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ONTARIO ENERGY BOARD

22 August 2007

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

2027/8

Dear Ms. Walli:

**Re: EB-2007-0630 – Distributed Generation Rates and Connection
Comments filed by GEC and endorsed by OSEA**

Enclosed are three copies of Paul Chernick's comments in response to the Board Staff paper, filed on behalf of the GEC. OSEA has instructed me to indicate its support for the positions outlined in Mr. Chernick's paper.

Sincerely,

David Poch

EB-2007-0630

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EB-2007-0630

Before the Ontario Energy Board
Consultation on Distributed Generation
Rates and Connection

Comments submitted on behalf of the
Green Energy Coalition

Prepared by Paul L. Chernick, Resource Insight Inc.

Terminology:

In considering the issues in this proceeding, the Board should be careful to distinguish between three distributed-generation configurations:

- Load-displacement generation: distributed generation connected behind the customer meter, reducing the host customer's load on the distribution system and never flowing power into the distribution system.
- Distributed-supply generation: sometimes called merchant generation, this is distributed generation attached to the distribution system for the primary purpose of exporting power off-site, with little or no load served through the connection to the distribution system.
- Hybrid distributed generation: intermediate situations, where distributed generation is connected behind the customer meter, reducing the host customer's load on the distribution system and also exporting significant amounts of power into the distribution system.

In these comments, we will identify the configurations to which each topic applies.

The Board should also continue its policy of promoting socially advantageous cleaner generation. In this regard we will refer to 'preferred generation' which should be read to include both renewables and high-efficiency gas-fired combined heat and power (CHP).

Standby Rates

(Applicable to load-displacement and hybrid generation)

1. **What might be a reasonable billing determinant for recovering demand-related costs?**

   Distribution-system costs are driven by loads in every hour. While maximum peak loads on any particular piece of equipment are important in determining the sizing of that equipment, other loads also impose costs:

   - number of high-load hours determine risk of load loss following equipment failure, and hence drive redundant investment for reliability,
   - number and extent of overloads determines life of insulation on lines and in transformers (both in substations and in line transformers),
   - all energy in high-load hours, and even all hours on high-load days, affects sagging of overhead lines and insulation aging in underground lines and transformers,
   - line losses depend on load in every hour (marginal line losses due to another kWh of load generally exceeds the average loss percentage in that hour)

   Hence, the distribution charge for backup supply during a few hours every year, with a load factor well below 1% and a randomly-timed peak load, should be much lower than the charge for full-service supply, with a load factor over 50% and a peak load correlated with the system load. The proposal "to charge the same rate for standby service as would be charged if electricity were actually being supplied to the load" would grossly overcharge many customers with distributed generation. It would also fail to distinguish between the costs of serving a customer whose distributed generation has a 1% forced-outage rate, and one with a 20% forced-outage rate.

Even within the class of costs driven by maximum loads, the type of load seen by the LDC varies from a single customers' maximum load (as for many service drops) to the coincident load of many thousands of customers (as for most substations). In general, costs related to the maximum loads of a single customer should be recovered through measures of that customer's maximum load, while costs related to the coincident load of multiple customers should be recovered through measures of contribution to that coincident load.

For very large customers with distributed generation, it may be practical to meter load hourly and charge the customer for its contribution to system costs based on its load coincident with the feeder and/or substation peak, or at time of contingencies that stress the local system. For smaller customers, time-of-use energy rates will offer the best practical method for tracking the customer's contribution to load at critical periods.[1]

See below under Rate Classifications for further discussion of related rate design issues.

2. **Should standby charges be further differentiated between backup, maintenance and supplemental services?**

Ideally, rate design would not require differentiation among backup, maintenance and supplemental services. This goal can be accomplished by recovering system costs through a combination of time-of-use energy charges and charges at the system peak hour.

More specifically, maintenance that can be scheduled off-peak should not be charged for peak-related system costs, and rare back-up service should be

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[1] Some commenters may assume that the best method for approximating a customer's contribution to system maximum demands is to measure the customer's own non-coincident demand. This confusion may result from the use of the term "demand." The high diversity among the peak demands of full-service customers belies this assumption; there is likely to be little or no correlation between random outages of distributed generation and peak loads of the distribution system.

less expensive than regular reliance on the distribution system for supplemental service. Both time-of-use energy charges and charges specifically targeted to the system peak hour would advance these goals.

Benefits of Load Displacement

(Applicable to all distributed-generation situations, with different applications.)

3. **How should any distribution and transmission benefits provided by load displacement generation be identified and quantified?**

All types of distributed generation provide a range of distribution and transmission benefits to the LDC: reduced line losses, avoided network transmission charges, and in many cases (especially for load displacement) reduced wear on distribution equipment and avoided distribution-expansion costs.

So long as rate design allows their bills to decline in proportion to their generation output, customers with load-displacement generation are rewarded for those benefits through lower billing determinants (MWhs and kilowatts), and hence lower charges for distribution, transmission and generation services (including the average level of line losses). Hence, it is important that rate design provide for standby rates charged on some combination of energy charges and coincident peak charges (as described above), at least for preferred generation technologies. Transmission savings should also be passed along in this manner.

For distributed-supply generation, and hybrid generation delivered to the distribution system, the LDC and its customers currently retain all these benefits. The Board should require that each LDC credit such distributed generation for:

- Reduced line losses, at the product of (1) the number of MWhs delivered by the generator, times (2) the LDC's loss ratio (energy delivered to the LDC ÷ energy the LDC deliver to its customers), times (3) the energy price paid by the LDC for supply to its customers.[2]

Marginal line losses on the distribution system can be very high, especially at peak periods. The following table provides three utilities' estimates of marginal line losses during the summer peak period and on the summer peak hour. All of these estimates are measured at the secondary distribution level.

	Energy Summer Peak Period	*Demand* Summer Peak Hour
Connecticut Light and Power [1]	7.7%	12.4%
New England Electric [2]	11.9% to 16.4%	18.0% to 25.0%
Vermont Department of Public Service [3]	13.7%	10.5%

Sources:

[1] CL&P 1992 Marginal Cost Study (Table B-1, p. 1 and Table B-5) The marginal energy loss factor reflects a 12-month peak period, not just the summer period.

[2] New England Electric, Conservation and Load Management: Annual Report, May 1, 1990, p. 28

[3] Vermont Department of Public Service, April 6, 2007 filing letter and accompanying spreadsheet "VTLDSW5"

- Avoided network transmission charges, at the product of the transmission supplier monthly charge times the energy delivered to the distribution system by the generators at the peak-load hour that sets the network charge.
- The value of reactive power from the distributed generation, valued as the sum of reduced line losses and avoided network transmission

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2 LDCs should be free to differentiate avoided losses by location and time period, to the extent supportable by available metering and by the rate structure of the generation-services contract.

charges due to the VARs of reactive power supplied by the distributed generation.

For small renewable or preferred distributed supply and hybrid generation, up to five MW of net flow into the distribution system, the Board should consider striking a default rate credit for system services, including avoided network transmission charges, avoided marginal line losses, reactive power and other quantifiable benefits provided by the generation. In addition, the Board should require that the LDCs offer credits to preferred distributed generation for allowing the delay of distribution capacity expansion. In many cases, high investment costs can be deferred by small load reductions, resulting in a very high value per kW of distributed generation. Since these values will vary from feeder to feeder, the Board should establish rules for the LDCs to apply in identifying emerging substation and feeder requirements and computing values to be offered to distributed generation that can provide load relief on the affected equipment.

4. **Should a different approach be adopted depending on the size of the customer?**

The form of both standby rate designs and compensation for benefits to the distribution system should vary with the size of the load customer and/or the distributed-generation installation. The compensation for system benefits (losses, transmission and reactive-power costs) should be in the form of standard credits for small installations (e.g., under 2 MW or 5 MW for renewables). For larger installations of preferred generation, the LDC should compute the site-specific value for each individual installation. For large conventional distributed generation, the LDCs should be encouraged to solicit bids to provide system benefits and negotiate conditions with developers.

5. **Should any benefit provided to customers with load displacement generation be recovered from all customers? If so, on what basis should this be done?**

Load-displacement generation, as we define that term, would not usually receive any specific payments from the utility. In situations in which load-displacement generation receives payments or credits for deferral of distribution expansion, as well as payments or credits to hybrid and distributed-supply generation, those costs should be recovered from all customers.

To the extent possible, the LDC should recover payments or credits to distributed generation for reducing system costs in the same manner as the LDC would otherwise recover the costs avoided. Most of the benefit of line-loss reductions is in reduction of supply costs, so the associated payments should be recovered in the same manner as generation supply costs.[3] Payments for reducing network transmission costs should be recovered in the same manner as are the transmission costs. Credits for deferring feeder and substation investments should be recovered in the same manner as the avoided distribution costs would have been recovered.

Rate Classification

6. Is a separate classification warranted and, if so, should it apply to all customers with load displacement generation, or to a subset of these customers as suggested in the EESC Report?

For most load-displacement generation, and especially preferred technologies, no separate classification is warranted. It is clear from the statement of the EESC Report that "standby rates are based on the facilities reserved to meet demand" that the purpose of standby rates is to *increase* charges to customers who have their own generation, compared to a non-generating customer with the same billing determinants (i.e., monthly MWh and billing demand). In fact, LDCs do not reserve facilities to meet demand beyond the customer's specific interconnection facilities (service drops, meters, transformers), which are covered through a combination of monthly customer charges and connection charges. Hence, no punitive standby charges are necessary.

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[3] If and when distribution customers are served by third-party suppliers, the payments for line-loss reductions will still benefit those customers, and a portion of the associated costs should be allocated to those customers.

Indeed, the standard rate designs overcharge load-displacement customers, since demand charges are set with the assumption that every customer's maximum metered demand is equally diversified from the maximum load on the feeder, the substation, and other portions of the distribution system.[4] This assumption is not fully correct even for normal firm customers, but is a reasonable rate-design approximation, since an office building, a store, or a factory will usually be operating at a fairly high load level (if not its peak) at the hour of the monthly maximum load on the feeder, substation, etc., since those maximum loads are usually driven by some combination of weather and the weekly work cycle, which are important in determining the loads of most large customers. But the uniformity assumption breaks down for load-displacement customers, which may have high maximum demands at odd hours when the generator is out of service but very low loads at the times of maximum load on the distribution equipment.

To correct this problem, the LDCs should offer alternative billing options for load-displacement customers, within each rate class with a demand charge. Depending on the metering available, the alternative billing option could be:

- Replacing the distribution demand charge with a time-of-use charge limited to the hours in which the distribution system (or for large LDCs, the distribution area) is likely to experience its maximum demand. That energy charge would be the regular class maximum-demand charge times the class ratio of (1) the sum of billing demands to (2) energy use in the peak hours defined for the time-of-use distribution charge.
- A demand charge levied at the time of the actual monthly maximum load on the distribution system. That coincident-peak charge would be the regular class maximum-demand charge times the class diversity factor (the ratio of the sum of billing demands divided by the class contribution to the distribution-system peak demand).

7. **Are there other criteria that should be used to justify a separate rate classification for a subset of these customers?**

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4 The same is true for the "peak demand" billing determinant used for customers with interval meters, which is the maximum demand from 7 AM to 7 PM weekdays.

Separate rate classification may be justified for distributed-supply generation, with little or no load. That rate classification might include those hybrid distributed-generation installations for which the customer desires the ability to flow more generation into the distribution system than its maximum load on the distribution system. For example, if a 2-megawatt load adds a 3-megawatt generator, and is willing to limit its flow into the system to 2 MW, the hybrid customer would be treated as load; if it wants the ability to flow 3 MW into the system when the host load is shut down, it might be included in the distributed generation classification.

8. **What would be an appropriate threshold for a generator rate class?**

No renewable or preferred load-displacement generator of less than 2 MW should be required to be on a special distributed generation rate. However it may be appropriate to create a rate class or classes to facilitate the payment of credits as discussed above.

Lost Revenues

9. **Has net revenue loss due to customers with load displacement generation been material?**

We have no Ontario data available to allow us to respond to this question.

10. **How might net revenue loss be quantified?**

Rather than asking the LDCs to compute net revenue losses from distributed generation (as well as energy-efficiency programs and potentially many other initiatives), the Board should switch from price-cap regulation to revenue-cap regulation, so that the LDC's revenues available for covering costs and return are not affected by distributed generation (or energy efficiency, etc.). This approach, often referred to as "revenue decoupling," is being widely adopted in US jurisdictions, including recent orders by the New York Public Service Commission (Case Nos. Case 03-E-0640 and 06-G-0746) and the Massachusetts Department of Public Utilities (Docket No. 07-50). Revenue-cap regulation would be particularly advantageous for Ontario, with its numerous small LDCs, since it reduces the importance of forecasts and eliminates the need for a range of adjustments and balancing accounts. The

Board should consider a transition of the LDCs to revenue-cap regulation in the next round of rate reviews.

If it is necessary to estimate net revenue losses, LDCs can use engineering assumptions for small installations (e.g., most photovoltaics, CHP under 1 MW). For larger installations, metering and data analysis of load-displacement distributed generation would be useful for many reasons, including generation, transmission and distribution planning; improved understanding of the operation of distributed generation; and the valuation of load relief.

11. How might the Board determine an appropriate method to compensate electricity distributors for such revenue loss?

As noted above, revenue-cap regulation provides a consistent approach for dealing with revenue losses caused by load-displacement generation and with revenue losses (or gains) caused by other factors such as weather, economic conditions, the demand response to changes in power-supply costs, national and provincial policy initiatives, and other factors. The difference between allowed and actual revenues would be amortized and rolled into annual rate adjustments.

In general, exit fees should be an absolute last resort for energy regulation. The Board should not permit the LDCs to impose exit fees for customers installing preferred (i.e. cleaner) distributed generation or improving their energy efficiency as this has the potential to lead to sub-optimal outcomes where societally cost-effective preferred generation is foregone.

Given the benefits that the LDC's customers share due to the presence of load-displacing generation (see above) it would be fair to allow an LDC to recover lost revenues from all of its load customers. However, the Board should consider developing special protections for very small LDCs against the loss of revenue from a very large customer as the rate impact on the LDC's small customer base could be undue. For the longer term, the Board might recommend legislative or administrative changes to socialize extraordinary lost revenues from desirable distributed generation across the province, through OPA or the transmission provider. Desirable distributed generation would include renewables, very-clean gas-fired generation, and perhaps other generation that would contribute to important public concerns, such as relieving stress on the transmission system.

Recovery of Connection Costs

12. What alternatives to the status quo should be considered and what is the rationale for each of these options?

For existing load customers no additional connection costs should be assessed due to the addition of load-displacement generation, which by definition never exports power in excess of the maximum load level and thus reduces the flow of power from the distribution system to the customer. For load displacing generation that requires the addition of new connection facilities sized beyond average net load to enable backup, and for small preferred hybrid or distributed-supply generation (e.g., less than five megawatts of net flow into the distribution system), the connection cost should be set at the average connection costs for load customers of similar size and voltage.

Any generator in the above-noted situation should have the option of having the utility finance the connection costs and recover the costs from the customer, amortized over 10 years at the utility's cost of debt.

LDCs should be allowed to increase rate base to reflect any difference between actual capital costs incurred by the LDCs to connect distributed-generation customers and the revenues collected from those customers. If these costs are significant, the LDC should be allowed to start recovery in the next annual rate adjustment.

13. If connection costs are socialized, is there a 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?

Uniform utility charges (which implies some level of socialization) inevitably create some minor discrepancies in price signals. Line losses, excess capacity on the feeder and connection costs will vary from one potential building site to another. Utilities rarely impose different costs for connecting load based on these geographical differences. If distributed generation pays the same monthly customer charges and receive the same extension allowances as load customers, any economic distortions should be minor, and much smaller overall than distorted incentives for locating new loads.

Socializing (and standardizing) connection costs, at least for preferred distributed generation, would reduce the temptation for distributors (at least those that are hostile to distributed generation) to gold-plate proposed interconnection requirements, and encourage them to design more-economic connections.

Other Aspects

14. Are there other rate-related issues associated with DG that should be addressed, or that should be addressed more fully? Is the experience in other jurisdictions on those issues relevant to the Ontario situation?

Experience across North America indicates that DG is not a major revenue issue for electricity distributors, unless they purchase power (at above-market prices) from the distributed generation. Neither lost revenues nor connection costs related to DG has turned out to be a serious problem, although utilities have often been very concerned about those issues in advance. See comments above under Rate Classification on other rate design issues.

15. Are there unidentified barriers or is separate treatment required for embedded generation projects or for projects falling below the threshold of a new rate class?

As discussed above, the distributor should credit distributed generators with line-loss reductions, reactive power, value of distribution deferral, and all upstream transmission network charge savings that the LDC receives. All payments for those benefits should be recoverable from load customers, who receive the benefits.

Reasonably-structured standby rates should minimize any adverse rate effects from bypass.