

2007 DOE-NARUC National Electricity Delivery Forum

General Session 3- “Who Pays for Electricity Delivery System Infrastructure? What are the Appropriate Cost Allocation Methodologies? Should Investors be Provided Incentives?”

Moderator: the Honorable *Susan Wefald* (Commissioner, N. Dakota PUC)

Panelists: the Honorable *Suedeem Kelly* (Commissioner, FERC)

Janet Gail Besser (VP, National Grid)

the Honorable *Sandra Hochstetter* (Chairman, Arkansas PUC)

Nina Plaushin (Asst. VP, WPPI and representing TAPS)

David Gates (VP, Northwestern Energy)

Issue 1- How should cost allocation decisions be made? Does a particular process result in optimum cost allocation decisions?

Leads: Janet Gail Besser, Nina Plaushin and David Gates.

Suedeem Kelly reply comments:

- As I will state again when the next discussion topic comes up, traditional cost allocation in cost-based ratemaking has always been about allocating costs fairly to the appropriate customers; those that cause the need for the costs to be incurred and those that benefit from the upgrades associated with the costs.
- Fairness has always been key so that no one ends up inappropriately subsidizing service to someone else - there should be no free riders and no windfalls.
- That is how it has always been, at least on a theoretical level, and I think it should remain so.
- As to what particular process may work best, I believe the specifics of each particular project and each particular regional system including the distribution of loads and resources may require us to accept that there is no one optimum process.
- Rather, there are a series of just and reasonable solutions to cost allocation but it is helpful to have the chosen solution in place in advance of working on particular projects.

Issue 2- Are traditional cost allocation principles relevant to the current cost allocation debate?

Leads: David Gates, Sandra Hochstetter and Suedeem Kelly.

Suedeem Kelly comments:

- Traditional cost allocation in cost-based ratemaking has always been about allocating costs fairly to the appropriate customers; those that cause the need for the costs to be incurred and those that benefit from the upgrades associated with the costs.
- In the old days of franchised service territories and integrated resource planning for vertically integrated utilities, this was a simpler matter because it was easier to see that those “causing” the costs and those “benefiting” from them were the same people; the ultimate customers.
- The advent of wholesale competition in generation made matters more complicated because it is harder to tie specific merchant generation to specific retail load.
- Retail competition, the advent of ISOs and RTOs providing service over the transmission grids of multiple utilities, and the need to accommodate new remote resources like renewables, make cost allocation decisions for delivery facilities even more complicated.
- The principle of assigning costs fairly to those who benefit from them is still absolutely appropriate, but the practice of it must be updated to take into account the modern realities of the industry.
- My hope is that the regional planning processes that are now mandated as part of service under the FERC pro forma open access transmission tariff will go far toward addressing this need to adapt.
- All that said, I strongly believe that one particular chestnut of old cost-based regulation must still play a prominent role in the new world of cost allocation; specifically, the idea of intergenerational equity.
- Transmission and distribution lines are among the longest-lived of utility assets; you can’t get much tougher than a steel cable.
- People who may appear to be the sole beneficiaries of new network facilities today, may not be beneficiaries in the future and vice versa, those that do not appear to benefit today, may in fact start benefiting in the future.

- Any cost allocation scheme must appropriately recognize this fact and avoid having one set of beneficiaries subsidize the service to other beneficiaries, both now and over time.
- Now this concern rarely arises when the cost of facilities is rolled into a rate to be paid over time because such rates are designed to collect the revenue requirement over the life of the facilities and as different entities join or leave the system, different entities will pay the rate and share in the cost.
- This issue arises more in connection with so-called “participant-funding” proposals that require the entity whose transaction triggers the need for a network upgrade to pay the full cost of that upgrade even though, by definition, others on the network will also benefit.
- Participant finding, thus, can have the effect of excluding some categories of beneficiaries from sharing in the cost of network facilities that will ultimately benefit them as well; in particular, those who become beneficiaries after the “triggering” event that causes the network upgrade to be built.
- In the organized RTO markets, this concern is somewhat ameliorated by the fact that such “participant funders” may be compensated in other ways, for example by receiving incremental FTRs, while those who escaped sharing in the cost directly may ultimately share in the cost indirectly through congestion charges.
- So far, this mechanism has not been duplicated in other areas, however, and I believe that any cost allocation proposal must respect and preserve intergenerational equity.

Issue 3- Is there a cost allocation methodology that works nationwide? If not, what considerations should be included in developing a regional cost allocation methodology?

Leads: Suedeem Kelly, Sandra Hochstetter and Nina Plaushin.

Suedeem Kelly comments:

- As I noted in my comments on the last discussion topic, I believe the underlying principle, allocating costs fairly to the appropriate customers based on cost-causation and beneficiaries, is appropriate nationwide.
- However, I do not believe that every region must adopt precisely the same methodologies and assumptions in following that principle.
- In fact the FERC has approved several different allocation schemes for FERC-jurisdictional regional entities and I will describe two of them now.

Midwest ISO:

- For example, in the Midwest ISO, “baseline” reliability projects identified in the regional planning process that are at or above 100kV whose costs are either more than \$5 million or comprise more than 5% of the Transmission Owner’s net transmission plant are subject to cost sharing.
- If a baseline project is between 100 kV and 345 kV, 100% of the cost is allocated to one or more zones, based on a line outage distribution factor study.
- For projects 345 kV and above, 80% of the cost is allocated to the affected zones based on the line outage distribution factor study, and the remaining 20% is allocated to the overall Midwest ISO footprint.
- Projects needed to provide new point-to-point transmission service, or to designate a new network resource that are not identified as needed as a baseline reliability project are directly assigned to the requester of the service.
- In return, those who pay for the project receive the incremental Financial Transmission Rights (FTRs) made feasible by the upgrade.
- Around the FERC headquarters, the Midwest ISO cost allocation I just described is often referred to as the “80-20” split.

SPP:

- Stakeholders in the Southwest Power Pool (or SPP) have developed a similar but

distinct allocation scheme.

- Generally, reliability projects identified in SPP's base plan at 60 kV and above with costs greater than \$100,000 are subject to cost sharing.
- One-third of the cost is allocated across the SPP footprint and two-thirds is allocated to the zones that benefit from the project as measured by SPP's MW-mile method.
- The costs of an economic project identified in the base plan are allocated according to agreements reached with the project sponsors.
- If an economic project would defer or displace the need for a reliability project, part of its cost may be allocated the way a reliability project's cost is allocated.
- Sponsors of economic projects receive transmission revenue credits for any subsequent transmission service over the new facilities by other entities.
- Projects needed for point-to-point service are charged a rate based on the "higher of embedded or incremental" principle, with customers that incrementally fund upgrades eligible for credits for subsequent transmission use.
- The costs of upgrades needed for network resources that meet certain criteria are allocated as reliability projects.
- Otherwise, the costs are directly assigned with transmission revenue credits given to the funding entity for subsequent transmission service that makes use of those upgrades.
- FERCers summarize this scheme as a "2/3 – 1/3" split.
- Again, Midwest ISO and SPP stakeholders have arrived at cost allocation schemes that are different but that both follow the principle of trying to allocate costs fairly to the appropriate customers based on cost-causation and beneficiaries.

Issue 4- If one favors a “beneficiary pays” approach, how should the beneficiaries of particular projects be identified?

Leads: Janet Gail Besser and Sandra Hochstetter.

Suedeen Kelly reply comments:

- Again, there are probably a variety of ways to identify current beneficiaries, like Midwest ISO’s line outage distribution factor analysis, but in the end I hope that the long lifetime of these facilities, with the attendant change in beneficiaries over time, will be taken into account and intergenerational equity will not be lost in any cost allocation proposal.
- In other words, the “beneficiaries” should not be artificially defined to include only those who “trigger” the need for an upgrade.

Issue 5- Should incentives be provided to investors?

Leads: Suedeem Kelly, David Gates, Nina Plaushin and Janet Gail Besser.

Suedeem Kelly comments:

- I have always been . . . cautious . . . about accepting the arguments that incentives are needed in cost-based ratemaking.
- This is primarily because cost-based ratemaking is already *required* to provide full cost recovery plus a reasonable return and many of the arguments for incentives seem to rely on the idea that regulators have not been granting reasonable returns even though they are required by law to do so.
- I am far from convinced that regulators have not been following the law.
- However, the Energy Policy Act of 2005 essentially directed FERC to make use of incentive ratemaking and we did so.
- That said, we recognized in our Order 679 rulemaking that the incentives sought must be tailored to address the demonstrable risks and challenges faced by the applicant in undertaking the project.
- This is known as the nexus test and not all projects will pass it.
- For example, Order 679-A discusses how “routine investments made in the ordinary course” will not qualify for incentives.
- Order 679-A does not prescribe the specifics of this nexus test and each FERC Commissioner, thus, must develop his or her own method of reviewing these cases to meet the principles of Order 679-A.
- Based on the individual cases we have received thus far, and comments received in the Order 679 rulemaking, I have settled upon a process that identifies and assesses, at a minimum, the following six characteristics of the transmission project: (1) the public interest benefits of the project; (2) the cost of the project in absolute terms; (3) the cost of the project in proportion to the current transmission ratebase of the applicant; (4) the difficulty of completing it due to the number of jurisdictions traversed and whether they are jurisdictions the applicant regularly deals with; (5) the difficulty of relying on normal rate recovery methods due to the length of time it will take to complete; and (6) whether the applicant would otherwise be required to build the project even without an incentive.
- The comments submitted in connection with Order Nos. 679 and 679-A, and the

experience gained in working on individual incentive cases over the past year lead me to conclude that these particular characteristics are most relevant to deciding whether the demonstrable risks and challenges faced by the applicant in undertaking the project warrant granting the incentives sought.

- As I have stated in separate statements appended to the last three incentive cases to be issued by the Commission, first and foremost in my analysis are the questions of whether the project brings broad regional benefits to the public interest and whether the applicant would otherwise be required to build the project.
- For example, if failure to build the project would jeopardize reliable service to the applicant's own native load, I deem the applicant to have an obligation to build it.
- If the project will also do little more than maintain the status quo, neither helping competitors nor allowing the applicant to improve its own service to customers beyond the status quo, then I will question the appropriateness of incentive rates, especially ROE boosters that raise customer transmission costs.
- To me it is a bedrock principle that incentives are meant to encourage behavior that is in the public interest but that is not otherwise required.
- Accordingly, only when a project brings broad public interest benefits and especially when it is not otherwise required, do I believe that incentives are appropriate.
- For everything else, normal rate recovery including regulated return should be more than adequate.