one expert's work is thoroughly tested (Dr. Kaufmann), but the work of the other experts is essentially untested. This is a perfect example of that problem. The Board would benefit from all the experts being in a position to answer questions on the use of the trend variable to denote TFP, in light of their respective analyses in their reports. The limited discussion of this point at the Stakeholder Conference, when it was sprung on all parties with no real warning, was insufficient for this purpose.

4.2.5 Second, there was a significant debate over whether Dr. Kaufmann's decision to exclude Toronto Hydro and Hydro One from the TFP calculation, because of their inordinate influence over the result, was methodologically sound. This exclusion changed the TFP from to -1.10% +0.10%.

4.2.6 There were several proposed solutions to this discussed in the reports and at the Stakeholder Conference.

4.2.7 Mr. Fenrick's proposal was to run the TFP calculation 73 times, each time excluding one utility, so that a "range" of TFP values would be created. The theory was that this would be a true "external" measure. His range was -0.56% to -1.18%, and he used this as a basis to justify the TFP figure including Toronto Hydro and Hydro One, i.e. -1.10%.

4.2.8 It is difficult to be polite in responding to this proposal, which appears to be only persuasive if one is suffering from the learning disability of innumeracy. Instead of removing Toronto Hydro and Hydro One, his proposal basically removes 1/73 of Toronto Hydro, and 1/73 of Hydro One. In effect, they remain in. As can be seen from the results he provided, removing anyone else doesn't matter, because the results when both Toronto Hydro and Hydro One are in the sample are clustered around a very narrow band. No surprise. Their influence is dominant in the data. Mr. Fenrick's own proposal proves that. Also, no surprise that this approach supports the figure of -1.10%. It is to all intents and purposes equivalent to including Toronto Hydro and Hydro One in the sample.

4.2.9 Another proposal is to use the median instead of the industry average. The industry average as originally proposed by PEG is the same as the weighted average of all of the TFPs of the individual distributors. Because it is a weighted average, all of the larger LDCs have a disproportionate influence on the result, particularly Toronto Hydro and Hydro One.

4.2.10 The median is also a legitimate measure of central tendency (which is what you're looking for here, on this formulation). However, in the median the size of each utility on the list is irrelevant. The TFP of whoever is in the middle is the number. In this case, and with the help of the Board's instruction letter of June 26, 2013, SEC calculates the median figure to be -0.19%. An equal number of LDCs were above and below this level during the study period.

4.2.11 Professor Yatchew proposed that this problem should be solved through moving from an index-based model to an econometric approach, using the PEG model but adding two additional business condition variables. His result is -0.75%, driven heavily by the trend coefficient in the model, -1.24%. We have commented above on the use of the trend variable.

4.2.12 The fourth solution was to use a simple average rather than a weighted average (or industry aggregate) approach. Dr. Kaufmann did a simple average of the individual TFPs for each distributor, and came up with a figure of -0.26%. This does not change dramatically if Toronto Hydro and Hydro One are removed, because they do not have a disproportionate weight in a simple average. They are each 1/73 of the calculated average.

4.2.13 Interestingly, Professor Yatchew also does the simple average calculation, and comes to a figure of -0.7%. SEC has attempted to replicate the simple average calculation, and reaches a figure similar to that of Dr. Kaufmann, so we do not understand how Professor Yatchew reached a much different number.

4.2.14 On the technical issue of how to deal with the impact of larger utilities on the TFP trend, we agree with Professor Yatchew (at page 15 of his report) that using different weights for different LDCs "seems odd given that the objective is to estimate an average productivity factor that is to apply to each individual distributor". Therefore, subject to our comments below, SEC believes that using a simple average rather than an industry aggregate, median, or any other approach, is more appropriate.

4.2.15 ***Policy Issue.*** The debate surrounding whether to include Toronto Hydro and Hydro One centred around their size, and therefore their disproportionate impact on the result. However, there was a second and underlying aspect of that discussion, i.e. the two utilities were low productivity performers, and their inclusion would bring the overall standard applied to all distributors way down.

4.2.16 The RRFE Report says (page 17), quoting the Board's 3rd Generation IRM report:

> *"The productivity component… is intended to be the external benchmark which all distributors are expected to achieve."*

4.2.17 SEC believes that inclusion of the TFPs of distributors with the lowest measured TFPs undermines the principle that this should be an external benchmark. This is a common standard. Inclusion of the lowest performers within this standard will tend to draw all other distributors down to that level.

4.2.18 Therefore, SEC believes that as a matter of policy the Board should compute the productivity trend all distributors are expected to achieve without including the lowest performing distributors.

4.2.19 SEC has used the Board's helpful information provided yesterday to calculate TFPs for individual LDCs, and therefore simple averages of various types. These figures are all for the period 2002 to 2011. Obviously they would have to be recalculated once 2012 data is available.

4.2.20 The simple average TFP of the top decile (7 LDCs), for example, is +2.38%. The top quartile (18 LDCs) averaged +1.56%, and the top third (25 LDCs) averaged +1.27%. At the other end of the scale, the simple average of all utilities but the bottom 10% is still positive (0.03%), and the average excluding the bottom third is +0.52%.

4.2.21 These results tell us that, but for a small number of utilities at the bottom end, the industry as a whole has achieved positive productivity on average. While 41 were negative, and only 33 were positive, the positives were relatively higher than the negatives, thus producing the results seen.

4.2.22 SEC believes that the Board should determine, as a general policy, that the external productivity benchmark to be used for LDCs should not include the poorer performers arising out of the past data. While it might be unfair, at this point, to calculate this productivity standard based on only the very top performers (e.g. +2.38%), a standard that does not bring the average down towards the level of the substandard performers would, in our view, be appropriate.

4.3 ***SEC Recommendation***

4.3.1 Based on our analysis above, and given the current state of the sector, including in particular the flexible rate options available to each LDC, SEC proposes that the Board calculate the TFP for 2014 as the simple average of the TFPs of the top half of the LDCs over the period 2002-2012. Without including 2012 data, we calculate that simple average to be +0.86%.

4.3.2 As we note later, in Section 7.2, SEC believes that this productivity figure should be updated annually. If the effect of excluding the lowest TFP performers from the calculation is that, in subsequent years, the TFP calculated on this basis improves (as we would hope), the Board could then consider whether excluding a smaller number of poorer performers would be better. Alternatively, if productivity trends on this basis were to deteriorate, the Board could then consider whether to exclude a greater number of the lower productivity numbers, thus in effect raising the standard.

5 TOTAL COST BENCHMARKING

5.1 *Introduction*

5.1.1 The PEG Report proposes that distributors be compared to each other in a manner similar to 3rd Generation IRM, with a combination of a unit cost and an econometric test, and five as opposed to three levels of resulting stretch factors.

5.1.2 SEC is conscious that distributors have over the last few years raised four main issues about the benchmarking/stretch factors exercise:

(a) The econometric component was almost impossible to relate to their own efforts to cut costs and thus improve their performance. (Ratepayers complained, as well, that these comparisons were difficult for the public to understand.)

(b) The peer groups used for unit cost comparisons did not always appear to the utilities to be reasonable.

(c) The tranches of stretch factor (three, in 3rd Generation) meant that for most utilities it was unrealistic to think that they could improve their efficiency level sufficiently to move to a different level and thus have a different stretch factor.

(d) The unit cost comparison was based only on OM&A, and capital is a major component of their operational management.

5.1.3 The Board has already determined in the RRFE Report that benchmarking must include total costs, so the fourth issue has been fully addressed. All proposals assume total costs.

5.1.4 With respect to the other three issues, SEC is of the view that the Board, in establishing its new benchmarking and stretch factor regime, should respond to each of these concerns directly, both in its report and in the solution the Board adopts**.** In our recommendations below, we try to propose such a solution.

5.2 *Issues That Emerge from the Experts' Analyses*

5.2.1 ***Basic Issue.*** As we understand it, this exercise is about how you compare the costs of 73 distributors that are, in fact, not exactly alike. There are basically two methods of doing that. Both establish an efficiency standard, and compare individual distributors to that standard. They just establish the standard in different ways:

(a) Normalize the costs for the differences. In this method – the econometric approach – you decompose the external drivers of costs to produce a cost number for each utility that is their "predicted" costs, i.e. costs calculated on the same basis as

everyone else. This has the advantage that it is comprehensive, but suffers from two disadvantages: it is difficult to understand, and it is highly sensitive to the specifications of the normalization model.

(b) Compare only to peers, not to everyone. By narrowing the comparison list, for most distributors it should be possible to find a group of others that they are sufficiently like to make meaningful comparisons. This is the unit cost approach. This has the advantage that it is very easy to understand, but also suffers from two disadvantages: the comparisons are not exact, only approximate, and it is highly sensitive to the selection of the peer groups.

5.2.2 ***The Use of Econometric Modeling in Comparing LDCs.*** The debate relating to comparative benchmarking was essentially all econometrics, all the time. The experts debated whether PEG's econometric model was properly specified, and whether the business conditions used were appropriate. More business conditions were proposed, and there was and is no apparent agreement on which ones should be used. They also debated the impact of the econometric model on the peer group selection, and therefore on the validity of the unit cost component of PEG's approach as well.

5.2.3 This part of the discussion is another example of a weakness in the record before the Board. Four experts have proposed four different approaches to the benchmarking, all in whole or in part driven by differing econometric approaches. Only one of the proposals has been tested. Two have been discussed only at a high level, despite differences in the details, and one has not really been discussed at all.

5.2.4 Individual proposals have individual flaws. For example (and these comments are just hitting the high points):

(a) Dr. Kaufmann's proposal to continue with a method similar to the current method does not deal at all with the first and second issues utilities raise about the current method, and only partly ameliorates the impact of the third issue.

(b) Mr. Fenrick's proposal, called the Unit Cost Econometric Model, makes the startling suggestion that all relationships between business conditions and costs are linear, which is unsupported by any evidence and fairly obviously wrong. While he claims it is easier to understand, to the extent that is true it is only because the model oversimplifies reality to the point where the model no longer represents reality. Further, his model – presented on behalf of the CLD – seeks to assume that whether your service territory is windy or dense or large or old is an external business condition, but whether you have a lot of customers and thus enjoy economies of scale is not a business condition but something within management control.

(c) Professor Yatchew rejects entirely the use of peer groups to compare unit costs, but

it is not clear whether he is then proposing i) use of the econometric model he proposes for TFP to compute relative efficiency, or ii) longitudinal comparisons of LDCs to themselves, without comparisons to others. If the latter is the proposal, it is clearly in the interests of neither the industry nor its customers.

(d) Dr. Cronin proposes comparisons of relative efficiency of LDCs using Data Envelopment Analysis (DEA), but because of the timing of his report, we are unable to comment on whether this is a sensible approach, nor on the results that he summarizes in his paper. We have not had any opportunity to review his proposals and hear the responses of the other experts to those proposals.

5.2.5 From the debate so far, SEC believes that the Board can reach the following conclusions about the econometric approaches being discussed:

(a) There is substantial disagreement about the appropriate business conditions, yet the model is extremely sensitive to the selection and specification of those business conditions. Some of the proposed business conditions are not obviously in or out, i.e. they are in some respects external factors relating to the service territory, and in some respects matters within management control. It is therefore not clear whether they should qualify as business conditions.

(b) The model is unlikely to have any staying power. As the underlying data changes, the statistical significance of individual business conditions may also vary substantially. To retain methodological purity, the model may have to be re-done completely, perhaps annually.

(c) The model can only be simplified by giving up accuracy. Any simplification that would be meaningful would likely take the accuracy below an acceptable level.

(d) Use of econometric models to differentiate between the distributors will not provide them with an incentive to drive cost reductions, because they will not be able to make a reasonable and intuitive connection between their operational decisions and the econometric results controlling their stretch factor.

(e) The public will have no understanding of why one utility is considered to be a superior performer, and the other is not.

5.2.6 ***Unit Cost Comparisons.*** Both unit cost and econometric methods of doing these comparisons have advantages, but significant flaws. PEG proposes, in keeping with the RRFE Report, to include both, in effect seeking to get the advantages, and minimize the weaknesses, of each. In our view, that is not the result. Rather, the combination ensures that the distributors and their ratepayers have to live with the weaknesses of both methods.

5.2.7 SEC therefore believes the Board should choose one method, design it as well as possible, and accept that it will not be perfect.

5.2.8 How does the Board choose between the two? In our submission, the question the Board should ask is "What do distributors do in fact?"

5.2.9 We have never heard of any distributor that compares itself to others using an econometric model. The only things we have ever heard any distributor say about econometric models is that they bear no relationship to the distributor's reality (sometimes put in more colourful terms).

5.2.10 We have, however, heard of many distributors (and companies in other markets, by the way) that compare themselves to peers on various metrics, usually unit-cost oriented, or to industry averages. A few have it formalized in reporting to Boards of Directors and shareholders. Others use the comparisons as internal management tools. In every case, with the exception of a few comparisons that work as industry averages, the comparison is to some form of peer group.

5.2.11 Subject to the problem of selecting peer groups, and the potential disproportionate impact of outliers within groups, the use of unit cost comparisons is an attractive approach. The unit costs themselves are easily understandable, and they relate directly to the operational decisions utility managers are making. Customers can readily understand that their utility is more or less efficient because other similar utilities have higher or lower unit costs. Unit costs can be compared in a number of different ways, and where there are anomalies the adjustments are usually simple (exclusion of a particular category of costs, for example).

5.2.12 ***Peer Group Selection***. We start with the knowledge that most utilities have an idea of the distributors that are most like them. Despite the number of companies, and the dollars involved, it is actually a fairly small industry, and the management of the distribution companies regularly talk with one another in both formal and informal venues. In short, they know each other.

5.2.13 Thus, in our view it should be possible to simply ask the distributors which other distributors are most like them, as it is information many of them already have.

5.2.14 The problem is that, if the Board just asks, and uses the information as it is, the question will not be heard as "Which other distributors are most like yours?", but instead "To which other distributors would you like to be compared for ratemaking purposes?". Clearly the answer to the second question may not be the same as the answer to the first question, and utilities would be incented to choose a comparison group that puts them in the most favourable light.

5.2.15 Therefore, if the Board is to seek information from distributors to develop peer groups,

it must ensure the distributors understand that:

(a) The list they provide is not the peer group to which they will be compared, but only part of the input to that analysis; and

(b) If a distributor provides input that is not responsive to the first question, but instead tries to game the process, there will be negative consequences for doing so.

5.2.16 In the next section, we provide a proposal for "crowd-sourcing" the peer group analysis to produce fair results while preventing individual distributors from attempting to game the system.

5.2.17 ***Outliers***. Even with well selected peer groups, there remains the potential that some groups will have unit cost outliers at the top or bottom of the list, and those outliers will skew the average for the peer group. Distributors in a group with an outlier will thus show performance that is substantially higher or lower than would be the case in the same group, but without the outlier.

5.2.18 To solve this problem, the experts discussed, and some have proposed, that comparisons be done not to the peer group average, but to the median. This will tend to reduce, if not entirely eliminate, the impact of outliers, and may in most cases more correctly reflect the central tendency of costs within the group.

5.3 ***SEC Recommendation***

5.3.1 ***Unit Cost Comparisons.*** SEC believes that the most effective way to measure efficiency for the purpose of the stretch factor is through unit cost comparisons, and that will also be the most successful way to incent distributors to improve their performance.

5.3.2 ***Median as the Benchmark***. For the reasons cited above, SEC believes that a comparison to the median rather than to the average of the group will largely remove the problem of outliers.

5.3.3 ***Peer Groups***. SEC proposes that the determination of peer groups be done through a "crowd-sourcing" process, as follows:

(a) Each distributor should be required to provide a list of ten other distributors that they believe are most like them from an operational and business point of view. The list should be ranked, from the most similar to the least similar. The distributors should be allowed, but not required, to provide reasons for the inclusion of distributors on the list, and/or the rankings.

(b) Board Staff should be charged with the responsibility to go through the lists and

propose names that should be removed or re-ranked because they are not really similar to the distributor that made the list. Distributors will thus be aware that if their lists of "peers" and rankings are not justifiable, their choices will simply not be part of the matching process. Their input into the appropriate peer group for them will be reduced, in essence their penalty for seeking the game the system.

(c) The Board should use commercially available matching software to compare the rankings on the adjusted lists, and produce a composite set of six to eight peer groups based on those matches and rankings. This is largely a mathematical exercise.

(d) The original lists, the proposed adjustments, and the result of the matching exercise, should be published on the Board's website, and anyone can comment on any of them.

(e) The Board should then make a final determination as to the peer groups to be used.

5.3.4 In the best of all possible worlds, the distributors get together themselves and decide who their groups should be, because that would be the very best way to ensure the result they prefer. A group of ten LDCs that jointly file identical lists would have, under the matching program, virtual certainty with respect to the composition of their peer group.

5.3.5 Even if the perfect world is not achieved, human nature suggests that distributors will try to provide cogent peer group proposals, because the collective result of the process is most likely to be in their best interests.

5.3.6 ***Toronto Hydro***. Mr. Fenrick has proposed that Toronto Hydro should be excluded from the benchmarking, because of its unique nature. No evidence has been filed in support of this proposition.

5.3.7 In our submission, if Toronto Hydro wishes to argue that a Board policy of general application – in this case the benchmarking component of 4th Generation IRM – should not apply to them, there is an accepted method for doing so. Toronto Hydro should lead evidence in their own rate case to show that this particular Board policy should not apply to them. If the evidence is compelling, that Board panel will exercise the Board's adjudicative powers to apply a different rule for Toronto Hydro.

5.3.8 SEC believes that, in this policy consultation, the Board does not have a sufficient evidentiary basis to make such a determination, which in any case is more appropriately made in a rate case.

6 STRETCH FACTORS

6.1 *Introduction*

6.1.1 SEC has proposed, in Section 5, the use of unit cost comparisons to the median of peer groups that have been selected with distributor input. The result of that exercise is that each distributor would have a ranking that is the percentage by which their unit costs are above or below their peer group median.

6.1.2 That leaves only the simpler question of how to apply those rankings to determine stretch factors**.**

6.2 *Issues That Emerge from the Experts' Analyses*

6.2.1 ***Negative Stretch Factors.*** The only expert report on which SEC wishes to comment specifically is that of Professor Yatchew. In his proposal, he suggests that the "stretch" factor should be symmetrical around zero. That is, some distributors would have a positive stretch, and some a negative.

6.2.2 In our submission, this can only be based on a fundamental misunderstanding of the purpose of the stretch factor. As we have noted earlier, the purpose of the stretch factor is to build in a ratepayer benefit. Without a positive benefit to ratepayers, IRM may not be in their interests, because so often efficiencies enjoyed by utility owners during IRM disappear by the time rebasing comes around.

6.2.3 In the proposal of Dr. Yatchew, it would be even worse. Distributors that are already fairly efficient would be told, through the negative stretch factor, that they can reduce their relative efficiency, and their ratepayers would have a built-in disbenefit from IRM. This is not, in our submission, realistic.

6.2.4 ***Stretch Factor Tranches***. With respect to all of the expert reports, we comment that none of them deal effectively with the complaint of many distributors that it is difficult to move from one tranche to another, and thus actually reduce their stretch factor. There is in theory a reward for improving efficiency, but for most distributors that achieve improvements, they cannot actually get the reward.

6.2.5 There is no reason, however, why the stretch factor has to be in discrete tranches, and SEC's proposal below seeks to remedy this problem, and increase the ability of distributors to be rewarded for efficiency improvements.

6.3 *SEC Recommendation*

6.3.1 ***Range.*** SEC agrees with most of the experts, and we believe most of the other stakeholders, that stretch factors must be positive, and that the range of 0.0% to 0.5%

which was discussed by many is a reasonable range, given the inflation and productivity factors we have proposed.

6.3.2 ***Analog Stretch Factor Formula***. Instead of five stretch factor levels, SEC proposes that the Board move to an analog approach, in which there are effectively an infinite number of stretch factor possibilities within the overall range of 0.0% to 0.5%.

6.3.3 Our proposal is that, once the unit cost comparisons have been done, each distributor will have a ranking which is a percentage variation (plus or minus) between their unit costs and the median of their peer group. Stretch factors should then be calculated for each distributor as follows:

(a) All of the distributors should be ranked in a single list by percentage variance from their peer group median, e.g. from the worst performer of, say, +38% to their peer group, to the best performer of, say, -41% to their peer group.

(b) This will produce an Efficiency Range, which is the number of percentage points between the best and the worst performer, in this example 79 percentage points (+38-(-41)).

(c) For an individual distributor, their Relative Inefficiency should be calculated as the number of percentage points their percentage figure is above the figure of the best performer. Lower relative inefficiency is better. In this example, a distributor that is +25% to their peer group is 66 percentage points above the best performer, which is at -41%.

(d) The stretch factor is calculated by the formula Relative Inefficiency/Efficiency Range*0.5%. In this example, it is 66/79*0.5% = 0.4177%. This distributor is relatively quite inefficient, and thus would have a high stretch factor. By contrast, a more efficient distributor with a -25% relative to their peer group would be 16 percent above the best performer. Their stretch factor would be 16/79*0.5 = 0.1013%.

6.3.4 The purpose of this proposal is to ensure that utilities that exhibit good cost management relative to their peers are always rewarded for doing so.

7 IMPLEMENTATION ISSUES

7.1 *Introduction*

7.1.1 SEC has comments on only two other areas.

7.2 *Implementation of TFP Changes*

7.2.1 The Board has asked for input on the timing of implementation of changes to TFP. The Board's question assumes, as the RRFE Report sets out, that TFP will be fixed for a period of time.

7.2.2 SEC has proposed an approach to TFP that allows for TFP to be updated on an incremental basis each year. Given that possibility, SEC proposes that TFP be updated with an additional year of information each year, using the same methodology we have proposed in the Section 4.

7.3 *Incremental Capital Module*

7.3.1 The one other area in which SEC believes an adjustment to 4th Generation IRM is required is in the calculation of the threshold for the ICM.

7.3.2 The current threshold is basically the distributor's depreciation level, plus a factor for customer growth and a factor for the IRM increase, plus a deadband of 20%. (The full formula is in the Board's Supplementary Report, September 17, 2008.)

7.3.3 This formula inherently assumes that level of annual capital additions over the historical TFP period is slightly more than 100% of depreciation. Amounts in excess of that are considered to be incremental, and eligible for the ICM if they meet the other tests.

7.3.4 The Board is now establishing an IRM formula based (at least with respect to TFP) on spending during the period 2002 through 2012. It would appear to us that the capital additions during that period were much higher than the assumption implicitly built into the current formula.

7.3.5 It is therefore submitted that the ICM threshold formula should be changed. The Board should calculate the average capital additions as a percentage of depreciation for the industry over the TFP study period. The term in the current formula, RB/d, which is a representation of the distributor's depreciation level relative to rate base, should be multiplied by that industry wide capital additions percentage, and the rest of the formula should remain unchanged.

7.3.6 While we don't have all of the data available to do this calculation, SEC believes that

the difference in the formula could be significant. The capital additions percentage in the last few years has exceeded 175% of depreciation. Even if the early years of the study period are lower, a threshold that starts at around 150% of depreciation, and then adds growth and the deadband, may well be the result.

7.3.7 Given the industry's levels of depreciation and capital spending, the difference in the level of qualifying incremental capital additions could be several hundred million dollars annually. Therefore, we believe that correction of the ICM threshold formula so that it is compatible with the new IRM formula is urgent, and should be addressed before 2014 applications are to be filed.

8 RESPONSES TO THE BOARD'S QUESTIONS

8.1 *Inflation Factor*

8.1.1 ***Question 1: Experts' recommended approaches.*** The appropriate learning from the work of the experts is that an industry-specific inflation factor will be too volatile, and there are no acceptable solutions to that problem applicable to today's distribution industry in Ontario.

8.1.2 ***Question 2: SEC Preferred Approach.*** SEC proposes continued use of GDP IPI FDD.

8.2 *Productivity Factor*

8.2.1 ***Question 3: Experts' recommended approaches.*** In general, we believe that the PEG calculations of TFP are to be preferred. However, the issue of the inclusion of Toronto Hydro, Hydro One (and potentially other poorer performers) has not been fully addressed by any of the experts.

8.2.2 ***Question 4: Appropriate Ontario TFP.*** SEC proposes that the productivity factor be calculated annually based on the simple average of the utilities in the top half of productivity over the study period. This produces a productivity factor for 2002-2011 of +0.86%.

8.3 *Total Cost Benchmarking*

8.3.1 ***Question 5: Experts' recommended approaches.*** All of the experts use econometrics in their benchmarking, in whole or in part. SEC believes that econometrics have not been demonstrated, in this particular context, to properly predict the relative efficiencies for Ontario electricity distributors. The differences between the model results for the experts is instructive in this respect.

8.3.2 ***Question 6: SEC Preferred Approach.*** SEC therefore believes that the Board should rely solely on comparisons of unit costs within peer groups.

8.3.3 ***Question 7: Unit Cost/Peer Group Model.*** We propose that the Board "crowd-source" the selection of peer groups to the LDCs, with appropriate controls in the event that anyone seeks to game the process.

8.3.4 ***Question 8: HV/LV Charges.*** We agree with the approach taken by PEG under the guidance of the Working Group.

8.3.5 ***Question 9: LV Services Data.*** No additional submissions.

8.4 *Efficiency Cohorts/Rankings and Stretch Factors*

8.4.1 ***Question 10: Experts' recommended approaches.*** The utilities are concerned that, using a cohort approach, it is difficult for an LDC to change their stretch factor through cost reductions. SEC believes that an analog approach – variable stretch factors based on ranking – is better. We agree that the range of 0.0% to 0.5%, proposed by most of the experts, is appropriate.

8.4.2 ***Question 11: Appropriate Stretch Factors.*** SEC proposes a formula for the stretch factors that varies an individual utility's stretch factor directly by their unit cost performance.

8.5 *Implementation Considerations*

8.5.1 ***Question 12: Ex Ante Monitoring of the PCI Formula.*** The Board is regularly monitoring the results of all of its policies. In our view, no *ex ante* determination or success or failure criteria is appropriate. The range of possible criteria is too broad.

8.5.2 ***Question 13: Implementation of Updated TFP.*** Because of the productivity factor we have proposed, SEC believes that updating it with an additional year of data annually is the simplest and most straightforward approach.

8.5.3 ***Question 14: Other Implementation Matters.*** It is important that the threshold for ICM exclude capital additions that are funded through the IRM formula. The level of capital spending over which TFP was calculated is included in the formula, and so the ICM threshold should start at that level (as a percentage of depreciation), plus the current factor for growth and the current deadband.

9 GENERAL ISSUES

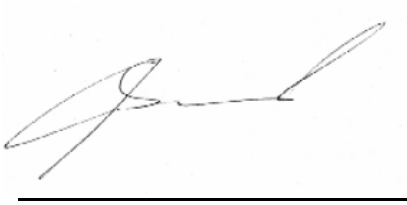
9.1 *Conclusion*

9.1.1 SEC appreciates being allowed to provide input to the Board on these important issues. SEC would like to continue to be involved in any further processes relating to the framework within which electricity distributors are regulated.

9.2 *Costs*

9.2.1 SEC submits that it has participated responsibly in this process with a view to providing assistance to the Board, and requests that the Board order payment of its reasonably incurred costs for that participation.

All of which is respectfully submitted.



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