AMPCO

May 5, 2014

Ms Kirsten Walli
Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor
Toronto, Ontario M4P 1E4

Re: Staff Discussion Paper Electricity Distributor Efficiency related to SAAs and MAADs Rate Making Policy Review
Board File No. EB-2014-0138

Dear Ms. Walli:

In response to the Board's notice dated March 31, 2014, attached please find AMPCO's comments in the above matter.

Please do not hesitate to contact me if you have any questions or require further information.

Sincerely yours,

Adam White
President
Association of Major Power Consumers in Ontario

Encl.

Association of Major Power Consumers in Ontario
www.ampco.org

65 Queen Street West, Suite 1510
Toronto, Ontario M5H 2M5
P. 416-260-0280
F. 416-260-0442

EB-2014-0138 Staff Discussion Paper

Review of the Board's Policies and Processes to Facilitate Electricity Distributor Efficiency: Service Area Amendments and Rate-Making Associated with Distributor Consolidation

AMPCO Comments

May 5, 2014

GENERAL COMMENTS

While AMPCO believe consolidation in electricity distribution is both desirable and inevitable, AMPCO also believes strongly that the interests of consumers need to be protected and that the burden of protection necessarily falls on the Board.

The Board should be fully prepared to let acquiring or merging distributors make mistakes and ensure that any consequences fall on the shareholders, not the customer.

This means the Board should not allow acquiring parties to shift the risk and cost of acquisition onto their customers. MAAD and SAA transactions should be demonstrably neutral or positive with respect to the interests of the affected customers.

Unfortunately, current policy with respect to incentive regulation provide numerous opportunities for distributors to increase the rate burden on customers after consolidation, mainly through use of the incremental capital module and custom IR.

SERVICE AREA AMENDMENTS

"Open for Competition" Approach:

Benefits
In principle, a truly open competition environment should provide the best result for the customer and the best distributors. The benefit to customers should derive from being served by the lowest cost supply option.

Implementation
This is not a simple discussion, however, for several reasons. Here are a few:

- The simple fact that a line exists alongside the location for a new building(s) does not mean that the service requirement will be within the capacity of the existing LDC facilities. If significant new investments are required to serve the customer, the question of opening the service to competition should be asked.

- The ultimate service requirement of a new development may cross service areas, even though the initial development may be entirely contained in one distributor's service area.
- The Board's obligation with respect to protecting the interest of consumers may be difficult to discern when the initial and ultimate customers are different, as happens with subdivision development.

To cut through the complexity of this issue, a few simple guidelines may be applied.

First, SAA considerations should be restricted to contiguous distributors, only in locations where the SAA would not result in a distributor having a non-contiguous service area. This may sound obvious, but there may be cases, such as subdivision development in rural areas, where a nearby LDC would want to serve the new customer(s) without taking responsibility for those customers between the new development and its current service area.

Second, the question of whether or not an SAA is to be considered should be left to the initiative of the Applicant Distributor. Practically, this will reduce the Board's burden to considering only SAAs where there is Applicant interest.

Third, the Board should allow competition for new customers anywhere an interested Applicant Distributor comes forward AND the additional service requirements necessitate material upstream investment in either the Applicant or Incumbent Distributor's system, or the regional transmission system.

Section 28 of the Electricity Act imposes an obligation on distributors only when two conditions are met: proximity of lines to the new building and the written request of the customer. This wording is overly simplistic given the realities of distribution systems and this is presumably the reason Section 28.1 was added; namely to allow for additional regulations to cover those situations where the Section 28 wording would lead to an inefficient result. In brief, once the Board has chosen its preferred approach to this matter, it would seem reasonable to request establishment of a regulation under Section 28.1 to give the new policy effect.

Offers on Fair and Reasonable Terms
The Board has policy and procedures in place to ensure customers receive fair and reasonable connection offers. There will be the potential for situations where the connecting customer would be assigned to the service territory of a higher cost distributor. Where this prospect exists, the Board should consider seeking input from the affected customer(s), if possible.

On a practical level, the Board could simply not allow SAAs that would materially disadvantage the new customer. Effectively, this recommendation would produce decisions similar to what would occur where the customer has a free choice of distributor.

Incumbent Distributor Considerations
It is hard to see any materially negative impact on an Incumbent Distributor or its customers if

it fails to acquire a new customer(s), other than the theoretical lost opportunity to spread its costs over a larger base. If the needs of customers are important, then it should normally be the needs of the connecting customer that are the primary determinant of service provider. Arguments with respect to the effect on other customers are usually difficult to validate in practice and have the potential to mire the decision process in hypothetical claims.

Municipal Planning and Municipal Boundaries

Municipal plans should be important in assessing the merits of an SAA decision; to the extent they are reliable. Municipal boundaries should not be relevant to an SAA decision. The remaining match of LDC service areas and municipal boundaries is an artifact of the political history of electricity distribution in Ontario and should have no impact on future distribution system design.

Analytical Criteria

Distribution costs in Ontario are largely driven by the cost of the assets providing distribution service and the cost of operating and maintaining those assets. Since the Board adopted the policy of setting distributor's earnings primarily on the value of its assets, there has been a marked increase in the proportion of distribution costs driven by capital investment. This is an issue the Board should address, but for this discussion the point is that it is asset cost that increasingly drives consumer cost.

Hence, the most important criterion for determining whether an SAA is to be approved should be the asset investment required to serve the new load. This should include any upstream cost of changes to the transmission system, where the new load may require such.

In selecting the minimum asset investment required, The Board should require and test estimates from the two distributors as well as the transmitter. Proposed investment costs should be consistent with costs implied in recent applications. Moreover, the successful party should be held to its estimates, in terms of the value of assets it is allowed to place into rate base. Any overage beyond a reasonable tolerance (collar) should be at the risk of the distributor's shareholders, not its customers. Placing this type of strict requirement on the parties should help reduce the chance that a high cost distributor would be preferred over a low cost distributor.

The evidence requirement should consist primarily of a capital plan for the connection requirement, both gross and net of customer capital contributions.

The Board may wish to consider using the services of an independent consultant to assess the estimates provided by Incumbent and Applicant Distributors in contested SAAs.

One other criterion that may be considered is the rates and rate history of the two distributors. Where they differ significantly (say, by more than 15%), this may argue for selecting the distributor with the better (lower) rate history.

Sector Economic Efficiency
Other than labour productivity, the key concern for sector economic efficiency should be the rising level of capital investment serving less demand. As noted above, minimizing the required capital investment to serve new load is likely the most effective way to decide an SAA application.

Timeliness
Generally, contested SAA applications only arise where the number of customers and/or the size of the prospective load are significant. In these cases, customer planning horizons tend to be more than a year out, and usually two or more years. The Board can set a reasonable expectation for accepting and hearing an SAA application (say, one year) and not expect to be an impediment to the project driving the application. For smaller or uncontested applications, especially those not affecting the transmission system, an expedited process should be available.

RATE-SETTING ASSOCIATED WITH MAADS

Rebasing the Deferral Period
Rebasing periods beyond five years should not be necessary. In unregulated sectors, the typical payback period for M&A activity is three to five years, which fits well with current OEB policy. These periods are driven by the understanding that M&A business cases always carry significant risk, and using a shorter payback period helps to mitigate that risk.

It should also be kept in mind that, even after the deferral period is complete, there will be ongoing opportunities to discover and implement productivity savings to a greater extent than were available to either of the predecessor organizations. While rebasing should in theory capture this opportunity, it can never do so completely, to the benefit of the consolidated organization's shareholder. Simply put, savings should continue to increase faster than the regulator can anticipate if the new entity is focussed on achieving them.

For distributors, the M&A risk and therefore the payback horizon requirement should be substantially less than in other sectors. After all, these are mergers not of companies in related businesses, as is usually the case in the private sector. These are mergers and acquisitions of virtually *identical* companies, with the same processes, product, regulator, tax jurisdiction, technology and often even labour unions. Even their customer bills, performance measures and complaint processes are virtually identical. If an Ontario distributor cannot put together an M&A business case that will at least break even in five years on an NPV basis, then the proposal is probably not worth considering.

There is also an arbitrage risk that should not be ignored if the deferral period is extended. Selling utilities would know that the buyer has a longer time to recover transaction cost and can thus be reasonably expected to demand a higher price, which inevitably will end up being paid by customers.

Another issue is the moral hazard that arises when a longer deferral period essentially reduces the business case risk for the purchasing utility. In turn, this reduces the incentive for due diligence by the purchaser. A longer deferral period would effectively transfer risk to the customer while increasing benefits for the purchaser.

Firmness of Rebasing Period

Per the above, AMPCO does not believe that rebasing periods longer than five years should be entertained. Should the Board decide otherwise, the question follows of whether or not the purchaser should be held to its request.

It is accepted that there may be exceptional circumstances whereby either the distributor or the Board should trigger the rebasing process. For example, if the general utility financial environment changes from one of low inflation to high inflation, some form of rebasing or adjustment may be needed for all distributors.

Generally, if a distributor asks up front for a specific rebasing period, it should be held to this period and also protected against later having it shortened against its wishes. If the distributor wishes to have the opportunity to revisit the deferral period after the transaction, it would presumably be because it had guessed wrong about its ability to profit from the transaction and wanted to transfer the (negative) consequences to its customers. As with the issue of an extended deferral period, allowing such recourse would create a moral hazard by transferring transaction cost risk to the customer while the distributor`s shareholder retains the profit opportunity of the original business case.

Should the Board wish to entertain some flexibility in the deferral period, this flexibility should be predefined and symmetrical. Such a process would mirror the collar approach to large capital projects taken in other jurisdictions, similar to the use of a dead band in determining the need for an ICM.

Custom IR

The purpose of the Custom IR option has been, to our understanding, to accommodate unusual capital requirements in terms of timing and magnitude. It is possible that there will be MAAD situations where one or both (all?) of the distributors involved in the transaction are on a Custom IR option.

To avoid the potential for a distributor to shift the cost of a MAAD transaction onto customers, access to custom IR should be severely restricted to only those situations where other driving factors justify its continuance (e.g., completion of a large infrastructure program that had been previously approved but not finished in the existing Custom IR period).

Normally, Custom IR should no longer be available once its term is complete. This should preclude distributors from using Custom IR to overhaul the acquired distributor assets at customer expense, when the need was not identified in the original MAAD application. Similarly, an acquiring distributor should not be allowed access to the incremental capital module mechanism for the acquired service area for a period of at least five years after acquisition, unless the need for the ICM is identified in the original MAAD application.

Custom IR Merits and Risks

As discussed above, AMPCO believes access to Custom IR would essentially provide acquiring distributors the opportunity to shift transaction and other known costs away from the utility and onto customers.

Modified ICM Merits and Risks

The difference between a modified ICM and Custom IR seems at best a labelling distinction. Customers should not be funding the transaction cost, nor should they become exposed to "surprise" investment requirements after the transaction is complete. The onus must be on the acquiring company to identify all near and mid-term requirements flowing from the MAAD transaction and incorporate these into the business case, including the price it is willing to pay for what may often be harvested assets.