April 20, 2012

Board Secretary
Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto, ON - M4P 1E4

Via e-mail and by courier

Dear Board Secretary:

Re: Board File No. EB-2010-0377; EB-2010-0378; EB-2010-0379; EB-2011-0043 and EB-2011-0004 - Renewed Regulatory Framework for Electricity

The Electricity Distributors Association (EDA) is the voice of Ontario's local distribution companies (LDCs). The EDA represents the interests of 77 publicly and privately owned LDCs in Ontario.

The EDA greatly appreciates the Board's initiative to consider innovative approaches for the renewed regulatory treatment framework. The attached submission has been prepared in consultation with distributors at a joint meeting of the EDA Councils. The EDA generally supports the innovative approaches suggested in the Board staff discussion paper as helpful tools that will facilitate streamlined regulation of the industry with a few expectations as noted in the submission.

The EDA looks forward to working with Board members and staff in this regard.

The EDA would like thank the Board for giving the opportunity to provide comments on this important initiative.

Yours truly,

"Original Signed"

Maurice Tucci,
Policy Director, Distribution and Regulation
Attached: EDA submission

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EDA Submission on Renewed Regulatory Framework for Electricity

Multi-year Capital Investment Plans

The EDA supports incorporating approval of multi-year capital investment plans within the regulatory process. Once the investment plan is approved on the basis of prudency, the actual capital invested each year based on the plan should automatically be included in rate base and rates adjusted accordingly.

The need for approving multi-year capital investments is caused by the current limitations of the Incremental Capital Module and the recognition of a significant amount of assets reaching end of life in the near term and needing replacement in a planned and timely manner. Most importantly, this approach also avoids the rate shock caused by needing to seek approval for significant capital investments at cost of service proceedings. Also this multi-year approach will allow better pacing of capital investment plans and more efficient use of resources.

The EDA notes that distributors need flexibility to move the timing of projects within the overall capital investment plan timeframe to address unforeseen issues and manage resources. The EDA believes distributors also need flexibility to request the OEB to review their long term capital investments plans for, three years, five years, or other terms appropriate to the needs of their individual service territories and their ability to forecast their capital investment requirements.

The EDA proposes that there would be automatic annual adjustments to rate base based on prior year(s) actual capital investments. Based on individual LDC's ability to accurately forecast its multiyear capital investment plans, distributors could choose one of the following options:

Option 1

For distributors who are in a position to provide a thorough and a reasonable forecast of multi-year capital plans because of their circumstances, rate base adjustments could be made automatically every year during the term of the plan, based on the forecasted rate base, subject to a prudency test at the cost of service review. This approach would require reporting and the review of actual capital expenditures during the term of the plan. The review could be either an oral or a written hearing depending on the materiality of variances from the approved capital plans. The variance between the forecast and actual would be trued-up at the next cost of service.

Option 2

For distributors who are unable to provide a thorough forecast of multi-year capital plans because of their individual circumstances or circumstances beyond the distributor's control, rate adjustments would be made automatically every year during the term of the plan to accommodate increased capital spending based on a pre-approved rate adder. The rate base would then be trued up at the end of the plan's term based on a prudency test of capital expenditures at the next cost of service review.

The EDA notes that a greater number of distributors are likely to choose Option 2 in the initial years of the new framework. As distributors gain experience with forecasting investment plans, there may be more distributors transitioning to Option 1.

The EDA notes that a revised incremental capital module may still be needed in exceptional circumstances for unforeseen required capital additions. The criteria for module should be made more predictable and consistent.

With respect to the proposal to use experts to assess utility plans and audit utility planning processes to assess the utility's effectiveness in prioritizing and pacing network investment, EDA members believe that if such a proposal were implemented that it would be important that a selection of experts be available to allow distributors to select from. Distributors believe that if experts are used, they must be knowledgeable, impartial, independent third parties.

Regional Planning

The EDA agrees that where there is a need for integrated regional planning, it should include consultation with the OPA, IESO, transmitters and distributors. The regional planning should be driven by the goal of optimizing investments from a provincial perspective and for the long term.

The EDA agrees with the OPA that its role as an independent planner with no vested interest in the outcome allows them to arbitrate the competing interests and impartially determine the optimal plan for meeting regional requirements. The OPA has noted that it will consider conservation, local generation, transmission, and distribution solutions for the integrated regional plan. Once the draft regional plan is stakeholdered and revised, the final OPA plan can then be used to support leave to construct applications, or rate application filings which are based on the regional plan and include facilities identified in the plan.

Given that the OPA currently uses a 20-year planning horizon, the EDA believes the long term perspective for the Regional plan should also be 20 years. A 20-years timeframe also potentially allows transmission right-of-ways to be established prior to being overrun by urban development. The EDA believes that associated costs to establish these future rights of way should be treated as current period cost even though they are being held to allow for future assets serving future needs. Otherwise there would be little incentive to incur this cost on behalf of future customers who would receive the benefit.

The EDA also agrees with the OPA's view that regions cannot be defined by geographical, political, or distributor boundaries because the scope for the regional plan is based on electrical needs that transcend these boundaries. Consequently the regions defined in the regional planning studies should be on a plan-by-plan basis, based on need.

The OPA has noted that the current transmission cost allocation rules using the cost causality principle has not been resulting in optimal planning solutions or efficient outcomes as was originally intended. When transmission lines are identified as the optimal solution for the long term, the issue of affordability and fairness is raised as a concern because transmission facilities are expensive and lumpy long term investments (e.g. a 230 kV line can serve up to 400 MW of load).

It has been also noted that there are legacy issues where some regions are benefiting today from long term transmission investments made in the past under a pooled model. Areas growing today needing new transmission investments are required to pay upfront, based on the current rule (TSC 6.3.6) that distributors that trigger the investment are required to pay a capital contribution. The main concern with the affordability issue is obtaining the funds for the upfront payment and more importantly the significant distribution rate impacts from recovering the carrying costs for the large capital contribution. To avoid this prohibitive rate impact, distributors are incented to pursue short term solutions to defer the in-service date of the transmission investments, and in effect pass higher costs to future customers.

The EDA has discussed with members the proposal to pool basic transmission line connections approved in the regional plans by the OPA. The EDA agrees that transmission connection lines often also serve other areas at times and agrees that pooling will be more equitable and solve the affordability issue. As a result the EDA believes that the pooling of transmission line connections should be pursued as a solution which would result in a more equitable cost allocation. The EDA notes that for direct customers that would continue to pay upfront for line connections, consideration should be given to keeping them whole from this change to the cost allocation.

The EDA also agrees that any requests for facilities that exceed the requirements of the approved OPA plan should be deemed premium service and not recovered in the line connection pool. This would include undergrounding facilities where a feasible overhead option exists, other modifications and improvements beyond existing standards or code requirements. The potential list of items considered premium service could be established jointly by the transmitter, the IESO and the OEB.

<u>Regulatory Streamlining</u>

The EDA believes work is required to further streamline the regulatory process. Changes to the current IRM model should also be made to better reflect change in rate base, industry circumstances including industry inflation, and a more realistic target for productivity improvements. Many EDA members believe the peer groupings methods for determining stretch factors could be improved. Continuing to have both a productivity improvement factor and a stretch factor will lead LDCs to postpone maintenance or asset replacement as revenues will not be sufficient to cover those costs.

With respect to the cost of service application process, the EDA believes that more standardized templates for cost of service applications and IRM applications should be developed to assist in clarifying reporting requirements, improving consistency in reporting and improving the quality of information provided, while reducing the time and costs of the current review process. Benefits will also be obtained from harmonizing information requirements for rate applications and record keeping requirements.

With respect to 'outcomes' based approach to regulation, the EDA proposes establishing key standards/metrics for service to measure performance of a utility which in turn could also be utilized to review rate applications. These standards should recognize the diversity between distributors and as such the standards should not be the same for every distributor. The EDA suggests that the standards and metrics should be similar to the ones used by distributors themselves for self appraisal. Using these standards and metrics should allow for a proportional approach to review distributors' rate applications. If set performance metrics are achieved by a distributor, the scrutiny of its rate application should be less rigorous.

It is recognized that revising the IRM, establishing templates and standards will require considerable resources, access to information, time, effort on behalf of all stakeholders and the OEB, and as a result this work needs to be prioritized and staged.

The EDA recommends that the OEB staff should lead and pre-screen interrogatories received from intervenors in distribution rate applications in order to avoid duplication of work. In addition, the OEB should grant intervenor status only to parties who clearly demonstrate that they represent a constituency within the service area of a distributor. Further, the OEB should consider setting caps for cost awards to incent stakeholders to focus on more material issues in order to reduce overall regulatory costs.

Bill Mitigation

The EDA believes that adopting multi-year capital investment plans will facilitate rate mitigation. EDA members support continuation of a pre-defined threshold for bill impacts related to rate increase attributable to proposed changes to distribution rates. Distributors should not be expected to provide a mitigation plan for increases resulting from other components of the bill for which they have no control which is approximately 78 per cent of the bill to customers.

Smart Grid

The EDA believes that information available through smart grid technologies will improve the system reliability and that it is utility best practice to continually enhance technologies and systems as part of a distributor's asset management and renewal process. Some technologies, such as electric vehicles or distributed renewable generators could reduce reliability in the short term until addressed by certain smart grid investments. In addition it should be noted that reliability results may appear to decline as outages are more accurately tracked through smart grid monitoring.

Further, the EDA recommends treating smart grid capital investments integral to all distribution investments. It is expected that these smart grid investments will be embedded in distributor's capital investments to revise and update plant. Only those technologies that are truly breakthrough innovations to address changing use and dynamics in the distribution system should be treated as standalone smart grid capital investments.

Next Steps

EDA proposes that the OEB establish working groups to further develop the major proposed changes requiring more time and effort. The scope for each working group should be defined with terms of reference and the working groups should be assigned with the responsibility to recommend to the OEB on how to implement the proposed changes and identify issues that require further study.

The EDA believes certain working groups should also be established to address the more pressing issues on an interim basis, in time for 2013 distribution rate applications. These interim issues include making suggested changes to the incremental capital module and identifying changes to the transmission system code to address regional planning. These interim issues should be documented and issued by the end of 2012, as rate applications will be well on their way to completion by that timeframe.