December 20, 2002

TO: **Distributed Generation Rates Workgroup**

FROM: **CenterPoint Energy Minnegasco**
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RE: **Comments requested on: Present proposals for agreement regarding standby services.**
Docket E999/CI-01-1023

In response to the December 11, 2002 meeting of the Distributed Generation (DG) Rate Workgroup, we jointly submit the following comments on the requested agenda item:

It is widely recognized that standby charges will continue to represent a decision factor for customers who are considering DG installations. These charges, particularly the reservation fees, dramatically impact DG economics and are a major barrier to DG development. The group agrees with the argument that reservation charges should reflect that a portion of the system is being held available to provide this service. However, these charges should reflect the true costs associated with the service.

Currently, the DG Rate Work Group is progressing in the notion that the existing standby charges in the electric utilities' tariffs are the fair reflection of the fixed costs. It may not be prudent to argue on the validity or the nature of these costs given the limited timeline of the current docket proceedings. Perhaps, a separate discussion or proceedings would be needed. Therefore, our discussion is focused on the credits for the DG customer to compensate against these standby reservation costs. In order to assign the pertinent credits applicable to the standby-related charges, the reservation fee costs structure has to be itemized under each electric utility's tariff.

Before we address the applicable credit requirements, the following three items needs some attention:

1) The standby service riders under each electric utility tariff should be applicable to any non-residential customer who requires over 100 kW of standby capacity. Therefore, Xcel's current standby tariff should revert to 100 kW instead of 40 kW.

2) Utility disturbances that knock a DG off line (i.e. voltage transients) should not be used as a reason to invoke standby rates or to count against the three allowed occurrences before the amount of standby is restated.

3) If an existing customer installs DG and elects zero standby capacity, an unauthorized use penalty shall be applied rather than (arbitrary) equipment removal as a means of

"penalizing" the system additions. To the extent there are potentially, hazardous system consequences to DG voltage and system stability, a study should be done at the distribution operators cost, and submitted to the DG for discussion and review, prior to any changes occurring. Notice of the removal and equipment consequences shall be provided in writing no less than 90 days prior to equipment removal.

Credit Requirements:

In the Menu of Services from DG Customer to Utility[1], the sub-group proposed and defined the credits pertinent to the DG customer. The reservation fees costs structure has to be itemized under each electric utility's tariff to actually reflect the pertinent credit. We propose that all credits are proportionate to the explicit value within a given utilities' tariff.

A. Generation Credit (capacity only):

We will use the Xcel's Reservation Fee of $3.15/kW/month for the template. The breakdown of the numbers is an assumption based on previous discussions in our Working Group meetings.

Generation component of the Xcel tariff:	$.68
100% Credit requirement for accreditable capacity provided:	$.68

B. Transmission credit:

Credit for a path not required.

Transmission component of the $3.15:	$.44
100% Credit requirement:	$.44

DG eliminates the actual flows by sourcing transmission AT the load within the distribution system.

C. Distribution credit:

Distribution should be viewed as two distinct parts, D1 (Bulk Distribution) and D2 (Local Distribution).

Distribution Component of the $3.15 is assumed:	$2.03

We are assuming 40% allocation of these charges to the bulk (D1) distribution, and 60% to the local (D2) distribution charges.

Bulk (D1) Distribution Component:	$0.82 (40% of $2.03)
50% D1 Credit requirement:	$0.41

Local (D1) Distribution Component:	$1.21 (60% of $2.03)
As described below:	

[1] Menu of Services From DG Customers, submitted to the DG Rate Work Group on October 29, 2002.

The concept tiered "Locational DG Distribution Credit" to be established for the DG Tariff. It would require the utility to segregate its service territory into 3 DG territories based on capacity constraints and/or costs for system upgrades:

1) "Red" - a very large benefit from DG installation [very constrained areas with high upgrade costs, which may be about 5-10% of its territory];

2) "Yellow" - a moderate benefit from DG installation [moderately constrained areas, maybe 15-20% of territory]; and

3) "Green" - a general benefit [the rest of the service area].

The PUC would determine the credit rate within each of these areas, based on the avoided distribution system upgrade costs that the utility avoids or defers because the DG has been installed in that location. The DG customer and utility share these costs.

D. <u>Line loss credit:</u>

DG relieves utilities of having to supply the additional generation capacity associated with line losses to serve the DG customer.

All percentages losses designated under Generation, Transmission, and Distribution by the electric utility shall be credited.

E. <u>Diversity credit for generation, transmission, and distribution:</u>

Utilities should give diversity credit in backup generation allocation better than 15% because small DG's require less reserve on a diversified basis than bigger units when applying the standard simulation process used by utilities. This method uses a threshold of risk of "once in ten years" that generation cannot meet load within MAPP. The key inputs are unit size and forced outage rates. Smaller units and smaller forced outage rates decrease reserve margins. Therefore, 8% is a reasonable estimate at this time as an appropriate reserve.

A diversity factor should be applied to bulk distribution system when allocating DG customer distribution even though service drop and local transformer must be sized to full load of customer without DG in operation. An option would be a big bulk distribution credit.

Other Credits:

Although the above credits can be directly implied against the reservation fee, we believe that credits (either offsetting standby rates or increasing the buyback rates) should be given to DG projects that are providing physical assurance, renewable, or meet certain thresholds of operational efficiency (e.g. high-efficiency cogeneration systems).

1. Physical Assurance Credit:

If a customer is willing to provide physical assurance to the utility, that customer should not have to pay for any facilities or peak demand related costs associated with distribution service and should have the ability to opt out of standby services entirely or elect to take maintenance or interruptible services.

2. Renewable Credits:

For DG renewable energy technologies, one option would be to provide renewable DG projects a credit for supplying power for utilities' mandatory green pricing programs. These programs allow utility customers to pay a premium on top of their electric rates for renewable energy.

State law allows utilities to use DG projects to meet utility green pricing program obligations. DG projects should be given the full amount of the current green pricing tariff of the particular green pricing program of the utility being interconnected to (less some administrative/marketing costs, which we believe is typically less than 10 percent). So for example, if a renewable DG interconnects with Xcel Energy's system, and their green pricing adder is 2.4 cents/kWh, the DG should get slightly less than 2.4 cents/kWh as a credit.

Another possible green credit scenario would be to allow a renewable DG customer to have the option of keeping their "green tags" for their project or selling them to the utility for a set amount, say 0.75 cents/kWh.

A third option, the PUC also requires the use of environmental externality values in certain situations for evaluating future power supplies. There may be some methodology to calculate an environmental externality credit for DG based on the adopted values or market prices for certain pollutants. This option would be less preferable due to the relatively low externality value for CO2 emissions.

3. Operational Efficiency Credits:

State law clearly has a preference for maximizing the efficient use of electrical energy including maximizing the efficiency of the production of electricity. These laws included energy conservation programs, building energy codes, tax breaks for high-efficiency products to name just a few. State law also provides a sliding-scale property tax system for high-efficiency cogeneration. The more efficient the cogeneration system is the lower your property tax bill.

The DG statute was put in place to "promote" clean and efficient sources of distributed electrical generation. The letter of the DG law can be met by providing an efficiency credit to high-efficient cogeneration. This credit would recognize the valuable environmental aspects of cogeneration for offsetting emissions and by utilizing what would otherwise be wasted energy.