AMPCO

July 7, 2009

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

Re: Staff Discussion Paper on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors (EB-2009-0152)

Dear Ms Walli:

AMPCO supports the Board's efforts to review its regulatory policies and processes from time to time to ensure necessary investments are made when needed and in manner that is fair both to customers and to asset owners. The current staff discussion paper provides a useful starting point for this process; it does not however put forward solutions that are acceptable to power consumers in Ontario. More work is needed: to define the problem, to articulate options, to develop a proper basis for resource planning and to evaluate and measure costs and benefits.

AMPCO appreciates the breadth and pace of the government's energy policy agenda for Ontario. As well, we understand the appeal of perceived rapid technological change arising from the combination of advanced meters and the application of information technologies to the electricity grid. Finally, we recognize the administrative complexities arising from the legacy issues and transient nature of Ontario's long-term approach to restructuring the electricity sector. We do not agree, however, with the basic supposition of the paper that Ontario's current infrastructure challenge is unique and without precedent and that (because it's new and unique) existing regulatory principles and mechanisms are inadequate or inappropriate. Given the trust placed in the Board by customers, a clear and strong case must be made before these long-established principles should be set aside. Such a case has not been made.

While the paper compares how FERC is addressing issues in the United States with how the Board might address similar issues in Ontario, it fails to acknowledge fundamental differences between the regulatory environment in which FERC operates in the United States and in which the Ontario Energy Board operates here. The Ontario Energy Board Act, 1998, provides ample opportunities for transmission and distribution companies to propose new investments and provides appropriate powers to the Board to review and approve them. As well, the Board has much latitude and recent experience in alternative and stream-lined review processes to reduce the burden of regulation for investors and customers alike.

There is no basis for an assumption that the current regulatory framework needs to be changed in order to accommodate changing risk assessment criteria established by banks or investors. Decisions of this Board consistently have provided transmitters and distributors with a very low risk business environment. There have been no business failures in this sector nor have there been any situations where the Board has declined to allow cost recovery for prudently incurred investments. The risk

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appetite of banks and investors will wax and wane as the economy cycles up and down. The Board must take a longer view.

The paper suggests a huge new challenge without making much attempt to define its scale or scope. A very large and urgent problem may justify a response different than one which can be met on a reasonable schedule with manageable investments. Whatever is provided for by the Green Energy Act, 2009, its regulations or direction from the Minister, Ontario is not going to be swamped with renewable energy and distributed generation projects tomorrow. However many projects investors propose, there will be other limits on resources that control the pace of development. The conversion of Canada's communications infrastructure from copper to fibre optics has been underway for over 35 years and remains incomplete. A sense of urgency is good but cannot justify expediency. In the telecom example, at least the risks created by the irrational exuberance of early investors were borne by those investors. We wish we could say the same for the risks that will be created as enthusiasm surges for new energy technologies in Ontario.

The paper suggests that some types of investment are qualitatively different than traditional utility investments, either because of an un-estimated quantitative challenge (i.e., the amount of money to be raised is huge compared to business as usual), or because they present a different investment risk or perhaps because they are more necessary in some way. It is not apparent that any of these conditions exist. Allowing different (i.e., more lax) regulatory treatment for projects that may be otherwise technically quite similar but which are perceived to serve a different purpose would seem to invite gaming on the part of applicants to secure the best regulatory treatment for specific projects, regardless of the primary driver of need.

The government may want to accelerate investment in new or renewable technology. That is its prerogative. The Board is being asked to facilitate the government's agenda. As it does this, however, the Board's basic duty has to be to consumers. The Act not only makes this explicit, it also lays out a framework by which this can be achieved: maintaining a financially viable sector, promoting efficiency, and protecting the interests of consumers with respect to price, reliability, etc. In plain language, electricity is to be delivered to consumers in a way that is safe, clean and efficient. If it's not being done at the least cost, then it cannot be efficient. AMPCO's most significant concern comes from the premise in the paper (and in other statements of the Board) that the least cost standard is to be relaxed. Whatever the basis for this suggestion, it represents a serious threat to the trust customers have placed in the Board to protect their interests.

Our detailed comments are attached. Please don't hesitate to contact me if there are any questions.

Sincerely yours,

Adam White
President

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Comments
Staff Discussion Paper on
The Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors

OEB File: EB-2009-0152

Responses to Specific Questions:

1. **Should the framework and mechanisms identified in this Discussion Paper apply to other rate-regulated entities? If so, why and for what types of projects?**

It would seem likely that, at some point in time, The Board will be instructed to promote natural gas technologies that are determined by the government to be beneficial or to direct specific measures by energy service providers.

2. Are there other broad classifications for investment, beyond "routine", "non-routine incremental", and/or "GEGEA-related" that should be considered? If so, what are they and what are the specific underlying drivers for such investment?

Lacking good definitions for such terms as "routine" and "non-routine incremental", it is difficult to see the value of these definitions. For example, an investment to serve a new subdivision in Vaughan would be arguably routine, but probably "non-routine incremental" if the same requirement occurred in Hearst. Similarly, conversion of a distribution feeder from 4.16kv to 27.6kV could be routine in one circumstance, non-routine in another and potentially GEGEA-related in both, since it could enable an increase in renewable generation while simultaneously reducing system losses.

The use of broad definitions to support regulatory categorization of specific projects or investment plans is problematic. If regulatory treatment is to be differentiated among specific projects, then precision of categorization becomes important in order to properly protect the interests of consumers. The Board may be best served by defining a narrow set of technical descriptions and planning criteria for projects that fit in any categories to be considered for special treatment.

Even if Board staff were perfectly prescient in defining categories of projects, the Board inevitably will have to deal with investments with joint costs and benefits. These kinds of projects are intrinsic to system or network investments, by their very definition. And in a way, these kinds of projects are ideal, since they simultaneously meet a combination of needs and requirements.

3. Should the mechanisms identified in this Discussion Paper apply to the recovery of costs incurred by electricity transmitters or distributors for investments to accommodate renewable generation or to develop the smart grid, or both? Why or why not?

There may be others, but there seems to be two reasons why alternative regulatory treatment for a specific investment would be required or justified:

1. It can be conclusively demonstrated that, without alternative regulatory treatment, these investments would not be made. Prior to the Act being introduced, this was the rationale for the hybrid approach to connection cost responsibility for transmission "enabler" lines. Since the Act now makes it clear that transmitters and distributors must make plans for such investments and carry them out (subject to Board approval), it is hard to see how these investments would not be made, unless perhaps the transmitter or distributor could establish that they could not otherwise raise the money to finance the investment.
2. It can be demonstrated that the alternative regulatory treatment is in the best interest of customers; i.e., that the long term cost of the investment is reduced by applying the alternative treatment. For example, alternative treatment may enable the applicant to secure lower cost financing or may reduce risk such that a lower ROE would be justified. The discussion paper does not appear to contain the type of analyses needed to support this argument, or to discriminate between the alternative treatments with respect to long term cost to customers. On page three of the Discussion Paper, specific reference is given to the Hempling and Strauss paper prepared for the National Regulatory Research Institute. After identifying the possible incentives that regulators could employ, Hempling and Strauss identify the considerations the regulator should take into account before approving such incentives. The first is that"any pre-approvals are granted ***only*** upon a supported showing that regulatory action will benefit customers"[1] (emphasis added).

AMPCO respectfully submits that, since transmitters and distributors in Ontario do not have discretion in making these investments, alternative treatment for any investment can only be justified if it clearly and demonstrably benefits customers.

4. Should the mechanisms set out in this Discussion Paper be applied to infrastructure investment if the cost of the investment is potentially recoverable through a Province-wide cost recovery mechanism? Why, or why not?

Recovery through a province wide mechanism does not alter the reality that the cost of the investment will be paid for by customers. This suggests separate considerations: (1) is the investment needed and likely to be prudent? (2) What is the best way to recover the costs from customers? Whether a decision is taken to collect revenues in a particular way

[1] Scott Hempling and Scott H. Strauss, *Pre-Approval Commitments: When and Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects,* Nov 2008. Page iv

outside a Board process should have no affect on the Board's considerations with respect to need and prudency.

5. Should the mechanisms set out in this Discussion Paper be applied to infrastructure investment in smart grid technology while it is at an early stage of development and where governing standards are yet to be developed? Why or why not?

No. It is inadvisable in any circumstance to promote investment in immature technologies that lack even a clear functional description, let alone technical standards. Absent these basic requirements, the Board should have no basis for confidence that such investments will become used and useful, or meet the requirements of the Act.

Board attention in the near term needs to focus on the functional definition, technical requirements and standards issues before contemplating large scale implementation. While imperfect, the development of the smart meter initiative may provide useful guidance in terms of lessons learned.

The current state of the smart grid concept appears to focus primarily on issues from a utility's perspective, such as integration of distributed generation, reductions in losses, control of voltage and power factor and improved response to distribution system component failures. The functional role of the smart grid with respect to serving customers is also a part of the definition in Bill 150, i.e., "expanding opportunities to provide demand response, price information and load control to electricity **customers** ". In AMPCO's view, the inclusion of direct customer benefit in the Act's definition is a clear signal regarding the functional definition of the smart grid. Before the Board approves, much less incents new smart grid investments, it should ensure that such investments meet the definition of a smart grid as described in the Act.

An additional consideration is that the Act defines the smart grid in the singular and does not appear to contemplate a large number of potentially incompatible smart grids or a set of smart grids with differing abilities to meet the intent of the Act.

6. Should "routine" investment made by a transmitter or distributor be eligible for one or more of the alternative treatments identified in this Discussion Paper? Why or why not?

If it can be established by evidence that alternative treatment of routine investments would benefit customers, then such treatment should be considered.

7. Should the mechanisms identified in this Discussion Paper be presumed to apply to certain types of investments (for example, to accommodate renewable generation)? Why or why not? If so, to which investments?

As stated above, the only rationale we can see for these mechanisms is if they can be demonstrated to benefit customers. If it is generally true that alternative treatments can benefit customers, there does not seem to be a particular reason why such treatment should be limited to an arbitrary class of investments, unless these investments present a different risk profile that establishes the need for alternative treatment. Since the Board has traditionally provided a very low risk investment environment for distributors and transmitters (witness the decision in EB-2006-0501 re the Niagara enhancement project), it is difficult to see what would drive such differentiation of risk.

If the conclusion is reached that certain types of investment should consistently receive an alternative treatment, then the Board needs to establish strict, not vague, conditions that must be met to qualify for presumption. For example, a proposal that claims to be to accommodate renewable generation should be supported with evidence, such as a connection agreement that supports the general case for the project as well as its specific technical parameters.

8. Should the Board be more prescriptive as to which type of investment may qualify and which will not? If so, what criteria might the Board use to make a determination on which type of investment would qualify?

The Board may wish to consider whether specific types of investments present risk profiles different from other projects, to the extent that the distributor or transmitter might incur different borrowing costs for such projects. This situation is difficult to envisage and probably does not exist. However, if it did occur, then differential treatment may be justified in order to benefit customers by either lowering borrowing costs or reducing ROE to a lower level than would otherwise be the case.

9. Should the Board permit applicants to request confirmation from the Board that prudently-incurred costs associated with any abandoned projects will be recoverable in rates if such abandonment is outside the control of management? Why or why not?

Yes. Stuff happens, and one benefit for customers of the conservative regulation in Ontario is a low business risk for transmitters and distributors with respect to eventual cost recovery for approved investments.

10. Should the Board allow for full or partial CWIP to be placed in rate base during the construction of transmission facilities to accommodate the connection of renewable generation and/or develop the smart grid? Why or why not? Should the Board allow this particular treatment for distribution investment? If so, on what basis?

The practice of placing CWIP in rate base violates the principle of inter-generational equity and should not be considered unless it can first be shown to produce benefit to customers overall. Given current low financing costs, it is hard to see why this mechanism should be considered. There is no apparent reason why distribution and transmission should be treated differently in this regard; transmission investments may be substantially larger, but they are also being made by larger entities.

AMPCO is also concerned that placing of CWIP in rate base may encourage transmitters and distributors to seek more rapid expansion of their rate bases than is necessary. The current policy of not allowing cost recovery to begin until assets are declared in service acts to provide a disincentive to overly rapid investment. This is good, since such investments impose long term obligations on customers.

AMPCO respectfully suggests that, if the Board wishes to consider placing CWIP in rate base, it first secure an independent analysis of the benefits and consequences of such a shift, using realistic expectations of T&D investment requirements in Ontario. Accelerated cost recovery should also require a matching advancement of depreciation; i.e., once cost recovery for an asset begins, so does depreciation. That is, any asset or portion of an asset deemed eligible for cost recovery should also be deemed to be in service.

11. Should the Board allow depreciation to be adjusted to match a contract term or the useful life of the connecting renewable generation facility? Why or why not?

No. Such a change would assume that the renewable generation facility would be decommissioned at the end of the contract term. More likely, the facility would be refreshed and continue in operation, with the assets serving it continuing to be used and useful.

12. In light of a legislative context in which the Board may mandate infrastructure investments, are incentives necessary or appropriate in Ontario?

No, unless the test of customer benefit can be clearly met.

13. If the Board were to provide for incentives, should it allow project-specific ROE? If so, should the Board consider adopting a range rather than a specific adder? Further, how might the Board determine an appropriate range or ROE adder?

No. Such a move would open up incentives for gaming in a variety of ways. It would also disadvantage applicants that did not have project opportunities in their jurisdiction. If a project requires a specific (presumably higher) ROE, this would appear to be an admission that a rationale and objective observer would have doubts about the advisability of the project.

14. If the Board were to provide for incentives, should it allow project-specific capital structures?

No. This would make regulation much more complex and introduce incentives that could induce perverse behaviour.

15. What other alternative mechanisms, if any, might the Board consider be made available to applicants? Why?

As noted in AMPCO's response to question #13 above, no convincing reasons for any alternative mechanisms in Ontario have been presented.

16. In addition to the potential considerations identified, are there any other matters that the Board might consider in making decisions on requests for alternative treatment?

Requests should establish benefit to customers, perhaps for example, if borrowing costs or ROE could be reduced.

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17. What performance conditions, if any, should be established?

AMPCO believes the Board currently has the authority and processes to verify that investments have been prudently occurred and competently managed. Cost recovery can and should be denied when these conditions have not been met.

18. Are the reporting requirements suggested appropriate and adequate?

No. To be meaningful, project schedules must include not only the pace of expenditure, but also what is expected to have been accomplished by milestone dates. This is difficult and requires the ability to verify on site. Checklists that appear to verify progress are seldom useful; most post mortems on large projects that fail reveal that the projects start to go off the rails well before being declared behind schedule. For this type of process to be effective, the Board will need to have its own project monitors.

Rather than attempt to manage such projects, the Board would be more effective by simply not allowing cost recovery when projects fail due to lack of proper management. Such denial of cost recovery could be the subject of a hearing, if the asset owner requested it.

19. Are there any other conditions that the Board might need to establish in relation to an approved alternative mechanism referred to in this Discussion Paper to protect ratepayer interests?

AMPCO's position is that any use of alternative mechanisms should be demonstrably beneficial to customers, or at an absolute minimum, neutral with respect to customer impact.

20. Beyond those already reflected in the Board's existing filing guidelines (e.g., the Z-factor test of causation, materiality, and prudence) and in the Board's jurisprudence, is there a specific test that successful applicants should be required to meet in order to be granted an alternative treatment?

See previous comments.

21. Are the Board's existing filing guidelines for electricity transmitters and distributors sufficient to support the case-by-case approach discussed in this Discussion Paper? If not, what additional information should an applicant provide?

A case by case approach should require a higher evidentiary requirement than transmitters and distributors have been accustomed to when seeking routine program approvals. For example, as an intervenor, AMPCO would want to examine the financial and technical parameters of a proposed project investment, as well as evidence that the project is required. An evidentiary requirement similar to that of Section 92 may be a good starting point.

22. Should the process for applying for the regulatory treatment of infrastructure investment discussed in this Discussion Paper be more prescriptive (e.g., the timing, sequencing,

and/or combining of applications)? Should it be combined with the process for approving infrastructure investment plans? If so, why and in what way?

Probably, at least until the applicants and the Board have a clear view of what the project and program requirements will be and at what pace investment will be required. At the same time, all parties must remain cognizant that the amount and timing of investment requirements will not be analogous to the smart meter initiative. For example, the challenges associated with smart grid development and investment will be different for large distributors than small and more challenging for distributors that lack SCADA systems or control centres. There may also be a need to recognize the significant differences among distributors with regards to the limited pool of technical expertise available in an evolving technical environment.

It would be best if planning approval and investment approval could be coordinated to reduce the regulatory burden on stakeholders. The Board may wish to consider development of a process that first can be tested with a sample of distributors to discover what the coordination requirements may be.

There are currently three processes for approving infrastructure investment plans; 3rd IRM without the capital module, 3rd IRM with the capital module and Cost of Service Review. Because the GEGEA type of investments are, for the time being, assumed to be outside of what a transmitter or distributor would normally spend to serve it customers, it seems appropriate that these projects would always be part of a 3rd IRM application in the capital module, or in a Cost of Service application.

Smart grid development particularly should be amenable to treatment in the capital module or as part of a COS application. The implementation of a smart grid will take several years and should follow a predictable project schedule.

Similarly, other projects that relate generally to accommodation of renewable generation (e.g., line capacity upgrades, system modifications to handle two way power flows) should have relatively predictable timelines and thus fit into existing process for improving investments.

It also seem likely that a numerical majority of distributed generation projects in the future will be of more modest size than the 10MW average capacity in projects that have occurred to date. For small but more frequent projects that will have short implementation timelines and modest impact on the distribution system, "blanket" investment accounts could be pre-approved for the distributor as part of its overall investment plan. AMPCO would suggest that, given the uncertainty in demand for such connections, any such accounts be closely monitored to learn how volume and unit costs develop.

A significant number of the larger projects, with presumably larger investment costs, should also be foreseeable to the time of a distributors or transmitter's periodic rebasing or COS application. These could also be readily integrated into the normal investment approval and revenue requirement application process. Hydro One has set some precedent for this type of treatment in EB-2006-0501, when it sought approval to budget for some projects prior to Section 92 applications.

The reminder will be relatively large projects that were not anticipated at the applicant's most recent COS or rebasing application. There may be two ways to handle this. First, the Board could set a materiality cost limit below which the applicants costs would simply be deemed to be prudently incurred project costs, for retroactive confirmation at its next application, This is somewhat risky for customers and the applicant, but should be manageable if the materiality threshold is kept reasonable and the rules are clear. For those projects that require large and unanticipated investments, approval may require a separate hearing. If the evidentiary criteria are clear and complete, written hearings may suffice.

23. Should the Board permit applicants to seek approval prior to construction of the facilities to determine whether the facilities qualify for the requested alternative treatment(s)? Why or why not?

As repeatedly noted above, AMPCO is not yet convinced of the need for special regulatory treatment of GEGEA related investments. However, if a case can be made for such treatment, it would seem that prior approval would be important to reduce the risk to the applicant.

24. What are the implications, if any, of using the single-issue rate review process?

A single issue review process should only be entertained if the proposed project can be clearly separated from the other investment programs of the distributor or transmitter. If there are overlaps between the proposed project and the existing "business as usual" work program, then single issue review should not apply. For example, a smart grid project that involved replacement of exiting voltage regulator or switch assets should affect other aspects of the applicant's work program, such as maintenance of this class of equipment. In such a case, intervenors would naturally object to not having the base work program also reviewed to ensure that all possible economies were being pursued.

25. Is the use of rate riders an appropriate approach for implementing rate adjustments associated with the alternate treatments identified in this Discussion Paper? Alternatively, should the adjustments be made directly to base rates?

Generally, rate riders should enhance transparency and be temporary. Rate riders may be appropriate for GEGEA related investments for applicants that are in a multi-year IRM regime and do not wish to rebase in order to meet the requirements of the Act. However, it is hard to see the justification for riders when an applicant is filing a cost of service application, or during rebasing. In short, AMPCO agrees with staff on this question.

26. Should the Board allow applicants to seek approval of multi-year rate riders or should the applicant be required to apply every year to adjust its rate riders to reflect any changes in project costs?

A rate rider associated with smart grid investment may work, since this could be planned as a multi-year project (once functional requirements and technical standards are known).

Some time should be allowed for all parties to accumulate experience before deciding on whether annual adjustments to rate riders are a useful idea.

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