DG RATE GROUP TARIFF MEETINGS

October 30, 2002

Docket No.E999/CI-01-1023

Summary of Discussion

The meeting focused on a discussion of a handout from the Department of Commerce proposing a way to calculate avoided energy and capacity costs (the information from the handout is included in the attachment to these notes). Some of the questions or concerns raised were as follows:

Q. A representative of a municipal utility that purchases a significant portion (if not all) of its electricity questioned whether it was appropriate to set a rate a year in advance, based on an average, when the cost of natural gas could increase greatly and have a significant effect on purchased power costs.

Discussion of this question included the following:

- Natural gas utilities, that purchase all of their natural gas supplies, have figured out a way to establish fixed prices a year in advance with hedging and other tools.
- *Municipal utilities proposed a **true-up of avoided costs** to minimize the risk they face in the market for electricity.*
- There was discussion about the possibility of using something like a fuel clause adjustment (FCA).
- There were questions from DG owners about the fluctuations that are in FCAs. The utilities and/or Department have that historical information and agreed to provide it to the group (this information for investor-owned utilities was provided by the Department in a November 6 e-mail to the group. The Department does not have this information for municipal or cooperative utilities.).
- DG owners saw that there may be some benefit to them of a variable rate and true-up since it would reflect the actual value of the power they provide to the utility. However, it was not clear how investors would view volatility in the pricing.
- The Department noted that, since DG is supposed to be treated like other resources, the pricing should be allowed to vary. However, the effects on DG investors should be considered as well. There could be two options: one with a fixed rate, one with a variable rate. Then the discussion would be on how to do the true-up. The true-up should be at the end of the year.
- The group appeared to agree that an option with a true-up would be preferable.

This discussion lead to the next question.

Q. Should calculations of avoided energy costs include purchases?

Long-term purchased power agreements should be included. Short-term economy purchases should be included only if the utility plans to make economy purchases. However, unplanned purchases cannot be included. Also, the more assumptions the utility makes about power costs, the more the utility will have to defend.

Q. How much differentiation should there be in the basic avoided energy rates?

Because it would promote great economic efficiency (e.g. DG owners would have better information about the value of energy they produce), there should be as much differentiation as practical. However, costs of metering needs must also be considered.

DG owners may be willing to pay for metering costs, and can certainly arrange with the utility to do so. But, for most DG owners, it is expected that metering costs would be prohibitive. Therefore, the discussion focused on two options (described in detail in the attachment) for pricing avoided energy costs:

- Setting on-peak prices for both the peak and off-peak season, and an off-peak price for the year (a total of 3 prices), or
- Setting peak and off-peak prices for each month (a total of 24 prices).

For these options,

- Both options would have an annual, lump-sum true-up, or
- There would be no true-up for the monthly option.

Group participants were asked to provide comments on these options. The intent is to finalize this issue for the next meeting.

Q. What is the definition of marginal cost of energy?

Marginal cost of energy is the incremental cost of adding one more kWh of power. Incremental means the plant or purchase that is avoided by the DG purchase.

Q. Isn't this information trade secret?

No. Both proposals for calculating avoided energy costs are based on projected average marginal costs. So these calculations should not reveal significant information.

Q. What is the appropriate rate to set for avoided capacity costs?

The Department read the proposal described in the attachment for calculating marginal capacity costs. The following issues were discussed.

What happens to capacity payments when a utility's resource plans change from one year to the next?

- The Department noted that, since the utility made the original resource plan, the DG owner should not be penalized for changes in those plans. As such, DG owners that entered into a contract with the utility under the original resource plan should continue to receive payments based on that plan. However, new DG owners who enter into contracts with the utility after the plan changes should be paid based on the most recent plan.

A one-year contract is different than a 10-year contract. There are different expectations on both sides of the issue. As such, the length of the contract is important.

If DG provides capacity when it's not needed, the value of the capacity isn't as great as in peak periods.

- ***The Department requested group participants to provide comments on how to recognize factors that impact the value of marginal capacity costs, such as the length of the contract.***

Capacity located on a part of the utility's distribution system that needs more capacity should have greater value than capacity added to a part of the distribution system that does not need the capacity.

- Recognition of this issue should be in the credit.

How should the ability to dispatch be addressed?

- This should be considered in the accreditation of DG power rather than in the calculation of the plant the utility avoids. (The group noted that the ability to dispatch is tested in the URGE test and transmission accreditation.)

How should DG capacity be treated in a year when the utility needs no new capacity?

- The group discussed how to address this issue, but did not come to a resolution. ***Group participants were asked to come up with specific proposals to address this issue***.

- Some of the issues raised were the negative effect a $0 capacity payment could have for a DG owner, the relatively small size of DG capacity that may not always be recognized in IRP models, and the perception that utilities have overbuilt.

- Some of the options proposed for a capacity credit were:

    a) Reflect the capacity value as the $ value in current dollars of avoiding capacity costs in the future.

b) Base the credit on decremental capacity (the value of the last unit that was added).

c) Base the credit on some default such as a CC unit.

- Based on this discussion, option (a) was the most likely approach to reflect the true value of capacity that the utility avoids.

- There was a question about intergenerational subsidies (i.e. that people pay now for costs they may not benefit from in the future when the plant is delayed). But it was also noted that, under the current system, sometimes customers pay too much for the bulkiness of plant additions. DG should be able to match load increases more accurately than the addition of larger plants.

Request for Comments

Group participants were asked to comment on the following issues by November 14:

- Please comment on the 2 options (in the attachment to these notes) for defining avoided energy costs.

- Please provide proposals for setting an appropriate value of marginal capacity costs when the utility does not need to add capacity for a number of years.

- Please comment on how to recognize factors that impact the value of marginal capacity costs, such as the length of the contract.

Next Meeting

The Group set the next meeting for:

Monday, November 18, <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.*