STATE OF MINNESOTA
PUBLIC UTILITIES COMMISSION

In the Matter of Establishing Generic
Standards for Utility Tariffs for
Interconnection and Operation
Of Distributed Generation Facilities
Under Minn. Stat.§ 216B.1611

Docket Nos. E999/CI-16-521 and
E999/CI-01-1023

Midwest Cogeneration Association and Heat is Power Association
Response to Commission Request for Comments
October 30, 2020

The Midwest Cogeneration Association (MCA) and Heat is Power Association (HiP) appreciate this opportunity to provide their response on the topics opened for comment in this docket by the Commission's August 28, 2020 Notice of Comment Period.

1. **The Consistency of Attachment 6 with existing statute and rules.**

MCA and HiP concur in the comments filed by the Minnesota Solar Energy Industries Association (MnSEIA) and the Environmental Law and Policy Center that Attachment 6 requires modification to ensure that it reflects the intent of Minn. Stat. 216B.1611 and PURPA that the value of Distributed Generation (DG) resources be based on the utilities' true "avoided cost", not simply the utilities' "least cost" marginal energy or capacity resource in the marketplace – whether that is for renewable DG resources or any other DG resource.

The thrust of Minn. Stat. 216B.1611 is to ensure valuation of the full array of beneficial attributes and avoided costs that DG offers utilities and their customers. This 2004 Minnesota statute recognized that the true value of a DG resource or any other generation resource to the grid is a function of the generation resources' attributes, such as reliability, peak availability, resiliency, location, line losses, distribution costs, and social and environmental costs associated with those energy and capacity resources. It would entirely undermine the intent of Minn. Stat. 216B.1611 to create or import from another statute a "least cost" marginal resource rate for DG that does not reflect a valuation of these attributes. To the extent that Xcel or any other Minnesota utility believes that it can apply a rate methodology from another statute to determine avoided costs for DG resources, Attachment 6 should expressly state that the methodology provided in Attachment 6 is the proper rate method for establishing avoided cost rates for DG.

2. **Guidance on insuring adequate transparency of negotiated rates and availability or consideration of Attachment 6 credits.**

Transparency is essential to ensuring that the true avoided cost of a DG resource is evaluated and credited. Utilities' "trade secret" or "business confidentiality" claims make this transparency impossible. Indeed, it is our understanding that no one actually knows whether Minnesota's IOUs have been complying with Minn. Stat. 216B.1611 and Attachment 6 because Minnesota utilities will not disclose the data necessary for an independent review of avoided costs. This lack of transparency completely undermines the statute and PURPA. It is essential that Attachment 6 expressly address this issue in order for the intent of Minn. Stat. 216B.1611 to be carried out.

3. Better alignment of avoided capacity costs with Integrated Resource Planning and other regulatory proceedings.

The Integrated Source Planning process is an excellent place for each utility to openly evaluate and publicly articulate how it will credit DG in its territory based on avoided costs. That process may include "Requests for Information" leading to "Requests for Proposals" for DG resources generally or for particular DG resources to meet load requirements in certain areas of the territory, together with a statement of the rates and credits for various DG attributes that can help the utility most efficiently provide reliable power in its service territory while increasing resiliency and reducing emissions.

This IRP process should consider not only avoided cost rates for sales to the grid, but also credits for the reliability, resiliency, emission reductions, line loss reductions ,and overall energy and capacity cost savings to the utility and its customers that are produced by customers' who install at their own expense DG self-generation, including Combined Heat and Power (CHP) and Waste Heat to Power (WHP), to meet their own load which would otherwise be placed on the grid.

4. Guidance that recognizes technology, location, and time-specific avoided cost considerations.

Guidance is necessary to ensure that the technology, locational, and time-specific cost savings are properly, fully and openly evaluated. MCA and HiP suggest that a Working Group that includes the Minnesota IOUs and DG and customer stakeholders be convened to make recommendations for standards and guidance on these and other attributes, such as emission reduction credits, to be credited under Attachment 6 and in the Integrated Resource Planning process.

5. Oher issue and concerns related to this matter.

A. DG host facilities that are subject to Standby Tariffs should be eligible for DG Rates and Credits.

As discussed in MCA's September 19, 2018 comments in this docket, among the problems in Attachment 6 is the conclusion that customers taking back-up and maintenance service under a standby tariff should not be eligible for energy or capacity credits under the DG Tariff 3 and/or that DG avoided costs and credits are already reflected in standby rates.

As an initial matter, it is MCA and HiP's understanding based on its participation in the generic standby tariff proceeding in Docket E-999/CI-15-115 that the avoided cost benefits of cogeneration DG projects to the utilities are not reflected in utility cost of service studies, are not expressly recognized in standby tariff language, and that cogeneration DG owner/operators are not otherwise compensated by the utilities for the benefits their DG brings to the overall grid.

There is no valid rationale for excluding cogeneration DG facilities that are required by law to take back-up and maintenance service from a utility – which is almost all cogeneration DG in the state -- from the energy and capacity credits offered to other DG under Minn. Stat. 216B.1611 and Attachment 6.

There are two scenarios to consider. In the first, cogeneration may be entirely serving a customer's own load. Minnesota law requires that standby service be taken to back-up that self-generation cogeneration in case of an unexpected or planned outage, even if the customer could reduce its load and avoid taking any back-up power from the grid. Modern cogeneration systems have very high availability rates (100%) and reliability rates (95+%) – thus standby service is very rarely required during peak hours (< 2.5%). Thus, unlike intermittent DG technologies, cogeneration DG can provide power to service a host or the grid 95% of the time. This is a greater reliability than the average utility-owned generation asset. Further, utilities bill cogeneration customers for standby power for these rare outages through energy and demand charges at rates that compensate (if not over-compensate) the utility for any capacity and energy actually taken. These host-serving cogeneration systems should be credited with all of the attributes that this high reliability, low-emission, resilient resource can bring to the overall utility portfolio 95+% of the time – and 97.5% of the time during peak hours. It is a fallacy to theorize that a utility is reserving energy and or capacity all the time for a <2.5% chance of a <10MW cogeneration system outage.

The diversity of generation resources and customer load as well as the diversity of the timing of unexpected "forced outages" over multiple cogeneration systems ensures that the utility need not constantly reserve energy or capacity for these small cogeneration systems. Even if a cogeneration system of this size failing were ever theoretically an issue for a Minnesota IOU, the back-up of the regional system is available.

It must be understood that the load served by the cogeneration system in this instance is utility customer load that "but for" the cogeneration system would be placed on the utility grid 95+% more often, including during peak hours, without providing the resiliency, no line losses, and distribution and emission reduction benefits of the cogeneration system. Thus, by failing to properly credit the utilities' avoided costs produced by host-serving cogeneration DG, the utility is receiving a windfall at the expense of the cogeneration customer and discouraging the private sector from investing in cogeneration DG.

In the second scenario, a host facility may be generating electricity partially or entirely for export to the grid. In this instance, just as with wind, solar or any other generation resource, the host facility does not require back-up or maintenance power from the utility in order to continue its operations. If standby service is nonetheless required to be contracted for by Minnesota law, this clearly is no basis for denying these cogeneration DG resources the rates and credits that would be available to any other DG resource under Minn. Stat. 216B.1611 and Attachment 6.

MCA and HiP request that the Commission review and revise Attachment 6 to clarify how standby tariffs and Attachment 6 interact and, if customer located cogeneration is to be treated differently than any other DG resource (which we believe would be improper), that the Commission clarify how the utilities' avoided cost benefits due to customer-located cogeneration – serving either the host's load or for export to the grid -- should be credited to cogeneration resources.

B. Line losses should be readily calculated from existing utility data – no study is needed.

Attachment 6 currently requires that a line-loss study be performed for each DG project in order for that project to qualify for avoid cost credit under Minn.Stat.216B.1611. This is unnecessary in light of the fact that utilities maintain this information for their territories. Performing individual studies is also a cost-burden on these small DG projects that is likely to outweigh the benefit of the credit.

C. Avoided capacity Look-Back should reflect the useful life of the DG resource.

The 5-year avoided capacity "look-back" period in Attached 6 is too short and discriminates against cogeneration and other privately owned DG resources. Utility-owned assets are rate-based based on the useful life of the asset. Similarly, financing for private DG projects is based on the useful of the equipment involved. Cogeneration systems are often said to have useful lives ranging from 15 -20 years, but in actuality MCA Members report that many cogeneration systems installed in the 1980's are continuing in service 40 years later. Attachment 6 should make it clear that the avoided capacity "look back" period should reflect the useful life of the DG technology.

D. Contract Term Length should reflect the useful life of the DG resource.

Attachment 6 would allow contract term length to be negotiated. Negotiated contracts are expensive and unnecessary for small DG projects. For the same reasons stated above – financing and fairness, Attachment 6 should expressly state that contract length should reflect the useful life of the DG system.

Respectfully submitted on behalf of MCA and HiP,

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