June 27, 2003

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Reply Comments of the Minnesota Department of Commerce**
Docket No. E999/CI-01-1023

Dear Dr. Haar:

Attached are the reply comments of the Energy Division of the Department of Commerce in the following matter:

> Establishing generic standards for utility tariff for interconnections and operations of Distributed Generation Facilities.

These reply comments respond to comments filed by parties regarding issues developed in the rate workgroup conducted by the Department. The Department requests a 14-day extension to file its comments on the technical workgroup. The Department is available to answer any questions the Commission may have.

Sincerely,

EILON AMIT
Statistical Analyst

EA/sm
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

REPLY COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE

DOCKET NO. E999/CI-01-1023

I. BACKGROUND

On August 20, 2001, the Public Utilities Commission (Commission) issued an Order initiating the instant Docket. The purpose of this Docket is to establish generic standards for utility tariffs for interconnection and operation of distributed generation facilities. The Commission issued this Order to comply with Minnesota Laws 2001, Chapter 212, codified in relevant part at Minnesota Statute § 216B.1611, subd. 2 of that statute states:

> (a) The commission shall initiate a proceeding within 30 days of the effective date of this section, to establish, by order, generic standards for utility tariffs for the interconnection and parallel operation of distributed generation fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than ten megawatts of interconnected capacity. At a minimum, these tariff standards must:
> (1) to the extent possible, be consistent with industry and other federal and state operational and safety standards;
> (2) provide for the low-cost, safe, and standardized interconnection of facilities;
> (3) take into account differing system requirements and hardware, as well as the overall demand load requirements of individual utilities;
> (4) allow for reasonable terms and conditions, consistent with the cost and operating characteristics of the various technologies, so that a utility can reasonably be assured of the reliable, safe, and efficient operation of the interconnected equipment; and
> (5) establish: (i) a standard interconnection agreement that sets forth the contractual conditions under which a company and a customer agree that one or more facilities may be interconnected with the company's utility system, and (ii) a standard application for interconnection and parallel operation with the utility system.

> (b) The commission may develop financial incentives based on a public utility's performance in encouraging residential and small business customers to participate in on-site generation.

In addition, Minnesota Statute § 216B.1611, subd. 3 states the following, which describes the process which will occur subsequent to the Commission's decisions regarding the guidelines to be established in this process:

> Within 90 days of the issuance of an order under subdivision 2:
> (1) each public utility providing electric service at retail shall file a distributed generation tariff consistent with that order, for commission approval or approval with modification; and
> (2) each municipal utility and cooperative electric association shall adopt a distributed generation tariff that addresses the issues included in the commission's order.

On February 3, 2003 the Minnesota Department of Commerce (Department) filed its Final Report on Distributed Generation Technical Standards and Tariffs (Final Report). This Report was the final report of the rate workgroup. As will be discussed further in its subsequent comments on the technical group, the technical workgroup filed additional reports.

On February 18, 2003 the Commission issued a Notice that acknowledged receipt of the Final Report, requested comments and asked a specific question.

On March 18, 2003 the Department filed comments in response to the Commission's February 18, 2003 Notice.

On March 20, 2003 the following parties filed comments on the rate aspects of the Department's Final Report:

Investor Owned Utilities (IOUs or IOU group) including:

1. Dakota Electric Association (A cooperative that has elected to be subject to be regulated by the Commission)
2. Interstate Power & Light Company
3. Minnesota Power
4. Northern States Power d/b/a Xcel Energy
5. Otter Tail Power

Cooperative (Coop) including:

Great River Energy

The Distributed Generation Coalition (DGC) including:

1. CenterPoint Energy Minnegasco
2. Hennepin County
3. Institute for Local Self-Reliance
4. Izaak Walton League of America, Midwest Office
5. Korridor Capital Investments LLC
6. Minnesota Chamber of Commerce
7. Prairie Gen
8. The Minnesota Project

Municipal representatives:

1 The Minnesota Municipal Utility Association (MMUA)
2. Missouri River Energy Services – a municipal power agency

Below is the Department's discussion of each of the above groups' comments.

II. DISCUSSION OF THE PARTIES' COMMENTS

The Department discusses only the comments that disagree with the Department's positions. The discussion follows the same order of guidelines as appeared in the Department's Final Report.

A. QUALIFICATIONS

Section III, B.3 of the Final Report states that the customer may sell all or part of its generated power to the host utility. The IOU group argues that any such transactions are under the sole jurisdiction of the Federal Energy Regulatory Commission (FERC) and therefore, the Commission should defer to FERC rules.

The Department disagrees. One of the main purposes of Minnesota Statute § 216B.1611 was to establish uniform terms and conditions for a distributed generation (DG) tariff across all utilities in Minnesota. The Commission's Order directing that the workgroups be established stated that one of the goals of the rate workgroup was to:

> ...draft documents and guidelines for tariffs so that a person interested in developing distributed generation can apply for interconnection to any electric utility in the State with the expectation that ... prices charged for power supplied by the generator to the electric utility will reflect the value of power to the utility.

As such it was clear from the outset that the Commission intended that the tariffs would pertain not only to services provided by the utility to the customer, but also to power received by the utility from the customer. No party asked for reconsideration of the Commission's Order.

According to the IOU's argument, there exists no need to develop a DG tariff, because the only relevant DG's services are standby services to customers that self generate their own power needs. At a minimum, such an argument should have been made much earlier in the process. In particular it should have been made either before the Commission issued its June 19, 2002 Order initiating working groups or, certainly, after it was issued. The DG tariff applies to retail customers only and pertains to power supplied to the utility of which the DG owner is a customer, not to the wholesale market in general. As such this transaction could be viewed simply as a negative purchase of electricity when a DG customer sells power to the host utility. To summarize, the Department concludes that the IOU's argument is untimely and inappropriate.

B. AVOIDED COSTS ISSUES

1. Avoided energy costs

The IOUs argue that there is no need for a trial period to compare actual marginal energy costs to forecasted energy costs because it is inconsistent with the treatment of qualifying facilities and because of the short forecasting period (one year). While the IOUs have a reasonable argument, the Department recommends that, at least for the first year after implementing the tariff, utilities should be required to file a report comparing the monthly actual marginal energy costs with the monthly forecasted marginal energy costs. This approach is intended to balance the goals of keeping administrative costs low while providing adequate assurance that the forecasts of marginal energy costs are in a range of reasonableness.

2. Avoided capacity costs

a. IOU

- Normal life of capacity of 30 years.

  The IOU group argues that setting the capacity life at the expected life of the specific capacity addition outlined in the most recently approved resource plan is preferred to a "generic" 30-year assumed capacity life. The Department agrees, but notes that the length of the capacity life should be based on the specific characteristics of the added capacity, and not for example on the length of the power purchase agreement between Xcel and the vendor providing the additional capacity.

- Capacity needs.

  The IOUs argue that capacity needs should be determined on the basis of the utility's needs in the next five-year period rather than on the basis of its needs over the 15-year planning period. IOUs argue that the requirement to pay now for future needs:

i. violates the principle of paying for avoided costs only,

ii. provides the wrong price signal,

iii. results in utilities paying for services not needed or required, and

iv. requires current customers to pay for services provided to future, not current, customers.

The Department continues to support its position as indicated in Section III, F, under the heading Avoided Capacity Costs, part 4.d. for the following reasons:

- The customers only pay an amount equal to the present value of the costs of future capacity needs. The present value of such costs is an accurate representation of the avoided capacity cost.

- The DG capacity allows the utility to sell its own capacity in the wholesale market. Therefore, in such a case the avoided capacity cost is not zero, as argued by the IOUs, but the wholesale price for capacity. For the same reasons, the price signal is not the wrong price signal and the utility does not pay for unneeded services.

- Finally, if the utility is able to sell its capacity in the wholesale market, current ratepayers would not be charged with payments for future services.

b. MMUA

MMUA states that many municipalities operate under all-requirements contracts, and none of them have to file an integrated resource plan (IRP). Therefore, the avoided cost methods as well as the methods of determining needs may not be applicable to municipalities.

The Department agrees that the issue of avoided capacity cost as applicable to municipalities and cooperatives under an all-requirements situation may require a separate proceeding. Such a proceeding may take place after the Commission issues its Order under Subd. 2 of Minnesota Statute 216B.1611.

C. Standby Rates

1. Reservation fees

a. IOU

The IOUs argue that certain DG customers will not be able to meet their native load requirement at certain periods due to their DG's characteristics (for example Photovoltaic generation). Therefore, such customers should not receive the full discount provided by the standby rates. (The discount in standby tariffs pertains to generation and a large portion of transmission costs.)

The Department agrees with the IOUs. Standby rates are designed under the assumption that generation and some transmission costs can be avoided on the system when a customers self-generates their load. However, if the customer makes greater use of the generation and transmission system, such costs are not avoided. It is appropriate that all customers who contribute to the incurrence of such costs pay for the costs to avoid undue subsidies.

This issue is similar to the issue of a regular standby customer which exceeds the number of hours allowed for provisions of standby services during a specific time period. Utilities' standby tariffs have special provisions that pertain to periods when the utility is buying energy for excessive use of standby services. The Department recommends that the utility develop similar provisions for DG customers.

b. DGC

The DGC group agrees with the principle of setting standby rates based on the reserve margin approach. However, they argue that the current reservation fee structure is inappropriate and must be changed.

The Department disagrees with DGC, because DGC failed to provide valid analysis to support their argument.

2. Distribution

a. DGC

DGC makes a distinction between what they refer to as the "Non-Bulk" and "Bulk" components of the distribution system. "Bulk distribution," according to DGC, includes terminals, substations and other equipment used to move power into the distribution grid.

DGC argues that standby customers should get the same discount on bulk distribution as the discount provided for standby generation services.

The Department disagrees. First, the distinction between bulk and non-bulk distribution is not well defined. Moreover, the distribution costs are largely fixed costs that cannot be avoided, and therefore, no discount is appropriate on such a service for a standby customer.

3. Maximum size to avoid standby charge.

Both the IOU and MMUA object to exempting any DG customer, with capacity no greater than 100 kW, from paying the standby charges. Their main argument is that such an exemption is counter to the key rate design principle that customers should pay for their cost of service.

The department continues to support the 100 kW exemption rule for the reasons explained in its initial comments.

D. CREDITS

1. Distribution credits

Both the IOU and the Coop object to the requirement that each utility publish on the internet its annual distribution capacity planning study. They are concerned about security risks and question the usefulness of such a study.

The Department notes that providing information regarding the distribution system is a very important element of promoting DG services. However, to address concerns about publishing the information widely on the internet, the Departments notes that any potential DG customer should be able to receive the needed information by contacting the host utility. Therefore, the Department recommends that the annual studies mentioned above would be provided by the utility to any potential DG customer, upon such a request from the customer.

In addition, the utilities should provide copies of the annual studies to the Commission and the Department to keep on file. This report can be included in the report required under Minnesota Statute §§ 216B.1161, subd. 4(b):

> (b) Every electric utility shall file with the commissioner a distributed generation interconnection report for the preceding calendar year that identifies each distributed generation facility interconnected with the utility's distribution system. The report must list the new distributed generation facilities interconnected with the system since the previous year's report, any distributed generation facilities no longer interconnected with the utility's system since the previous report, the capacity of each facility, and the feeder or other point on the company's utility system where the facility is connected. The annual report must also identify all applications for interconnection received during the previous one-year period, and the disposition of the applications.

2. Renewable credits

The DGC group argues that a DG facility that provides green power should always be paid a renewable energy credit. The Department disagrees. The DG should be paid the avoided cost of renewable energy (i.e. receive a green credit) only if the DG allows the utility to avoid the purchase of "green power" elsewhere. Otherwise the utility should pay the DG customer the utility's avoided cost regardless of the type of DG facility.

3. Emission credits

The IOU group objects to the Department's recommendation that a DG customer be paid for the avoided costs of non-tradable emissions. They argue that such a compensation may impact the dispatch order counter to the Commission's intent in its Order regarding externalities values, and would result in the utility paying the DG while avoiding no actual costs.

The IOU group also states that the Department misrepresented the way in which a selected vendor is compensated for emission reductions.

The Department continues to support its initial recommendation for the following reasons.

First, the Commissions' externality Order simply did not deal with this issue directly, but stated that the externality values should be considered in all resource selection proceedings. The Department's proposal clearly does not violate the Commission's Order on externalities.

Second, an appropriate rate design would set rate as close as possible to the avoided societal costs, not just the avoided private costs. Since the DG would allow the utility's ratepayers to avoid some of the emission costs otherwise being imposed by the utility, the DG customers should be compensated accordingly for the reduction in emissions.

Finally, the Department did not misstate the way in which a selected vendor may be compensated for emission reductions. It appears, instead, that the IOUs did not understand the argument provided by the Department. The Department never argued that the vendor is paid directly for the emission reduction. Instead, the Department explained that when a more costly resource is selected because its societal costs (private plus emission costs) are lower than another resource with a lower private cost, the ratepayers are paying an additional amount to account for the lower emission rate of the selected resource with the higher private costs.

E. MUST BUY ISSUES

Missouri River Energy Service (MRES) claims that the "Must Buy" provision in the proposed DG tariff far exceeds the statutory mandate for the Department's report. It states that the DG statute (§216B.1611) has no requirement that the interconnecting utility must be required to purchase the output of the generator. MRES further states that § 216B.1611 stands in stark contrast to purchase requirements in Minnesota Statute § 216B.164, § 216B.1691 and § 216B.2411. The Department concludes that MRES's argument are without merit as explained below.

As noted above, Minnesota Statute § 216B.1611, subd. 2 requires the following:

> Subd. 2. [DISTRIBUTED GENERATION; GENERIC PROCEEDING.] (A) The commission shall initiate a proceeding within 30 days of the effective date of this section, to establish, by order, generic standards for utility tariffs for the interconnection and parallel operation of distributed generation fueled by natural gas or a renewable fuel, or another similarly clean fuel or

> combination of fuels of no more than ten megawatts of interconnected capacity. At a minimum, these tariff standards must:
>
> (1) to the extent possible, be consistent with industry and other federal and state operational and safety standards;
>
> (2) provide for the low-cost, safe, and standardized interconnection of facilities;
>
> (3) take into account differing system requirements and hardware, as well as the overall demand load requirements of individual utilities;
>
> (4) allow for reasonable terms and conditions, consistent with the cost and operating characteristics of the various technologies, so that a utility can reasonable be assured of the reliable, safe, and efficient operation of the interconnected equipment; and
>
> (5) establish; (i) a standard interconnection agreement that sets forth the contractual conditions under which a company and a customer agree that one or more facilities may be interconnected with the company's utility system; and (ii) a standard application for interconnection and parallel operation with the utility system.
>
> (b) The Commission may develop financial incentives based on a public utility's performance in encouraging residential and small business customers to participate in on-site generation.

That is, subd. 2 requires the Commission to initiate proceedings to develop DG tariffs which apply uniformly to all the utilities in Minnesota. Subd. 2 also sets minimum requirements for the tariff, but otherwise allows the Commission's initiated proceeding to determine the appropriate terms to be included in the tariff. Nowhere in Minnesota Statute § 216B.1611 are there requirements to exclude certain terms and conditions from the DG in general, or to exclude a "must buy" provision in particular. In short, other than the minimum requirements in Subd. 2, the terms and conditions of the tariff are left to be determined by the process set by the Commission. Based on the above discussion it is clear that MRES's claim has no basis.

MRES also claims that the language in Subd. 2 of Minnesota Statute § 216B.1611 stand in stark contrast to the explicit purchase requirements in Minnesota Statute § 216B.164 (Qualifying Facilities), Minnesota Statute § 216B.1691 (Renewable Energy Objectives) and Minnesota Statute § 216B.2411 (Distributed Energy Resources). First, the Department observes that only Minnesota Statute § 216B.164 sets specific purchase requirements. Second, the language in the above mentioned statutes may be more specific than the language in Minnesota Statute § 216B.1611. However, the more general language in Minnesota Statute § 216B.1611 by no means denies the Commission the right to include a "must buy" provision in the DG tariff. The Department concludes that the comparison between Minnesota Statute § 216B.1611 and the other Minnesota statutes mentioned by MRES is irrelevant to the issue of a "Must buy" provision.

III. CONCLUSIONS AND RECOMMENDATIONS

A. CONCLUSIONS

Based on its review and analysis of parties' comments, the Department concludes that:

1. MRES's claim that the Department exceeded the statutory mandate in its report, particularly with respect to the "must buy" provision is without a merit, and

2. the methods of determining avoided costs and resource need for municipalities and cooperatives operating under all requirements contract may need to be determined in a separate process, that may be initiated by the Commission after its Order setting the DG tariff guidelines for electric utilities in Minnesota.

B. RECOMMENDATION

The Department continues to recommend the same guidelines proposed in Section III of its DG Final Report to the Commission with the following exceptions:

1. Avoided Capacity Costs.

   The assumed life of a capacity addition should be the same as the expected life of the type of capacity needed by the utility as indicated in its IRP instead of the generic 30 years previously recommended by the Department.

2. Upon a request from a potential DG customer, the utility should allow the customer access to its annual distribution capacity planning study (this provision substitutes for requiring utilities to publish their annual studies on the internet). In addition, utilities should file copies of the annual distribution capacity planning studies with the Commission and Department.

/sm