EB-2009-0326

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF a proceeding initiated by the Ontario Energy Board to determine and implement a distribution rate for embedded generators having a nameplate capacity of 10 kW or less.

Submissions of the GEC

Introduction

GEC member organizations have been active in the development of the Green Energy Act and welcome the opportunity to participate in the Board's work to implement regulatory changes necessary to achieve the goals of the legislation.

GEC's has the following submissions specific to the enumerated issues:

Service Classification

Issue 1. Is the description/definition for the embedded micro-generation service classification shown in Appendix D appropriate? If not, what should be the description/definition of this service classification?

GEC submits that simplicity is a virtue. Given the relatively small range in generator capacity within the Micro-FIT program, a minimum number of classifications would be preferable. Distinctions such as degree of intermittency or peak coincidence may warrant differentiation by the OPA in its tariff, but do not significantly affect the cost of *administrative* services for the LDCs. The one variant that may be significant for LDC administrative costs is whether the generation is billed to the load customer or requires a separate account and bill to a new (separate) generator entity. However, that matter can be dealt with either by way of a distinct charge for a second bill etc. or by way of a second classification. Thus GEC submits there should be either one classification or, if administratively preferable, two classifications: load customer micro-FIT generation and non-load customer micro-FIT generation.

Cost Elements to be Recovered

Issue 2. Are the same cost elements applicable to all micro-generation customers? If so, what cost elements should be used to establish the rate?

Based on the Uniform System of Accounts (USoA), which specific accounts or components ought to be included in the development of the rate?

If not, what cost elements should be used to establish the rate?

Based on the USoA, which specific accounts or components ought to be included in the development of the rate for microFIT projects that are:

a. Directly connected

b. Indirectly connected

c. Owned by the load customer entity at that location vs. owned by different entity

The Board in exercising this role will be cognizant of its new statutory objective: "The promotion of renewable energy, including the timely connection of renewable energy projects to transmission and distribution systems". In GEC's submission this explicit mandate to *promote* renewable energy suggests that the Board must be cognizant of government policy and the actions of key players such as the OPA and strive to regulate in a manner that does not frustrate or conflict with steps taken by these entities to promote renewables.

In the particular case of fixed charges for Micro-FIT generators the OPA was charged by the government to produce a tariff that would ensure a reasonable return on investment and foster development of a domestic industry. As is noted on the OPA website, the development of the rates was based on costs plus a reasonable return. OPA notes:

> **How were the FIT Program prices determined?**
> The FIT Program prices were developed based on experience in Ontario and other jurisdictions. Prices differ based on project size and type of renewable energy technology. ***They cover facility construction and operating and maintenance costs and allow for a reasonable return on investment*** over a 20-year contract term (40 years for waterpower projects).

The FIT Program prices were also discussed during the OPA's stakeholder engagement sessions. The OPA incorporated much of the feedback from stakeholders into the price schedule. ***For greater clarity on how the prices were derived, please refer to the April 7, 2009 and May 12, 2009 stakeholder engagement sessions*** under the FIT Program Archive. [1]

(***emphasis*** added)

The April 7, 2009 materials[2] which are referred to above set out the specific assumptions. Slide 4 therein notes the FIT prices including the 80.2 c/kWh small solar tariff and Slide 36 shows the OPA's assumptions that are behind that price offering:

FIT Pricing – PV Assumptions

- PV costs and performance estimates are from a Navigant Consulting study performed for the OPA

	Rooftop ≤ 10kW	Rooftop 10-100kW	Rooftop 100-500kW	Rooftop > 500kW	Ground mounted
Typical Size (kW)	5	100	500	1,000	10,000
Contract year	2009	2009	2009	2009	2009
Construction Lead Time (yr)	1	1	2	2	2
Start Year	2010	2010	2011	2011	2011
Capacity Factor	13%	13%	13%	13%	14%
Capital Cost ($/kW)	9,200	8,160	6,690	5,650	4,600
Fixed O&M ($/kW/yr)	10	11	12	13.5	15

36 Source: Navigant Consulting, Inc., *Photovoltaics in Ontario, January 2009*

OPA Ontario Power Authority

[1] http://microfit.powerauthority.on.ca/Program-resources/FAQ/FAQ-Pricing-and-Payment.php

[2] http://fit.powerauthority.on.ca/Page.asp?PageID=122&ContentID=10114&SiteNodeID=1061

Of critical importance to a consideration of service charges is the OPA's assumption that Fixed O&M would total 10 $/kW/yr. Given that this category includes fixed annual expenses such as insurance as well as LDC service charges, this suggests that the OPA assumed there would be no significant service charges, presumably because it was understood that most micro-FIT participants would be load customers and load customers already pay for maintaining their customer account, meter reading and billing services.

Thus, if the Board were to impose significant service charges such as the interim charges which are based on the charges levied for load customers, the policy objective of ensuring an adequate return would be undermined. To illustrate, consider the example of a typical residential rooftop solar generator. Assuming a 2 kW array, and a 13% capacity factor, the gross annual revenue for such a generator would be:

2 kW X 8760 hours X 13% X 0.802 $/kWh = $1826 or $152/month

The OPA's assumed $10/kW/yr, which must cover the fixed charge plus insurance, would cover $1.66 per month in this example ($10 X 2kw/12months).

If fixed charges anywhere near the range of load customer fixed charges were levied it is apparent that the return allowed for by OPA in the tariff would be eradicated. For example, if a $25 monthly service charge were levied (lower than HONI's rural, more than its urban load customer service charges) it would reduce the gross revenue of a 2kW array by over 16% which would wipe out the $1.66 and all of the "reasonable return" built into OPA's assumptions and tariff.

Accordingly, in GEC's submission, the OEB should impose minimal service charges based on marginal costs assuming that the vast majority of micro-FIT customers are already load customers with customer accounts already in place, meters already being read, bills already being mailed and payments already being managed. After the start up period for this program, customer care expenses such as inquiries, complaints, collections, and bad debt expense should be minimal as there will be no payment defaults by customers, and few if any incremental service interruption inquiries beyond what would arise from the pre-existing load customer. In short, the Board should approach this question not as if these generators are added customers, but rather by treating them as existing customers simply accessing a new service.

The only significant added administrative cost that we believe may warrant a service charge is for the situation where the owner and load customer are different billing entities and a second account is required and a second bill is rendered. Even then, there should be minimal added meter reading charges (as this will either be automated or at the same physical location) and only the marginal costs of these services should be levied to ensure consistency with the government policy as implemented by OPA.

Hydro One in its evidence (letter of November 4th) proposes that the appropriate approach is to set the service charge to recover the costs associated with the extra meter as all other costs are already being recovered. This charge is described as being equivalent to the credit given to unmetered scattered load for the fact that no meter is required. In the EB-2009-0096 HONI 2010-11 rate case evidence at Ex. G1, Tab 4, Sched. 5 HONI indicates:

> "Hydro One has completed a Cost Allocation Study which enables a proper fixed charge credit to be established for USL customers. This credit reflects the nature of USL customers, that is, no meter or meter reading costs should be recovered from USL customers. This approach was approved by the Board in Proceeding EB-2007-0681."

GEC agrees with the methodological approach proposed by HONI with a few adjustments. We understand that HONI includes expenses such as depreciation and debt and equity return on meter costs which would not be appropriate where the customer has paid for the capital cost of the meter. Further, we understand that HONI's connection charge exceeds $1000 which suggests that it includes costs beyond the capital cost of the meter. Since most installations will be via the customers' existing connection, the only labour cost for the LDC is to simply insert the meter head in the meter base. Accordingly, it appears that HONI is charging for costs such as general plant related to meters in their connection charge and this should therefore not be included in the monthly charge. The credit derived from HONI's customer cost allocation model amounts to $6.15. Adjusting this amount downward to reflect the deduction of depreciation and returns would yield a charge that would we expect would not be inconsistent with the assumption made by OPA in setting the tariff.

EDA in its evidence lists 12 load customer fixed charge components. GEC respectfully suggests that many of EDA's proposed inclusions are simply inappropriate or are for cost categories for which micro-generation would cause *de minimus* expense and that in the interest of regulatory economy are best ignored. As the Board noted in its issues determination (Procedural Order No. 2, Page 6 in regard to LPMA's suggestion of "negative" costs) the matters under consideration are metering, billing and settlement costs. Further, with the exception of meter maintenance, it would be inappropriate to allocate any of EDA's categorized costs to micro-generators at the same per customer level as a load customer, which appears to be EDA's proposal. Accordingly, even where a category of expense may be applicable, the allocation should not be taken to equal the per customer amount allocated for each load customer. For example, while the bill calculation for a micro-gen customer would involve an extra addition step, that automated addition would be a minor cost and certainly not double the attributable billing expense for that customer.

We offer the following additional comments on EDA's specific proposals:

(1) Operation Supervision and Engineering – These charges are not customer-specific and should be excluded (see discussion below). Further, LDCs already levy a connection charge that is intended to cover the costs of engineering and supervision. Inverters are required to meet automatic anti-islanding disconnect requirements and no added engineering should result on the LDC side of the meter nor added operational requirements. While existing protocols that ensure lines are de-energized prior to work being conducted may need to be adjusted, once in place, these protocols should not require engineering or supervision.

(2) Load Dispatching – Again, these charges are not customer-specific (see discussion below). Further, the impact of micro-gen on utility power flows will be dispersed and there is no evidence to suggest that they will not be a *de minimus* consideration. This lack of significant impact was surely part of the considerations that went into the definition of micro-generation.

(3) Customer Premises - Operation Labour – again, connection charges will cover the site visits to ensure correct installation and connection. ESA will also inspect. Site problems, like any household electrical problem are the owner's problem and will be addressed by private electricians.

(4) Customer Premises - Materials and Expenses – again, this is covered by the connection charge or is outside of the LDC mandate.

(5) Maintenance of Meters – GEC agrees that this is an appropriate charge.

(6) Meter Reading Expense – any on site reading expense will be *de minimus* as there is already a load meter on site.

(7) Customer Billing – load customers already have accounts and receive bills – there is only a *de minimus* expense to print the added line (if indeed that is permitted by regulation). GEC does agree that in the case of separate billing for contiguous load and generation that a charge would be appropriate.

(8) Amortization Expense - General Plant assigned to Meters – meters are paid for by the customer. Any charge for this expense should only be for meter-related expenses apart from those associate with the capital cost and installation cost of the meters as connection charges for these would already include a contribution for use of general plant.

(9) Admin and General – there is little or no added cost to provide the added service for existing customers (see above and our comments below).

(10) Allocated PILs – we assume these costs are allocated based on capital or income and are therefore inapplicable.

(11) Allocated Debt Return – there is no significant capital investment for this service – meters and the capital cost of connections (however 'owned') are paid for by the customer. As is evident from EDA IRs tab 4-1 and 4-2, EDA seems to suggest that generation customers pay for the capital cost of the meter but LDCs nevertheless obtain PILs, debt and equity return and amortization in that regard. This is inconsistent with the practice of charging generators for the meter.

(12) Allocated Equity Return – again, there is no significant capital investment for this service – meters and capital cost of connections are paid for by the customer.

Finally, in the case of centralized generation, the Board has not assessed costs beyond connection to the generators. The convention is to treat transmission and distribution apart from connection costs as for the benefit of load customers. There is no reason to distinguish between dispersed and central generation in this regard. This would suggest that if there are incremental expenses in EDA's categories such as Load Dispatching, Engineering and Supervision and General Plant they nevertheless should be borne by load customers, either in conformity with this practice for large generators or due to the operation of section 3.3.3 of the DSC and charged to all provincial load customers. (We assume this to be the rationale behind the Board's reference in P.O. # 2 to metering, billing and settlement costs as the substance of this process.) Alternatively, if charges downstream of dispersed generators are to be charged to the generators, then it would be fair to reassess the allocation of the major network costs that are necessitated by the existence of large central generators with whom renewable generators compete in public policy and planning determinations.

In summary, GEC suggests that the tests or considerations to be applied are:

1. Is the related to metering, billing and settlement, i.e. purely customer-specific, or is it analogous to network construction, re-configuration, operation, maintenance and supervision that is needed to incorporate centralized generation and this appropriately charged to all load customers?

2. Has the cost been captured in whole or part in the connection charges?

3. Are there economies in delivering the service as a 'marginal' expense due to the physical or account co-location with load customer equipment and services?

4. If after applying the above tests the cost category is found to be appropriately charged to the generator, is the level of cost causation on par with the costs created to serve the average load customer? If not, the charge should be reduced or, if *de minimus,* ignored.

5. Is the resulting total charge consistent with government policy, the OEB's mandate to promote renewable power, and the OPA tariff formulation intended to maintain a reasonable return for the generator?

Rate Design

Issue 3. Should the approved rate be a uniform rate for all distributors, or should different distributors have different rates?

It would be preferable to provide a single province-wide rate to allow for ease of information gathering for potential micro-FIT generators. We understand that HONI proposes a rate derived from its model which would likely apply to the majority of Micro-FIT customers. Accordingly, the HONI rate may be a suitable candidate rate for province-wide application. As well, and as discussed below, a single rate will provide certainty to prospective generators and reduce regulatory costs.

Issue 4. Should the costs be recovered through a fixed charge, a volumetric rate or a combination of the two? If there is to be a volumetric rate, what should be the basis for establishing the charge determinant? If there is to be a combination of fixed and volumetric, what should be the basis for the cost recovery split?

GEC sees no justification for volumetric charges as *administrative* costs do not vary due to energy throughput or capacity. We note that the benefits to the LDC and its customers in the form of loss reduction, reduced equipment stress, and lower transmission charges, will vary due to the characteristics of the generation, but we understand that such matters have been excluded from consideration in this case.

Implementation

Issue 5*. What should the effective date be for any new rate or rates created by this proceeding? Does the incentive regulation framework pose any difficulties for implementation?*

GEC submits that the use of existing load customer service charges (the interim approach) is inconsistent with the Board's determination that the service charge be for administrative items only. As the Board noted in its issues determination (Procedural Order No. 2, Page 6 in regard to LPMA's suggestion of "negative" costs) the matters under consideration are metering, billing and settlement costs. By comparing Hydro One's rural low density service charge of $54.91[3] to its urban charge of $15.54 (or to Toronto Hydro's residential charge of $16.85[4]) it is apparent that the LDCs include costs that vary with density (i.e. wires and poles) not simply administrative charges in their allocation models for current load customer service charges.

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[3] http://www.hydroonenetworks.com/en/regulatory/rate_schedules/HONI_RateOrder_Appx_20090601.pdf

[4] http://www.torontohydro.com/sites/electricsystem/pdf/M1_T02_S01_2009%20OEB-APPROVED%20RATE%20SUMMAR_V01.pdf

Again, such costs should be considered to be for the benefit of all load customers just as network costs for the delivery of centrally generated power are allocated. Further, as discussed above under Issue 2, these levels of service charges are inconsistent with the cost assumptions used by OPA in developing the micro-FIT tariff and will frustrate the policy objective of promoting renewables if allowed to persist. Accordingly, we urge the Board to act quickly to set reasonable charges that do not conflict with the objectives of the government's green energy initiative and with the Board's own green energy objectives. The resulting charges should be implemented immediately and be retroactive to the implementation date of the micro-FIT tariff to avoid marring the start up of the micro-FIT program.

EDA has proposed a two phase process to allow its members to gain experience with Micro-FIT generation before the final charge is set. The EDA acknowledges that its approach would involve a multiplicity of proceedings: "The two-phase model presented by EDA members has been proposed to permit individual LDCs, the OEB and the Ontario electricity industry to gain experience with the work and costs involved in this new type of generation facility. As this experience is established, individual LDCs would be able to apply for ***an LDC-specific charge*** if for some reason they believe the provincial rate is unsuitable to their particular circumstances."[5] GEC urges the Board to reject this approach as it will inject needless cost and uncertainty into the process for potential Micro-FIT generators. As noted above, the charge size is critical to the cost-effectiveness of small installations. If there is significant uncertainty as to the charge this could frustrate the government policy and the OEB's objective to promote renewable generation. Further, it is doubtful that the LDCs will be able to track and provide meaningful cost allocation data to support subsequent adjustments to the charge without disproportionate study and regulatory expense relative to the actual marginal costs caused by the micro-generators. It is more likely that the prospect of such proceedings will simply encourage needless studies, needless regulatory costs and overzealous additions of staff to support claims of incremental costs. Such an approach is at odds with the government policy and the OEB's policies to date that support a streamlined and simplified regulatory approach to encourage Micro-generation.

All of which is respectfully submitted this 10th day of December, 2009.

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Counsel to GEC

[5] EDA response to LPMA #2 – emphasis added