M E M O R A N D U M

TO: Distributed Generation Rate Work Group

FROM: Alliant Energy
Dakota Electric
Minnesota Power
Otter Tail Power
Xcel Energy

DATE: January 20, 2003

SUBJECT: Comments on Issues Raised in January 10, 2003 e-mail from DOC

Following are brief consolidated comments of Alliant Energy, Dakota Electric, Minnesota Power, Otter Tail Power and Xcel Energy regarding issues raised in the January 10, 2003 e-mail from Kate O'Connell at the Department of Commerce.

Locational DG Distribution Credit

Issue
It has been suggested that the concept of a tiered "Locational DG Distribution Credit" be established for the DG tariff. Implementing this concept would require each utility to segregate its service territory into three DG territories based on capacity constraints and/or costs for system upgrades including the following:

1. "Red" -- A very large benefits from DG installation.
2. "Yellow" -- A moderate benefit from DG installation.
3. "Green" -- A general benefit from DG installation.

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

Response
While the concept of a tiered locational DG distribution credit acknowledges that the benefit from installing DG will vary depending on local circumstances, identifying, segregating and updating electric utility service territory into these three tiers would be extremely difficult to accomplish from both an engineering and administrative perspective. In addition, this concept generally does not follow current rate-making theory as utility rates do not change based on the location of the customer. Also, there may be situations where distribution benefits do not exist and distributed generation may cause additional costs and safety concerns.

However, as we have stated many times in previous comments, we believe the identification of distribution benefits is an important element in providing credits to potential DG customers. Since the circumstances of each DG installation can be unique, we suggest that a better way to identify the potential distribution credits/costs is to incorporate this analysis in the up-front system study required for each DG installation. Evaluating potential distribution credits/costs at this point should not significantly delay the study and review process at the beginning of such projects and, more importantly, will result in more accurate accounting of site-specific credits/costs for each installation.

Line Loss Credit

Issue
It has been suggested that DG relieves utilities of having to supply the additional generation capacity associated with line losses to serve the DG customer. Accordingly, it has been suggested that all percentage losses designated under generation, transmission, and distribution by the electric utility be credited.

Response
The development of costs for generation, transmission and distribution service inherently reflects the impact of line losses. Accordingly, the generation and transmission credits discussed by the Work Group at the January 8, 2003 meeting already incorporate the benefit of reduced line loss. However, there may be specific circumstances where the location and operation of a DG facility could provide additional generation and transmission line loss benefits. Accordingly, we recommend that the identification and quantification of such additional line loss credits be included in the up-front study as we proposed above for identifying Locational DG Distribution Credits.

Diversity Credit

Issue
It has been suggested that utilities give a diversity credit for DG installations that recognizes a reduced reserve margin because small DGs require lower reserves on a diversified basis than larger utility generating units.

Response
The amount of reserve margin each member has to carry is set by MAPP, not by the utility. MAPP develops the reserve margin level based on reserve margin studies of the generation in place and the contingencies the region wants to protect for. As the generation mix changes because of the development of small distributed generation, MAPP will adjust the reserve margins accordingly. However, in a region that has a mixture of large generation resources as well as many small generators, the determination of reserve margin levels needed will still be set by the existence of those large generators. Since any potential diversity benefit from small DG facilities will not translate to lower required reserve margins as required by MAPP, such a diversity credit is not justified on an avoided cost basis.

Renewable Credits

Issue

It has been suggested that additional credits be provided to renewable DG installations. Suggested options for determining these credits include:

1. Externality -- based credit.
2. Market -- based credit.
3. Hybrid of market and externality methods.
4. Green tags credit.
5. Green -- pricing charge.

Response

Renewable DG projects will already receive a benefit of the externality -- based concept in that renewable DG projects will be evaluated within the context of the avoided externality benefits as identified by the MPUC.[1] This evaluation, including the price paid by the utility, will occur through the IRP Process. Although DG customers do not need to go through the IRP process, they will still benefit from the avoided cost setting part of the IRP. Therefore, the delivered price of a renewable DG project may be higher than other alternatives and yet be selected as the next resource after consideration of such externality benefits.

Also, for energy the DG uses internally to offset load, the value they receive is in avoiding paying the retail rate for their power supply needs. As the IRP process brings higher cost renewable power into the utility's resource mix, the retail rate will rise and the value the DG received from avoiding paying that rate will rise. Therefore, the DG will directly receive the benefit for renewables (even if the DG isn't renewable) from the MPUC approved IRP treatment of renewable value.

The proposal for market--based credits, hybrid of market and externality methods, and green tag credits have no bearing on existing avoided costs and as such should not be applied as a credit method.

Furthermore, the suggestion that renewable DG should receive a payment based on the premium price adder 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, this price adder reflects the higher costs of securing and delivering renewable energy to meet customer load requirements instead of more conventional generating resources.

Finally, any credits that are developed by this rate group should be cost-based and should only be applied if there are measurable benefits to the utility. Any other credits that relate to societal benefits are outside the scope of this rate group as they must be driven by legislative policy.

---

[1] Externality benefits are used in resource planning analysis for the purpose of selecting a proposed plan for MPUC approval. No actual externality costs are collected or paid.

Operational Efficiency Credits

Issue
It has been suggested that operational efficiency credits be provided to DG units that recognize that these units provide electric energy at lower thermal requirement than conventional generating units.

Response
To the extent that any distributed generation unit can operate at higher efficiency levels than conventional generation resources means that such DG facilities will have lower operating costs than conventional generating units. Assuming that wholesale energy is bought and sold in a competitive market, such DG installations will naturally receive higher earnings than those from conventional generating resources. Offering an additional operational efficiency credit is not necessary.

MN0650201/sja