**CASE 07-E-1507**
**ERP DELIVERABLE 1:**
**COST ALLOCATION & RECOVERY**
**FOR**
**REGULATED ELECTRIC BULK-SYSTEM RELIABILITY PROJECTS**
**Staff Discussion of Comments**
**February 15, 2008**

## Purpose & Goals

Staff carefully read each comment and is appreciative of the guidance offered, which informed our modifications to the Straw Proposals.

## Cost Allocation

The Straw Proposal for cost allocation was developed through the NYISO stakeholder process, including extensive discussions and negotiations among the TOs. The NYISO (at 3) supports the Straw Proposal's cost allocation, claiming that its development "was consensus driven and, at least until recently, engendered no opposition to its substantive provisions after it was refined in a collaborative process that lasted nearly two years." The NYISO (id.) argues "the methodology is fair because beneficiaries pay according to their contribution to the reliability need and potential free riders are accounted for."

National Grid (at 2) argues that the "Staff proposal for cost allocation should be revised to remove the proposed credits for Locational Capacity Requirements ('LCR') from the formulae." National Grid (at 3) argues that all loads across the state should share equally, on a load-ratio-share basis, in the costs of reliability solutions to statewide needs. National Grid objects to the credit for loads in zones satisfying explicit LCRs, arguing that such credits "would require evidence that the other zones (i.e., zones without explicit LCRs) are less reliable, have a greater need, and benefit to a greater extent from the additional capacity still required for the entire control area." Multiple Intervenors (MI) (at 3) similarly expresses its concern that the draft allocation methodology may not be equitable to Upstate customers in instances where there is a statewide reliability need, and suggests that the cost allocation methodology should be worked out within the NYISO stakeholder process. MI (id.) urges the Commission to adopt the same cost allocation principles for generation and demand-based projects that FERC ultimately approves for the NYISO with respect to transmission reliability backstop projects.

Con Ed, O&R and NYPA (Joint Companies) defend Staff's proposal for cost allocation (at 2): "The proposed process includes four steps that first consider locational capacity requirements deficiencies, then Statewide resource deficiencies, then binding interface constraints, and a final step to share costs Statewide should any needs remain that are not met by the first three steps." They continue (at 3), regarding solutions to locational needs, all of those costs are assigned to customers in the location (NYC or LI) in which the needs arises, "even though the reliability benefits of implementing such a solution will be realized by all zones across the State…." ) Regarding solutions to statewide needs, the Joint Companies state (at 3-4) that the proposal "then allocates the remaining statewide needs in proportion to the locational zones' participation in statewide markets, or to the specific zone(s) that cause the remaining need. This is consistent with how the NYISO's markets works generally, and specifically in how its capacity requirements are implemented to meet reliability needs. In capacity markets, costs necessary to meet locational reliability requirements are paid for by customers in that locational zone, while those same customers also pay a pro-rata share of Rest-of-State (ROS) costs necessary to meet their overall reliability requirements."

Staff offers an example that may help illustrate the difference in cost allocations between the Straw Proposal's and National Grid's alternative. In "Examples of Cost Allocation for Reliability Projects 08-13-07," Case 1,[1] the costs of a hypothetical statewide solution were allocated across load zones according to the Straw Proposal. In the example, zone J (NYC) was responsible for 35% of the NYCA peak load, and zone K (LI) was responsible for 16% of the NYCA peak load. However, the Straw Proposal's formula multiplies zonal load by the factor (1-LCR), where locational capacity requirement (LCR) is the locational requirement for the zone, i.e. 80% for NYC and 99% for LI. As a result, the formula only counted 20% of zone J's peak load and 1% of zone K's peak load. The net result is that the Straw Proposal allocated just 13% of the costs to zone J and 0.3% to zone K. Under National Grid's alternative, zone J would be allocated 35% of the costs, and zone K would be allocated 16% of the costs, equal to their share of total load.

The Joint Companies argue (at 3) that the Straw Proposal's cost allocation is consistent with the NYISO's implementation of capacity requirements. However, there is a significant difference between the Straw Proposal's allocation of costs and the NYISO's allocation of capacity requirements. The NYISO's capacity requirements include a statewide installed reserve margin (IRM) currently set at 16.5%, meaning that all LSEs are required to procure a minimum amount of installed capacity equal to 116.5% of their peak load. The LCR is also a function of peak load; thus LSEs serving zone J (NYC) are required to procure capacity equal 80% of their peak load from within NYC; the remainder, equal to 36.5% (116.5% - 80%) can be procured from Upstate. Similarly, LSEs serving zone K (LI) are required to procure capacity equal 99% of their peak load from within LI; the remainder, equal to 17.5% (116.5% - 99%) can be procured from Upstate.

Thus, to make the Straw Proposal's cost allocation consistent with the NYISO's allocation of capacity requirements, the formula should take into account the IRM as well as the LCRs. In the above example, the formula would be adjusted by replacing the factor (1-LCR) with the factor (1+IRM-LCR). As a result, the adjusted formula would count 36.5% of zone J's peak load and 17.5% of zone K's peak load. The net result is that the adjusted formula would allocate 18% of the costs to zone J and 4% of the costs to zone K. Staff recognizes that cost allocation is not an exact science, but believes that the proposed formula should be considered as a possible compromise which would be consistent with the allocation of minimum capacity requirements.

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[1] See ESPWG meeting materials for August 15, 2007, "Cost Allocation for Reliability Projects Clean," pp. 2-3: http://www.nyiso.com/public/webdocs/committees/bic_espwg/meeting_materials/2007-08-15/Cost_Allocation_for_Reliability_Projects_clean.pdf

**Cost Recovery**

PSC Jurisdictional Projects

Questions were raised both at the All Parties Conference on January 30, 2008 and in the written comments as to what generation and demand response projects would be subject to a PSC-jurisdictional cost recovery methodology. Independent Power Producers of New York (IPPNY) (at 1-2) questions the “bases for such jurisdiction” and requests that DPS staff “explain how a generation project, selected as an ‘alternate developer’ to resolve a reliability problem and selling its output in wholesale markets, would be subject to PSC jurisdiction and any bases therefore.” Competitive Power Ventures and New Athens Generating Company (CPV/AGC) state (at 1-2) that the “PSC cannot approve a wholesale sale, and FERC cannot approve a retail sale” and suggest that neither Model 1 nor Model 2 could be lawfully applied.

The Public Service Law (PSL) provides the Public Service Commission with broad authority over electric generation corporations doing business in New York State and electric generation facilities located in New York State. For instance, a generator is an "electric corporation" pursuant to Section 2(13) of the PSL and a generation facility is an "electric plant" pursuant to Section 2(12). Section 5(1)(b) states that the "jurisdiction, supervision, powers and duties of the public service commission shall extend" to "the manufacture ... of electricity for light, heat or power..., and to electric plants and to the persons or corporations owning, leasing or operating the same." Section 5(2), moreover, states: "The commission shall encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually and cooperatively, for the performance of their public service responsibilities....."

Section 65(1) provides that "every electric corporation shall furnish and provide such service, instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable" Section 66(1) gives the Commission general supervision of all electric corporations. Pursuant to section 66(2), the Commission has "the power to order such reasonable improvements as will best promote the public interest...and have power to order reasonable improvements and extensions of the works...of electric corporations."

Section 66(9) gives the Commission the power to examine the accounts, books, contracts, records, documents and papers of electric corporations. Section 68 of the PSL states that "[n]o ... electric corporation shall begin construction of a[n] ... electric plant without first having obtained the permission and approval of the commission" in the form of a certificate of public convenience and necessity.

Over the years the Commission has issued several orders awarding a lightened regulatory regime to competitive, as opposed to regulated, generation facilities.[2] In the context of discussing the Commission's jurisdiction over competitive generators, let alone generators seeking regulatory assurance of cost recovery, the Commission stated on page 5 of the AES decision: "AES is therefore subject to provisions, such as PSL sections 11, 19, 24, 25 and 26, that prevent producers of electricity from taking actions that are contrary to the public interest."

The question of which project would be subject to PSC jurisdiction can best be examined through examples.

Example 1: Suppose a utility proposed to build a new plant and requested full cost recovery in exchange for a guaranteed rate of return. All risk is placed on the ratepayer. The PSC would apply full regulation including any warranted review of prudent costs, determine the proper rate recovery in a filed tariff and arrange for the appropriate cash flow. The utility would be expected to operate the plant in the interest of ratepayers and any market-based revenues would be credited to the ratepayer. These same principles would apply to a demand-based project.

Example 2: Suppose an independent generator proposes to build a new plant and requested full cost recovery in exchange for a guaranteed rate of return. Just as in example 1, all risk is placed on the ratepayer. The generator would be treated as any other regulated utility by the PSC. The PSC would apply full regulation including any warranted review of prudent costs, determine the proper rate recovery in a PSC-filed tariff for recovery of capital cost and arrange for the appropriate cash flow. The independent generator would be expected to operate the plant in the interest of ratepayers and any market-based revenues would be credited to the ratepayer.

Example 3: Suppose a utility executed a long-term contract with an independent generator for energy. This would be a FERC jurisdictional contract. However, given that the utility has a prudence exposure with the PSC, the utility would present the contract to the PSC for approval before pursuing it at FERC.

Example 4: Suppose an independent generator proposes to offer a reliability service for a fixed price for a fixed term. In other words, the generator will gain most of its revenues in the market but only requires a relatively small fixed incremental amount to ensure that it continues operation and participates in the NYISO markets. Here ratepayers have a much smaller risk, which would likely warrant some level of lightened regulation for the generator, and the requirements that market-based revenues be returned to the ratepayer would not apply. The PSC would arrange for a cash flow to cover the service.

[2] See, for example, Case 98-E-1670, Carr Street Generating Station, Order Providing For Lightened Regulation (issued April 23, 1999) and Case 99-E-0148, AES Eastern Energy, L.P. and AES Creative Resources, L.P. Order Providing For Lightened Regulation (issued April 23, 1999). These orders will be posted on this proceeding's Web page for convenience.

Market Impacts

IPPNY proposes (at 3) that an "RPS-like structure should be considered in this proceeding" as it is the methodology that the PSC favored to encourage otherwise "uneconomic renewable energy projects" and provides the least market impacts. The Commission did not preclude any option. If a developer proposes an alternative project with an RPS-type mechanism for recovery, it will be weighed against the other proffered projects on its merits.

Both the Retail Energy Supply Association (RESA) and the Small Customer Market Coalition (SCMC) are concerned that there is potential for harming competitive retail and wholesale markets depending on how costs are collected at retail. Staff is very aware of this possibility which can be easily handled in Model 1 by applying the same delivery rate to customers whether they are ratepayers of the host utility or are customers of an ESCO. Under Model 2 it is possible for customers of ESCOs to be charged different rates from those charged to similarly-situated full-service customers of the regulated utility. For example, if ESCOs are subject to payments to the project sponsor under the FERC ISO tariff, then the ESCOs may have to recover those costs from their customers over a smaller base (customer, kW, kWh) than the regulated utility whose cost recovery could be spread to all customers in its service territory, which might cover multiple zones. Further, the PSC cannot dictate on what bases the ESCOs will recover the payments from their customers. For example, the ESCOs might choose to recover their payments on a per customer basis while the PSC mechanism might require utility payments to be recovered on a usage (kW, kWh) basis. Obviously, similarly situated customers could be affected differently based on the method of payment recovery.

Cost Overruns & Prudence

Commenters seem to have misinterpreted Staff's intent regarding how cost overruns and prudence would be handled. IPPNY (at 3) contends that the proposal for staff to "monitor the reasonableness of construction costs on an ongoing basis for a potential prudence proceeding is contrary to the ERP Order." IPPNY (at 4-5) also contends that under Model 2 "developers would be forestalled from seeking a higher recovery from FERC when these contracts are filed" resulting in giving transmission projects an unfair advantage. CPV/NAG (at 7) assert that "non-transmission project costs would be capped."

As illustrated in the Example projects listed under the jurisdiction section, the level of cost monitoring and prudence review would be dependent on the level of risk to ratepayers. If the project is structured such that the ratepayer is assuming a significant amount of risk, then the cost monitoring efforts would need to be significant also. If the project is a contract with guaranteed prices that are judged to be reasonable at the time the contract is executed, then future cost monitoring is not required.

Staff has no intention of recommending to the Commission that it preclude recovery of prudently-incurred costs. While the path to requesting recovery for such costs would be different between transmission and non-transmission projects, the risk should be similar. It is anticipated that if the PSC chooses a generation or demand-based project that it would also speak to the level of costs that are recoverable at that time. If the actual project costs are different from the projected costs before construction, then the developer has the right to return to the PSC with a presentation of the cost overruns with an explanation as to what led to the higher costs. Assuming the costs were prudently incurred, the PSC would then designate those costs as being recoverable.

If the PSC were to choose a transmission project, then the decision would be based in part on the projected costs of the project. The Commission would also be looking at cost estimates where the project is subject to the Article VII siting process. If the actual project costs are significantly higher than had been presented to the PSC at the end of construction and those higher costs are presented to FERC for recovery, then the DPS would no doubt intervene in the proceeding at FERC to make the case for a prudence review in that venue.

Contracts Enabling Beneficiaries Pay

Several parties see the Model 1 proposal to have a contract among the developer and beneficiary utilities as a problem. IPPNY (at 4) views "negotiating such a contract … to be highly contentious." CPV/NAG contend (at 8) that "a tariff approach is more efficient", less burdensome and more transparent." The Designated Transmission Owners (DTOs) (at 2) find that "it is not clear which PSC jurisdictional entities would be required to enter into contracts." The DTOs assert (at 3) that "registration and execution of these multiple contracts may be time consuming and costly." National Grid (at 4) proclaims that contractual arrangements would be "cumbersome, time-consuming and potentially controversial, … difficult to administer, not appear to assure certainty of cost recovery" and is unclear as to how disputes would be resolved.

Staff does not agree. Contracts are the main form of business relationships and all involved parties negotiate agreements on a regular basis. The contract staff is suggesting should be simpler than most given this contract will be for the specific purpose of moving retail ratepayer funds to a developer. The dollar amounts and schedule will be provided by the PSC for each beneficiary in an Order resulting from an open proceeding. Where applicable, the NYISO will provide project revenue amounts to offset the revenue requirement. The terms of the contract will not be dependent on the type of project. The benefiting utilities will not be assuming any project oversight responsibilities in this contract. After the contract(s) for the first project is established, it should provide a format for future contracts. Disputes could utilize PSC ADR processes or be settled in state court.

The Joint Companies (at 1-2) suggest that contractual obligations could be minimized "through the encouragement (or mandating) of jointly owned and/or developed opportunities among the Responsible TOs when the reliability needs cross several zones." While there are no obstacles to the parties negotiating joint ownership agreements, it is beyond the scope of this phase of the proceeding to explore all the ramifications of mandating joint ownership.

Super-Sized Projects

The NYISO, MI and IPPNY presented concerns that the specifics for cost recovery for a super-sized project should not be addressed in this phase of the proceeding. Further, MI and IPPNY expressed their concern that portions of a super-sized project possibly would be an economic project. And, MI indicated that such projects could squelch market-based projects. The NYISO observes that these issues would benefit from further discussions at the ESPWG.

Staff does not plan to recommend to the Commission that it pursue a project larger than is technically feasible to resolve identified reliability needs. PSC authorization of projects supported by regulated dollars need to be in the public interest. Part of that public interest involves consideration of market impacts. Part of the public interest consideration involves ensuring that ratepayer funds are spent wisely. Public interest decisions involve minimizing environmental impacts of projects. Where a developer's focus is maximizing profits, the PSC has a much more complex responsibility that could lead to a decision for a larger project than is specifically required in the CRPP in a particular year. As an example, it is inefficient to site a bulk transmission line as a single circuit if there is a foreseeable need for a second circuit on that right-of-way; therefore, the original construction should be for double-circuit towers with the ability to string the second circuit in the future. Staff also recognizes that there are possible economic issues related to super-sized projects. Staff agrees with the NYISO that the issue of cost recovery for super-sized projects would benefit from additional discussion in the ESPWG.

As a balance between the parties' desire to not address super-sized projects in this phase of the proceeding with the need to reassure developers that if the PSC orders a larger project they will be provided a revenue stream for the increased portion, staff suggests replacing the super-sizing bullet in the straw proposal with a plain statement that the PSC will ensure recovery for all authorized projects under their jurisdiction. Issues related to under what conditions a project may be super-sized are left to future phases of the proceeding.

<u>Other</u>

Several parties suggested supporting arguments and model modifications that address: 1) what projects should be eligible for recovery; 2) whether a Responsible TO will be required to sign a contract with a project developer; and, 3) background process leading up to the selection of a project. Project selection and responsibility is the subject of Phase Two of this proceeding, and therefore, are not incorporated in the models. Given that we do not have that determination yet, the recovery models must be built upon an unspecified project sponsor/developer. Furthermore, the subject of this phase of the proceeding is strictly cost allocation and recovery for PSC-jurisdictional projects – not the validation of the process that produces a project to be subject to cost allocation and recovery. Likewise, these provisions have not been included in the models.

DEC raises issues relating to environmental justice, environmental compatibility, and other state policy concerns. These are attributes that need to be considered in the evaluation and selection of regulated reliability projects, which will be addressed in the two subsequent phases of this proceeding.

CPV/NAG's comments propose a new model that is presented in the straw options document as Model 3.

State Jurisdictional Costs in a FERC Tariff

Staff's key concern is that were the PSC to agree to allow recovery of state jurisdictional costs in a FERC tariff, then FERC and the courts may determine that the PSC has ceded jurisdiction of those costs to FERC. (FERC staff has stated as much in phone conversations.) Moreover, the station power case is illustrative of this issue.[3] In that case, the PSC agreed to allow the calculation and recovery of station power costs, which are state-jurisdictional, to be handled in the NYISO's tariff. Even though the PSC had expressly reserved its jurisdiction over retail sales, the court determined that it had ceded its jurisdiction by allowing recovery to occur through a FERC tariff. The PSC may not voluntarily cede its jurisdiction.

[3] Niagara Mohawk Power Corporation v. FERC, 452 F.3d 822 (D.C. Cir. 2006).