<u>APPENDIX B – REDLINED COPY OF RECOMMENDED ATTACHMENT 6 CHANGES</u>

State of Minnesota

Guidelines for Establishing the Terms of the Financial Relationship Between an Electric Utility and a Distributed Generation Customer with No More Than 10 MW of Capacity

1. AVAILABILITY

The DG customer must connect in parallel to the utility distribution system.

2. QUALIFICATIONS

a. The DG facility must be an operable, permanently installed or mobile generation facility.

b. Must buy: The utility must buy all the energy and capacity offered for sale by the DG customer selling the power. Utilities that are full requirements customers of wholesale suppliers may need to require the wholesale supplier to assume this obligation in order to abide by contractual requirements with their wholesale supplier.

c. Customer options: Customer may sell all the DG energy to the utility, "sell" all the DG energy to itself, or self-generate part of its needs and sell the remaining energy to the utility. The DG facility determines how much energy and capacity it will commit for sale.

d. Transactions outside the tariff: DG owners and utilities may pursue reasonable transactions outside the DG tariff. However, such transactions are beyond the scope of the work group.

3. LIST OF SUPPLY SERVICES TO BE PRICED

a. Energy and capacity.

b. Scheduled maintenance service (energy, or energy and capacity, supplied by the utility during scheduled maintenance of the customer's non-utility source of electric energy supply).

c. Unscheduled outages (energy, or energy and capacity, supplied by the utility during unscheduled outages of the customer's non-utility source of electric energy supply).

d. Supplemental service (electric energy, or energy and capacity, supplied by the utility to the DG customer when the customer's non-utility source of electricity is

Commented [s1]: This change is substantive.

The on-site requirement seems no longer necessary given the breadth of the Interconnection Standards.

Commented [JH2]: This change is not substantive.

This change captures the already-existing requirement that utilities are obligated to purchase energy and capacity from qualifying DG facilities. This change is meant to remove ambiguity.

Commented [JH3]: This change is not substantive.

This change captures the already-existing requirement that DG facilities can determine how much energy and capacity it can sell. This change is meant to remove ambiguity.

insufficient to meet the customer's own load).

e. Other services deemed necessary herein.

4. PRINCIPLE OF SETTING RATES FOR SERVICES PROVIDED BY DG CUSTOMERS TO UTILITIES

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.

5. PRINCIPLE OF SETTING RATES

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.

6. CALCULATION OF AVOIDED COSTS

a. Avoided Energy Costs

Distribution utilities that are full requirements customers of wholesale suppliers may use their suppliers' rate schedules to determine avoided energy costs. Other utilities should follow these steps:

i. System-wide hourly marginal energy costs are calculated with a production model for each hour of the future year.

ii. Based on those costs, the average on-peak and off-peak marginal energy costs are calculated for each month.

iii. The on-peak annual rate is based on the average monthly on-peak marginal energy costs. The off-peak annual energy rate is based on the average monthly off-peak marginal costs. Thus, there are two rates set for the year, with an on-peak and off-peak rate.

iv. The annual on-peak and off-peak energy rate must be escalated annually by the expected inflation rate.

b. Avoided Capacity Costs

i. Calculate the installed capital cost plus fixed O&M costs plus startup costs ($/kW-year). If the next (marginal) unit is from a competitive bid, the utility must estimate these costs and fully defend the estimate.

ii. Calculate the Levelized Annual Revenue Requirements (LARR) ($/kW-year).

Commented [JH4]: This change is substantive.

This change is meant to simplify the avoided energy cost rate. Rather than having 24 different monthly on-peak and off-peak rates, there will now just be 2 different rates: on-peak and off-peak. This should not result in materially different rates than the former monthly rates, but it will result in more simplicity.

Commented [JH5]: This change is substantive.

The old Attachment 6 has similar language for escalating capacity costs (which is still retained below), and the language added to the energy rate section is based on that prior language in the capacity rate section. Adding this language to the energy rate section creates a simple method of forecasting avoided energy rates over long-term, multi-year contracts.

iii. Divide the amount in (ii) for the next year by twelve to get the capacity marginal costs ($/kW-month).

iv. These marginal costs must be escalated annually by the expected inflation rate.

(1) The need for capacity is established in the utility's most recent integrated resource plan (IRP). A need exists if the utility shows a deficit at any year in the IRP's 15-year planning period.

(2) Capacity payments should be made for the total fully accredited DG capacity, regardless of when the power is delivered to the system.

(3) The expected life of a capacity addition is the expected life of the specific capacity addition from the utility's most recently approved integrated resource plan.

(4) If the contract to purchase power from a DG source begins at the time the utility needs the capacity, then the full capacity payment is made, adjusting only as needed for the length of the contract (i.e., there is no discount for adding capacity sooner than it is needed).

(5) The formula for adjustments to capacity payments is:

$$A2 = \frac{(1+i)^m - 1}{(1+i)^n - 1} * \frac{(1+i)^{n-a} - (1+e)^{n-a}}{(1+i)^m - (1+e)^m} * A1$$

Where:
Al = Levelized annual value of a capacity purchase at the time of need.
A2 = Levelized annual value of the capacity paid for in a power purchase contract.
m = Expected lifetime of ordinary (alternative) future capacity addition.
n = Length of power purchase contract.
i = Utility Cost of Capital.
e = Escalation rate affecting value of new capacity additions.
a = Length of time between beginning of contract and time of need for capacity.

c. Technology-specific Renewable Avoided Cost

A DG customer who installs a renewable DG facility should be paid the avoided cost of "green power" to the extent that installation of the DG facility allows the utility to avoid the need to build or purchase "green power" elsewhere. Otherwise a renewable DG facility should be paid the utility's regular avoided costs, as calculated above.

“Green power” is defined as the specific renewable technology that the utility would

Commented [JH6]: This change is substantive.

A 15-year planning period corresponds with the 15-year planning period that already exists in an IRP. This also ensures that DG facilities are adequately compensated. Under a 5-year framework, it is nearly impossible to receive any capacity credit, as demonstrated by the fact that there has been no DG facility utilizing the DG Tariff.

Commented [JH7]: This change is substantive.

The language of the first paragraph is largely lifted from the old Attachment 6, *infra* page 5 of 6, from a subsection titled “Renewable Credit.” That subsection allowed technology-specific avoided cost rates, but it was ambiguous as to what such rates entailed. This language attempts to provide clarity.

otherwise need to build or purchase. For example, if a utility must build or purchase solar energy to comply with a technology-specific requirement imposed by state law or Commission order, then a DG facility that allows the utility to avoid building or purchasing from a solar energy facility should be paid a rate based on those technology-specific avoided costs.

The Commission's policy regarding the renewable energy objective may affect the question of whether it is reasonable for utilities to pay a credit for renewable power at the approved green-price premium even if a utility does not need the green power.

7. STANDARD CONTRACT TERM LENGTH

Commented [JH8]: This change is substantive.

Long-term contracts are necessary in order for DG customers to obtain financing for their DG facilities. 25 years is the time period most utility capacity additions are measured and 25 years is long enough to ensure DG customers have reasonable access to financing.

The utility must offer contract terms up to 25 years in length with fixed rates.

8. STANDBY RATES

a. General

i. DG customers do not have to buy standby power. However, if standby power is not purchased, it may not be available.

ii. DG customers do not have to buy as much standby power as necessary to equal the full amount of their own DG capacity. However, if, for example, the customer has a 5 MW DG facility and buys only 2 MW of standby power, there must be a guarantee that the facility will never take more than 2 MW of standby service.

b. Firm Service

i. Generation (capacity): The monthly reservation fees are equal to the percentage of the planned reserve margin of the utility times the applicable capacity tariffed rates.

ii. Transmission: Terms, conditions and charges for transmission service are subject to the individual utilities' or MISO's Open Access Transmission Tariffs or their successors as approved by the FERC.

iii. Local Distribution: The monthly charges equal the monthly charge under the applicable distribution charge. There is no discount in the local distribution charge.

c. Non-Firm Service

i. Generation (energy and capacity): There are no monthly reservation fees for energy and capacity for a non-firm DG customer.

ii. Transmission: There are no monthly reservation fees for transmission for a non-firm DG customer.

iii. Local Distribution: The monthly rates equal the monthly charge under the applicable distribution charges. That is, there is no discount on the distribution charge.

d. Physical Assurance Customer

A physical assurance customer is a customer who agrees not to require standby services and has a mechanical device to insure that standby service is not taken. The cost of the mechanical device, which must be reasonable, is to be paid by the DG customer. A utility's tariff may deal with other issues not addressed here.

e. Maximum Size to Avoid Standby Charge

A DG facility that determines it will not need standby service is exempted from paying any standby charges.

Commented [JH9]: This change is substantive.

Attachment 6 already specified that a DG customer can determine how much energy and capacity it wants to sell, which Movants attempt to clarify *infra* page 1 of 6, and this change clarifies how standby charges are charged. It would be discriminatory and unfair to allow a utility to charge a DG facility—regardless of size—for standby service if the DG facility has reasonably determined that it will not need standby service.

Commented [JH10]: This change is not substantive.

This change removes reference to a Commission promise to review this section in 2006. Movants are unaware of whether the Commission ever conducted such a review.

9. CREDITS

a. General

Credits should be given to a DG customer if the installation of a DG facility reduces the utility's costs of providing the service. These lower costs could be generation, transmission or distribution related costs.

b. Distribution Credits

i. Distribution credits to a DG customer should equal the utility's avoided distribution costs resulting from the installation of the DG facility.

ii. Each utility should provide, upon request, a list of substation areas or feeders that could be likely candidates for distribution credits as determined through the utility's normal distribution planning process.

iii. Upon receiving a DG application, the utility will perform an initial screening study to determine if the DG project has the potential to receive distribution credits. The DG customer is responsible for the cost of such a screening study.

iv. If the utility's study shows that there exists potential for distribution credits, the utility must, at its own cost, pursue further study to determine the distribution credit, as part of its annual distribution capacity study.

c. Diversity & Reliability Credit

i. No additional Diversity & Reliability Credits for energy and capacity should be given to DG customers who contract for standby service.

ii. Diversity & Reliability Credits shall be provided for customers that are not on standby service and shall be equal to the amount of reserve capacity it requires to back up a supply of electricity from smaller generators. This can be determined using an effective load carrying capability measurement, which may be modeled for the average DG generator the utility expects to receive under this tariff, or a Peak Load Reduction approach, which takes the maximum distribution load over the Load Analysis Period minus the maximum distribution load over the Load Analysis Period.

d. Line Loss Credits

A line loss credit should be applied to the avoided energy cost rate by multiplying it by the utility's system wide line loss factor plus 1. The calculation is:

$$A2 = (1 + a) * A1$$

Where:

A1 = avoided energy cost rate
A2 = avoided energy cost rate modified by line loss factor
a = system wide line loss factor (expressed as a percent)

For example, if a = 2.2% and A1 = $.04/kWh, then A2 = $.04088

No additional line loss credits (above the credits already included in the avoided cost calculations) should be paid to a DG customer with the following exception: A DG customer may request the utility to provide a specific line loss study and receive additional line loss credits if the study supports such credits. The DG customer is responsible for the cost of the study regardless of the study's outcome.

e. Renewable Energy Credits (RECs)

A DG facility retains RECs generated by its DG facility.

However, if a DG customer qualifies for a technology-specific "green power" avoided cost and opts for the "green power" rate, *supra* § 6.c, then the DG facility must agree to transfer its REC to the utility without additional compensation for the REC because the difference between the utility's avoided cost and its "green power" avoided cost already compensates the DG facility for the "green power" represented by the REC.

Commented [s11]: This change is substantive.

This change combines diversity and reliability credits, and the formula for calculating them is taken from the Value of Solar Methodology and replicated to fit a "model" DG facility. *See* In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. § 216B.164, subd. 10 (e), Docket No. 14-65, Order, Attachment titled MINNESOTA VALUE OF SOLAR – METHODOLOGY at 18 (Apr. 11, 2014).

Commented [JH12]: This change is substantive.

In the old version of Attachment 6, its language (which is retained here) made reference to line loss credits included in the avoided cost calculations. However, nowhere in Attachment 6 nor the Commission's September 2004 Order was there any guidance on how line losses would be included in the avoided cost calculations.

This change provides a simple calculation of how line losses should be included in the avoided cost calculation, and it is based on a similar formula that Michigan uses to apply line loss credits to its avoided cost calculation.

Commented [JH13]: This change is not substantive.

This language was moved to § 6, which deals with avoided costs. This language allows technology-specific avoided costs and it was unclear why it was outside of the avoided cost section.

Commented [JH14]: This change is substantive.

In the old Attachment 6, it stated that a DG customer cannot receive both (1) emission credits and (2) "green power" credits. This seemed equitable because the "green power" credit was really technology-specific renewable avoided costs and because emission credits are commonly captured by renewable facilities as RECs. It would be unfair to allow a DG facility to obtain both technology-specific renewable avoided costs and RECs.

This change clarifies that DG facilities retain their RECs under the regular avoided cost rate but allows the utility to obtain the RECs under technology-specific renewable avoided cost rates, since this "green power" rate includes compensation to the DG facility for the RECs it generates.