DG RATE GROUP TARIFF MEETINGS

November 18, 2002

Docket No.E999/CI-01-1023

I. Summary of Discussion

A. Avoided Energy Costs

1. Option A or B

The group discussed Options A and B presented prior to the meeting (see attached). A third option, setting the prices at the beginning of each month, rather than at the beginning of the year, was briefly discussed and rejected, due to the concern that the potential variability in pricing would cause too many problems in DG financing.

DG owners generally preferred Option B while utilities generally preferred Option A, at least for small DG facilities (2 MW and less). Utilities stated that administrative costs of having 24 prices per year would be too high, but did not specify what the costs were.

2. True-up

Utilities did not want true-ups because it would be too difficult to do. It was noted that, in the last meeting, a municipal utility advocated for a true-up because they purchase essentially all of their power and do not want to face the risk of prices set without a true-up. However, for the utilities participating in this workgroup, the circumstances are different since they own a substantial portion of the facilities on which they rely for power. The focus of this workgroup is on the utilities under the Commission's jurisdiction. However, municipal and cooperative utilities may pursue variations to the results of this workgroup and the Commission's subsequent Order, per Minnesota Statute 216B.1611, subd. 3 that states (in relevant part):

> Within 90 days of the issuance of an order under subdivision 2:
> …each municipal utility and cooperative electric association shall adopt a distributed generation tariff that addresses the issues included in the commission's order.

There was a concern by DG owners that, without a true-up, DG owners may not get a fair price for their power. To address this issue, it was decided that a trial period would be needed to assess how well utilities forecast prices. While a certain amount of forecast error is expected, there should not be any systematic errors in forecasting.

3. Proposed Resolution

The compromise proposed for the group is Option B; setting 24 prices (on- and off-peak prices for each month) at the beginning of the year. To decrease administrative costs, there would not be a true-up, at least initially. However, there would need to be a trial period to see whether, in practice, utilities are able to forecast these energy prices sufficiently well.

B. Avoided Capacity Costs

The following issues were noted:

- DG owners may support being paid the value, in today's dollars, of capacity needed years in the future (the example discussed in the group was a need for capacity in 10 years)

- Minnesota law allows qualifying facilities to wheel power through their incumbent utility to another Minnesota utility that needs power. Specifically, 216B.164, subd. 4, part c states:

  > For all qualifying facilities having 30-kilowatt capacity or more, the utility shall, at the qualifying facility's or the utility's request, provide wheeling or exchange agreements wherever practicable to sell the qualifying facility's output to any other Minnesota utility having generation expansion anticipated or planned for the ensuing ten years. The commission shall establish the methods and procedures to insure that except for reasonable wheeling charges and line losses, the qualifying facility receives the full avoided energy and capacity costs of the utility ultimately receiving the output.

- However, wheeling power produced from all other sources is beyond the scope of this proceeding.

- Nonetheless, any DG owner that wanted to negotiate with the utility to have the utility act as an agent to sell their power on the open market could do so. Such transactions would be at the wholesale level, beyond the jurisdiction of the Commission and subject to federal regulations.

- The source of dispute is that DG owners want to be paid for their capacity but ratepayers shouldn't have to pay for capacity they do not need.

- Utilities assert that, if the utility doesn't need power for, say, 10 years, the capacity payment should be $0. Utilities argued that it's not appropriate to make ratepayers pay today for capacity they won't need until far in the future. It was stated that this is the approach used for qualifying facilities.

- However, at least one utility noted that it may be reasonable to make capacity payments a few years in advance of actually needing the capacity due to uncertainty in the need for the power.

- DG owners stated that they should not have to pay for standby service if they do not need it. The group agreed that DG owners should not have to pay for such service if they do not need it.

- DG owners asked for a right of 1^{st} refusal on need to add capacity. Utilities responded that a "must buy" situation implies that there is a right of 1^{st} refusal for DG owners. DG owner said that utilities likely wouldn't give right of 1^{st} refusal since the options on DG would give DG facilities too much.

- While the group explored various arguments, the parties did not agree on a method to calculate avoided capacity costs.

- In light of the discussion, all parties were asked to justify their positions on the payments for avoided capacity costs as clearly as possible, responding to the arguments brought up by other parties.

C. Length of Contract

Parties discussed how to measure the value of DG contracts that are less than 10 years. It was noted that:

- DG owners sometimes want to have short contracts because they would like to free up their capacity and power if they think they will get a better deal in the near future. However, they may not be able to finance their project if they have only a short-term contract.

- There is a greater value to utility ratepayers in a longer contract. Also, fewer administrative costs in renegotiating each year.

- The Department proposed setting the value of a contract for a period less than 10 years, say "X" years, as the difference between a 10-year contract today and a 10-year contract X years in the future. The parties asked for more explanation of this method; the Department intends to do so by December 6.

- It was also noted by DG owners that, if there is a downturn in the economy, short-term contracts may provide more flexibility to the utility system by allowing contracts to be shed more easily. While there is a reasonable point to this argument, a balancing factor is that utilities have an obligation to serve, so they must address the risk and responsibility of this obligation.

D. Performance of DG Plant

Performance of the plant is an important factor to be considered in capacity payments. It's also important to recognize that capacity available at the utility system peak is more valuable than capacity that is not available during the utility's peak.

- DG owners are responsible for paying for URGE testing and transmission accreditation.

- Demand metering may work, but small DG owners may not have demand meters.

- Paying accredited capacity wouldn't work because DG owners aren't required to run their plants – they may decide not to sell their power to the utility.

- Proposal was presented:

    - Only pay for capacity delivered at utility peak. The way to measure or estimate that is:

        - <25 kW: assume no demand meter, and make capacity payment if the DG facility produces more than 65% of its accredited capacity in a month (i.e. greater than 65% capacity factor). However, if these customers want a demand meter, they could pay for one;

        - >25 kW: must have demand meter to get capacity payment, which is made only for power delivered at utility peak.

II. Request for Comments

The Department intends to provide, by December 6, more information about the proposal for evaluating contracts that are for periods of less than 10 years.

Group participants were asked to provide the following. To allow parties to read what is provided by other parties prior to the next meeting, parties are asked to provide this information by **December 6**:

- Please justify your positions on the payments for avoided capacity costs as clearly as possible, responding to the arguments brought up by other parties.

- Please respond to the proposal for performance indicated in section D above.

III. Next Meeting

At the next meeting, one hour will be set aside to discuss any open issues that have been brought before the group to date. After that, the group will move on to discuss credits and other issues. The Department noted that the second workgroup report to the Commission is due in mid-December, and the final report is due February 1, 2003.

The Group set the next meeting for:

Wednesday, December 11, <u>9:30 to 12:30</u>
Minnesota Department of Commerce (85 7th Place East, Suite 500)

Options for Pricing Avoided Energy Costs

Option A:

Using a production model the following steps are used to calculate the marginal energy rates:

1. System-wide hourly marginal energy cost is calculated for each hour of the future year.

2. Based on (1), the average on-peak and off-peak marginal energy costs are calculated for each month.

3. Peak-season months are aggregated and the average on-peak marginal energy cost is calculated for the peak period; non-peak months are aggregated and the average on-peak marginal energy cost is calculated for the non-peak period. Off-peak marginal energy costs are aggregated over the entire year.

4. Following the calculations in (3), the on-peak rate for the peak season is set at the average on-peak marginal energy costs in the peak months. Similarly, the average on-peak marginal energy rate in the non-peak months is set at the average on-peak marginal energy costs in the off-peak months. The off-peak marginal rate is calculated as the average off-peak marginal costs over the 12-month period. Thus, the energy tariff have the following three rates:

On-peak for peak season	$/kWh
On-peak for non-peak season	$/kWh
Off-peak	$/kWh

5. At the end of the year, a lump-sum true up is used to reflect the difference between estimated and actual energy costs.

Option B:

Using a production model the following steps are used to calculate the marginal energy rates:

1. System-wide hourly marginal energy cost is calculated for each hour of the future year.

2. Based on (1), the average on-peak and off-peak marginal energy costs are calculated for each month.

3. The on-peak monthly rate is set at the average on-peak marginal energy costs. The off-peak monthly energy rate is set at the average monthly off-peak

marginal costs. Thus, there are 24 rates set for the year, with an on-peak and off-peak rate set for every month.

4. At the end of the year, a lump-sum true up is used to reflect the difference between estimated and actual energy costs.

Note: one question that was raised for Option B is whether there is a need for a true-up since it is expected that the rate would reflect estimated costs better than in Option A. As such, it is possible that the administrative costs of a true-up may outweigh the expected benefits of a true-up in Option B, at least for some utilities.

Also, the benefits of true-ups are expected to be different for utilities that produce most of their electricity as opposed to purchasing significant amounts of energy on the market.

Proposal for Pricing Avoided Capacity Costs

The marginal capacity cost is the cost per kW of adding the next capacity unit [e.g. a combustion turbine (CT), combined cycle (CC), or power purchase] to the utility electric system. For example, if the utility's integrated resource plan (IRP) calls for the addition of a CT, then a CT must be considered the marginal unit. The following steps are used to calculate the marginal capacity costs.

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

2. Calculate the levelized Annual Revenue Requirements (LARR*) ($/kW-year).

3. Divide the amount in (2) for the next year by twelve to get the capacity marginal costs ($/kW-month).

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

*<u>*More on LARR:</u>*

1. *Calculate Total Revenue Requirement of the Project.*
2. *Calculate the Average Revenue Requirements Per Year.*
3. *LARR = Average Revenue Requirements Per Year divided by the annual capacity of the project.*