

**January 17, 2003**

**TO: Distributed Generation Rates Workgroup**

**FROM: CenterPoint Energy Minnegasco  
Hennepin County  
Institute for Local Self Reliance  
Izaak Walton League of America, Midwest Office  
Korridor Capital Investments, LLC  
Minnesota Chamber of Commerce  
Prairie Gen  
The Minnesota Project**

**RE: Comments requested on: DG Customers proposal on Credits  
Docket E999/CI-01-1023**

In response to the January 8, 2003 meeting of the Distributed Generation (DG) Rate Workgroup, we jointly submit the following comments on the requested agenda item:

The discussion in the last DG Rates Workgroup was centered on defining credits pertinent to the physical assurance of load reduction. The amount of credits was defined to offset charges against the monthly standby reservation fees if a DG customer elected physical assurance on a portion or its entire load. For the DG customer electing physical assurance option of existing load, the generation and transmission reservation charges were defined to be zero. However, the customer is expected to pay the monthly distribution charges portion in the reservation fee or pay it out as one-time *distribution stranded costs* to avoid monthly standby distribution charges.

Before the DG Rates Workgroup proceeds to address other pertinent DG credits, we believe further clarification is needed in the physical assurance credits discussion particularly related to distribution charges:

1. The entire distribution charges portion in the standby reservation fee should not be considered as the total stranded distribution costs. The distribution charges should be itemized under the electric utilities tariffs to reflect the true cost allocation as the bulk or

local distribution charges. A DG customer should only pay for the stranded distribution costs related to the local distribution charges since the bulk distribution assets would become available to serve other loads.

2. The stranded distribution costs should be based on the current book value of the localized distribution system instead of the replacement costs. The electric utility will continue to own and maintain the portion of that distribution system even if the DG customer pays off the stranded costs. To the extent the electric utility benefits by reselling that portion of the distribution of the system, a credit, as a reimbursement of payments, should be given back to the DG customer.
  3. The standby charges, including the entire distribution portion, should be zero if a customer elected physical assurance on a new DG load (i.e. green-field or capacity addition).
  4. Physical assurance should be based on the *customer elected generation capacity*. A DG customer should have an option to elect the entire or portion of its DG load. For example, a 5 MW peak load customer with a 2 MW DG system should be able to elect physical assurance between 0 to 2 MW.
  5. Under physical assurance option, the customer's load from the grid must not exceed the required peak capacity. This can be done by capping the subscribed demand under the applicable tariff. For example, a 5 MW customer elected 1 MW as a physical assurance, the required peak load, or a load on the utility meter, must not exceed 4 MW regardless of whether the DG unit is being utilized at that given moment.
  6. A DG customer should have a flexibility to elect physical assurance with the firm or non-firm standby services on partial DG loads as needed.
- In the non-firm standby by category, we believe it may be necessary to pay D2 (local distribution), but we believe D1 (bulk distribution) should be zero just as it is for Transmission.

The table on the next page summarizes our recommendation on how the physical assurance, firm, and non-firm standby services can be categorized as part of the reservation fees requirements.

**Table I**

| <b>Reservation Fees Categories</b> | <b>Physical Assurance</b>  | <b>Firm Standby</b> | <b>Non-firm Standby</b> |
|------------------------------------|----------------------------|---------------------|-------------------------|
| Generation                         | 0                          | G                   | 0                       |
| Transmission                       | 0                          | T                   | 0                       |
| Distribution:                      |                            |                     |                         |
| D1– Bulk Distribution              | <b>0</b>                   | D1                  | <b>0</b>                |
| D2– Local Distribution             | <b>D2 (stranded costs)</b> | D2                  | D2                      |

The net offset in all generation, transmission, and distribution (both D1 & D2) categories can be allocated as the Workgroup addresses value for other credits. The following outline summarizes our discussion and recommendation pertinent to other credits.

We have already outlined the definition of other pertinent credits in previous documents submitted to the DG Rate Workgroup. Please refer to: the Part II section in the ‘combined’ Menu of Services document dated December 19, 2002, the DG Customer Comments on Standby Service document dated December 20, 2002, and Comments on Green Credits for Distribution Generation document dated January 8, 2003.

In this document, we will attempt to define ‘how’ these credits can be applied.

**1. Distribution Constrained Credit:**

The concept of tiered "DG Distribution Constrained Credit" should be established for the DG Tariff. It would require the utility to segregate its service territory into 3 DG territories (red, yellow, and green) based on capacity constraints and/or costs for system upgrades.

The distribution constrained credit should be applicable to both Bulk (D1) and local (D2) distribution. The credit should be available to all DG customers regardless of selecting the services under the firm standby, non-firm standby, or physical assurance options.

The distribution constrained credit should be valued on how the DG mitigates utility investment. The credit could be a short-term payment until the utility upgrades the distribution zone, or a long-term payment if it completely offsets utility investment. The three DG territories’ designated maps should be available to any DG customer considering DG

installations, and it should be updated on an annual basis. A similar transmission constrained credit should be applied if the DG provides benefit to the transmission grid.

## **2. Diversity Credit:**

We assume that standby charges and the components that make them up are consistent across the Minnesota electric utilities. For example, all utilities' standby charges related to generation should only reflect reserve margins as designated by MAPP, and should not reflect utilities' total generation costs. If standby charges in any current Minnesota electric utilities tariffs do not reflect this type of diversity, these charges should be reevaluated prior to setting DG rates.

MISO is typically requiring member utilities to maintain reserve margins in the range of 15%-18% based on loss of load probability studies. As a result, utilities are proposing to use this same factor in determining the amount of generation needed to back up DG's. For example, the utility must install or acquire 15-18 MW of generation to back up 100 MW of DG capacity.

Since DG units are smaller than utility units and operate at a higher availability factor, this family of units requires less back up capacity than a typical utility per MW of installed capacity. We estimate that 8% reserves should be used either to recognize the proper amount of utility generation assigned to back up DG customers or to be recorded as a credit from the utility prescribed tariff.

## **3. Line Loss Credits:**

DG relieves utilities of transmission and distribution losses otherwise necessary to serve an equivalent amount of new customer or existing customer load. The following method based on calculating the demand and energy losses can apply as a credit:

- a. Demand losses calculated on the basis of the capacity value of generation times the demand loss factor. For example, 3% for transmission loss times the DG size in kW times the capacity value (\$/kW) of generation.
- b. Energy losses calculated on the basis of the off-peak and on-peak value of the energy (kWh) otherwise delivered. For example, 3% for transmission times the

DG size times the hours operated in each period (peak and off-peak) times the generation value (fuel and O&M) of the energy.

In addition to the foregoing, the actual capital cost avoidance for releasing capacity can be measured by the tariff for transmission or distribution. For example, the firm transmission in MISO is approximately \$1.25 per kW per month. It can be multiply by the DG rating to obtain tariff savings.

#### **4. Renewable Credits:**

We support the idea that there should be a credit for renewable DG projects. Customers should be allowed to opt out of this credit if they so choose. The “greenness” of the electricity is a non-power attribute that has a potential future market and can be separated from the energy and capacity of the DG project. If the DG customer can find a better market for this non-power attribute, they should be allowed to do so.

We support the idea that renewable DG projects should be given a credit if the utility is selling more electricity through their green pricing program than renewable DG projects are producing on their system. The credit in this case should be whatever the premium is of the green pricing program less some administrative/overhead component. So if a utility's green premium is \$0.025 per kWh, the renewable DG owner should get that amount per kWh less a justified administrative offset.

If the DG customer is taking credit for supplying power to the green pricing program, the utility would also be entitled to the green tags (attributes) for the electricity supplied by the DG project.

A utility that has more renewable DG on its system than it needs for its green pricing programs should be required to pay for the renewable DG's green attributes if the DG would like to sell them. Since Minnesota does not have a renewable energy credits trading system, we are not able to assign a marketplace value to the green attributes. Until such a trading system is in place, the green pricing premiums that utilities charge are a way to assign a value to renewable energy DG projects. Once the utility pays for the DG project's green attributes, the utility can apply that amount of renewable energy toward the legislative directive to make a 'good faith effort' to generate 10 percent of their electricity from renewable energy.

## **5. Emission Credits:**

We support the idea that DG projects should be eligible to receive a credit for their impact in lowering utility system emissions. The Public Utilities Commission has set environmental externalities values for six pollutants (PM, SO<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub>, PB, CO), which are indexed for inflation. We suggest that these values be used as a basis for calculating the emission credit. In the case of NO<sub>x</sub> and SO<sub>2</sub>, market rates could be used in place of the externalities values. Markets do not appear to materialize for the other pollutants.

Since a DG project will displace a mix of electricity sources and not electricity generated by a particular plant on a utility's system, a credit can be designed by comparing the emissions from the DG project to the average emissions per kWh of a given utility's system.

If a renewable energy project seeks an emissions credit it should not also be eligible for the green credit. And the renewable energy DG project should have the right to keep the green attributes or "green tags" associated with the project. Unless the utility pays the renewable DG for the green attributes, those attributes should stay with the owner of the DG project.

## **6. Operational Efficiency Credits:**

We conclude that the operational efficiencies of a given project will be accounted for within the framework of the emissions credit as long as the emissions credit is based on the total energy output of a given DG project. So, in the case of the CHP project, both the electric and thermal output should be included in the calculation of emissions. This could be done by converting the Btus of thermal energy into kWh. This will ensure that CHP projects with the highest efficiency levels will receive the largest credit.

## **7. Reliability Credits:**

The reliability credit should be given on the basis of the DG system availability during utility's critical peak time. As part of the peak interruptible tariff, electric utility provides tiered controllable demand (kW) discounts to the peak interruptible customers on the basis of their performance factors (PF) where the higher performance factor customers attain more discounted controllable demand charges. Since the DG system operates continuously, it has a higher system reliability or performance factor. Comparatively, some DG facilities may have a higher performance factor than other DG facilities.

The current firm standby charges do not differentiate the system availability or performance factor within the DG class of customers. We recommend a similar tier approach should be established to discount the firm standby charges on the basis of DG reliability. Thus, the reliable DG systems should get discounted standby charges.

**Conclusion:**

Based on our preceding comments, the following table is an attempt to assign how credits can be applied towards the generation, transmission, and distribution. The net offset against the standby reservation fee could be positive or negative depending on how these credits benefit the grid.

**Table II**

| <b>Credits applied</b>             | <b>Generation</b> | <b>Transmission</b> | <b>Distribution (D1 and D2)</b> |
|------------------------------------|-------------------|---------------------|---------------------------------|
| - Distribution constrained credit: | -                 | -                   | Yes                             |
| - Transmission constrained credit: | -                 | Yes                 | -                               |
| - Diversity credit:                | Yes               | Yes                 | Yes                             |
| - Line Loss credit:                | -                 | Yes                 | Yes                             |
| - Reliability credit:              | Yes               | Yes                 | Yes                             |
| - Renewable credit:                | Yes               | -                   | -                               |
| - Emission credit:                 | Yes               | -                   | -                               |
| - Operational efficiency credit:   | Yes               | -                   | -                               |