EDA

The Voice Of Ontario's Electricity Distributors

August 24, 2007

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

*Via email to BoardSec@oeb.gov.on.ca and by courier*

Dear Board Secretary:

**Re: EDA Submission on the OEB Staff Discussion Paper on Distributed Generation: Rates and Connection - Board File No. EB-2007-0630**

The Electricity Distributors Association ("EDA") is the voice of Ontario's electricity distributors.

The EDA is pleased to provide comments on the OEB's Staff Discussion Paper on rates and connection in relation to distributed generation.

Please direct any questions or comments to Kevin Mackenzie at 905.265.5334 or at kmackenzie@eda-on.ca.

Yours truly,

Kevin Mackenzie

for Richard Zebrowski
Vice President, Policy and Corporate Affairs

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Attach.



**_Electricity Distributors Association_**
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**EDA Submission on the OEB Staff Discussion Paper on**
**Distributed Generation: Rates and Connection**
**Board File No. EB-2007-0630**

The EDA supports the current review of the rate treatment and connection costs of distributed generation. The EDA has long advocated for an appropriate standby charge for load displacement customers and agrees that there is a more urgent need to resolve this issue given recently announced initiatives to encourage more distributed generation.

Distributors have sought standby charges in order to recover the cost of providing reserved distribution capacity to load displacement customers who require backup service. The goal behind the design of standby charges is for the recovery of the fair share of costs rather than the recovery of lost revenues. Distributors would want to recover this cost when the reserved distribution capacity is material relative to the capacity of the feeder. Generally there is agreement that for many distributors a materiality threshold could be established for generation facilities greater than 500 kVA, but it should be noted that in some cases a much lower threshold is required to recover costs and distributors will require flexibility to address these situations.

The EDA agrees that a standard methodology for standby charges is preferable and should be based on costs. The EDA does not agree that system benefits should be recognized in the utility standby charge. The relevant benefits to be considered in a rate charged by distributors are the benefits that are provided to the local distributor or its local customers. The benefits from distributed generation vary based on location, generator operation, DG diversification (e.g. ten 1 MW generators vs one 10 MW generator) and other factors. Benefits can vary widely depending on the specifics of each application and therefore it is inappropriate to consider the use of a single generic benefit measurement to use as an offset against a standby charge, especially on a local basis where benefits of DG may vary depending on the operating characteristics of the DG. The DG benefits should not be recognized by not charging or discounting standby charges, and another means should be used to recognize site specific benefits.

The following are the questions from the OEB staff discussion paper and the EDA's response.

**What might be a reasonable billing determinant for recovering demand-related costs? For example, the demand charge could be calculated on the basis of annual contract demand, or alternatively be based on the maximum demand for backup service.**

The EDA believes that the billing determinant for the standby charge should be based on both an annual contract demand and a maximum demand for backup service. The standby charge would apply to the amount of distribution capacity reserved under contract, namely the contract backup demand. The standby charge could be the same as the existing demand charge for the customer class. The annual contract demand could be based on negotiations reflecting the nameplate value and initiatives to reduce the need for full backup (e.g. proposed load shedding) and the contract demand could be reviewed quarterly to ensure contractual commitments are met and to discourage gaming. If the actual capacity used in an instance of standby service is more than the contract demand, then the difference should be back billed for the preceding 11 months plus interest.

Note that when the generator runs continuously over the month, the billed backup demand is equal to the contract backup demand. When the generator runs only part of month (or billing period), the billed demand is greater of the maximum metered demand with generator off or the maximum metered demand plus contract backup demand with the generator on.

In addition there would be an administration charge for monitoring, billing, and administration for standby service.

This standby charge proposal was brought forward by a rate handbook working group in 2005.

**Should standby charges be differentiated based on backup, maintenance or supplemental service?**

The EDA does not support a standby charge differentiated based on when standby is taken because distribution facilities are held in reserve to supply standby capacity at all times irrespective of the type of service provided, and the costs are not less for distribution if standby is taken on scheduled times. Customers with load displacement generation generally utilize price signals from commodity charges to schedule generator outages to occur during off-peak periods. The EDA believes approaches to encourage scheduled outages are more applicable to vertically integrated electric utilities rather than distribution companies.

**How should any distribution and transmission benefits from load displacement generation be identified and quantified?**
**Should a different approach be adopted depending on the size of the customer? Should any benefit provided to customers with load displacement generation be recovered from all customers? If so, on what basis should this be done?**
**Are there other operational or implementation issues that should be considered by the Board?**

DG applications could provide a range of benefits that includes environmental, technical, operational, cost and others, and so there is indeed a pressing need to establish a comprehensive methodology that will recognize and quantify these benefits. From a distribution utility perspective the major areas of benefits could include reduction in losses, deferral of future investment, operational efficiencies (e.g. voltage support), and the like.

The OEB staff paper notes that DG may reduce transmission losses and distribution losses. Loss reductions are very site specific and in some cases losses can increase due to local generation, e.g. in generation rich areas. At this time distribution losses are treated as a pass through to customers, with distributors continuing to carry out best industry practices in managing losses. Given that the reduction of distribution losses is a benefit to customers and that this benefit varies considerably depending on the specific situation, possibly a new approach is required to recognize and reward loss reduction by generators.

In addition, some consideration could be given to looking at rewarding DG for providing distribution loss reduction, based on a payment by the distributor for a portion of the savings provided. Given that the loss reduction could vary over time, the reward should also vary. More experience is required to identify how to measure and verify the reduced losses provided by DG. In some cases DG has increased losses.

It should also be noted that DG can increase costs because of VARS and the reduced voltage regulation they can cause, and this cost should also be recognized in a fee to DG that reflects the costs imposed on other customers.

The OEB staff paper notes that DG may also defer or avoid transmission and distribution investments. If there are transmission savings, then the recognition of the transmission savings to the DG should be provided by the transmission company. The relevant benefits to distributors are the benefits provided to distributors or its local customers.

It should be clarified that DG does not reduce existing distribution costs. DG can reduce the need for future investments, but this benefit is very specific to the location and timing of the DG.

The EDA notes that distributors are gross load billed for transmission connection services. A load displacement DG would receive a benefit on its transmission costs with the existing retail transmission rate practice. However, the gross load billing for transmission connection service at the wholesale level means that other customers in effect subsidise the savings paid to the DG.

Indeed the other customers, including distributors, who are connected to the transmission system in Ontario annually will have added to their billing demand a charge for line connection service and transformation connection service, in the amount of the demand that is supplied by embedded generation with an installed capacity of 1 MW or more for non-renewable generation, and 2 MW or more for renewable generation.

As a result, existing retail transmission rates should be designed to pass on the costs of gross load billing for line connection and transformation connection service to load displacement generation customers with generation above 1 MW (or 2 MW in the case of renewable generation). If retail transmission rates for load displacement customers do not reflect the gross load for line connection and transformation connection, then these costs would be passed on to all the other customers of the distributor. The use of different billing determinants for wholesale and retail transmission rates would result in the distributor investing additional time and funds to accommodate this change.

Given that there are potential distribution system savings from a DG, distributors would like to have the ability, through a local integrated plan that reviews the relevant options to avoid building new or enhanced distribution facilities, to provide incentives to DG to locate in a certain area. The incentive could be an upfront capital contribution by the distributor, which would then be included in the distributor's rate base (similar to treatment of contributions paid to Hydro One for transmission facilities). The contribution by the distributor would represent a portion of the present value of the savings of the avoided or deferred distribution investments. This approach of recognizing avoided and deferred costs could be coordinated with the Ontario Power Authority (OPA) so that system benefits could also be recognized in the agreement with the DG.

**Is a separate classification warranted and, if so, should it apply to all customers with load displacement generation, or a subset of these customers as suggested in the EESC report (based on size)?**
**Are there other criteria that should be used to justify a separate rate classification for a subset of these customers?**
**What would be an appropriate threshold for a generator rate class?**

Distributors do not believe that a separate classification for load displacement customers is required. The rationale given for a separate classification was to facilitate the implementation of credits for the benefits they provide. As noted above, the benefits are specific to each situation and using a generic benefit is not supported, nor is a discounting of the standby charge.

A different mechanism is required to reward load displacement generation for the benefits provided, recognizing that many of the benefits flow to the load displacement customer, and recognition of the local benefits provided would only be necessary if it is determined that it is required to move the project forward. The benefits to local customers could be recognized through a contribution based on the avoided costs or deferral benefits of planned distribution investments.

As noted above, a materiality threshold for the application of standby charges could be established for generation facilities greater than 500 kVA, but it should be noted that in some cases a much lower threshold is required and distributors will require flexibility to address these situations.

**Has net revenue loss due to customers with load displacement generation been material?**
**How might net revenue loss be quantified?**
**How should the Board determine an appropriate method to compensate electricity distributors for such revenue loss?**
**Consideration should be given to a consistent approach between revenue loss caused by customers with load displacement and revenue loss caused by other load customers due to factors such as economic conditions. In evaluating each of the options presented above, consideration should also be given to the incentive regulate framework under which electricity distributors are currently operating.**

When considering load displacement generation, distributors do not initially know the extent of the revenue loss. The EDA believes that the revenue loss will be modest but real: with an appropriate standby charge, revenue losses would be minimized. However, the EDA believes that the impact of these losses will be eliminated once the rates are rebased.

Distributors would like to have the option to be able to track the revenue loss from load displacement through a variance account. The account would only be used if it is anticipated that the revenue losses will be material. Revenue losses can be tracked accurately when the load displacement generator has a separate meter. If the load displacement generator is not metered separately, the revenue losses could be estimated in part through discussions with the customer on the typical operation of the generators.

**What alternatives to the status quo (on connection costs) should be considered and what is the rationale for each of these options?**
**If connection costs are socialized, is there risk of uneconomic DG projects going forward? If so, how can that risk be mitigated or avoided? Would this approach affect the incentive for distributors to design economic connections?**

Distributors believe having DG projects pay upfront for connection costs can be a barrier to Merchant DG. Load displacement generation already has a connection to the distribution system, thus the issue is primarily the standby charge and reserving capacity for these customers. Distributors would prefer that merchant DG become a new customer class and pay a user fee similar in structure to existing distribution rates. The connection costs would be recovered through the rates. For a new connection, an economic evaluation would be run and if the present value of revenues is not adequate to recover the actual costs, then a capital contribution would be required. The main advantage of this approach is the generators would pay for the connections over time and thus minimize the amount of borrowing for their project. Alternative mechanisms involving a third party providing the connection costs could be considered, e.g. OPA funding. Similar to other larger new customers, a letter of credit would be required to address the risk of not collecting all the connection costs, if the DG goes bankrupt or ceases operation before the expected time.

The issue regarding the potential for uneconomic projects going forward if they don't pay connection costs upfront is addressed by the capital contribution requirement when the costs of connection exceed the present value of revenue from the DG connection rate. DG project proponents will consider the long term costs of paying the DG connection rate and if required, the upfront capital contribution, when assessing the viability of a project. As a result, uneconomic projects should not proceed.

The EDA believes that monthly charges should be established for merchant DG in order to address the administration costs, such as billing and settlement.