STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

OPINION NO. 01-4

CASE 99-E-1470 – Proceeding on Motion of the Commission as to the Reasonableness of the Rates, Terms and Conditions for the Provision of Electric Standby Service.

OPINION AND ORDER APPROVING GUIDELINES FOR THE DESIGN OF STANDBY SERVICE RATES

Issued and Effective: October 26, 2001

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COMMISSIONERS:

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BY THE COMMISSION:

INTRODUCTION

This proceeding was instituted, jointly with an investigation of the costs and benefits of distributed generation (DG),[1] for "the formulation of general guiding principles and policies for developing standby tariffs, which would then be implemented at the time a utility introduces new standby tariffs or rates."[2] The two proceedings were conducted in a coordinated, collaborative process, which began on April 5, 2000, following the submission of statements of interests by parties. The collaborative process, which commenced under the

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[1] Case 00-E-0005, Costs, Benefits and Rates Regarding Distributed Generation.

[2] Cases 99-E-1470 and 00-E-0005, Order Instituting Proceedings (issued January 10, 2000), p. 3.

direction of Administrative Law Judges William Bouteiller and J. Michael Harrison, followed two tracks thereafter, one for consideration of DG issues and the other for consideration of standby rates issues. This opinion and order addresses standby rates issues, and DG issues are addressed in an opinion and order contemporaneously issued in Case 00-E-0005.

Following a series of informational and educational presentations held in May and June 2000, working group meetings on standby rate issues commenced. After several meetings, most of the active non-utility parties agreed to work together to formulate a position paper on standby rates and station power.[3] Likewise, the electric utility companies formulated a joint position statement regarding standby service issues.[4] The position papers of both groups were submitted within the collaborative on September 18, 2000.

Thereafter, discussions continued briefly, but did not result in consensus on major issues. DPS staff developed a straw proposal for a conceptual approach to designing standby rates, which was distributed to the parties by ALJ Harrison on March 29, 2001. A plenary meeting of the parties was held on April 24, at which the staff proposal was presented by DPS Staff and discussed. It was determined that the parties would comment

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[3] The "Non-Utility Working Group" included representatives from Distributed Power Coalition of America (DPCA), IBC Engineering, Inc. (IBC), Independent Power Producers of New York, Inc. (IPPNY), Multiple Intervenors (MI), Orion Power New York GP, Inc. (Orion), Owners Committee on Electric Rates (OCER), Southern Energy New York (SENY), and Trigen-Nassau Energy Corporation (TNEC).

[4] The investor-owned electric utilities jointly submitting comments included Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation (Niagara Mohawk), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation (RG&E).

on the straw proposal, after which it would potentially be clarified or revised, resubmitted to the parties for additional, reply comments, finalized, and submitted to the Commission. Accordingly, initial comments were submitted on May 15 by 1st Rochdale, DPCA, the six investor-owned electric utilities jointly (the Utilities), IPPNY, KeySpan-Ravenswood, Inc. (KeySpan), Mirant New York, Inc. (Mirant), MI, National Energy Marketers Association (NEM), NRG Companies (NRG), Pace Energy Project (Pace), and Plug Power, Inc. (Plug Power).

The straw proposal was resubmitted to the parties, with minor changes suggested by parties, and reply comments were filed on June 15 by Capstone Turbine Corporation (Capstone), Plug Power, IPPNY, NRG, the Utilities, NEM, DPCA, the Non-Utility Working Group, MI, New York Energy Research and Development Authority (NYSERDA), Mirant, and New York Energy Buyers Forum (NYEBF).

Following submission of proposed Guidelines at the August 2001 session, at which time the matter was put over for further evaluation, an additional round of comments focusing specifically on changes to the Guidelines introduced following the June 15 comments was requested and received on September 17, 2001. Parties filing these supplemental comments included Plug Power, IPPNY, Pace, National Fuel Gas Distribution Corporation (NFG), NRG, DPCA, the Utilities, NEM, and MI.

THE PROPOSED GUIDELINES

The “Guidelines for the Design of Standby Service Rates” (the Guidelines), attached to this opinion and order (Attachment A), reflect consideration of all of the comments filed by the parties. As can be seen by the summary of the comments (Attachment B), there are unresolved disputes among the parties on a variety of fundamental issues regarding the straw proposal. Before discussing those comments and our

determinations on the various aspects of the Guidelines we approve, a summary explanation of the Guidelines will be provided.

Fundamental Principles

1. Applicability

The Guidelines are intended to apply to the proper design of standby delivery service rates. Thus, they do not apply to the energy component of a standby customer's requirements. Standby customers would be expected to arrange for energy supply in the competitive market, and even if energy is provided through the utility, the delivery service rates for standby customers would be independent of the energy rates they would pay.

A standby service customer is essentially a customer which normally does not obtain all of its energy via deliveries through the utility’s transmission and distribution grid. Two general categories of such customers were identified during the collaborative process: (1) customers with on-site generators (OSGs) that produce energy primarily to serve the customer’s native load; and (2) wholesale generators that operate mainly to produce and sell electricity in the wholesale market. The standby rates would apply to both types of customers to the extent they rely on the electric utilities to deliver power that would otherwise be supplied by the generator. This would include what the wholesale generators have referred to as “station use.”[5]

[5] Station use includes such loads as power used for heating, lighting, air-conditioning, and office needs of the building housing the generator, when such needs are not part of the native load served by the generator, or power used in re-starting a generator after an outage.

The Guidelines propose, however, to exempt, while they are operating, wholesale generators that provide for all of their station use “behind the meter” (i.e., the electricity is not provided via a point of interconnection between the generator’s facility and the utility’s retail delivery system) from the application of certain components of standby rates. Moreover, in some instances, where the station use is provided from the same bus bar as the generator’s point of interconnection with the transmission system, the Guidelines would recognize those circumstances to be equivalent to provision of station use behind the meter. Consequently, under this configuration, the as-used demand charge would equal zero when the generator is operating. However, when the generator is not operating and if station use is served via the utility's retail delivery system, the as-used demand charge would apply.

The Guidelines also distinguish customers with on-site generation used principally as a source of emergency backup when utility service is interrupted. Since such customers are reliant on utility service for the vast majority of their needs, all service to these customers should be provided under the otherwise applicable full service tariff.

The Guidelines recommend fundamental cost-based rate design principles that in most cases avoid reliance on measurements of energy consumed (kWh) for charges for delivery service. While these principles might conceivably apply to the recovery of delivery service costs from all utility customers, the Guidelines recommend implementation of these principles for standby service, as a specialized form of retail delivery service. Consideration of changes in delivery service rate design for full-service delivery customers was not the subject of this proceeding and it would, therefore, be inappropriate to conclude that these principles should be applied to delivery service other than standby service at this time.

The Guidelines recognize that additional charges or credits may also apply to properly designed standby rates. These might include surcharges applied to the otherwise applicable service classification that would appropriately be applied to standby rates or certain credits or surcharges (such as interconnection charges) directly attributable to individual standby customers.

2. Stranded Production Costs

The applicability of stranded production cost recovery from standby delivery service customers was debated during the collaborative process. The Guidelines provide that if a utility has stranded production costs it is allowed to recover from delivery service customers, then customers that take standby delivery service from the utility should also contribute to the recovery of the stranded costs. With a uniform markup of all delivery service rates, standby customers would contribute to stranded cost recovery in the same proportion of their delivery rates as customers in the otherwise applicable service classification.

Rate Design for Standby Services

1. General Principles

The Standards reflect the premise that standby delivery service is sufficiently different from full delivery service to justify some difference in treatment, but that not enough valid cost data exists for OSGs to justify creation of a separate service classification or classifications for standby service. Until such time that significant data exists on the operation and cost causation of various standby service customers to justify the creation of a separate standby delivery service rate classification, the Guidelines provide that standby delivery service will be provided as part of the otherwise

applicable full-requirements class tariff. That applicable service class will be based on the standby customer's maximum potential, or contract, demand. However, as explained below, the unique usage characteristics of standby customers, by virtue of these customers' intermittent and more random reliance on the delivery system, will be recognized through rate design.

Pending appropriate cost of service analyses for non-wholesale generators, the Guidelines provide, costs now allocated to each standard service classification would serve as the basis for designing revenue-neutral,[6] class-specific standby service delivery charges. That is, the existing allocation of costs to the various service classifications would be reflected in the distribution delivery service charges, inclusive of customers with OSG.

As mentioned above, because standby service is a delivery service, the Guidelines propose that standby rates would be established exclusive of any rates or terms for the provision of electricity supply. And the costs of any additional interconnection facilities and equipment not utility rate-based would be recovered directly from customers that install OSG through separate, up-front interconnection related charges. Lastly, a fixed monthly access charge for each service class would be established as part of the standby tariff rate to recover all customer-related utility rate-based system costs not recognized in customer-specific interconnection charges.

2. Distribution Delivery Rate Design

The Guidelines propose that distribution system delivery costs should be recovered through a combination of

[6] "Revenue neutral" here means that the full service class (not any individual customer) would contribute the same revenues if the full class were priced under either the standard service class rates or the standby rates (given the historic usage patterns of the customers in that class).

class-specific contract (fixed) demand charges and daily, as-used, on-peak demand charges. The utilities would use the contract demand charge, to the extent possible, to recover the costs of “local” facilities, those that are closer to a customer’s site and were put in place mostly to serve the individual customer. The Guidelines provide that these fixed, contract demand charges should apply to the customer’s maximum annual demand. Customers who have changed their usage characteristics resulting in reduced maximum annual demand would be allowed to apply for a reduction in the historic-based contract demand charge.

The Guidelines posit that delivery system facilities located further from customer sites are considered “shared” facilities, and that costs associated with these shared facilities ought to be recovered in a manner that recognizes the customers' overall coincidence of the service classification, through as-used demand charges.[7] Because wholesale generators and OSGs have a uniquely intermittent demand for standby delivery service, the as-used demand charge applicable to these customers would be the otherwise applicable charge, expressed as and applied on a daily basis. Moreover, the as-used demand charge should apply only to the customer’s daily maximum metered demand that occurs during the utility’s delivery system peak periods.

Since the Federal Energy Regulatory Commission's (FERC) transmission charge is part of the overall revenue requirement for each service classification, it would be inherently included in the derivation of the as-used demand charge.

[7] The coincidence assumed for the purpose of allocating system costs would be the same for standby and full service customers initially but, as discussed earlier, with sufficient load data, demand charges based on an allocation of system costs to a class of standby customers could be developed in the future.

3. Metering

Interval metering necessary to implement rates designed on the foregoing basis would be required of all customers with contract demands at or above 50 kW. A standby customer with a contract demand below 50 kW, but nevertheless subject to demand metering under the otherwise applicable service classification, would have the option of taking service at either (1) the monthly demand rate for the otherwise applicable full-service classification, or (2) the interval meter rate mandatory for customers at or above 50 kW.

Unless otherwise proscribed, the Guidelines would allow a standby customer that would otherwise be served in a non-demand metered class to take standby delivery service under a rate structure similar to the otherwise applicable full-service rate structure. That is, such a customer would pay a standby delivery rate comprising a customer charge that reflects the average embedded customer costs for the service classification (including metering and billing costs) as well as the fixed distribution costs that are considered "local" in nature, and would otherwise be recovered through a separate contract demand charge.[8] These standby customers would not pay an as-used demand charge, but instead would compensate for the cost of "shared" facilities via a volumetric usage charge (an energy rate for delivery service). The Guidelines propose that the volumetric rate for standby customers without demand or interval metering would be revenue neutral for the entire service class. That is, it would be set at the amount that would have to be charged to the entire class to recover the balance of the revenue requirement of that class not recovered by the revised customer charge.

[8] Alternatively, a utility could use the customer components of the distribution system identified in a fully allocated embedded cost of service study.

DISCUSSION

The Guidelines strike a balance between two opposing and irreconcilable points of view regarding standby rate issues. On the one hand, standby customers would prefer to continue paying regular service rates, applicable to all customers, under typical current rate designs in which most costs of distribution delivery service are collected via metered kWh consumption of electricity. Because these customers generate most of the electricity for their loads with OSG, they can substantially minimize or eliminate the amount they would have to pay for delivery service simply by minimizing or eliminating consumption of electricity delivered over the utility interconnection. On the other hand, the utilities argue that their obligation to serve and cost of serving standby customers is the same as for full service customers and would prefer to charge the standby customers on the basis of their entire consumption of electricity, irrespective of whether their energy is mostly self-generated.

The Guidelines call for recovery of retail delivery costs through a combination of contract and as-used demand charges, reflecting the premise that the costs are caused in proportion to the total connected load or coincident customer demand, not to how much electricity is consumed by customers. The rate design principles that they embody, not surprisingly, would result generally in greater cost responsibility for standby customers than if these retail delivery service costs were recovered strictly on the basis of the metered consumption of energy (kWhs) delivered over the utility’s distribution system, but would result in less cost responsibility than if the standby customers were charged on the basis of potential peak demand with no recognition given to the implications of self-generation, as the utilities propose.

Nearly all of the parties in the collaborative proceeding supported the general proposition that rates should be cost-based. As we will discuss, the intermediate approach reflected in these Guidelines has a better cost basis than either of the more extreme positions proferred by the parties on both sides of the argument. A number of non-utility parties expressed the view that standby rates should provide an incentive for the development of distributed generation (DG) and OSG. If by that the non-utility parties mean to suggest that standby rates need not be established on a cost of service basis, we disagree. Cost-based standby delivery rates should provide neither a barrier nor an unwarranted incentive to customers contemplating the installation of DG or OSG.

Some of the comments argue that there are identifiable benefits associated with DG or OSG installations that are not reflected in the rates, such as reduced delivery system requirements. To the extent such economic benefits are not reflected in the utilities' cost of service, they could be addressed within other proceedings such as the Generic Distributed Generation proceeding or System Benefits Charge (SBC) proceeding. However, the main point to make in responding to these arguments is that the economic "benefits" of reduced or avoided utility delivery system costs are reflected in the standby rates under the Guidelines. The use of daily, as-used demand charges for standby service is a direct reflection of the lower cost responsibility of standby customers for service classification coincident peak loads. This essentially, and effectively, recognizes the "benefit" of lower levels of shared costs.

One party argues that an inadequate evidentiary basis exists for departure from the principles established in Case 27574, Consolidated Edison Company of New York, Inc., Opinion No. 82-10, Opinion and Order Establishing Rates,

Charges, Rules and Regulations for Electric Service Provided to Customers with On-Site Generation (issued May 12, 1982). The context for these principles has vastly changed over the intervening 19 years, especially with the deregulation of wholesale generation, and some change is due. We rely here only upon general facts and theories of which we may properly take notice, recognizing that more justification will be required for specific rates designed in specific utility filings.

Volumetric vs. Demand Charges

Using volumetric rates as the basis for recovering delivery service costs for standby customers is not appropriate because the local costs of providing delivery service correlate with the size of the facilities needed to meet the generating customer's maximum demand for delivery service. This varies, not with the volume of electricity delivered, but with the peak loads that must be delivered. Comments by parties such as 1st Rochdale and DPCA favoring continued use of volumetric charges for the recovery of delivery service costs do not dispute this fundamental principle, but appear instead to reveal concerns about the alternatives. For example, the argument that recovering more system costs through fixed or demand-based charges would tend to reduce the incentive of standby customers to avoid use of the delivery system does not adequately reflect the fact that reducing consumption of electricity during off-peak periods in the short run does little or nothing to reduce the associated delivery system costs. Similarly, Pace's argument that use of demand charges would foreclose opportunities to change usage patterns addresses the same point, and in any event both concerns have been addressed in the Guideline's rate design, which would use daily, coincident peak demand as a basis for a portion of the standby charge. The Utilities are correct that continuing to rely on volumetric

rates for the recovery of standby delivery service costs, most of which are not related to the volume of commodity services delivered over the delivery system, under-recovers those costs from standby customers.

Therefore, we underscore this principal feature of the Guidelines, which moves from volumetric-based standby delivery service cost recovery in the direction of a better cost basis for designing these rates. We recognize that, for very small OSGs, the Guidelines continue to rely, albeit to a lesser degree, on volumetric rates as a surrogate for measured demand, because the cost of demand or interval metering is presumed currently to be prohibitive. Overall, however, the compromise moves sharply closer to economically efficient rates.[9]

Fixed vs. Variable Demand Charges

The Guidelines propose the use of two separate vehicles for the recovery of delivery service costs from standby customers. Fixed, "local" costs, those that can be attributed exclusively or nearly exclusively to the customer involved, would be recovered through a fixed contract demand charge. Variable and shared-facility costs, the incurring of which cannot be singularly attributed to individual customers, would be recovered through an as-used demand charge.

The main arguments here center on how delivery service costs should be allocated between these two charges and how these charges should be applied to standby service customers. Some non-utility comments argue for as little as possible of the costs to be placed in the contract demand charge, asserting that the allocation between contract and as-used will be difficult to make. The Utilities, on the other hand, propose effectively to allocate most, if not all, delivery service costs to a fixed

[9] See Appendix A, ¶ II(G)(3).

monthly contract demand charge. In support of this position, the Utilities argue that maximum demand does not vary with usage and, therefore, delivery costs attributable to standby service customers are much the same as those attributable to full-requirements customers.

No parties' comments are persuasive, however, as they do not reflect cost causation. We have already rejected the Non-utilities' suggestion that incurring of delivery service costs is related to the volume of energy consumed rather than peak loads. We must also expressly reject the Utilities' position that the costs incurred to provide standby delivery service are the same as the costs incurred to provide delivery service to full service customers. That argument implies, wrongly, that standby customers would all contribute to a service classification's peak load in the same way as full service customers, who place steady demand on the system. The Utilities argue facilely that there is no evidence in this proceeding to the contrary. However, it would defy logic to assume that the far more occasional demand of standby customers could occur with such simultaneity as to approximate the coincident peak demands of full service customers. The important point is that there is no evidence supporting the Utilities' extreme assumption.[10] We conclude firmly that standby customers' responsibility for the costs of "shared" facilities is adequately and fairly represented in the as-used demand charge.

The rate design presented in the Guidelines effectively provides the recognition sought by standby customers

[10] The Utilities may be conceptualizing the issue as one of stranded investment--that standby customers are former full service customers for whom delivery service investment has already been made. But the incurring of costs and system development are far more dynamic than that would imply, as evidenced by the DG pilot program adopted in Case 00-E-0005.

of the diversity of their loads, and it thereby obviates the need, asserted by some parties, to create separate service classifications for standby customers. Significant load data for standby customers simply does not presently exist, although the Guidelines allow for the creation of separate classes if and when sufficient load data are compiled to support such a class differentiation.[11]

The method for allocating costs between the contract demand and the as-used demand charge should be set forth in each utility's formal standby rate filing. Such allocations should be based on delivery system design and cost causation. Fundamentally, we would expect the utilities to apportion facilities designed on the basis of customer coincident peak loads for recovery via as-used demand charges. Similarly, delivery facilities designed on the basis of aggregate customer non-coincident peak loads should be apportioned for recovery through contract demand charges. The allocation of costs between as-used and contract demand charges for each customer class might be determined for each category of facilities used to provide delivery service to that class,[12] or by a different method of allocation selected by the utility.

Several parties have expressed concerns about the implementation of the guidelines. DPCS and PACE maintain that the Commission should provide explicit guidelines for distinguishing between "local" and "shared" facilities. Although the concerns of these parties are legitimate, no standard set of principles appears possible at this time, given

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[11] IPPNY argues that wholesale generators have sufficient operating data to demonstrate diversity in their loads, and low coincidence with the system peak. Such data can be brought to bear in rate design in connection with individual utility rate filings.

[12] I.e., secondary distribution, primary distribution, sub-transmission, and transmission.

likely differences among utilities in cost studies, facilities, customer classes, and other pertinent considerations. MI requests that, at a minimum, the "illustrative table" used in the earlier straw proposal be included. Although parties may find it useful, we stress that this is purely illustrative, and utilities' cost of service studies may produce different results. This issue, therefore, must be addressed in the context of specific rate proposals made by the Utilities.

With respect to computing the contract demand charge, the Guidelines circulated for comment provided that it should be based on a customer’s "maximum anticipated" demand. The Utilities argue that this standard would entail estimating the number and capacity of on-site generators, as well as the likely operating conditions of the generators. The Utilities argue further that the standard should be the total connected or "potential" load, as this is more readily determined, and also is representative of the size and type of facilities put in place to serve each customer. We agree, and the Guidelines are modified accordingly.

Metering

Although encouraging the installation of interval demand metering for demand-metered customers, 1st Rochdale along with Plug Power emphasize that this equipment is expensive and, if required of all standby customers, could seriously discourage installation of small OSGs. The Guidelines adopted here reflect that concern, by providing an alternative, surrogate rate design for the smallest OSGs and by making interval demand metering optional for demand metered customers below the 50 kW threshold. Interval metering, as required for standby customers with contract demands in excess of 50 kW, is not expected to discourage OSG installation.

Commodity Charges

As already explained, the Guidelines provide for establishment of standby delivery service rates exclusive of the prices for electricity supplies. MI comments that it should be clarified that standby customers may purchase commodity either from the utility or from a third-party supplier. Certainly standby customers should be permitted to purchase electricity pursuant to the same alternative options that are available to other customers. Nothing about the Guidelines is intended to limit the competitive options that would otherwise be available to all customers.

Applicability Issues

1. FERC's PJM Orders

IPPNY, together with Keyspan and NRG, argue that FERC has exempted from the states' retail rate jurisdiction the self-supply from a remote location of station power requirements by wholesale generators, concluding that self-supply from a remote location is not a sale. They argue that under the PJM Orders,[13] utilities cannot require wholesale generators to purchase power when the generator is self-supplying from a remote location, and that this prohibition extends to payment for use of the distribution system. At most, say the wholesale generators, the Commission can impose on them only the costs of distribution facilities employed in the delivery of netted generation, on a basis proportionate to their use of those facilities.

[13] PJM Interconnection, LLC, 94 FERC ¶61,125 (March 14, 2001); PJM Interconnection, LLC, 95 FERC ¶61,633 (June 1, 2001).

The PJM Orders do not preempt State jurisdiction over delivery rates. Instead, in the PJM Rehearing Order, FERC expressly ruled that the state-federal delineation of jurisdiction, as described in its Order No. 888,[14] remained in full force and effect. FERC, in the PJM Order, also rejected assertions by wholesale generators that their status as wholesalers exempted them from state jurisdiction over retail deliveries. Similarly, in the "Standby Ruling" and "Standby Rehearing Ruling," the Commission decided it retained jurisdiction over delivery of electricity to wholesale generators.[15] Those Rulings remain in effect, and the rationales are dispositive here.

The wholesale generators misinterpret the PJM Orders, by misreading FERC's provisions for the netting of electricity usage at one generator against output from another generator operating at a remote location. FERC decided only that a utility could not compel a generator to purchase the energy commodity from the utility if the generator could net energy use against energy output from a generator under common ownership at a remote location. But the Guidelines provide for a rate design that is unaffected by the remote netting privilege, because the proposal provides for the unbundling of energy supply. After unbundling, nothing in the Guidelines prevents a generator from supplying its energy needs through remote located netting, just as the generator can access other non-utility sources of energy

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[14] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Docket No. RM95-8-000, Order No. 888, ¶31,036 at 31,783 (1996). The Commission is pursuing an appeal of Order No. 888 in the United States Supreme Court.

[15] Case 00-E-0757, Consolidated Edison Company of New York, Inc. - Petition for a Ruling on Jurisdiction, Declaratory Ruling on Jurisdiction Over Stand-By Service (issued September 29, 2000); Case 00-E-0757, supra, Order Denying Rehearing (issued February 8, 2001).

supply. The Guidelines are therefore consistent with the PJM Orders.[16]

In conformance with the unbundling approach, FERC stressed that the usual Open Access Transmission Tariff (OATT) rates would adhere to the transmission of netted energy supply. Likewise, state-jurisdictional rates adhere to the delivery of the netted energy, just as they adhere to delivery of the netted energy from other non-utility suppliers.

As FERC also emphasized, its Order No. 888 finding on State jurisdiction over unbundled standby delivery rates is continued under the PJM Orders. As discussed in the Standby Rulings, that jurisdiction extends to retail delivery services. Under FERC's BART Order,[17] State jurisdiction pertains to retail customer delivery even in the absence of any distribution-level facilities attributable to a particular customer. Consequently, there are no limitations on a State's design of standby delivery rates under the PJM Order, once unbundling of energy is accomplished. The wholesale generators may be charged the standby delivery rates described in the Guidelines.

2. Wholesale Generators

In supplemental comments, a controversial issue was whether charges should apply to wholesale generators taking station power off a bus bar used to export power. IPPNY argues that no standby rates should apply at all, while the Utilities

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[16] The wholesale generators also discern in the PJM Orders limitations on the structure and content of state-jurisdictional delivery rates. The Orders, however, may not even apply to generators that take service through state-jurisdictional retail meters, as do many of the generators participating in this proceeding. In the PJM Order, FERC left open the question of jurisdiction over energy use by that type of generator.

[17] San Francisco Bay Area Rapid Transit District v. Pacific Gas & Electric Company, 87 FERC ¶61, 255 (1999).

argue that as-used demand charges should be imposed at all times, not merely when the generator is not running.

When a wholesale generator is running, and thereby supplying the system with power, it is reasonably assumed that the generator's station service is effectively being self-supplied behind the meter, and that the utility's facilities are being used to sell power, not take it. Therefore, an as-used demand charge is unnecessary. However, when the generator is not running and the generator is receiving station power, those facilities over which that power is delivered are being used to provide standby service, and an as-used demand charge is appropriate. Since wholesale generators are standby service customers, they would be subject to all other applicable charges, including a customer charge and contract demand charge, but only to the extent that such facilities have not already been covered in an interconnection agreement. Further, the basis of these charges should be the otherwise applicable standard service classification for the maximum station service power to be served.

The Guidelines circulated for supplemental comments contained the provision that load incidental to the generator should be charged at standby rates, while other loads that are separately metered should be charged at standard service rates. The Utilities argue that this formulation is confusing, and that the standard for applying standby rates should be simply whether a particular load can be self-supplied by the generator. The intent of the Guidelines is, as the Utilities argue, for standby rates to apply if a generator can self-supply the load in question, and the load is not isolated from the system. The Guidelines have been modified for clarification in this respect.

3. Existing Contracts

One commenting party, Mirant, observes that it is already operating under a contract with Orange & Rockland Utilities, Inc., for the provision of station power, and contends that the approval of principles here should not supercede its contract. We agree, and it is important to clarify that these principles do not nullify any existing contractual arrangements for the provision of standby services.

IPPNY, in its supplemental comments, contends that wholesale generators should be given sole discretion to maintain existing contracts or choose the resulting standby tariff rates. We disagree. The existing contract should govern unless it provides otherwise.

4. Applicable Credits and Surcharges

The draft Guidelines circulated for supplemental comments included a statement that additional charges and/or credits might also be applicable to standby customers, to reflect other costs or savings uniquely attributable to them. The Utilities argue that no credits should be applied to standby rates, and that any compensation for utility system benefits of DG should be limited to the RFP process envisioned in Case 00-E-0005.

This section of the Guidelines has been revised to clarify that surcharges and/or credits that apply to the otherwise applicable service classification would also apply to standby customers.

5. Other Issues

MI seeks clarification on another matter, arguing that a standby customer should be able to purchase the balance of its load not served by OSG (supplemental load) at the standard offer delivery service rates. The Guidelines provide cost-based

delivery service rates that apply to the entire delivery service taken by a customer with an OSG regardless of whether the OSG serves all or only a portion of that customer's load. Should a customer choose to separately meter a portion of its load, that service would be eligible for the applicable standard service classification.

Beyond this, MI also argues that standby customers should retain an option to return to a standard service offer. This would be inconsistent with the premise of the Guidelines, that an appropriate level of rates for standby customers is reflected in the proposed rate design. Other than the option provided in the Guidelines for demand metered customers below the 50 kW threshold, there would be no reason to permit standby customers other options.

Stranded Investment

Several comments have addressed the issue of stranded cost recovery. With respect to the stranded production costs that are currently being recovered by some utilities, NEM has argued that OSG customers should be exempt from stranded cost responsibility, so as not to discourage the installation of new generation. IPPNY argues that wholesale generators should be exempt, as they are not customers and did not participate in creating the stranded costs. The Utilities respond that the wholesale generators should participate in stranded cost recovery. MI supports the imposition of stranded costs on customers in the manner proposed by the Guidelines. NFG argues that stranded costs should be recovered in the same manner from all customers. For example, if stranded costs are recovered through usage charges for other customers, they should be recovered only through usage charges from standby customers.

We conclude that all customers should bear a proportional share of the responsibility for the recovery of

stranded production costs. If the underlying rates are cost-based, the burden will be fairly apportioned among all customers. By "proportional," we mean "in the same percentage of the delivery service bill," as the standard is formulated by MI in its supplemented comments.

The Utilities also suggest that the stranded production cost mechanism could be used to recover lost delivery revenues. This idea is not appealing, however; in moving to more cost-based rates for standby service there should be no material lost delivery service revenues. To the extent there are such lost revenues, standby customers should not be singled out to compensate for reductions in previous levels of revenues collected from them through the application of less cost-based rates. Moreover, the Utilities under normal ratemaking practices are held responsible for their planning, and are not entirely free from the risk that revenues will not always cover the costs thusly incurred.

PURPA Compliance

MI argues that the proposed contract demand charge for standby service customers would be inconsistent with PURPA, since full requirements customers in the same rate class are not similarly charged. DPCA argues that the Guidelines violate PURPA because they assume that standby and full service customers within each class have the same level of peak load diversity. The Utilities oppose these arguments, claiming that PURPA is not violated.

Under the PURPA regulations, standby rates "shall not discriminate against any qualifying facility [QF] in comparison to rates for sales to other customers," albeit rates based on "accurate data and consistent system-wide costing principles"

shall not be considered discriminatory.[18] The regulations also prohibit back-up or maintenance power charges based on an assumption that QF forced outages "will occur simultaneously, or during the system peak."[19]

The rate design proposed in the Guidelines complies with these regulatory requirements. The rate design will be applicable to both QF and non-QF generators. Because QFs are treated the same as similarly-situated owners of generation, compliance with the PURPA regulations is achieved.

The rate design is otherwise consistent with the anti-discrimination principles underlying the PURPA regulations. OSG customers are included in the same rate classifications as other customers, and the rates for the OSG customers are based on consistent system-wide costing principles, as PURPA requires.

DPCA's argument about peak load diversity also lacks merit. As noted, PURPA regulations require adequate cost data to justify differing treatment, and data adequate to support separate service classifications for OSG customers is unavailable. However, the rate design differences within each classification do properly recognize OSG diversity. The contract demand charge recovers those costs that are clearly attributable to individual OSG customers. The as-used demand charge properly recognizes coincidence factors and diversity, and applying that demand charge on a daily use basis, only to the demand that is metered during peak periods, recognizes the potential for diversity among OSG customers. In short, PURPA does not require a separate service classification for OSG customers and the rate design properly recognizes diversity of OSG customer use of delivery facilities.

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[18] 18 C.F.R. §292.305(a)(1)&(2).

[19] 18 C.F.R. §292.305(c)(1).

SEQRA Review Requirements

One commenter has argued that the Commission is required to issue an environmental impact statement (EIS) in connection with actions taken in the opinion and order. The basic purpose of the State Environmental Quality Review Act (SEQRA)[20] and its related administrative regulations (6 NYCRR, Part 617) is to incorporate the consideration of environmental factors into the existing planning, review and decision-making processes of state, regional and local government agencies at the earliest possible time. To accomplish this goal, SEQRA requires that all agencies determine whether the actions they are requested to approve may have a significant impact on the environment, and, if it is determined that the action may have a significant adverse impact, prepare or request the applicant to prepare an EIS.

An agency must first determine whether the action is subject to SEQRA.[21] The SEQRA regulations define three categories of actions. The three categories are “Type I”, “Type II,” and “unlisted” actions. “Type I” actions are those actions or projects determined to carry with them a presumption that they are likely to have a significant adverse impact on the environment and may require the preparation of an environmental impact statement.[22] “Type II” actions are those actions or classes of actions which have been determined not to have a significant effect on the environment or are otherwise precluded

[20] New York Environmental Conservation Law, Article 8 (McKinney 1997).

[21] 6 NYCRR Part 617.6(a)(1)(I).

[22] 6 NYCRR Part 617.4(a)(1).

from SEQRA review.[23] Type II actions do not require an EIS or any other determination or procedure under the SEQRA regulations.[24] "Unlisted" actions are all those actions or classes of actions that are not otherwise categorized as Type I or Type II.[25]

Further, SEQRA[26] allows each agency to adopt its own Type II actions to supplement the list of Type II actions in Part 617.5(b)(7). The Commission has adopted such a supplementary list of Type II actions.[27] Among these Type II actions are policies, regulations and procedures if they relate to practices by utilities concerning administration and management of utility functions including, but not limited to, preparation of tariff schedules.

The action contemplated in this proceeding is the adoption of guidelines for the design of standby service rates to be used by the utilities in formulation of new standby tariffs to be filed within six months. The proposed action falls within the Type II definition listed in 16 NYCRR 7.2b(2)(ii) and there are no further SEQRA responsibilities under 6 NYCRR 617.

Filing Requirements

MI argues that there should be no more than 30 days delay, following the issuance of this opinion and order, in the implementation of new standby tariffs, and NYSERDA argues that new tariffs should be implemented as soon as possible by all

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[23] 6 NYCRR Part 617.5(a).

[24] 6 NYCRR Part 617.6(a)(I).

[25] 6 NYCRR Part 617.2(AK).

[26] 6 NYCRR Part 617.5(b).

[27] 16 NYCRR Part 7.2

utilities. We would agree that the principles of the Guidelines should be implemented as soon as practicable. The Utilities will therefore be required to file new standby delivery service rates based on the principles of the attached Guidelines no later than six months from the issuance of this document.

CONCLUSION

The Guidelines adopted here represent a reasonable approach to the development of cost-based rates for standby delivery service. They reflect modifications to the original straw proposal that address, to the extent appropriate, concerns raised by intervening parties in their written comments. At the same time, they do not include extraneous factors sought by various parties, such as public policy values or benefits to utilities from DG, which in our view do not belong in the development of standby delivery rates. Rather, such factors should be considered and applied, if appropriate, in the context of a utility's distribution planning process. These values or benefits do not impact the design of embedded cost-based delivery rates.

Accordingly, we adopt the attached standby delivery rate Guidelines. Future utility filings addressing standby rates should abide by these guidelines. We would expect appropriate standby service rates to be implemented as soon as practicable, on a utility-specific basis, in the context of individual utility filings, within six months. We will monitor implementation of the principles discussed above in order to balance our interest in assuring the recovery of prudent, unavoidable utility costs with our goal of not impeding the development of alternative sources of energy.

The Commission orders:

1. The Guidelines in Appendix A are hereby formally adopted as guiding principles for the establishment of Standby Delivery Service rates.

2. Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are hereby directed to file Standby Delivery Service tariffs in compliance with this Opinion and Order and the Guidelines in Appendix A no later than six months from the issuance of this document, to become effective on 90 days' notice.

3. Rochester Gas and Electric Corporation is directed to file a supplement to cancel its currently suspended standby rate tariff leaves at the time it files new leaves implementing the Guidelines in Appendix A.

4. This proceeding is continued.

By the Commission,

(SIGNED) JANET HAND DEIXLER
Secretary

Appendix A

Guidelines for the Design of Standby Service Rates

Case 99-E-1470

I. Fundamental Principles

A. Applicability:

1. Standby service rates shall apply to:

   a. Customers with on-site generation serving load that is not isolated from the grid;

   b. Wholesale generators that rely on the electric utility to serve electric loads that would otherwise be served by the generator such as station power used for the heating, lighting, air-conditioning, and office equipment needs of the buildings housing the generator and associated support facilities located on a generating facility's site, and/or to facilitate the re-starting of the generator following an outage. Standby rates will also apply to wholesale generators that take station service through the same bus bar as it supplies the wholesale grid. However, when the generator is operating, station service is effectively being "self-supplied" and, therefore, no as-used demand charges will apply.

2. Standby service rates shall not apply to self supplied power where a wholesale generator, when operating, supplies all of its electric energy needs from "behind the meter" (that is, the energy does not pass through the point of interconnection between the generator's facility and the utility's retail delivery system to which it is interconnected).

3. All separately metered power not otherwise served by the generator (e.g., power to the facility's guardhouse) shall be provided at standard tariff rates.

4. Surcharges and/or credits that apply to the otherwise applicable service classification may also apply to standby customers.

B. Stranded Production Costs:

1. To the extent that a utility has stranded production costs for which the commission allows recovery from the utility's delivery service customers, Standby Delivery Service customers should also contribute to the recovery of stranded costs.

2. The contribution to stranded costs by Standby Delivery Service customers should be established through a uniform percentage mark-up of the applicable rate components established for Standby Service such that standby customers contribute to stranded cost recovery in the same proportion of their delivery rates as customers in the otherwise applicable service classification.

II. Rate Design Principles for Standby Delivery Service

A. The nature of standby service is sufficiently different from that of other customers to reflect appropriately the unique service needs of wholesale and on-site generators in tariffs for standby service.

   Sufficient data may exist to base rates for wholesale generators on this group's own characteristics. However, because many aspects of the utilities' provision of standby service for customers with on-site generation mirror those of other customers, fully separate service classifications are not required. To the extent standby service has cost causation characteristics that differentiate it from the balance of the customers in the otherwise applicable service classification, rates reflective of those differences should be developed within each classification and applied to customers taking standby service.

   Pending appropriate cost of service analyses, costs now allocated to each standard service classification will serve as the basis for the design of class specific, revenue-neutral, standby service delivery charges. That is, the standby rates for each service classification should produce the same revenues as the standard rates, using the class billing determinants.

B. The cost of any and all additional interconnection facilities and equipment unique to the provision of standby service, and beyond those facilities normally required to provide firm retail delivery service to customers of comparable size, should be recovered

directly from customers that install on-site generation through separate up-front interconnection charges.

C. Commodity Rates

1. Because Standby Service is a delivery service, rates should be established exclusive of electricity supply prices.

2. The customer retains the right to acquire electricity supply from the utility or an alternative provider, pursuant to applicable utility or alternative supplier rates and terms.

D. Fixed monthly access charges for each service class should be established to fully recover all customer-related costs (to the extent not recovered through interconnection charges).

E. Distribution Rates

1. To maintain revenue neutrality as previously noted (and absent new cost-of-service studies showing otherwise), basic distribution delivery charges for each service classification should reflect the existing allocation of costs to the various service classifications, inclusive of customers with on-site generation.

2. Distribution delivery costs should be recovered through a combination of class specific Contract (Fixed) Demand Charges and Daily As-Used Demand Charges.

3. Contract (Fixed) Demand Charges (by service classification)

a. Facilities that are closer to a customer's site ("local") are assumed to have been put in place to mostly serve that individual customer and thus are less "fungible."

b. These "local" facility costs should be recovered in a manner that recognizes the individual customer's more direct cost responsibility.

c. Therefore, costs associated with "local" facilities should be recovered to the extent possible through a Contract (Fixed) Demand Charge.

d. Contract (Fixed) Demand Charges should apply to the customer's maximum potential annual metered demand or connected load. Where an individual customer's usage characteristics have demonstrably changed, the customer should be permitted to apply for a reduction in the contract demand level.

4. Daily As-Used Demand Charges (by service classification)

a. Distribution facilities located further from the customers site are considered to be "share" facilities.

b. Costs associated with "shared" facilities should be recovered in a manner that recognizes standby customers' intermittent and shared use of these facilities.

c. Therefore, costs associated with "shared" facility costs should be recovered through a Daily As-Used Demand Charge.

d. The Daily As-Used Demand Charge should apply only to the customer's daily maximum metered demand that occurs during the utility's system peak periods.

F. The FERC transmission charge is part of the overall revenue requirement for each service classification. Therefore, it is inherently included in the derivation of the as-used demand charge.

G. Metering

1. Interval metering necessary to implement rates designed in accordance with the above principles will be required of all standby customers with contract demands in excess of 50 kW.

2. A standby customer with a contract demand less than 50 kW, but more than that required for demand metering, will have the option of taking service at ether (1) the otherwise applicable demand rate or (2) the interval meter rate that is mandatory for >50 kW standby customers within its class.

3. Except as may otherwise be proscribed, a standby customer that would otherwise be served in a non-demand

metered class will pay a rate with a customer charge equal to the average customer costs for the service class. Major components of this charge would be metering, billing and fixed distribution costs. Distribution costs could be based on either the customer components of the distribution system identified in a fully allocated Embedded Cost of Service Study, or an analysis of the local distribution facilities typically serving these customer that would otherwise be recovered through a contract demand charge. The volumetric rate for delivery service would be revenue neutral for the entire service class. That is, the energy rate would be the amount that would have to be charged to the entire class to recover the full revenue requirement of that class, if the customer charge had been the full customer component described above.

APPENDIX B

POSITIONS OF THE PARTIES

INITIAL COMMENTS

DPCA

Protesting that the Straw Proposal is inconsistent with previous Commission policy and federal law, the Distributive Power Coalition (DPCA) claims the outcome is to impose unjust fixed charges on standby customers. DPCA maintains that the Straw Proposal does not adequately reflect diversity of usage among standby customers, and that standby rates premised on the proposal will increase the cost of entry for small DG, thereby discouraging its installation.

DPCA believes that standby service is separate in character from full service. It contends that billing determinants for full service retail customers are not appropriately used to develop cost allocations and rate design for standby service. Standby rates, says DPCA, should be designed on a volumetric basis rather than through the fixed charges recommended in the Straw Proposal. Fixed rate components, it insists, are inappropriate, because they fail to recognize that many costs of service to standby customers vary significantly with the time or extent of the customer's generation facility outage.

According to DPCA, the Straw Proposal is premised on the assumption that standby customers share the same level of peak load diversity with full service customers in the same rate class. DPCA argues this conclusion is inconsistent with PURPA and Opinion No. 82-10, and it should not be assumed that standby customers share characteristics with full requirements customers.

DPCA would build rates for standby customers from the bottom up. This approach, it claims, would properly account for

diversity in load among standby customers and would recognize the actual avoided generation capacity costs associated with standby service. DPCA maintains that sufficient data exists to support a calculation of the diversity of use among on-site generation (OSG) customers. So recognizing diversity, DPCA believes, is necessary to comply with PURPA. DPCA, however, would follow the full service rate structure for establishing time-of-use rating periods.

A rate design that over-allocates revenue responsibility to standby customers, DCPA argues, is bad public policy, because it would discourage economic activity and reduce capacity supplies. DPCA believes that erring in favor of encouraging the installation of new generation is a preferable public policy. Claiming the Straw Proposal is overly concerned with revenue neutrality, DPCA perceives that neutrality is not needed, because utilities in New York receive risk premiums embedded in their returns on equity. Finally, DPCA would exempt from standby rates some OSG installations, such as facilities designed to offset peak prices or supply back-up power in the event of a grid failure. Those customers, it continues, should remain full tariff rate customers.

EU

The Consortium of Electric Utilities (EU) views the Straw Proposal as a valuable initiative that moves toward more efficient rate design. EU believes that fixed costs of service should be recovered through fixed charges, and variable costs through variable charges. Utilities, however, should not be required to file new standby rates at any particular time, but should instead make filings consistent with their currently effective rate and restructuring plans.

While conceding that demand and usage patterns of standby customers may be substantially different from those of full requirements customers, EU asserts that the cost of

providing standby delivery service is not significantly different from the cost of providing full requirements delivery service. Perceiving that standby customer demand is essentially unpredictable, EU nevertheless asserts it is known that standby customers will consume smaller volumes of electricity than comparable full requirements customers. EU contends, however, that standby customer maximum demand will not similarly decline. EU consequently believes that recovery of most costs through fixed, rather than volumetric, charges is appropriate.

EU supports the conclusion that there is insufficient experience with OSG to support compilation of convincing data on changes in customer demand patterns attributable to those generators. EU argues that OSG will not enable a utility to avoid the costs of distribution facilities, and, while diversity of load may reduce coincident peak demand on transmission-level facilities, data on that topic is not yet available. As a result, EU contends that the fixed costs of providing standby service are the same as the fixed costs for providing full requirements service.

EU maintains that use of volumetric rate components to recover a major portion of fixed costs would result in substantial under-recovery of those costs. The Straw Proposal, says EU, recognizes this difficulty. While providing for recovery of electric supply through a volumetric per kWh charge, the fixed costs of delivery service would be recovered in three distinct rate components: a customer charge, a contract demand charge (based on maximum meter demand) and a variable as-used demand charge (based on maximum metered demand during the billing period). The as-used charge, EU continues, would recover a portion of delivery service costs associated with shared facilities. According to EU, the as-used charge will thereby vary with measured demand, even though utility costs remain fixed. Under-recoveries, EU explains, could result. EU

would instead recover all fixed costs through the contract demand charge.

EU would allocate to its contract demand charge the total delivery service revenue requirement for a given service class. The allocation factors would reflect a principle that the closer the delivery system component is to the point of interconnection with the customer, the lower the diversity among customers, and the greater the impact on the system of each customer's individual demand. Where diversity affects the proportion of usage, such as for the high voltage transmission system, EU would allocate revenue requirements accordingly. For delivery system components situated between the transmission system and local facilities allocated to a single customer, EU would apply intermediate proportional allocations.

In contrast to this bottoms up method, EU suggests utilities could also apply a top-down approach. This would begin with the subtraction of energy supply costs from total delivery system revenue requirements for a given service class. The result is a class-specific delivery service revenue requirement that, EU asserts, reflects diversity among customer demands.

EU would take this annual delivery service revenue requirement for each service class and divide it by the sum of the non-coincident peak demands of all customers in that class. That sum, EU says, is the sum of the contract demands for that class. The result would be the annual per-kW revenue requirement for the class, which could then be allocated to the contract demand charge.

Turning to stranded cost recovery, EU argues that the standby rate design should not affect the means nor the amount of stranded cost recovery. EU complains that, under the Straw Proposal, reductions in a customer's energy consumption or monthly metered demand, which would accompany installation of

OSG, would reduce the total charges payable to the utility for delivery service. To the extent that the stranded cost surcharge under the Straw Proposal is a fraction of those other charges, rather than an adder to them, EU believes stranded cost recovery could be adversely affected.

The surcharge that recovers stranded costs, EU asserts, should be designated as an adder to other charges. EU would not limit the surcharge to recovery of stranded production costs given the potential it sees for other strandable investments. EU also foresees that the surcharge could be used to recover costs in addition to marginal delivery system costs.

While opposing reliance on as-used demand charges, EU agrees that the Straw identifies a reasonable principle for the allocation of delivery facility costs between contract and as-used demand components. That is, the closer a delivery system component is located to a customer, the more appropriate a contract charge becomes, while the further distant the component is from the customer, the more appropriate use of an as-used demand charge becomes. Actual allocation of facility costs in accordance with these principles, EU contends, requires further thought.

EU argues that some delivery system components must be designed to meet maximum demand, and, for these facilities, coincidence and diversity between customer peak demand and system peak demand are not an important design consideration. The costs for those facilities, built to meet demand that is relatively unaffected by load diversity, would be recovered through contract demand charges. Another broad category of delivery system components, including most transmission facilities, is dedicated to the service of larger groups of customers. Diversity of peak demand is appropriately recognized at this level, based on coincident aggregate peak load, and

these costs therefore may be recovered through as-used demand charges.

While favoring allocations based on these principles, EU would allow an individual utility to propose a different method of allocation. Once such alternative, it says, would be based on the distinction between embedded and incremental system investment. Investment undertaken prior to commencement of standby service by a customer would be an embedded cost recovered from that customer, through a fixed contract charge, if it subsequently requests standby service. Incremental investment, on the other hand, takes into account cost avoidance attributable to the customer's use of OSG, and those costs may be allocated to the as-used demand charge. Other allocations, EU theorizes, may also be appropriate.

Responding to the Straw Proposal chart depicting potential allocations of costs between the demand and as-used charges, EU maintains that the actual proportional allocation must be determined on a utility-specific basis. It explains that each utility's load and planning parameters differ, affecting the appropriate allocation the utility would perform. As an example, EU points to the cost of transmission-level facilities, which generally reflect downstream diversity. For a customer directly tied to a transmission line, however, transmission facilities must be built to meet non-coincident peak demand, and therefore those transmission costs should be recovered from that customer through a contract demand charge.

First Rochdale

First Rochdale Cooperative Group Ltd. (First Rochdale) maintains that installation of DG should be encouraged. It declares that the Straw Proposal discourages DG and contravenes sound ratemaking principles, because it fails to recognize standby customer load diversity. First Rochdale also opposes combining standby customers in rate classifications with full

requirements customers. First Rochdale would create a separate rate class and rate design for standby customers that recognizes load diversity.

Contradicting the premise in the Straw Proposal, First Rochdale insists historical data demonstrating the diversity of standby load exists, and also proves that standby load is not coincident with system peak. Outages of OSG units, First Rochdale explains, would either occur randomly or would be scheduled for low load periods. Requiring standby customers to pay for service through demand charges, it complains, would not reflect this diversity of load and would overcharge standby customers.

Usage sensitive rates, First Rochdale argues, are essential for standby customers. Without volumetric rates, First Rochdale complains that there is no incentive to forego consumption or conserve energy. The result of the Straw Proposal, says First Rochdale, is that standby customers would have little opportunity to adjust their usage to respond to price signals.

First Rochdale also believes that overuse of fixed charges is a disincentive to greater reliability. Once the fixed charges are established, it complains, a standby customer would pay those charges regardless of how frequently it used the distribution network. As a result, it protests, installation of more reliable DG units would not be rewarded with savings.

Criticizing the distinction between local and shared facilities that underlies the Straw Proposal's contract and as-used demand charges, First Rochdale argues that the distinction would be difficult to apply. It fears distribution system costs would be over-allocated to fixed demand charges.

First Rochdale would limit fixed demand charge recovery to costs of distribution facilities dedicated to a single customer. It would recover distribution system costs not

dedicated to a particular customer through as-used demand charges and a volumetric rate. It would time-differentiate the volumetric rate, discouraging on-peak consumption. This approach, it claims, would encourage installation of reliable DG units that would moderate the need for distribution system investments.

To effectuate this approach to standby rates, First Rochdale would encourage the installation of interval meters for demand-metered customers. First Rochdale would qualify standby customers for the metering installation incentive programs currently in place for the demand-response initiatives. In contrast, First Rochdale perceives, the Straw Proposal requires all standby customers to install demand meters. First Rochdale maintains that this requirement would be cost-prohibitive for smaller DG customers. For those customers currently too small to qualify for demand meters, First Rochdale would institute optional time-of-use rates, with metering costs shared between the individual customer and the utility.

IPPNY

The Independent Power Producers of New York (IPPNY) maintains that the Straw Proposal is a step backward for standby rate design. It opposes assigning standby customers to existing service classifications. IPPNY also believes the proposal misprices station power service, unnecessarily burdening wholesale generators with higher costs that they will recover through the wholesale market from all customers. IPPNY argues that FERC, in the PJM Order,[28] exempted from retail rate jurisdiction those wholesale generators that can self-supply their station power requirements from a remote generating facility. IPPNY believes that State jurisdiction adheres only

[28] PJM Interconnection, LLC, 94 FERC ¶61,251 (March 14, 2001).

to generators that cannot self-supply their station power and must purchase station power from third parties, because FERC ruled that self-supply from a remote location is not a sale. To the extent states have jurisdiction to impose standby rates for station use, IPPNY argues such rates should be based solely on the costs associated with the specific distribution facility the generator uses.

Expanding upon its criticism of the proposed standby rates for station service, IPPNY denies that wholesale generators are similar in cost causation to full requirements customers. IPPNY would distinguish wholesale generators' load factors, and coincidence with class peak, from those of full requirements customers. It also maintains that an abundance of operating data exists for wholesale generators demonstrating these distinctions. In particular, IPPNY insists that wholesale generator demand occurs intermittently, at low load factor, and with low coincidence with peak load.

Instead of as-used demand charges, IPPNY would recover delivery rates through per kWh charges. The charge would be developed from standard rate classification costs by applying the monthly per kW demand charge from the standard rate to the average monthly kWh/kW of the average customer in the class. This procedure would be applied to obtain appropriate per kWh charges for each time-of-use period.

IPPNY maintains that a wholesale generator consuming station power through a "side door" delivery is serving itself with station power. According to IPPNY, the PJM Order supports its conclusion. To the extent there is State jurisdiction over side door deliveries, however, IPPNY would establish a specific facilities charge on a plant-by-plant basis. IPPNY would also require the local electric utility to demonstrate it is not recovering the cost associated with the side door facilities through other means.

This sort of specific facilities charge could also be used, IPPNY suggests, if it is decided the Commission has jurisdiction over local delivery of station power from a remote facility. IPPNY would limit the specific facilities charge to the few distribution facilities the generator actually utilizes.

IPPNY would also exempt wholesale generators from stranded cost recovery. The logic of stranded costs, it says, is that the load for which generating facilities were constructed should be responsible for the resulting stranded costs. IPPNY maintains wholesale generators have not created any stranded costs, because they were built, along with their station power requirement, to serve the normal loads of the utility's system.

KeySpan

KeySpan-Ravenswood, Inc. (KeySpan) insists that station power use is outside the scope of this proceeding. Wholesale generators, it asserts, are distinct from other types of OSG customers and so the rate design for OSG customers is not properly applied to wholesale generators. KeySpan also joins in IPPNY's interpretation of the PJM Order. It maintains that, since utilities were allowed to self-supply their generators with station use from remote locations, wholesale generators should be afforded the same privilege.

MI

Multiple Intervenors (MI) believes that the Straw Proposal departs from the rate design adopted in Opinion No. 82-10, but that the evidentiary record here is insufficient to justify that departure. It would adopt only those features of the Straw Proposal that are consistent with Opinion No. 82-10. Otherwise, MI fears that the Straw Proposal will discourage installation of desperately-needed new generation capacity, including installation of DG units.

Criticizing the Straw Proposal, MI claims it does not adequately reflect diversity of standby load. MI disputes the conclusion that standby customers resemble full requirements customers with the same load characteristics at a given level of consumption. The differing coincidence factors between the two groups of customers, MI insists, is not recognized in the Straw Proposal. While, MI asserts, most full requirements customers in a service classification have similar coincidence factors, this is not true for standby customers, because their outages are either random or scheduled for low load periods.

In Opinion No. 82-10, MI asserts, load diversity was properly recognized, because costs were collected through volumetric rates. The failure of the Straw Proposal to follow Opinion No. 82-10, MI argues, results in rates that are not just and reasonable. In particular, MI criticizes the proposed as-used demand charge, because it is based on a customer's maximum monthly billed demand. This contradicts Opinion No. 82-10, says MI, where it was decided that less variable charges must be based on load data that clearly supports the need for the more fixed charge. MI maintains no such load data has been presented here.

Under the Straw Proposal, MI perceives, standby customers would pay the same demand charge whether usage was on-peak or off-peak, in contradiction of fundamental cost-of-service pricing principles. Instead of recovering as-used demand on a monthly basis, MI would prorate the charge so that it is recovered on an hourly, or, at most, a daily basis. This approach, MI believes, would appropriately recognize load diversity and reward more efficient and reliable OSG units that consistently operate on-peak.

In the Straw Proposal, MI discerns, costs for facilities local to a standby customer's location would be collected through a contract demand charge. That approach, MI

argues, was rejected in Opinion No. 82-10, as inadequate to properly reflect load diversity. Instead, a ratcheted as-used demand charge was adopted there, to recover the standby customer's contribution to class and area peak costs. That demand charge, MI continues, accords with proper rate design principles, because it imposes more costs on customers that operate inefficiently. A contract demand charge, it insists, does not encourage efficiency. Moreover, it argues that to impose a contract demand charge on standby customers contradicts the PURPA anti-discrimination provision, at 18 C.F.R. §292.305(a)(ii), because the charge is not imposed on full requirements customers.

MI claims that the Straw Proposal requires customers who take standby service to relinquish their rights to standard offer service. MI would clarify that a customer that serves only a portion of its load with an OSG facility could obtain electricity supply for the remainder of its load at standard offer service.

Moreover, MI would permit a standby customer to return to standard offer service after a waiting period tied to the utility's planning for its purchases for its customers' needs. This segregation of customer load into standby and standard offer components, says MI, requires that supplemental service rates remain in place. Those rates would apply to the portion of load not served with OSG.

An outcome of this approach, MI continues, is that some billing formula or protocol is necessary to differentiate between the two rates. MI would establish a level of supplemental contract demand for each customer, and consider the first usage through the meter as supplemental to any usage in excess of the standby service contract demand. The supplemental service contract demand would be subject to change with reasonable notice, and would be time-differentiated. MI claims

that OSG customers should always be afforded the option of taking electricity at the most economical tariff, even if that means taking all service at a full requirements rate.

MI would adopt, as a reputable presumption, the Straw Proposal chart which identifies the allocation of distribution delivery costs at different voltage levels to the as-used and contract demand charges. MI would also clarify that standard delivery rates are not at issue in this proceeding, and that standby customers can purchase commodity either from the utility or a third-party supplier.

Mirant

Mirant New York, Inc. (Mirant) reports it operates wholesale generators in O&R's service territory. It notes it purchases station use from O&R under contract. It argues that any standby rate proposal adopted here should not supercede its contracts.

NEM

The National Energy Marketers' Association (NEM) criticizes the Straw Proposal as failing to reflect the societal benefits of DG. It would develop standby rates on a bottom up approach, based on the actual costs utilities incur in serving the back-up power needs of OSG customers. Implementation of the Straw Proposal, says NEM, should await completion of bottoms-up unbundling and cost-of-service studies.

NEM joins with other critics of the Straw Proposal in asserting that diversity of load is not adequately reflected. The outcome, it asserts, is that the contribution of standby customers towards peak load is overstated.

NEM would also exempt OSG customers from stranded cost recovery. To do otherwise, it claims, would discourage installation of much-needed new generation. NEM opposes including OSG customers in the same service classifications as full requirements customers. It insists that, until proper cost

of service studies demonstrate otherwise, standby rates should be recovered through a variable charge only.

NRG

The NRG Companies (NRG) maintains the Straw Proposal contradicts FERC's PJM Order. NRG joins in other wholesale generators' analysis of that Order, as allowing generators to self-supply station use from remote locations.

NRG interprets the PJM Order as finding that remote self-supply is not a sale. As a result, NRG infers that retail rates would not adhere to such a use of electricity. NRG also points out that, under the PJM Order, utilities cannot require wholesale generators to buy station power when the generator is self-supplying from remote locations. According to NRG, this prohibition extends to payment for the use of the distribution system related to the remote self-supply. Nevertheless, it would accept imposition of a separate equipment usage or facilities charge if it were limited to recovery of the costs of any distribution components that are involved in the remote self-supply.

NRG would exempt wholesale generators from stranded cost recovery, on cost causation grounds. NRG also finds the Straw Proposal inappropriate for wholesale generators, because their load characteristics do not resemble those of full requirements customers.

Pace

Pace Energy Project (Pace) criticizes the Straw Proposal because it discourages installation of DG. It argues the fixed charges relied upon in the Straw Proposal are inefficient and inequitable because they bear little relationship to standby customer cost causation. Fixed charges, it continues, are unavoidable and therefore discourage alternatives to consumption.

Preferring a volumetric charge, Pace joins in other critics of the Straw Proposal in claiming that it fails to properly recognize load diversity. Pace disputes the conclusion that OSG customers resemble full requirements customers in cost causation. Pace also criticizes demand charges on the grounds that they are insensitive to actual customer usage and will foreclose opportunities to change usage patterns that would result in more efficient utilization of the distribution network. In particular, says Pace, the contract demand charge would tie customers to fixed usage characteristics. Pace also joins in the argument that the Straw Proposal does not adequately discourage on-peak consumption or encourage off-peak consumption.

Pace claims that adoption of standby rate principles is an action triggering preparation of an Environmental Impact Statement (EIS) under the State Environmental Quality Review Act (SEQRA). Pace asks that a detailed analysis of the economic, environmental and other social impacts of standby rate policy alternatives be undertaken. The EIS, Pace points out, should be an integral part of the decision-making process.

Pace insists a broader range of policy questions should be considered. It would expand the scope of the inquiry to consideration of issues like shifting revenue burdens between classes, allocation of risk between the OSG customer and the utility, utility incentives for cost minimization, effects on DG development, and impacts on generation, transmission, and distribution investment.

Plug Power

Plug Power, Inc. (Plug Power) opposes the Straw Proposal, complaining it singles out DG customers for unfavorable rate treatment. Substituting the demand charges for variable charges, Plug Power continues, would greatly increase a customer's overall costs, and make those costs unavoidable.

This would constitute a substantial barrier to entry for DG technology.

Plug Power joins in the criticism that relying upon demand charges rather than a volumetric rate will discourage energy efficiency and conservation. It further asserts that the fixed charges do not send accurate price signals, but instead are adopted because of the ease of administration and the reduction in risk for the regulated utility. Instead, says Plug Power, a rate design that encourages installation of DG should be adopted, based on volumetric rates.

Plug Power complains that the Straw Proposal fails to balance DG benefits against DG costs. DG, Plug Power insists, allows utilities to avoid investment in the delivery system and can increase the system's reliability. Plug Power also perceives that the Straw Proposal resolves uncertainty against the low-usage standby customer, by imposing on that customer all the costs that a full requirements customer pays.

Plug Power joins in the criticism that requiring demand meters for all standby customers would erect a barrier against DG installation, because customers would have to bear the higher costs of the demand meter. Plug Power also joins with Pace in claiming that an Environmental Impact Statement should be prepared under SEQRA.

REPLY COMMENTS

Capstone

Capstone Turbine Corporation (Capstone) supports DPCA's approach to designing standby rates. DG installations, Capstone claims, will operate counter-cyclically to utility load curves, because they will generate at peak times when most needed. Capstone therefore disputes EU's contention that standby customer demand will be more variable and unpredictable than full-requirements customer demand.

Capstone also opposes EU's proposal to increase fixed cost recovery through a contract demand charge. Capstone claims such a charge creates an incentive for customers to remain with the utility rather than select economic DG alternatives. Capstone would limit contract demand charges to recovery of delivery facilities that are dedicated to a customer's exclusive use.

DPCA

DPCA argues that the comments it submitted in this proceeding on September 20, 2000 were disregarded in developing the revised Straw Proposal issued in response to the May 15 comments. Objecting further to the revised Proposal, DCPA complains that the revision unduly favors utility parties. DPCA concludes it is unlikely that any further comment from it would be productive.

EU

EU finds most of the criticisms other parties level against the Straw Proposal unpersuasive. It also answers the legal arguments other parties present.

A. Rate Design Issues

Efforts to distinguish standby customer usage patterns from full requirements customer patterns, says EU, are not dispositive of standby rate design questions, because the design and cost of the delivery facilities used to provide standby services are the same as those used to provide retail delivery service to other customers. Utilities, EU asserts, must stand ready to serve all customers at any given time, and there is no basis for distinguishing diversity of load for standby customers from diversity of load for other customers.

EU posits that diversity of load need not affect rate design. Where unbundled delivery charges have been efficiently priced, EU maintains, all customers appropriately pay the same charges. EU distinguishes rate design developed here from that

developed under the prior contribution to coincident peak methodology, which was utilized to allocate generation capacity costs. With the advent of competition, EU continues, generation capacity and supply is now appropriately priced by hourly signals, while the Straw Proposal rate design appropriately guides development of delivery-only rates.

Coincident peak methods, EU claims, have never been used for the allocation of distribution system costs. EU explains that such a methodology may not accurately capture the cost of delivery facilities or services. No reason has been provided here, EU asserts, for adopting that methodology for delivery services now.

EU also opposes greater reliance on volumetric rates, claiming that fixed costs must be recovered through fixed charges. Otherwise, cost under-recoveries would result in subsidization of standby customers by others. EU emphasizes that, when it comes to delivery rates, customer demand drives facilities and associated costs, which are comparatively non-responsive to customer usage.

Unproven claims of diversity of load among small OSG operators, EU suggests, is not a basis affording those customers a purely volumetric rate either. Rather than charging smaller customers solely through a volumetric rate, EU would collect the otherwise applicable contract demand charge through the fixed monthly charge, adjusting the volumetric rate accordingly. EU is also skeptical of other parties' claims that the installation of demand meters for smaller customers would not be cost effective. EU points to the System Benefits Charge, administered by NYSERDA, as a source of funding for metering.

EU denies that sound rate design principles will forestall achievement of benefits associated with DG installations. These issues, EU maintains, are best considered in the companion DG proceeding, Case 00-E-0005. In any event,

EU claims that economically-efficient pricing principles will identify generation sources that are economically beneficial to society, rather than discouraging any worthwhile DG projects. EU also notes that DG facilities are generally installed in response to electricity supply costs, not in response to delivery service costs.

Recovering most delivery system costs through fixed charges, EU argues, is the proper pricing principle that will identify those DG projects that are uneconomic, and essential to avoiding discrimination among standby customers. EU would not encourage installation of uneconomic facilities through a distorted rate design.

EU responds to MI's proposal to allow standby customers to return to full requirements service. EU perceives a tension between DG advocates who imply delivery facility enhancements may be avoided by DG installation, and those DG advocates that would allow customers to return to utility service, thereby burdening those delivery facilities. Since customers may return to utility service, at least until provider of last resort obligations are clarified, EU insists that existing facility design principles must be retained in order to ensure that delivery facilities are sized adequately to meet all demand.

EU criticizes MI's proposal to continue the practice of providing both standby and supplemental service through a single meter. EU opposes MI's approach to allocation of costs between the two services, arguing that MI's hourly allocation method is overly complex. In any event, EU believes the subject is best addressed through individual utility filings. Finally, EU suggests that the delivery cost allocation chart in the Straw Proposal is illustrative only, and would not establish a presumption premised upon it.

B. Legal Issues

EU denies that the Straw Proposal violates PURPA. Those regulations, says EU, require non-discriminatory rates for qualifying-facility (QF) standby customers that are based on consistent system-wide costing principles. They also prohibit rates premised upon the assumption that forced OSG outages will occur simultaneously, or during system peak.

The ratemaking principles here, EU maintains, are non-discriminatory, because rates for all customers are set on the same cost causation principles. In fact, says EU, the new rate design makes no assumptions regarding the specific operating characteristics of a standby customer, because the rate design is applicable to all customers, including full requirements customers.

Turning to MI's complaint that only standby customers are subject to the new demand charges, EU argues that the rates are still non-discriminatory under the PURPA regulations. The appropriate comparison, says EU, is between QFs and non-QFs, not between generators and non-generators. Pending the development of better data, EU continues, all customers owning generation are assumed to have similar load and cost characteristics. According to EU, the application of the same rate design methodology to QFs and other OSG is non-discriminatory under PURPA.

EU asserts that other parties misinterpret the PJM Order and PJM Rehearing Order.[29] Those Orders, EU declares, do not exempt wholesale generators from State jurisdiction or from the application of distribution rates. EU notes that the Orders provide for the uniform application of retail transmission charges to wholesale generators, and EU interprets the Orders as also allowing application of retail distribution rate charges.

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[29] PJM Interconnection, LLC, 95 FERC ¶61,633 (June 1, 2001).

EU disputes the contention that the potential for remote self-supply excludes generators from State jurisdiction. The PJM Rehearing Order, says EU, explicitly provides that State retail jurisdiction is unaffected. In fact, EU interprets the PJM Rehearing Order as providing that remote self-supply is subject to any applicable retail distribution charges. Accordingly, the delivery of station power through local distribution facilities is a matter subject to State regulation, through State Commission decisions on retail delivery service tariffs.

Turning to SEQRA compliance, EU argues that an EIS is not needed. EU claims that this is a ratemaking proceeding, and ratemaking is not an action under SEQRA, because ratemaking is a Type 2 action outside the scope of SEQRA under the Commission's regulations and court decisions.[30] EU dismisses contentions that more than ratemaking is involved in this proceeding. The Straw Proposal, it claims, merely sets policy for utility tariff rates and charges, and does not concern matters that might be related to site-specific environmental impacts. EU also describes this action as ministerial, because it does not require an exercise of discretion.[31]

If SEQRA were to adhere to the Straw Proposal, then, EU contends, a negative declaration is appropriate. That declaration would be based on a finding that there is no significant adverse environmental impact and that preparation of an EIS is not required. The Straw Proposal, EU continues, must be an unlisted action if it is not a Type 2 action. A Lead Agency may review an Environmental Assessment Form (EAF) for a Type 2 action and then determine that an EIS is not required.

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[30] 16 NYCRR §7.2(b)(ii); Citizens For Orderly Energy Policy v. Cuomo, 159 A.D.2d 141 (3rd Dept. 1990), aff'd, 78 N.Y.2d 398 (1991).

[31] Environmental Conservation Law §8-0105(5)(ii).

Such an EAF for the Straw Proposal, EU posits, would address changes in practices and services, rather than physical construction activities and site-specific impacts. EU concludes the latter sort of impact is absent here, and an EAF would demonstrate there are no adverse environmental impacts otherwise.

EU would honor pre-existing contracts for standby services, such as those entered into between Mirant and O&R. In a similar vein, EU would avoid interference with existing rate and restructuring plans for electric utilities. Those plans, EU asserts, provide for stranded cost recovery. EU propounds that exempting wholesale generators from stranded cost responsibility is legally barred, because that approach would violate the plans, and because it is discriminatory in that full requirements customers must support stranded cost recovery.

Dismissing complaints that the Straw Proposal does not follow Opinion No. 82-10, EU points out that the purpose of this proceeding is precisely the reconsideration of that Opinion. EU also claims that standby service is not mandatory, contrary to DPCA's interpretation. OSG installations, says EU, may avoid utility requirements by declining to interconnect with the utility's distribution system.

IPPNY

Characterizing the Straw Proposal as a step backwards from prior rate design principles, IPPNY argues that wholesale generators should not be assigned to rate classes that are designed for full requirements customers. IPPNY asserts the usage characteristics of the two categories of customer differ substantially. In particular, IPPNY insists that wholesale generators typically consume station power off-peak, while other customers consume on-peak.

IPPNY repeats arguments that overcharging wholesale generators for their electric usage raises wholesale prices and

is inconsistent with FERC's PJM Orders. It also reiterates its prior arguments on "side door" deliveries and stranded costs.

MI

MI voices its agreement with other parties that the failure to recognize diversity of standby loads will result in excessive standby rates that erect uneconomic price barriers against DG installations. MI disputes the contention that the costs of serving standby and full requirements customers is much the same.

MI would interpret the PURPA regulations as mandating that the diversity of standby load be recognized. MI would continue the interpretation of the PURPA regulations it says were adopted in Opinion No. 82-10, where it was decided that, in the absence of load data demonstrating otherwise, system peak costs should be recovered in variable charges. MI asserts that there is no data to support overriding the Opinion No. 82-10 prescription in favor of variable charges.

Disputing EU's contention that electric utilities must build their systems to serve each customer's maximum demand, MI believes that diversity of demand enables utilities to construct their systems on least cost planning principles, which include recognition of demand diversity. Utilities may also, MI discerns, derive the coincidence factors necessary to implement this approach from the outage records of existing standby customers.

MI opposes EU's proposal to recover additional costs through contract demand charges. MI argues that as-used demand charges are preferable, albeit it favors use of variable charges. That as-used charges produce less revenue than contract charges is appropriate, MI asserts, because standby customers impose fewer costs on the system. Shared, fixed costs are therefore better recovered through as-used charges than through contract charges. Use of a contract charge, says MI,

would also discriminate against standby customers, because utilities often recover shared fixed costs from full requirements customers through volumetric charges.

The contract demand charge, MI notes, is premised upon the customer's maximum demand. Standby customers, MI believes, should be afforded the flexibility to negotiate a contract demand charge that is less than maximum demand. Using historic demand to set the charge, MI continues, might overstate it, because customers may be able to reduce demand below historic levels.

MI would not impose on standby customers the obligation to fund stranded cost recovery at the same level as full requirements customers, as EU desires. MI maintains that this approach would overcharge standby customers, and would extinguish virtually all OSG installations. The historical usage approach EU favors, MI adds, is not an appropriate basis for establishing stranded cost charges and would be anti-competitive. MI believes the Straw Proposal approach, of recovering stranded cost predicated upon a customer's current usage characteristics, is appropriate. MI continues to support use of the Straw Proposal chart, on allocation of delivery costs to demand and as-used charges, as a rebuttable presumption.

MI also responds to EU's proposal on implementation of the standby rate principles. Contrary to EU, MI would not delay translation of the principles into effective utility tariffs. MI would require utilities to file new standby rate tariffs within 30 days of issuance of an Order here. MI would also prohibit utilities from deviating from the principles adopted here in designing their standby tariffs.

Plug Power, says MI, advocates a different rate design for smaller standby customers. While MI supports Plug Power in many of its rate design proposals, MI believes that the standby

rate principles should apply to all customers regardless of size.

Mirant

Mirant reiterates its argument that existing contracts for standby service should not be supplanted in this proceeding. It asks that its concern be specifically addressed.

NEM

NEM opposes the modifications EU proposes to the Straw Proposal. According to NEM, EU concedes that there are fundamental differences in patterns of demand and volumetric usage between standby and full requirements customers. NEM claims that these differences justify a separate rate classification for standby customers. It reiterates that those rates should be constructed through a "bottoms up" unbundled cost of service study.

NEM joins in MI's criticisms of EU's stranded cost recovery proposal. Stranded costs, says NEM, should be recovered from all consumers in a competitively-neutral manner. NEM also opposes EU's proposal to move costs from as-used to contract demand charges, arguing that instead volumetric rates are more appropriate than either.

NYEBF

New York Energy Buyers Forum (NYEBF) urges rejection of EU's arguments. It supports other parties in contending that the Straw Proposal would discourage DG by imposing unnecessarily high standby rate costs on them. The competition DG represents, NYEBF asserts, should be recognized in establishing standby rates.

NRG

NRG reiterates that the Straw Proposal is in conflict with the PJM Orders. It interprets those Orders as deciding that remote self-supply does not involve retail delivery service. NRG adds that, where remote self-supply involves only

use of the transmission system, only the FERC OATT rate applies. NRG maintains that retail transmission does not exist in the context of remote self-supply.

NRG continues to dispute the classification of wholesale generators as standby customers, and opposes recovering stranded costs from wholesale generators. NRG also argues wholesale generators differ in their operating characteristics from other standby customers, such as OSG.

NYSERDA

The New York State Electric Research and Development Authority (NYSERDA) maintains new standby rates are needed to avoid the disincentive to installation of DG that accompanies some existing utility standby rates. NYSERDA interprets the Straw Proposal as charging OSG customers no more than other customers in the same service class, and maintains that the new rate principles should be implemented as soon as practicable.

NYSERDA, however, would interpret maximum metered demand used in setting the fixed demand charges as limited to the metered demand for electricity delivered through the utility. According to NYSERDA, this would clarify that metered demand does not include the electricity produced by the OSG unit.

Plug Power

Plug Power complains the policy implications of the standby rate proposal are ignored. It disputes EU's contention that usage variability among small standby customers will be greater than the variability experienced with small full requirements customers. According to Plug Power, there is no proof the distinction exists.

Plug Power disagrees with EU's contention that electric utilities must build their systems to meet all potential demand, including that served by OSG units. It maintains OSG outage diversity and diversity with system peak

will enable the utilities to avoid unnecessary construction. Plug Power reiterates its fears that the Straw Proposal may erect pricing barriers against DG installation.

Plug Power characterizes the Straw Proposal as a pricing mechanism that reduces utility risk while discouraging energy efficiency. It advocates instead decoupling utility revenues from customer usage levels through performance ratemaking. Plug Power views the Straw Proposal as a step backwards from revenue decoupling. It also reiterates its contention that an EIS is required in this proceeding.

SUPPLEMENTAL COMMENTS

DPCA

DPCA argues there are conceptual improvements in the revised Guidelines. However, DPCA expresses concern that utilities will disproportionately classify utility distribution facilities as "local," improperly driving up the fixed cost of standby service.

EU

EU indicates that its support for the Guidelines has been compromised by several changes to the straw proposal it finds troublesome. EU argues: (1) it should not be presumed that sufficient data may exist for the development of rates for wholesale generators as a separate service class; (2) wholesale generators should pay demand charges when they deliver self-supplied station power over a utility-owned bus; (3) standby rates should apply to any wholesale generator load which may be served by both the generator and the utility, not just loads incidental to the generation function; (4) credits should not be offered to standby charges for purported benefits provided by generators; (5) the daily as-used demand charge should be rejected; (6) the reformulated contract demand charge is too ambiguous; (7) transmission facility charges should not be

collected through the proposed daily as-used demand charge; and (8) customers below 50 kW should not be permitted to pay a separate, non-demand metered volumetric standby rate.

IPPNY

IPPNY maintains that, although the revised Guidelines contain some significant improvements over earlier straw proposal, several concerns remain. Specifically, IPPNY argues: (1) no standby charges at all should apply when a generator self-supplies its station service, as opposed to merely not applying as-used demand charges; (2) full cost-of-service studies should be conducted to produce a better alternative to the daily as-used demand charge, and before any unique "additional charges (and/or credits)" are implemented; (3) station service loads should be treated differently from the loads of on-site generators, which have different load coincidence characteristics; (4) wholesale generators bear no responsibility for, and should not pay, stranded generation costs; (5) it should be clarified that demand charges will not apply where there is separation between the system bus bar where the generator’s output enters the system and system bus bar from which the station service supply re-enters the generator’s site; (6) the distinction between “local” and “shared” facilities needs better deefinition; and (7) rates developed for retail station power service should not supercede existing contractual arrangements for station service supply, except at the discretion of the generator.

MI

MI expresses its support for introduction of the daily as-used demand charge to recover shared, or non-local, transmission and distribution costs from standby customers. MI contends, however, that the revised Guidelines need further clarification, specifically: (1) to clarify that the "uniform percentage mark-up" of standby rate components for stranded costs would result in an identical percentage of the bill going towards stranded costs for both standby and full service customers; (2) to reintroduce the straw proposal's table for allocation of distribution delivery costs at different voltage levels; and (3) to clarify how rate design will be "revenue-neutral" for particular service classes.

NEM

NEM argues again that the Guidelines fail to reflect the societal benefits provided by DG, including deferral of distribution upgrades and other avoided utility costs. NEM states that, although the revised Guidelines offer improved perspectives on differences between standby and full service customers, rates should be implemented which are consistent with today's needs to enhance competitive energy options, lower costs, and to enhance reliability.

NRG

NRG maintains that the Guidelines, as amended, still fail to comply with FERC orders. The Guidelines, NRG argues, fail to fully acknowledge that there is no sale of power when station power is self-supplied, and fail to exempt divested generation facilities from responsibility for stranded generation costs.

Pace

Pace argues that the revised Guidelines marginally improve upon the straw proposal, but would suffer in implementation. Without direction on how to distinguish between

"local" and "shared" costs, Pace asserts, utilities will generally characterize facilities as predominantly attributable to the individual standby customers. A working set of rules, Pace argues, should be developed.

Plug Power

Plug Power argues that the Guidelines' new approach to ratemaking for non-demand-metered customers will be cumbersome, unfair, unnecessary, and harmful to small customers and to the development of DG technologies. Plug Power is concerned that a large customer charge is an unfair substitution for demand-metered billing for small customers. According to Plug Power, until a method for accounting for the benefits of DG has been put into place, DG units that are not eligible to participate in wholesale power sales should receive standby service with no fixed charges.

NFG

As a gas-only utility, NFG expresses its interest in opportunities for DG development. Although it supports the proposed Guidelines, NFG seeks clarification that the principles are not meant to impede economic DG utilization, and suggests that any standby rates enacted pursuant to the guidelines should be considered unjust and unreasonably if they impede business expansion.

NFG agrees that stranded costs should be applied to standby rates "in the same manner" as applied to other services. Moreover, NFG continues, standby service should be offered on an interruptible basis, and it would clarify that the FERC transmission charge is to be recovered through the daily as-usual demand charge.