STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC REGULATED ELECTRIC UTILITIES COMMISSION

LeRoy Koppendrayer	**Chair**
Ellen Gavin	**Commissioner**
Marshall Johnson	**Commissioner**
Phyllis Reha	**Commissioner**
Gregory Scott	**Commissioner**

In the Matter of Establishing Generic Standards For Utility Tariffs for Interconnection And Operation of Distributed Generation Facilities	Docket No. E-999/CI-01-1023 March 21, 2003

COMMENTS OF REGULATED ELECTRIC UTILITIES

I. INTRODUCTION

These consolidated comments are submitted by Dakota Electric Association (Dakota Electric), Interstate Power and Light Company (Interstate or IPL), Minnesota Power (MP), Northern States Power Company d/b/a Xcel Energy (Xcel Energy) and Otter Tail Power Company (Otter Tail or OTP) in the above-referenced matter[1]. Specifically, these comments: (i) address the question posed by the Minnesota Public Utilities Commission (Commission) in its February 18, 2003 Notice; and (ii) respond to the "*Report on Distributed Generation Technical Standards and Tariffs*" submitted by the Minnesota Department of Commerce (Department or DOC) on February 3, 2003 (Department Report).

[1] collectively, the "regulated electric utilities"

II. RESPONSE TO QUESTION IN COMMISSION MEMO

On February 18, 2003, the Commission issued its "*Receipt of Workgroup Report and Establishment of Comment Periods*." In its Notice, the Commission stated that it would like to hear comments from interested persons regarding the remaining unresolved issues. The Commission also stated that it would like to hear why distributed generation (DG) tariffs should be limited to retail electric service customers of electric utilities as opposed to being available to an investor with no on-site load independent of occasional station power needs. The regulated electric utilities respond to the Commission's question regarding the scope of the DG tariffs by addressing two issues: a) ownership of DG facilities (i.e., customer versus third-party) and b) use or function of DG facilities (i.e., merchant versus non-merchant).

A. <u>Ownership</u>

The regulated electric utilities believe that a DG facility may be owned by a customer, utility, third party or any combination thereof. The generic interconnection standards being developed in this proceeding will be applicable to all DG interconnected to one of the regulated utilities in order to maintain public safety and system reliability, regardless of ownership. While ownership may vary, the regulated electric utilities believe that it is critical that the ownership of the DG unit be clearly identified as it relates to equipment operation and maintenance, compliance with utility and other requirements, as well as legal liability.

B. <u>Use (or Function)</u>

The regulated electric utilities believe that merchant DG facilities are outside the scope of this docket. Minnesota Statute 216B.1611 (Statute) itself limits the application of the DG tariff to transactions between a utility and a customer of that utility. In addressing the requirements of the tariff, the Statute refers to establishing "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." The Statute further states that "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, early in this process, the rate workgroup (Rate Workgroup or Workgroup) appeared to agree that the scope of this docket is limited to services provided between a utility and a retail end use customer installing DG.

At the September 18, 2002 Rate Workgroup meeting, the issue was raised whether discussions should include sale of power from distributed generators to the wholesale market in general (i.e., the DG facility selling power to entities other than the electric utility of which they are a customer and to which they are interconnected). At that time, the Department clarified that the scope of the Workgroup, as indicated in the Commission's June 19, 2002 Order, is focused on two aspects of DG: utilities providing interconnection and backup service to DG customers, and utilities buying power services from DG customers.

At the October 9, 2002 meeting, the Department restated that the scope of the Rate Workgroup does not extend to sales by DG owners to the wholesale market in general. A DG owner may seek to make such sales by qualifying as an exempt wholesale generator under the federal rules and regulations. At the October 9 meeting, the Workgroup appeared to agree that merchant DG plants (e.g., those that have no retail load and are dispatchable) are outside the scope of this proceeding. Since they are not native load retail customers, such plants would likely be exempt wholesale generators under federal regulations.

Finally, at the November 18, 2002 meeting, it was noted that Minnesota law allows qualifying facilities to wheel power through their incumbent utility to another Minnesota utility that needs power (Minnesota Statute 216B.164, subd. 4(c)). The regulated utilities already have tariffs on file with the Commission providing the contractual terms and rates for purchases from or transmission services for qualifying facilities. In addition, wheeling power produced from all other sources is a required service for which the utility must charge a distribution wheeling fee. The Department stated that any DG owner that wants to negotiate with the utility to have the utility act as an agent to sell their power on the open market could do so. However, the Department stated that such transactions would be at the wholesale level, beyond the jurisdiction of the Commission and subject to federal regulation.

III. PROPOSED GUIDELINES

The regulated electric utilities commend the Department for the work efforts they conducted to bring the differing viewpoints together and forge consensus where it was achievable. As the Department points out in the report, there are issues where consensus was not reached and the regulated electric utilities offer in these comments, explanation of the regulated electric utilities' views on these. The key issues in which the regulated utilities differ from the recommendations presented by the Department are as follows:

- the need for a trial period and true-up on the payment for energy purchased from DG facilities
- specific assumptions for determining a reference for capacity value
- requirement to pay for capacity in advance of need
- the option for up-front payment of stranded distribution facilities
- elimination of standby requirements for DG facilities between 40 kW and 100 kW in size
- cost responsibility for distribution studies
- payment for non-tradable emissions credits

In addition to the comments offered on these issues, the regulated electric utilities provide clarification and expansion on many of the other issues presented in the Department's Report.

A. <u>Availability</u>

The purpose of the Statute is to "establish the terms and conditions that govern the interconnection and parallel operation of on-site DG." The regulated electric utilities clarify that, although the minimum standards contained in the "*Proposed State of Minnesota Requirements for Interconnection of Distributed Generation*"[2] applies to DG customers that are interconnected in parallel with a utility system for any length of time, the DG tariff is applicable to continuous parallel operation only.

[2] See the Technical portion of the Minnesota Department of Commerce Report on Distributed Generation Technical Standards and Tariffs, February 3, 2003

B. Qualifications

Must-Buy Qualification

The must-buy obligation is established by the requirement to file the DG tariff with the Commission. While the regulated electric utilities agree with the Department's conclusion that it is the intent of the D G tariff that the host regulated utility buy the entire net output of the DG facility, this statement is more of an obligation of the host utility rather than an eligibility qualification of the DG customer. In addition, while the must-buy obligation applies both to the energy and the capacity provided by the DG customer, as will be discussed later, an important part of the must-buy obligation is the price the utility must pay for the capacity. The regulated electric utilities believe the Commission should determine that they must pay the DG customer for the capacity under this must-buy (pay for) obligation only if the utility actually needs the capacity. Furthermore, the utility should not be required to buy more capacity than is needed.

Customer Options Qualification

The Federal Energy Regulatory Commission (FERC) has ruled that it has exclusive jurisdiction over any small generator (20 MW or less) that "makes wholesale sales in interstate commerce at either the transmission or distribution voltage level."[3] This sale condition includes sales to the host utility on a full or partial basis. Therefore, the Commission should rule that in two of the three options identified for potential operation of the DG facility, the rules ultimately promulgated through the FERC rulemaking on Standardization of Small Generation Agreements and Procedures will govern. Even when these rules are formalized by the FERC, as will be discussed later, the DG customer still has options regarding the services purchased from the utility.

C. List of Supply Services to be Priced

[3] FERC Docket No. RM03-12-000, Standardization of Small Generation Interconnection Agreements and Procedures, Advance Notice of Proposed Rulemaking, Issued August 16, 2002.

Attached as Exhibit A is "*Distributed Generation Menu of Services – Utility to DG Customer*" extracted from the "*Distributed Generation Menu of Services - 12/19/02 Draft"*, which was developed during the Rate Workgroup discussions. All drafts were distributed to the Workgroup members and maintained on the Institute for Local Self Reliance website[4] created to facilitate information exchange during the Workgroup process. Discussions that led to the creation and ongoing revisions of the DG menu of services (Menu of Services or Menu) are highlighted in the minutes of the August 7, 2002 and September 4, 2002 Rate Workgroup meetings.

This Menu contains the services provided by the utility to the DG customer that must be included in a comprehensive DG tariff. The regulated electric utilities suggest that the list contained in the Department Report be expanded to include Interconnect Services (Section I. A.) and Delivery Services (Section I. C.) as well as the full list of Supply Services (Section I. B.).

Following is a listing of the Interconnect, Supply, and Delivery Services from the Menu of Services:

I. FROM UTILITY TO CUSTOMER

A. INTERCONNECT SERVICES

1. Engineering/Design Studies
2. Utility System Upgrades
3. Testing
4. Operating Services (Optional)

B. SUPPLY SERVICES

1. Backup Services

[4] http://www.newrules.org/dgtariff/

2. Supplemental Service

3. Economic Dispatch Service

4. Station Power

5. Residual Retail Service

6. Net Metering

C. DELIVERY SERVICES

1. Transmission Service

2. Distribution Service

3. Indirect Services

4. Ancillary Services

In addition, the regulated electric utilities suggest that the summary definitions of Scheduled Maintenance Service, Unscheduled Outages, and Supplemental Service contained in Section III. C. of the Department Report be replaced with the more comprehensive definitions from Section I. B. of the Menu of Services.

D. <u>Principle of Setting Rates for Services Provided by DG Customers to Utilities</u>

The regulated electric utilities concur with the Rate Workgroup position that "encouraging" DG means removing barriers, not requiring other customers to subsidize DG. The work completed by the technical and rate Workgroups in this proceeding have removed barriers by standardizing and simplifying the:

- Customer application;
- Review and installation; and
- Tariffed services (i.e., pricing and conditions).

There are two key concepts included in the principle specified in the Department Report pertaining to setting rates for services provided by DG customers to utilities. First, rates should reflect the value of the DG to the utility and its customers. Second, this value should reflect the utility's avoided costs on the generation, transmission and/or distribution system. The regulated electric utilities concur with these two key concepts in this principle.

E. <u>Principle of Setting Rates</u>

The Department summarizes this principle as follows:

> *Rate should reflect the costs the utility expects to avoid.*
> *To the extent practical, these costs should reflect*
> *seasonal and peak/off-peak differences in costs.*

The Department Report indicates that this principle applies to the prices paid both for the energy and capacity purchased from DG facilities and for the services provided by utilities to DG customers. The calculation of avoided costs for capacity and energy purchased from DG facilities is described in greater detail in Section F of the Department Report.

A necessary extension of the principle of setting rates relates to the services provided by utilities to DG customers. The Rate Workgroup discussed other cost principles in addition to avoided cost -- including the concepts of both incremental and embedded costs. Incremental costs include direct costs associated with interconnecting a DG facility to the utility's system, such as the cost of distribution plant improvements or reconfiguration and required metering. The utility must ensure that the rates paid by customers that install DG facilities provide at least sufficient revenue to cover the utility's incremental cost of providing service to those customers. This approach will ensure that non-participating customers are not economically disadvantaged by the action of customers choosing to implement DG.

Beyond incremental costs, rates applicable to DG should also reflect the utility's embedded expenses of operation and maintenance, customer accounts, customer service and information, administrative and general, depreciation, interest and taxes – which are allocated equitably to all other customers. Application of this embedded cost principle would ensure that any standby rates are fair in the sense that DG customers who impose the same costs on the electric system as non-participating customers would pay their fair share through similar rates. Customers who take traditional bundled retail service and use the generation, transmission and distribution facilities of the regulated utilities must pay these costs. DG customers do not take bundled services, but the entire integrated system makes it possible for the DG facility to function as intended. As such, DG customers should make their fair contribution to system cost recovery.

F. Calculation of Avoided Costs

Avoided Energy Costs

The regulated electric utilities confirm their understanding that the calculation of avoided energy costs will follow the same methodology used by each utility in their respective annual Cogeneration and Small Power Production Tariff[5] filings for qualifying facilities, with the exception that average on-peak and off-peak marginal energy costs are calculated for each month. Thus, there are 24 rates set for the year, with an on-peak and off-peak rate set for every month.

The regulated electric utilities disagree with the use of a trial period to determine whether, in practice, utilities are able to forecast these energy prices sufficiently well. Depending on the trial results, it was proposed that a lump sum true-up might be used at the end of the year to reflect the difference between actual and estimated energy bills. The regulated electric utilities disagree with the use of a trial period and true-up for the following reasons:

a. The current method used to determine avoided energy costs in the utilities' annual Cogeneration and Small Power Production Tariff filings has been accepted for qualifying DG facilities for many years. There is no requirement, or need, for a trial period or true-up for DG facilities qualifying for service under this existing methodology.

b. The avoided energy costs are based on a one-year forecast. No adjustment should be necessary for such a short-term forecast. Furthermore, imposing an adjustment for a one-year energy forecast is inconsistent with the assumption that there is no need for an adjustment to reconcile a 5- to 15-year capacity estimate.

c. If a trial period is mandated, a mechanism for both a true-up as well as a true-down should be instituted -- the error in the forecast could go either way. This type of adjustment, however, would not only increase administrative costs to the utility, but would also increase the risk to the DG customer of fluctuating energy payments.

d. The total energy generated from DG facilities is not expected to be substantial during the suggested trial period, while the administrative costs for individual regulated utilities to calculate the true-up could be substantial. The rates need to be reasonable, and use of the existing methodology provides both predictability and administrative ease.

Avoided Capacity Costs

The regulated electric utilities would like to make the following minor clarifications with respect to avoided capacity costs:

a. The regulated electric utilities' confirm their understanding that the calculation of avoided capacity costs will also follow the same methodology used by each utility in their respective annual Cogeneration and Small Power Production Tariff filings.

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[5] http://www.revisor.leg.state.mn.us/arule/7835/

b. The regulated electric utilities agree that the avoided capacity costs calculated in this manner should be escalated annually by an expected inflation rate; however, an escalation rate directly affecting the value of the new capacity addition (e.g., Handy-Whitman Indices) should be used rather than a general inflation rate.

c. The regulated electric utilities agree that the need for capacity should be established in the utility's <u>most recently approved integrated resource plan (though only in the five year action plan timeframe)</u>; however, the calculation of avoided capacity cost depends on identifying the type of capacity need (i.e., peaking capacity versus baseload capacity). That is, that the capacity payment should be based upon the type of capacity actually *needed* by the utility, not the type of capacity *provided* by the DG customer. In addition, the regulated electric utilities should be permitted to reserve the right to limit the capacity purchased from DG customers to that amount identified as needed by the utilities in their respective integrated resource plans. If there is no limit tied to the capacity purchase, the possibility exists for the utility to be required to purchase new capacity well beyond its needs as approved by the Commission.

d. The regulated electric utilities also understand that a capacity payment will be made only for accredited capacity and that in order to receive accreditation, the DG customer must not only complete periodic URGE testing, but meet any other accreditation requirements established by the historic regional power pools (i.e., MAPP, MAIN) or their successor entities such as the Midwest ISO. It should also be noted that there are different accreditation tests utilized for different generation resources. For example, in MAPP, wind generation resources typically fall under a Variable Capacity accreditation procedure. On the other hand, a natural gas-fired generator dispatched by the utility would fall under a Thermal Capacity accreditation procedure.

The regulated electric utilities would also like to identify the following areas of disagreement with the Department:

a. The regulated electric utilities disagree with the Department's assumption that the "normal life" of a capacity addition is 30 years. Instead, the regulated electric utilities recommend using the expected life for the specific capacity addition outlined in the utility's most recently approved integrated resource plan. Use of a standard 30-year life will be problematic under several circumstances. For example, if the utility's integrated resource plan identifies a capacity need that is only a few years in duration (e.g., if the next capacity addition is a short-term purchase), setting a "normal life" of 30 years would be incorrect. Or, if the "normal life" of the generation technology is unknown or unproven (e.g., micro turbines), automatically setting the "normal life" at 30 years may not be prudent.

b. The regulated electric utilities disagree with the Department criterion of 15 years as an indicator of capacity need. Instead, the regulated electric utilities recommend that a capacity payment be made only if the utility's most recently approved integrated resource plan shows a capacity deficit in the five-year action plan timeframe. This is a compromise position between:

    i. the Department's current recommendation that the need for capacity exists if the utility shows a deficit at any year of the 15-year planning period of its most recently approved integrated resource plan; and

    ii. the regulated electric utilities' original position that if capacity is not needed by the utility at the time of the contract with the DG customer, the utility should not be required to provide a capacity payment to the customer. This position is identical to what is allowed under the federal Public Utility Regulatory Policy Act (PURPA).

The regulated electric utilities believe that the rate principles and scope established by the Rate Workgroup in this docket support the position that if capacity is not needed by the utility, the utility should not be required to provide a capacity payment to the DG customer. That is, if the utility's avoided capacity cost is zero, the value to the utility of capacity from the DG customer is zero, and therefore the rate paid for such capacity should be zero.

At the September 18, 2002 DG meeting, the Workgroup agreed on the following overall principle to be used in discussions for setting rates for the power purchased from a DG customer:

> ***Rates should reflect the value of the distributed generation to the utility, including any reasonable credits for emissions or for costs avoided on the generation, transmission and/or distribution system.***

Furthermore, in pricing the value to the utility of energy and capacity service from a DG facility for any purchases the utility must make, the Department proposed the following principle at the October 9, 2002 meeting:

> ***Rates should reflect the costs the utility expects to avoid. To the extent practical, these costs should reflect seasonal and peak / off-peak differences in costs.***

These rate principles lay the groundwork for establishing the use of avoided costs to price services provided from a DG customer to the utility. Following the intent of these rate principles, it is clear that if capacity is not needed by the utility to which the DG is interconnected, the utility should not be required to provide a capacity payment to the DG customer. That is, if the utility's avoided capacity cost is zero, the value to the utility of capacity from the DG customer is zero, and therefore the rate paid for such capacity should be zero.

As described above, at the September 18, 2002 meeting, the Rate Workgroup also agreed that promoting DG means removing barriers rather than requiring other customers to subsidize DG. If the utility's avoided capacity cost is zero, current utility customers should not be required to pay now for future capacity additions. Levelizing capacity payments to account for a purchase of capacity from a DG customer before there is an established need for capacity by the utility, while reducing the impact, still leaves <u>current customers paying for future capacity additions</u>. Many factors support this argument that a current payment for a forecasted capacity addition is neither just nor reasonable. These factors include the uncertainty of a long-term forecast (e.g., load loss) and the fact that the DG customer, when not under a must-sell obligation, could decide to sell elsewhere, scale back or cease operations.

At the October 9, 2002 meeting, it was noted that the value of capacity during peak periods should be recognized as being more valuable than the value of capacity at off-peak times. At a minimum, prices paid should reflect differences in summer and winter (seasonal) costs and, preferably, peak and off-peak period costs. The connection of DG units will impact the utility's least cost economic dispatch by, in effect, creating a "must run" operation that reduces the need for generation or purchases from other resources. Avoided costs should include the costs of purchases the utility avoids making in the wholesale market to serve retail customer's needs. The Workgroup generally agreed that gathering detailed information becomes cost-prohibitive at some point, but the better the available information, the more efficient the system becomes in terms of encouraging DG customers to produce power when it is more valued in the utility's system. Following that pricing logic, <u>providing capacity payments when the utility's capacity need is zero sends the wrong price signals to DG customers</u>. The capacity should be priced based on its value to the utility. The utility or its other customers should not be required to subsidize the business plans of the DG customer.

At the November 18, 2002 meeting, some participants stated that they do not wish to pay for services from the utility that are not required (e.g., standby). Under that same argument, using a 15-year planning period versus a five-year planning period could cause the utility to pay for service not required or needed. <u>Overpayment for capacity can occur when a utility purchases capacity that is beyond what is needed</u> (i.e., used and useful principle). By setting the planning period too far out in the future, the likelihood of overpaying for capacity increases.

Finally, <u>the use of a five-year timeframe is also consistent with the rationale for determining capacity need in other forums</u>. Consider the planning period criterion of PURPA and of the Minnesota Cogeneration and Small Power Production Tariff filings, as shown in Exhibit B., the PURPA criterion can be zero years (for further explanation, see Note 1 in Exhibit B). That is, if there is no immediate need for capacity, then the avoided capacity cost is zero, and no capacity payments are made. Basing capacity payments only on immediate need is consistent with the use of higher eligibility size of 80,000 kW allowed under PURPA. That is, use of a planning period would put the utility at a greater risk due to the high eligibility size. On the other hand, the Cogeneration and Small Power Production Tariff filings use a planning period of up to 10 years; however, the eligibility size of these offerings is only up to 100 kW – a much smaller risk for utilities. Therefore, a five-year planning criterion for an eligibility size up to 10,000 kW is more reasonable and in line with the rationale for determining capacity need established in other DG forums.

G. <u>Standby Rates</u>

The Rate Workgroup spent a significant amount of time ensuring that all aspects of the services that utilities must provide to DG customers were understood. To achieve this objective, the service components were separately identified or unbundled in order to develop the appropriate charges or credits. For example, the various components of backup service for DG customers are separately listed in the Department Report.

While there was consensus on the need to have backup service options available to DG customers, not all utilities currently offer tariffs for all the different services proposed for DG customers. Therefore, appropriate terms and conditions must be developed for DG facilities. In some cases, existing utility standby or supplemental tariffs may be appropriate; however, with the potential addition of technologies and situations that were not contemplated when those tariffs were developed, utilities may be required to develop new or expanded backup service tariffs. Also, some types of backup services discussed by the Rate Workgroup (e.g., economic dispatch, station power) have never been provided by utilities in Minnesota.

General

The consensus of the Rate Workgroup was that DG customers do not have to buy standby ***generation supply***. As discussed in Paragraphs 2.b., 2.c., 2.d. and 3.c. of the Department Report, DG customers must pay for distribution and transmission facilities through the charges contained within the utilities' standby and/or supplemental service tariffs. Finally, if the DG customer elects not to buy standby generation supply, the utility will not plan for this service and it ***will not*** be available to the DG customer (as opposed to the statement in the Department Report that it ***may not*** be available).

Firm Service

The Department is correct that there was not agreement on how to price the different components of standby services. The Department's recommended guidelines represent one approach. The regulated electric utilities offer further discussion on this for the benefit of the Commission.

a. Generation

The regulated electric utilities agree that all energy delivered to backup a DG customer's load would be charged at the full cost of serving that load; and clarify that only the capacity charges would be subject to the recommended 82 to 85 percent discount. That is, that the reserve margin discount concept is used only in calculating the <u>capacity</u> component of standby rates.

The regulated electric utilities agree that to the extent the DG is able to meet part of the capacity needs of the load on the system, the charges for the utility to backup that capacity should reflect that ability. One approach to reflect this is to treat the DG customer as having met the load serving capacity requirements of the load served by their generation and have the utility provide reserve capacity requirements through the backup service. Therefore, if the DG customer's generation has been accredited under MAPP or MAIN URGE test requirements, then an approach where the backup reservation fee is set based on the reserve margin level (e.g., 15% to 18%) will in fact yield a 82 to 85 percent discount of the generation capacity charge as compared to a customer that does not install its own generation.

The key requirement to the approach described by the Department, however, is that the customer owned DG must in fact be able to meet the load serving capacity requirements of the load served by the DG. Most of this will be taken into account through the URGE test requirements; however, because the DG owner retains control over when the generator will be used and will make decisions based on their individual needs as opposed to generation that is operated to meet system needs, additional examination of the expected operation of the DG generation is needed.

Therefore, an integral part of setting the appropriate charges for providing backup service to a customer is the performance characteristics of the DG generation. For example, a photovoltaic generator that produces power when the sun is the brightest has a high likelihood of being able to meet its load serving capacity requirements during the summer season and, therefore, would be able to meet the performance commitments that would justify the Department's recommended approach for charging for backup service. However, during the winter season, the greatest load serving requirements will be during the coldest and potentially darkest timeframes. Thus the photovoltaic generator will not be able to meet the load serving capacity requirements of the load being served by the generation. In this case little or no discount in capacity charges is justified because the performance characteristics of the customer-owned DG leaves the utility with all of the capacity requirements for the load (load serving and reserves).

In summary on this issue, the determination of the appropriate charges for providing backup capacity supply to a DG customer is highly dependent on the performance characteristics of the specific generator.

b. Transmission

The Department recommends following the transmission pricing approach used by one utility in its existing standby service tariff. At the time that tariff was brought to the Commission for approval, the regulatory treatment of transmission was considerably different than it is today. Without elaborating on those differences, the Department Report should recognize that the terms, conditions and charges for transmission service are subject to the individual utilities' or MISO Open Access Transmission Tariffs (OATT) or their successors as approved by the FERC. Standby and other ancillary service charges for the transmission needs of DG customers must comply with those requirements and provisions.

c-d. Bulk/Non-Bulk Distribution

The conclusion reached by the Rate Workgroup and captured in the Department Report is that there is no basis for treating certain parts of the distribution system differently from other parts for ratemaking purposes. Therefore, the DG customer must pay for all of the distribution system needed to meet its service requirements. The regulated electric utilities, therefore, recommend that the terminology distinction between "bulk" and "non-bulk" distribution be removed.

Non-Firm

The regulated electric utilities agree that in a truly non-firm backup service situation, elimination of the reservation fee for parts of the backup service is appropriate. The key is determining if a non-firm backup situation can actually exist. In the most straightforward sense, this type of service means that the DG customer has no assurance that there will be sufficient generation, transmission and distribution available to back up the load served by the DG facility when the generator is out of service (or at reduced operation). The DG customer must first ask the utility if there is available generation, transmission and distribution supply to back up the load for customer generation outages. If there is not available backup generation, transmission or distribution supply, the load that is served by the DG facility must be shut down when the DG facility is taken out of service.

Clearly, non-firm backup service will not be appropriate in all situations. Many customer load types will not be able to operate on a non-firm basis and it will be up to the customer to determine the appropriateness of non-firm backup for their load. More importantly, however, the utility facilities may not be suitable for provision of non-firm backup supply. In spite of what will be a contractual requirement for DG customers taking non-firm backup service to ask permission before using backup service from the utility, instantaneous backup of the customer load will take place for unplanned (forced) outages of the DG facility.

If the utility's system is not capable of safely and reliably providing this backup on an instantaneous basis because of capacity limitation (generation, transmission or distribution), the first option given to the DG customer is to have them pay for system upgrades to allow for the backup services requested. If the DG customer is not willing to incur these costs, then the utility cannot provide non-firm backup service. This is because in spite of the contractual agreement for the backup service to be non-firm, the instantaneous operation of the electrical system will not be constrained by the contract.

The regulated electric utilities propose that non-firm service be excluded from the standard tariff because of these safety and reliability limitations and, instead, recommend that the service be available on a negotiated, case-specific basis. As an alternative, utilities may offer non-firm backup service that is physically protected from forced outages of the DG facility. This "physical assurance" protecting the electric system from outages of the DG facility is discussed in the next section.

a. Generation

As discussed above in the section addressing generation for firm backup service, the appropriate level of charges for load serving capacity requirements is dependent on the performance characteristics of the specific generator of the DG customer. This is just as necessary for non-firm backup service as it is for firm.

b. Transmission

The charges and provisions of transmission service for non-firm backup to DG customers is also subject to the individual utilities' or MISO OATT or their successors as approved by the FERC.

c-d. Bulk/Non-Bulk Distribution

The regulated electric utilities agree with the Department that the customer must pay for all of the distribution system needed to meet their service requirements.

Physical Assurance

The regulated electric utilities are not opposed to the use of a device that provides physical assurance that no backup generation capacity service is required of the host utility. However, the following additional comments are offered:

First, the charges and provisions of transmission service for physical assurance backup to DG customers are also subject to the individual utilities' or MISO OATT or their successors as approved by the FERC. Further, the concept of physical assurance is new to regulated electric utilities in Minnesota and as such, no terms and conditions of this service have been specifically developed. While physical assurance type backup service has been provided by utilities in other parts of the country, careful development and approval still needs to be done for each of the regulated electric utilities under the Commission's jurisdiction.

Upon further review, the regulated electric utilities also recommend against the option to pay up-front for stranded distribution facilities. The reasons for this position are:

- Stranded investment cost determinations are always controversial both in determining what facilities are stranded and what costs should be assigned to them.
- Installation of DG facilities may not be permanent or even long-term. Therefore, the stranded facilities cost compensation may need to be "undone" if and when the DG facility is no longer in service.
- Customers at service points change periodically and tracking which customer has which rights/obligations over time may become administratively burdensome.

This cost issue is not unlike those faced by utilities concerning other facility charges for retail customers. For example, at one time Xcel Energy offered customers the option of paying the additional cost of underground distribution service to the residential location through either an up-front lump sum payment or through a monthly increase in their customer charge. Keeping the status of this option election straight for an individual customer versus a service address, in combination with the differing approaches on how a housing developer may elect to use the option, soon became very problematic. Xcel Energy elected to eliminate this option and required that all underground customers be treated the same (i.e., no up-front payment offered).

Given the potential problems with up-front payments for stranded distribution costs and the past experience utilities have had with keeping these option elections straight, the regulated electric utilities recommend that the Commission not offer the suggested option and instead require DG customers to pay for distribution facilities through traditional monthly rates.

Maximum Size to Avoid Standby Charges

The suggested compromise to allow DG customers sized between 40 kW and 100 kW to escape paying their full cost of receiving backup service from the utility is in conflict with the principles of setting rates discussed early in the Department Report. The Department even acknowledges that there is no economic justification for this proposal.

Following the rate principles adopted by the Rate Workgroup, all DG customers should be required to pay the full cost of providing backup service, regardless of the DG size. It is inappropriate to suggest that this subsidy to DG customers of 100 kW and below is acceptable because the effect on other customers will be of "no significant impact".

The Commission has already reviewed the appropriateness of providing subsidized backup service to customers in the 40 kW to 100 kW range in Xcel Energy's Distributed Generation Filing (Docket No. E-002/M-01-937). As a result of its review in that Docket, the Commission has already agreed with the proposal to eliminate this rate subsidy for DG customers over 40 kW in size.

H. <u>Credits</u>

Distribution Credits

The regulated electric utilities agree with the Department's characterization that the Rate Workgroup reached consensus on the concept that distribution credits to a DG customer should equal the utility's avoided distribution costs resulting from the installation of the DG facility. The Department further recommends a process for identifying likely geographic areas where distribution credits would be applied. The first step of this process would require each utility to publish on the internet its annually conducted distribution capacity planning study that identifies capacity needs, upgrades and load growth on area distribution feeders. This recommendation poses three concerns for the regulated electric utilities. First, there are security concerns about identifying potentially vulnerable distribution areas on the internet. The FERC in responding to this very concern has just modified its rules for the interstate transmission system so that this type of information in not on the internet. Such information could be used for purposes other than intended. Second, not all regulated electric utilities necessarily conduct an annual distribution capacity planning study. Third, the regulated electric utilities question the value of publishing an entire distribution capacity planning study on the internet. If the purpose of this first step is to identify likely areas, it may be more prudent to simply provide a list of substation areas or feeders to potential DG customers that could be likely candidates for distribution credits. Such information would be provided at a customer's request and would be treated as confidential.

The Department then indicates that, upon receiving a DG application, the utility will perform an initial screening study to determine if the DG project has the potential of receiving distribution credits. The Department recommends that the DG customer be responsible for the cost of such a screening study. The regulated electric utilities concur with this initial screening step and having the customer be responsible for the cost of this study. Finally, the Department recommends that, if the initial screening study shows a potential for distribution credits, the utility must then, at its own cost, pursue further study to determine the distribution credit as part of its annual distribution capacity study. The regulated electric utilities concur that, if this more detailed study is part of its routine distribution capacity study, then the customer will not be responsible for additional costs. However, as noted above, electric utilities do not always conduct such annual studies. If a customer requires a study prior to the utility's next scheduled distribution capacity study, or the study requires work beyond this normal study, then the regulated electric utilities recommend that the customer should pay for such special studies.

Renewable Credits

The regulated electric utilities would like to emphasize the following three points regarding renewable credits:

- Utilities should be required to pay DG customers a renewable premium only when the utility needs more renewable power either as part of a program to sell renewable energy to customers or to meet other renewable objectives;
- DG facilities must be certified for participation in a renewable program; and
- Utilities should make such DG purchases at no more than the avoided cost of renewables the utility would have otherwise purchased.

The Rate Workgroup discussed a number of possible credits to be provided to renewable DG installations. The regulated electric utilities note that renewable DG projects will already receive the benefit of externality-based credits in that renewable DG projects will be evaluated within the context of the avoided externality benefits as identified by the Commission. This evaluation, including the price paid by the utility, occurs through the integrated resource planning process. Although DG customers are not included in the utilities' integrated resource planning, they will still benefit from the avoided cost-setting part of that process. Although the delivered price of a renewable DG project may be higher than other alternatives in the resource plan, the project may be selected as the next resource after consideration of such externality benefits. The cost of this higher priced resource is then already reflected in the avoided cost calculation for the DG facility. It is important to note that externality benefits are used in resource planning analysis for the purpose of selecting a proposed plan for Commission approval. No actual externality costs are collected or paid.

The suggestion that renewable DG should receive a payment based on the premium price reflected in retail rates ignores the fact that this retail price adder is necessary to deliver the renewable energy to customers on an equivalent load basis to the utility's other generating resources. Electric utilities are not making additional money from this retail price adder. Instead, the price adder reflects the higher cost of securing and delivering renewable energy to meet customer load requirements instead of more conventional generating resources.

Emission Credits

The regulated electric utilities agree with the Department's comments on tradable credits, but disagree with the Department's position on non-tradable credits.

The Department Report proposed the following:

a. Tradable Emissions: For tradable emission such as SO_2, if a low emission DG facility allows the utility to capture the value of the emission credit, then the DG owner should receive the credit revenues. The work group agreed on this guideline.

b. Non Tradable Emissions: The Department proposes that DG owners should receive emission credits for non-tradable emissions. These credits should equal the utility's avoided emission costs, calculated as the emission per kWh of the next unit the utility plans to construct or purchase less the emission per kWh of the DG facility.

Note: Part "b" above represents the Department's position, but some of the work group's participants may not agree with it. The rational for "b" is that emission costs are considered by utilities in their resource selection process and, if a resource is selected that would result in higher costs absent emission costs, the owner of this resource is compensated for this lower emission resource. Therefore, renewable DG facilities should be compensated for producing lower emissions in this same manner."

The following two principles were adopted by the Rate Workgroup and serve as the basis for the utilities' comments on tradable and non-tradable emission credits:

Rates should reflect the value of the distributed generation to the utility, including any reasonable credits for emissions or for costs avoided on the generation, transmission and/or distribution system.

Rates should reflect the costs the utility expects to avoid. To the extent practical, these costs should reflect seasonal and peak / off-peak differences in credits.

a. Tradable Emission Credits

Using the above principles, the regulated electric utilities agree that it would be appropriate to pay only those avoided emission costs that can be quantified. At this time, the only emission that meets those criteria is SO_2. There is an established market for SO_2 credits and the Acid Rain Program requires affected utilities to have allowances available to cover its SO_2 emissions each year.

The regulated electric utilities propose that the credit for avoided SO2 allowances be included as part of the avoided energy cost calculation used to develop the energy portion of the DG tariff. A utility that avoids power purchases due to DG unit operation would assume that the cost of environmental compliance is already "bundled" with the purchased power price and would therefore require no further consideration for DG unit compensation. When a utility generates less from its own resources, there is no capital cost savings, leaving the avoided variable costs the primary basis for calculating DG unit compensation. Variable costs would include avoided purchase of emission credits for the utility unit that generates less as a result of the DG energy purchase. When natural gas generation units are at the margin for utility dispatch, there is no basis for avoided SO2 emission allowance credit valuation because of the nominal SO2 emissions from natural gas generation.

The value of the SO2 allowances themselves can be established based on the historic values from entities such as Cantor Environmental Brokerage or on some other agreed upon basis. It is noteworthy that the DG resource may not be subject to environmental emission regulatory restrictions that require emission allowances due to size exclusions or that the DG resource may emit creditable emissions at a higher emission rate than the utility's generating unit displaced at the margin.

The utilities acknowledge the concept of taking the utility SO2 emissions and subtracting the SO2 emissions of the DG unit to determine the net quantity of SO2 emissions avoided. This quantity does not, however, reflect the actual cost the utilities expect to avoid due to the addition of the DG unit. The utility is only responsible for its own SO2 emissions. Likewise, the DG owner has responsibility for its SO2 emissions. Therefore, the regulated electric utilities propose to use a tradable emission credit based solely on the emissions avoided by the utility and to have this emission credit embedded in the avoided energy cost.

Should compliance for other tradable emission credits be required in the future for utilities, the regulated electric utilities would agree to also pay those avoided emission costs at such time compliance is required. The utilities would not pay for avoided emission credits prior to the first period of compliance.

b. Non-Tradable Emission Credits

The regulated electric utilities are strongly opposed to the Department's proposal that utilities pay avoided non-tradable emission credits on the basis that the utility is not avoiding any actual costs for non-tradable emissions. The Department's concept goes against the two rate principles listed above.

The Department's proposal uses externalities in a manner that was never intended when they were developed. The regulated electric utilities emphasize again that externalities values as established by the Commission were never meant to be paid out, they were only meant to be used for analyzing new generating resource selections. Furthermore, externalities were never intended to impact the dispatch order of the utility[6]. Basing any avoided non-tradable emission credit on externality values—using externalities to establish a cash payment to a DG owner—would impact a utility's dispatch order.

The regulated electric utilities would like to address a statement made in the Department's recommendation that incorrectly represents what occurs in the resource planning process with regard to setting prices for resources. The statement is as follows: " . . . if a resource is selected that would result in

[6] Minnesota Public Utilities, Order Establishing Environmental Cost Values, Docket No. E-999/CI-93-583, Official Issue Date: January 3, 1997.

higher costs absent emission costs, the owner of this resource is compensated for this lower emission resource." The utilities want to clarify that the resource owner is not compensated for producing lower emissions based on the resource planning analysis. In fact, the resource owner sets the price he or she is willing to sell the resource for in the proposal that is submitted to the utility for evaluation in the resource plan. There is no intermediate step to adjust the price paid to the DG owner based on the resource planning analysis. If a resource is selected, the price included in the original proposal is the price the resource owner will receive.

The bottom line is that proposals evaluated in the resource planning process do not receive any direct compensation for producing lower non-tradable emissions, and neither should DG units. As mentioned in the section on Renewable Credits, the DG projects, whether they are evaluated in the context of a resource planning process or not, will benefit from environmental externalities being included in the resource planning process because the results of the resource planning process are used to develop avoided energy costs.

IV. Conclusion

The regulated electric utilities appreciated the opportunity to participate in the Rate Workgroup and to provide these comments addressing the Commission's Notice and the Department's Report.

If you or your staff have any questions regarding these comments please contact: Doug Larson for Dakota Electric (763) 755-5122; Dave Prazak at Otter Tail Power (218) 739-8595; Dan Tonder at Minnesota Power (320) 632-2318, ext. 5031; Linda Hendrickson at Minnesota Power (218) 722-5642, ext. 3601; Amy Isaachsen at Interstate Power and Light (608) 458-5195; or Paul Lehman at Xcel Energy (612) 330-7529.

Exhibit A

DISTRIBUTED GENERATION
MENU OF SERVICES
12/19/02 Draft

I. FROM UTILITY TO CUSTOMER

A. INTERCONNECT SERVICES

1. Engineering/Design Studies
   a) Customer System – Professional engineering services done under contract for customer to determine equipment necessary for interconnect to utility system.
   b) Customer System – Review of interconnect design and specifications to ensure compliance with the interconnection standards.
   c) Utility System – Engineering study to determine potential impact of DG on utility system.

2. Utility System Upgrades
   a) Metering
   b) Transformer Capacity
   c) Service Capacity
   d) Distribution Primary Line Capacity and Associated Equipment
   e) Protective/Coordination System Changes
   f) Monitoring
   g) Transmission Line Capacity and Associated Equipment

3. Testing

   a) Functional Test – Field-testing individual protective systems. A functional test is a complete test of the entire protective system including the CT's and PT's, protective relay and the breaker. This test ensures that the entire protective relaying system was wired and installed correctly and is "functional" so if you inject current into the relay and the breaker trips, at the expected level of current, then the system functions correctly.

   b) Commissioning Test – Field testing entire installation. The Commissioning test involves running the generation control system through it paces ("A test drive"). While the Functional test checks out the protective elements, this test confirms that the generation control system is working correctly. On a larger and more complex system the Commissioning test will involve a very complex set of test steps to confirm that all of the independent control systems are working together properly. One may introduce reasonable failures into the system, to then prove that the control system properly responds to the failure and operates or shuts down the generation as necessary.

c) Periodic Interconnection Test – Periodically the protective system must be functionally tested to ensure that the equipment remains in compliance with the interconnection standards.

4. Operating Services (Optional)
   a) Generator Periodic Run Testing
   b) Technical Support
   c) Maintenance agreement - Utility
   d) Maintenance agreement - 3rd party
   3) Monitoring

B. SUPPLY SERVICES

1. Backup Services (Standby Service)

   a) Scheduled Maintenance – Energy or energy and capacity reserved by the customer or supplied by the utility during scheduled maintenance of the customer's non-utility source of electric energy supply.

   b) Unscheduled Outages – Energy or energy and capacity reserved by the customer or supplied by the utility during unscheduled outages of the customer's non-utility source of electric energy supply.

2. Supplemental Service – Energy or energy and capacity reserved by the customer or supplied by the utility to supplement the variable output characteristics of the customer's non-utility source of electric energy supply. This is intended to provide energy or energy and capacity to complete the customer's energy production needs during normal operation and is not intended to be the energy or energy and capacity that is needed by the customer's non-utility source of electric energy supply during full or partial scheduled or unscheduled outage periods.

3. Economic Dispatch Service – Capacity and energy reserved by the customer or supplied by the utility to the customer's non-

utility source of electric energy supply operating in an economic dispatch mode.

4. Station Power - Energy consumed by a generation facility (or by equipment or facilities located at the site of such generation facility) and used in the operation, maintenance, or repair of such generation facility, regardless of whether the facility is operating when the station power is consumed.

    a) Net Metering of Station Power is permitted for any size facility and over a "reasonable" time period (FERC Order in Dockets ER00-3513-000, EL99-86-000 & EL00-113-000). FERC approved use of one month as a reasonable time period in Docket EL-01-50-000.

    b) Wheeling of Station Power is permitted when a generator "is self-supplying station use power from … remote generating resources, since in those circumstances, there is no energy sale" even though the end use load may at times be considered retail (lights, fans, motors, heat, etc.) in nature.

    c) When a generator is not supplying itself either from on-site or remote generating resources, the FERC is "unconvinced that the third-party supply of Station Power is something other than sale for end use [retail supply]". Thus if a generator can not supply themselves and is for some reason unable to meet a reasonable net metering time period, the supply of Station Power falls under state retail requirements (service territory and rates of Backup Supply).

5. Residual Retail Service - Capacity and energy reserved by the customer or supplied by the utility to a customer site that is above the capability of the customer's non-utility source of electric energy supply.

6. Net Metering - The process by which a generator may net its on-site power requirements against the generating facility's gross output whenever the generating facility's gross output exceeds or equals its on-site power requirements, that is, when the generator is self-supplying its on-site power requirements.

    a) Many State Commissions have allowed retail load to be Net Metered for small generation facilities.

b) Recent FERC orders permit Net Metering for any size facility for Station Power.

c) The challenge for Net Metering issues is to separate Station Power for which FERC treatment applies from on-site retail power requirements for which State treatment applies.

C. DELIVERY SERVICES

1. Transmission Service – Reservation and delivery of capacity and energy on either a firm or non-firm basis over Transmission Providers' Transmission System.

2. Distribution Service – Reservation and delivery of capacity and energy on either a firm or non-firm basis over Company's Distribution System.

3. Indirect Services – Allocated support services or expenses including operation and maintenance, customer accounts, customer service and information, administrative and general, depreciation, interest and taxes.

4. Ancillary Services – Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of Transmission Provider's Transmission System in accordance with Good Utility Practice. (Note: Includes only FERC recognized ancillary services.)

    a) Scheduling, System Control and Dispatch Service – Service required to schedule the movement of power through, out of, within, or into a Control Area.

    b) Reactive Supply and Voltage Control from Generation Sources Service – Service required to maintain transmission voltages on Transmission Provider's transmission facilities within acceptable limits. Generation facilities (in the Control Area where Transmission Provider's transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by Transmission Provider.

c) Regulation and Frequency Response Service – Service necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load.

d) Generator Imbalance Service – Service provided when a difference occurs between the scheduled and the actual delivery of energy over a single hour by a generator into a Control Area.

e) Operating Reserve – Spinning Reserve – Service needed to serve load immediately in the event of a system contingency. Generating units that are on-line and loaded at less than maximum output may provide spinning Reserve Service.

f) Operating Reserve – Supplemental Reserve Service – Service needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load.

Comparison of Distributed Generation Offerings – Current and Proposed

	PURPA Qualifying Facilities	Minnesota Cogeneration And Small Power Production Tariff	Electric Utility Proposed Distributed Generation Tariff
Criteria/Feature			
Eligibility/Size	Less than 80,000 kW	Less than 100 kW	Less than 10,000 kW
Energy Payment	Avoided Cost	Avoided Cost	Avoided Cost
Capacity Payment	Avoided Cost	Avoided Cost	Avoided Cost
Capacity Planning Horizon	Can be 0 years (Note 1)	Up to 10 years	Up to 5 years
Physical Assurance	Not Applicable (Note 2)	Not Addressed	Included
Maximum Size to Avoid Standby Charge	None	Less than 40 kW	None
Credits			
Distribution	Avoided Cost	Not Addressed	Avoided Cost
Diversity	None	None	None
Line Losses	Avoided Cost	Avoided Cost	Avoided Cost
Renewable	Not Addressed	Not Addressed	Avoided Cost
Emission - Tradable	Not Addressed	Not Addressed	Payable based on Avoided Cost
Emission-Non Tradable	Not Addressed	Not Addressed	Not Payable – no Current Avoided Cost
Reliability	Not Known	No additional credit	No additional credit

Notes

1.Although PURPA does not specifically have a "Capacity Planning Period", there is support for a utility not paying for capacity (and or energy) if these purchases result in "net increased operating costs to the electric utility" (Federal register/Vol. 45, No. 38, on Monday, February 25, 1980, section 292.304(f)). Also, FERC has ruled on the following; On December 12, 1995 FERC interpreted section 210 of the PURPA and determined that the statute prohibits states from ordering utilities to purchase power from Qualifying Facilities at rates that exceed the utility's avoided costs (Docket EL93-55).

2. PURPA requires the utility to provide Standby or Backup Services under tariffs that are non-discriminatory compared to other similar retail customers (i.e., if a utility offers it to one customers it offers it to all)

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