EB-2007-0673

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

AND IN THE MATTER OF the review by Board Staff of 3rd Generation Incentive Regulation for Electricity Distributors.

SUBMISSIONS ON THE STAFF SCOPING PAPER

FROM THE

SCHOOL ENERGY COALITION

1. The Board has initiated a process to establish guidelines for the 3rd Generation Incentive Regulation mechanism for Electricity Distributors. On August 2, 2007 Board Staff published a paper (the "Scoping Paper") setting out background and seeking input on the issues to be addressed in this process, and in particular the issues to be addressed by a Working Group, of which a representative of the SEC is a member. The Scoping Paper was followed by a Technical Conference on September 12-13, 2007. In a related process, the Board is also considering information on the best ways to compare distributors (EB-2006-0268). These are the submissions of the School Energy Coalition with respect to the Scoping Paper. To the extent necessary, they also consider the impact of the Comparators process on the issues to be addressed by the Working Group.

2. These submissions are divided into two parts. In the first part, we discuss certain issues of principle that have arisen in the Scoping Paper and the Technical Conference, and in our view could create difficulties in achieving a proper IRM. In the second part, we provide a draft Issues List for the Working Group, and some commentary on the specific issues set forth in that list.

Principles

3. ***Paralysis by Analysis.*** At the Technical Conference, and in discussions about IRM in the past, we have heard many comments about getting the "principles" right. We agree that discussion of objectives and principles is an important exchange of ideas and views. However, we are concerned that obtaining a consensus on those objectives and principles is an impossible goal, and one that has the potential to divert the Working Group from achieving consensus on some or all of the practical issues surrounding multi-year ratemaking.

4. Therefore, we are providing below some comments below on key principles that we believe need to be understood. We do not expect the distributors, or even all of the ratepayer groups, to embrace these principles. What we do expect is that other parties, and the Board, will derive,

from these principles below, a good sense of the perspective the School Energy Coalition is bringing to the process, and goals we believe should be sought.

5. ***Costs Do Not Drive Rates.*** In the many discussions about incentive regulation, distributors and even ratepayer groups repeat the common fallacy that rates, to be "just and reasonable", must allow the utilities to recover their reasonably incurred costs from ratepayers. This, based as it is on the cost of service ratemaking paradigm, is completely incorrect with respect to incentive regulation. In fact, even in a cost of service environment, it is not in fact correct. Rates are never actually based on costs.

6. In fact, rates are always set based on a budget for a future period of time. Choosing a ratemaking model is about choosing the best way to make and/or assess that budget. There are three broad techniques that are used for setting that budget:

   a. *Cost plus.* This is the cost of service model. The utility forecasts its costs to deliver the distribution service for a future period (one or more years), the regulator assesses whether the forecasts are reasonable, and adopts the final reasonable costs as the basis for rates. The utility then has its budget, but is free to spend within that budget any way it likes. Note that actual costs are not a factor in rates. The cost forecast – never the same as the costs actually incurred – is simply a method of getting to a budget number. Management then has to manage within that envelope, and typically does so by moving spending around to maximize efficiency (and sometimes ROE).

   b. *Marketplace.* Even in a cost of service environment, the regulator will usually take some account of market forces. If the budget requested by the distributor would produce a substantial rate increase, regulators will often approve a reduced budget so that a fairer balance between ratepayers and cost pressures is achieved. In some cases, this will also include benchmarking, either to costs of other distributors, or to prices charged by other distributors. Again, the budget number then becomes the envelope within which management manages.

   c. *Formula from Past History.* Indexing formulae are not just used in incentive regulation. Most cost of service applications include implicit or explicit formulae, applied to past data, to get some or all components of the requested budget. This is not just true in a regulated environment, but is also common in budget-making processes for competitive companies. The formula is just a method of getting to a budget number, on the assumption that a particular percentage change should be sufficient to deliver the service efficiently. We note that a formula is also often employed in ADR to reach settlement.

   In practice, most rate cases use more than one of these techniques, in varying proportions, to get to the budget within which management must operate for the future period. A good example of this is the Enbridge 2006 rate case. In that proceeding, the applicant sought a large increase in its capital budget, providing a detailed list of how it wanted to spend the money. The Board said, in effect: "We believe your capital budget is too high. We aren't going to provide a new list of projects that are approved, since you can do what you like anyway. Instead, we are giving you a number - $300 million – and you have to set your priorities within that envelope."

7. The School Energy Coalition believes very strongly that an excessive reliance on the concept that costs drive rates is a mistake for this process, and this Working Group. The job of the Working Group is to establish a method for determining future budgets that is transparent, fair, and practical. Future costs may indeed be a factor in that analysis, and may be a component of the method eventually approved by the Board, but they are not the sole determinant of rates.

8. ***Regulation as a Proxy for Competitive Markets.*** This leads naturally to the second principle that needs to be emphasized, and one that we believe is not sufficiently adopted in some regulatory regimes. That is, rate regulation of monopoly service providers is intended to be a proxy for competitive markets. To the extent that the regulatory model causes results similar to those in competitive markets, then even if those results are not particularly pleasant, the model is a successful one, doing the job it is supposed to do.

9. It is instructive to look at how competitive models "control" the costs of market participants, and deal with some of the issues raised by the distributors in the Technical Conference and past submissions:

    a. *Historical Costs, Vintage, Asset Condition.* Many distributors have noted that IRM needs to account for their varying needs to upgrade, refurbish, or otherwise spend money on their systems, and for their legacy cost structures including things such as union contracts, etc. In a competitive market, these needs are only recognized if the requirement to spend, or the legacy cost structure, is common to all market participants. Where that is the case, prices from all participants rise to cover the higher costs (ie. the market price increases). A good example of this is changes in technical standards. Where a standard change increases costs, all participants can build that into their prices. (Smart meters may be the best analogy for LDCs.) On the other hand, if as is the case with most LDCs future cost pressures and existing legacy cost structures are specific to their individual system, the market does not respond to that. <u>The market does not generally accept excuses.</u> If you have an old factory, and need to spend money to upgrade it, the market will not allow you to increase your prices to cover those costs. You still have to live within the competitively set prices, which your more efficient competitors establish at the frontier.

    b. *Short Term Impacts.* In the short term, low cost suppliers set the market price. High cost suppliers cannot sustain a higher price to cover those costs. They simply lose market share until they get their price back to the market level. That means they make less than their target ROE, or they even lose money, as long as their costs are not at the frontier.

    c. *Longer Term Impacts.* In the longer term, low cost suppliers make a reasonable, sometimes even excellent, rate of return for their shareholders. If high cost suppliers cannot get their costs down, the situation (continuing losses or low returns, or inadequate service quality) eventually becomes untenable. The market has a well-known solution for that. The high cost supplier is sold, at a loss, to a new owner who will drive costs down. Sometimes that is done through economies of scale, and sometimes it is done through the cost adjustment inherent in the loss on sale. Whatever the source of the cost change, it must happen, because, as noted above, the market does not accept excuses.

d. *Final Result.* In the normal course, competitive markets drive all market participants to the frontier price, and therefore to frontier costs. The pressure to get there is inexorable, and failure is simply not tolerated. Of course, some market participants adjust by changing their service offering (a "premium" priced product), but this is nothing more than exiting the competitive market in which they were unable to compete, and entering a new market in which their costs are at a frontier level, or they have no competition.

10. We understand, of course, that in the real world markets don't always operate efficiently, and companies with costs above frontier levels find ways to survive through things like customer loyalty, marketing tricks, and other techniques. That does not change the fact that, by design, competitive markets drive market participants to the lowest sustainable price. Any regulatory model that does not seek that same goal is, it is submitted, not properly designed.

11. Looking at the competitive markets analogy, it is at least arguable that the Board should identify the frontier price for electricity distribution (perhaps with some exogenous factors adjusting the price for local conditions, as a competitive market would do), and set that as the rate level for every distributor. Any distributor not already at the margin would be forced to act decisively to cut costs, and until that process was successful the municipal shareholders would have reduced ROE, or even losses, in their LDC investments. Some distributors would succeed in cutting their costs. Others would not, and eventually the municipal shareholders would have to sell those LDCs, maybe even at a loss, to allow them to operate profitably under new ownership. Sector consolidation would be achieved by natural forces, and, at least in theory, an optimal mix of LDCs would be achieved.

12. That, of course, is somewhat Draconian, and we are not proposing that the Board go in that direction. However, we do believe:

   a. The Board should keep in mind the goal of a competitive market, ie. to drive all market participants to the lowest sustainable prices over time, and

   b. The Working Group should consider options such as mandatory long range cost reduction plans, to allow LDCs to get their costs down in a less onerous, but no less inexorable, way, to something approaching frontier levels.

13. ***Application of Private Company Rules to Electricity Distributors.*** During the Technical Conference, some of the LDC representatives commented that applying the same rules to electricity distributors as to gas distributors is wrong, because electricity distributors are usually owned by municipalities, and so are in the "public sector". In most cases, this is used as a justification for some type of pure "cost plus" ratemaking.

14. It is our view that, when the government chose to restructure LDCs to be like private companies, with a private company capital structure and risk-driven return on equity, the ability to say that LDCs should be treated like public sector entities ended completely. Of course, the market

changes that drove the government policy in the late 90s did not materialize, but the shareholders of the LDCs are still getting a cost of capital and ROE based on the private company model, and their ratepayers are still paying the substantially higher rates that change created.

15. From a policy point of view, it is not unreasonable to consider the possibility that LDCs would go back to a public sector model. That is not the Board's call, but the government's, and as far as we know is not being proposed. Part of that change, if it ever happened, would be a change in the cost of capital, and a removal of the ROE component of rates.

16. What is unreasonable is the proposition that the shareholders of LDCs can continue to collect ROE based on a private company model, but somehow have rules based on a public sector model (including protection from risk). The ROE is compensation for taking risks, just like the owner of a private company. Once you accept payment for taking the risks, you can't then come to the regulator and ask it to relieve you of those risks.

17. By way of example, if the Board adopts a rate-setting model that includes a frontier pricing target, that may mean that some LDCs are not able to make very good returns while they are getting their costs in line. Those LDCs cannot complain about that on the basis that they are largely owned by the public sector. As long as they are under the private company structure, they must take the bad with the good. That structure gives them rewards if they do a good job running the LDC, but it also takes those rewards away if they do a poor job.

Issues List

18. ***Draft Issues List.*** We have prepared a draft issues list that sets out in a preliminary way what we believe to be the appropriate issues for the Working Group to consider. It is attached to these Submissions. This list was initially based on the issues list in the recent Gas IR proceeding, with some changes to reflect the different circumstances of electricity distributors as opposed to gas distributors at this point in time. Below we comment on some of those issues.

19. ***Applicability and Opting Out.*** Perhaps the biggest single issue in 3rd generation IRM for electricity is the question of how binding the rules or guidelines should be. Should the selected ratemaking method apply to all LDCs, or only some of them, and is there any right for LDCs, or ratepayers, to seek rates set on a different basis?

20. There are both legal and policy issues associated with this question. On the legal side, we have argued extensively in our October 20th submissions in EB-2006-0087 that the Board is not in a position to make rules that set rates unless that is done in the context of a hearing process, so that the Board's ratemaking powers are engaged and the process is compliant with the requirements for exercise of adjudicative powers. That situation has not changed, and the Board cannot, in our view, establish rules that set LDC rates unless it adopts the approach we have recommended in those submissions.

21. In any case, it is probably not a good idea to make the rules fully binding right now, even if the Board could. Ontario's electricity distributors are all at different stages of a transition from one type of entity to another, and it is likely still premature to issue a one-size-fits-all approach.

22. It must, we submit, be part of the role of the Working Group to look at various options for applicability of the Board's 3rd generation IRM. Those may include techniques such as a) a preliminary hearing where parties can make submissions on the right approach for a given LDC, b) ratemaking models with flexible components such as terms and productivity factors, c) joint opting-in by LDCs and ratepayers, d) opting out by LDCs or ratepayers, with the right to contest, e) default cost of service for LDCs that don't opt for the more streamlined approach (the current situation), etc. The options considered may change based on the IRM model recommended, as the applicability approach right for one model may not be suitable for another model.

23. Of critical importance in this is symmetry. It cannot be up to the LDCs to decide the ratemaking method that applies to them. Not only does this promote gaming the system, but it also creates a built-in upward bias on rates. Fairness to ratepayers requires that any method of opting in or out be available to the ratepayers as well as to the utilities.

24. ***What Issues Should be Pre-Determined?*** Another meta-issue is the question of whether answers to design issues have to be fixed. It should be open to the Working Group to suggest that some design components, even if normally fixed, should instead be left to the individual hearing panel to determine.

25. For example, the Working Group should be free to recommend that the IRM term should be established for an individual utility by a hearing panel based on their particular circumstances. Even if the LDC files for five years, the hearing panel should be left to determine the number of years for which its decision would apply, much as the Board did with Hydro One Transmission recently. Thus, rather than answering a "term of plan" question on the Issues List with a number of years, the Working Group should be free to recommend that the question be determined by the hearing panel, if that is the optimal choice given the IRM model recommended.

26. ***IRM Model.*** Like most parties, we believe that the models available to be considered by the Working Group should not be limited to price cap vs. revenue cap. In particular, we think there is merit in looking at multi-year cost of service approaches (and variations of them), so that there will be a way of building into rates cost reduction targets responding to benchmarking data, and then monitoring the results of those efforts.

27. In its analysis, it will be critical, in our view, for the Working Group to consider whether specific rate-setting frameworks are applicable only to certain categories of distributors, such as those at a specific stage in their transition, or those with particular cost structures, etc.

28. ***Board's Existing Schedule.*** The Board should make clear, in our submission, that the Board's current schedule for cost of service rate cases, built from 2nd generation IRM, cannot be allowed to constrain the choice of IRM model.

29. The best example of where this question might arise is British-style IRM, favoured by some as a method of responding to the individuality of each LDC. The problem with this method is that the starting point is a rebasing year in which multiple years of cost of service or quasi-cost of service information is filed. However, the first rebasing year for 3rd generation IRM is now, and

some of the applications are already filed on a different basis. Further, even those filing in 2008 may not have time, if a decision on 3rd generation IRM is made in April or May, to file multi-year cost of service in a timely manner for 2009 rates. In our view, if this model is the best to choose, then the Board's current schedule should be adjusted to accommodate it. Good solutions should not be rejected because they require something more than a formula based on single year rebasing.

30. ***CDM Spending and Impacts.*** It is clear that various components of CDM spending and impacts will have effects on distributor costs and revenues during the plan period.

31. In general, we believe that the cost impacts of CDM should be borne by OPA, unless they are for CDM on the utility side of the meter, in which case they are like any other efficiency initiative the utility carries out.

32. On the other side, the Working Group will have to consider all impacts of changes in average use, including those generated by CDM programs, by price effects, by changes in technology or standards, and other causes. Whether the adjustments necessary for each of these causes are combined, or separate, is something that the Working Group should address.

33. ***Distributed Generation.*** Another general impact is costs and revenues associated with rapid expansion of distributed generation in the province.

34. As a general rule, costs associated with distributed generation should be part of the commodity cost of electricity in the province. LDCs should be neutral in that respect, although their revenues to transmit distributed generation within or through their franchise area may create a downward pressure on distribution rates. The Working Group should consider methods of ensuring that DG costs do not inadvertently increase the costs borne by the distributor.

35. ***Service Quality.*** There is always a danger that an incentive regulation mechanism will incent distributors to cut corners on service quality in order to reduce costs. Our view is that the primary protection against this is enforcement by the Board of strict service quality standards as licence conditions.

36. That having been said, it is reasonable for the Working Group to consider whether service quality metrics can be built into the rate-setting framework, either as incentives, as part of the benchmarking exercise, or otherwise.

Conclusions

37. At this point, we believe that the Working Group should have the broadest possible mandate to consider potential approaches to multi-year ratemaking, and provide the most creative recommendations they can to the Board for implementation.

38. We thank the Board for the opportunity to participate in this consultation, and hope our input is of assistance. We are eager to continue to be involved as the process moves forward.

Respectfully submitted on behalf of the School Energy Coalition this 21st day of September, 2007.

SHIBLEY RIGHTON LLP

Per: ______________________
Jay Shepherd

ELECTRICITY DISTRIBUTORS

3RD GENERATION IRM (EB-2007-0673)

PROPOSED ISSUES LIST FOR WORKING GROUP

1. Applicability and Opt-Out

1.1. To what extent, if any, should distributors be required to use the methodology established by the Board in this guideline?

1.2. If the answer to 1.1 is that the methodology should be binding, what process should the Board undertake to ensure that the methodology chosen is appropriate?

1.3. To what extent, if any, should distributors be required to file specific information in their individual rate applications, whatever the methodology used to set rates?

1.4. In the event that the methodology is not binding, to what extent, if any, are intervenors entitled to challenge the use of the methodology when the distributor chooses to follow it?

1.5. What procedural safeguards should be established in individual rate cases to ensure that the best methodology is used to set rates for each distributor?

2. Choice of Multi-Year Ratemaking Framework

2.1. What are the multi-year ratemaking methods that the Board should consider for Ontario electricity distributors?

2.2. What are the implications associated with revenue caps, price caps, and other alternative multi-year ratemaking frameworks?

2.3. Are different methods suitable for different types or categories of distributors? If so, how should distributors be divided into categories for this purpose?

2.4. How should benchmarking of costs, service quality, and/or prices between distributors be used, if at all, to adjust rates during the plan period? What steps should the Board take, if any, to ensure that its benchmarking data and methods are useful in the rate-setting process?

2.5. How should service quality targets or metrics be used, if at all, to adjust rates during the plan period? What steps should the Board take, if any, to ensure that its service quality rules, data, and metrics are useful in the rate-setting process?

3. Term of the Plan

3.1. What is the appropriate term of the plan?

3.2. Should the same term be applicable to all distributors? If not, what are the criteria to be used to determine the appropriate term for any individual distributor?

4. Inflation Factor

4.1. Should the plan include an inflation factor?
4.2. If so, what type of index – industry specific or macroeconomic – should be used?
4.3. Should the inflation factor be based on actual or forecast?
4.4. How often should the inflation factor be updated?

5. Cost of Capital

5.1. Should ROE or cost of debt be updated during the term of the plan?
5.2. If so, how often?
5.3. On what basis (eg. actual, deemed, etc.) should the update be carried out?

6. X Factor

6.1. Should the plan include a productivity factor? If so, how should the productivity factor be determined?
6.2. Should any productivity factor be the same for all distributors? If not, what criteria should be used to set the productivity factor for each distributor?
6.3. Should the plan include a stretch factor? If so, how should the stretch factor be determined?
6.4. Should any stretch factor be the same for all distributors? If not, what criteria should be used to set the stretch factor for each distributor?
6.5. What cost and revenue changes forecast for the period of the plan should be taken into account in determining the appropriate X factor?
6.6. In particular, what adjustment, if any, should be included to reflect capital spending needs during the plan period? If an adjustment is appropriate, how should it be calculated for each distributor?
6.7. Also in particular, what adjustment, if any, should be included to reflect costs associated with distributed generation?

7. Average Use Factor

7.1. Is it appropriate to include changes in average use in the annual adjustment? If so, how should that impact be calculated?
7.2. Should all parts of changes in average use (utility supported CDM, government/OPA/gas utility supported CDM, price elasticity effects, etc.) be adjusted?
7.3. Should weather risk continue to be borne by the utility?
7.4. How should the impact of changes in average use be applied as between rate classes, and as between rate components within a rate class?

8. Y Factors

8.1. What Y factors, if any, should be included in the plan?
8.2. How often, and on what basis, should Y factors be cleared to rates?

9. Z Factors

9.1. On what basis, if any, should Z factors be included in the plan? What criteria should be used to determine if any event or circumstance qualifies as a Z factor?
9.2. Should there be materiality tests and, if so, what should they be?

10. Off-Ramps

10.1. Should any off-ramps be included in the plan?
10.2. If so, what should be the parameters?

11. Earnings Sharing

11.1. Should an earnings sharing mechanism be included in the plan?
11.2. If so, what should be the parameters?

12. Reporting Requirements

12.1. What information should the Board consider and stakeholders be provided with during the plan period?
12.2. What should be the frequency of reporting during the plan period?
12.3. What should be the process, if any, for considering the information provided, and what should be the role of the Board and the stakeholders?

13. Rate-Setting Process

13.1. Annual Adjustment

13.1.1. What should be the information requirements for the annual adjustment to rates?
13.1.2. How should rate changes be applied to rate components (fixed vs. variable charges)? Under what circumstances, if any, can a distributor apply rate changes in a different manner for a particular year?
13.1.3. What should be the process, the timing, and the role of the stakeholders in the annual rate-setting process?

13.2. New Energy Services

13.2.1. What should be the criteria for a distributor to implement a new distribution service that requires a newly designed rate?
13.2.2. What should be the process, the timing, and the role of the stakeholders in the distributor’s application to add the new service?

13.3. Changes in Rate Design or Levels

13.3.1. To what extent, if any, can distributors change the structure of their rates during the plan period?
13.3.2. In the event that the Board makes a determination to adjust cost allocation for some or all distributors, how will that impact the IR plan?
13.3.3. In the event that the Board makes a determination to adjust rate structures for some or all distributors, how will that impact the IR plan?
13.3.4. How should harmonization of rates within a utility or after a MADD transaction be dealt with during the plan period?

13.4. Non-Energy Services and Rates

13.4.1. Should the charges for these services be included in the plan?
13.4.2. If not, what should be the criteria for adjusting these charges, and what process should be followed, including information requirements and role of stakeholders?
13.4.3. What should be the criteria to obtain approval for new non-energy services, and what process should be followed, including information requirements and role of stakeholders?

14. Adjustments to Base Year Revenue Requirements and Rates

14.1. What adjustments, if any, should be made to base year revenue and/or rates to make them suitable as a basis for rates going forward?
14.2. How should any such adjustments be determined?