76 FERC - 101 FERC, 88 FERC ¶61,138, Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc.,, Federal Energy Regulatory Commission, (Jul. 29, 1999)

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Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation and New York Power Pool, Docket Nos. ER97-1523-003 and -004, OA97-470-004 and -005, and ER97-4234-002 and -003

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Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation and New York Power Pool, Docket Nos. ER97-1523-003 and -004, OA97-470-004 and -005, and ER97-4234-002 and -003

Order Denying in Part and Granting in Part Rehearing and Clarification and Conditionally Accepting Compliance Filing

(Issued July 29, 1999)

Before Commissioners: James J. Hoecker, Chairman; Vicky A. Bailey, William L. Massey, Linda Breathitt, and Curt Hébert, Jr.

This order addresses the requests for rehearing and clarification of our January 27, 1999 order (January 27 order) [1] conditionally accepting the tariff and market rules and approving the proposed market-based rates of the New York Independent System Operator (New York ISO or ISO). In this order, we also address the compliance filing submitted by the Member Systems of the New York Power Pool (NYPP) (collectively Member Systems or Transmission Providers) [2] in compliance with the January 27 order. With the modifications

[61,379]

discussed below, we conditionally accept the compliance filing of the Member Systems.

I. Background

On June 30, 1998, the Commission issued an order conditionally authorizing the establishment of the New York ISO. *Central Hudson Gas & Electric Co. et al.*, 83 FERC ¶61,352 (1998), *order on reh'g*, 87 FERC ¶61,135 (1999) (June 30 order). The order made an interim finding that the Member Systems' proposal, with certain modifications, satisfied the Commission's 11 ISO Principles as outlined in Order No. 888. [3] The order also directed the Member Systems to submit a revised governance proposal and deferred consideration of the tariff issues, market rules and request for market-based rates. [4]

On January 27, 1999, the Commission issued an order conditionally accepting, with modifications, the proposed New York ISO Tariff and the proposed market rules of the New York ISO. The order also granted the Member Systems' request for market-based rates and set for hearing certain aspects of the proposed rates. The Member Systems' proposal included several key operational features, including: (1) the establishment of an hourly spot energy market under a two-settlement system; (2) the implementation of congestion pricing for transmission services, both of which are centered around the concept of locational based marginal pricing (LBMP); (3) the creation of a new financial instrument--transmission congestion contracts (TCCs); and (4) markets for certain ancillary services. Finally, the order required the Member Systems to submit a compliance filing reflecting tariff revisions and other required changes within 90 days of the order.

On April 30, 1999, the Commission issued an order in which we addressed the requests for rehearing and clarification of the June 30 order, rejected a settlement related to the governance of the ISO filed pursuant to that order and authorized the transfer of jurisdictional transmission facilities to the New York ISO. [5]

Requests for Rehearing and Clarification

Timely requests for rehearing and/or clarification of the January 27 order were filed by the Municipal Electric Utilities Association of New York State (MEUA),4 Enron Power Marketing, Inc. (EPMI),5 Sithe/Independence Power Partners, L.P. (Sithe), Independent Power Producers of New York, Inc. (IPPNY), National Energy Marketers Association (NEMA) and the Member Systems.

The Member Systems and IPPNY filed responses to the requests for rehearing and Sithe filed an answer to the Member Systems' response.

Compliance Filing

On April 30, 1999, the Member Systems submitted various revisions to its tariffs and related agreements in compliance with the Commission's directives in the June 30 and January 27 orders.

In response to the June 30 order, the Member Systems state that the compliance filing reflects modifications concerning the relationship between the ISO and the NYSRC and local reliability rules. In addition, the filing also reflects the Settlement Agreement on ISO governance that was filed with the Commission on October 23, 1998.

To comply with the January 27 order, the Member Systems have submitted a filing that includes separation of the transmission and non-transmission functions into two separate tariffs--the ISO Open Access Tariff (ISO OATT or OATT) and the ISO Market Administration and Control Area Services Tariff (ISO Services Tariff or Services Tariff).

The ISO Service Tariff sets forth the terms and conditions regarding the operation of the ISO administered markets and non-transmission services. These markets and services include the LBMP energy market, the ancillary

[61,380]

services markets, and the installed capacity market and services.

Customers who elect to use the ISO Services Tariff will be able to buy and sell energy in the LBMP market, buy and sell capacity, sell ancillary services, and purchase control area service from the ISO. Additionally, any entity that withdraws energy to supply load in the New York Control Area (NYCA), whether it is through the LBMP market or bilateral transactions must also take service under the ISO Services Tariff.

Parties taking service under the ISO Services Tariff will be billed based upon actual energy withdrawals in the NYCA, plus purchases from the LBMP market to supply external load. The costs associated with the operation of the ISO administered markets and non-transmission services include costs related to the operation and administration of the LBMP energy market, the installed capacity market and installed capacity requirements, the administration of control area services other than ancillary service, administration of market monitoring functions, and other activities related to the maintenance of reliability in the NYCA. [6]

In contrast, the OATT provides the terms and conditions regarding the provision of transmission services in the NYCA. These include firm and non-firm point-to-point and network service, transmission expansion, and interconnection to the grid. Any party that wishes to take any of the transmission services described above must take service under the ISO OATT. In particular, parties that purchase energy from the LBMP market, and purchase ancillary services from the ISO administered market must take service under the ISO OATT. Parties taking service under the ISO OATT are billed based upon actual energy withdrawals to service load in the NYCA plus any exports from and energy wheeled through the NYCA.

In addition, the Member Systems have made revisions to items such as firm and network transmission service, treatment of existing contracts, installed capacity requirement information, congestion management, ancillary services and treatment of external generators.

The Member Systems further note that additional revisions have been made to enable LIPA to participate in the ISO and to correct errors and inconsistencies in the prior filings. The Member Systems also request approval of two effective dates. The first effective date it requests is August 8, 1999 and would reflect approval of the cutoff date for grandfathered transmission contracts. The second effective date of September 1, 1999 reflects the date the New York ISO intends to commence operation.

In this order, we shall address the requests for rehearing and clarification of the January 27 order as well as the April 30, 1999 compliance filing submitted by the Member Systems in response to the June 30 and January 27 orders. We also approve the ISO OATT, ISO Services Tariff, and each of the related ISO Agreements submitted by the Member Systems. [7]

II. Notice of Filings and Interventions

Notice of the Member Systems' compliance filing was published in the *Federal Register*, 64 *Fed. Reg.* 26,390 with protests and interventions due before May 28, 1999. [8]

Motions to intervene were filed by the New York ISO, PG&E Generating Co., Citizen's Power, L.L.C. (Citizen's) and the California Electricity Oversight Board (CEOB). Protests and/or comments to the compliance filing were submitted by the New York State Public Service Commission (New York Commission), Coral Power/EPMI, PECO Energy Co., New York ISO, Citizen's, 1st Rochdale Cooperative Group, Ltd. and Coordinated Housing Service Inc. (1st Rochdale), Selkirk Cogen, IPPNY, MEUA, Sithe, NEMA, New York ISO, Multiple Intervenors (MI). [9] On June 15, 1999, Hydro-Quebec (HQ) filed a protest out of time. In addition, the Independent Electricity Market Operator (IEMO) filed a motion for leave to intervene out-of-time in ER97-1523-000 *et al.*

On June 30, 1999, the Member Systems filed a response to the protests and comments filed by the intervenors.

[61,381]

III. Discussion

A. *Procedural Matters*

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §385.214 (1999), the timely, unopposed motions to intervene serve to make the New York ISO, Citizen's, CEOB and PG&E Generating Co. parties to this proceeding. In addition, given the stage of this proceeding, and the absence of undue delay or prejudice, we find good cause to grant the untimely, unopposed motion to intervene of IEMO. We will also grant the untimely protest of HQ given the absence of any undue prejudice or delay.

Although the Commission's Rules of Practice and Procedure do not permit answers to protests, [10] given the complex nature of this proceeding, and given that the answer helps in clarifying certain issues, we will accept the answer filed by the Member Systems. Moreover, although the Commission's Rules of Practice and Procedure do not permit responses to requests for rehearing, we will accept the responses to the rehearing requests and clarification at this time.

B. *June 30 Order Issues on Compliance*

The Member Systems state that they have complied with the Commission's directions in the June 30 order to modify certain provisions of their filing with respect to ISO governance, the relationship between the ISO and the NYSRC, and Local Reliability Rules. Subsequently, on April 30, 1999, the Commission issued an order on the governance aspects noted above. Consequently, the Member Systems' April 30, 1999, compliance filing reflects settlement provisions which the Commission rejected in its April 30 order, wherein additional procedures were required. [11]

The Member Systems have revised the NYSRC Agreement concerning local reliability rules. The NYSRC Agreement now provides that if a Transmission Provider proposes that a local reliability rule be adopted as a reliability rule by the NYSRC, the NYSRC will use the same procedures to adopt or modify local reliability rules that it uses to adopt or modify other reliability rules. This change is consistent with our directions. Also consistent with our January 27 order, the Member Systems have amended their code of conduct to reflect a six-month period for divestiture of financial holdings.

C. *January 27 Order Issues on Rehearing and Compliance*

In the January 27 order, the Commission required the Member Systems to revise the New York ISO tariffs and agreements concerning a variety of issues. First, the Commission directed the reinstatement of the *pro forma* tariff definitions for eligible customer and native load customer and the *pro forma* tariff reciprocity provision. The Member Systems have complied with these directives.

The Member Systems have also followed our directions regarding FERC jurisdictional disputes between the ISO and the NYSRC, the filing of arbitration awards resulting from the dispute resolution process, the disclosure of certain information, and the elimination of the installed generation reserve requirement as a condition for obtaining transmission service.

We will accept the above aspects of the compliance filing without further discussion.

In the January 27 order, we also required that the Member Systems file a transmission tariff that is separate from the ISO Services Tariff. The Member Systems' revised filing provides for this change.

Customers who elect to use the Services Tariff will be able to buy and sell energy in the LBMP market, buy and sell capacity, sell ancillary services, and purchase control area services from the ISO. In addition, eligible customers can request transmission service under the ISO OATT without requesting service under the Services Tariff.

The ISO OATT provides for the basic services required by the *pro forma* tariff, including point-to-point firm and non-firm service, network service and ancillary services. The ISO OATT differs from the *pro forma* tariff in certain respects in order to implement regional practices or to incorporate congestion pricing which the Commission approved in its January 27 order.

While we will discuss certain specific provisions, including TCCs, more fully later in the order, we find that, generally, the Member Systems have complied with our directives to file separate tariffs and provide for long-term transmission services in the ISO OATT.

Point-to-Point and Network Services

[61,382]

In the January 27 order, we stated that the Member Systems failed to offer long-term firm transmission services that are required under the *pro forma* tariff and disagreed that the availability of six-month TCCs would approximate the long-term firm transmission commitments. We directed the Member System to reinstate the *pro forma* tariff long-term firm transmission services and to extend to all users enough six-month TCCs to cover the length of their transmission service.

The Member Systems' proposal now provides for a TCC auction from which both short-term (six-month) and long-term (greater that one year) TCCs can be purchased to ensure firm service. However, long term TCCs will not be available until Spring 2000. The Member Systems note that deferring the auction of long-term TCCs until Spring 2000 will enable customers to gain experience in operating in this new environment. Accordingly, customers should be more capable of making an informed bid for long-term TCCs.

We conclude that the Member Systems have complied with the requirement to provide long-term service, even though long-term TCCs will not be available until Spring 2000. We find that the service offered by the ISO is consistent with or superior to that offered under the *pro forma* tariff.

Transmission Expansion and Requests for Interconnection

In the January 27 order, the Commission rejected the Member Systems' fragmented proposal concerning transmission expansion because it disbursed responsibilities among different parties. The Commission directed the Member Systems to reinstate the *pro forma* terms and conditions, which require the transmission provider to expand the system in response to a valid request for transmission service.

The Commission also directed the Member Systems to include provisions for new generators that wish to be interconnected to the New York ISO grid when the generator itself will not be seeking to take transmission service.

Compliance Filing

In its compliance filing, the Member Systems have incorporated the *pro forma* terms and conditions related to transmission expansion. The ISO OATT states that, when the ISO receives a customer request to expand its system, it will conduct an estimated system reliability impact study.

The Member Systems' filing provides that in order to undertake an expansion, a transmission customer must ask the ISO for a system impact study. That transmission customer would be responsible to pay for the system impact study. The system impact study will identify any additional facilities or upgrades necessary to meet the transmission customer's request. The transmission customer must then pay the affected transmission providers to conduct a facilities study. Such a study would include estimates of the cost of additional facilities, the transmission customer's share of the cost for network upgrades, the time needed to complete construction, and a non-binding estimate of feasible TCCs resulting from the transmission expansion. The New York Commission can also request a study of transmission reinforcement options at no cost.

The Member Systems have also added sections detailing procedures for requesting new interconnections and reinforcements. An eligible customer wishing to interconnect with the New York ISO grid must submit its interconnection proposal to the ISO. The ISO and relevant transmission providers will perform a system reliability impact study (to be paid for by the eligible customer), to determine the interconnection's effect upon reliability. Studies will be prioritized by the date in which they have been requested. The study will focus upon the proposed interconnection's impact on system voltage, stability, thermal limits, interface transfer capability, the magnitude and likelihood of such impacts, and whether modification will be required to mitigate these impacts. If the study finds the interconnection adversely affects reliability or the ability to operate the New York ISO grid reliably, then the interconnection will not occur unless and until the necessary transmission upgrades are made. The customer can then decide whether it wishes to pay for the necessary upgrades. If a customer pays for the transmission upgrades, it will receive TCCs for the associated transmission capacity. If the interconnection is approved, the eligible customer can enter into an agreement with the transmission provider with whom the customer will be interconnected.

Intervenor Comments and Member Systems Response

The New York Commission wants the Commission to clarify, in the ISO Agreement, that the ISO Operating Committee does not have final approval over transmission studies requested by the New York Commission. It wants specific language added that will state the ISO will perform any transmission study requested by the New York Commission.

HQ believes that the date of submission is not sufficient for the assignment of priority for system impact studies for interconnection. HQ also believes that the system impact study should specify the method used to estimate the system upgrade and should specify the cost of interconnection as well as the allocation of system

[61,383]

upgrade costs between the transmission provider and the party requesting the interconnection.

MI claims that the transmission expansion section of the tariff prohibits the ISO from ordering the transmission provider to construct new facilities or modify existing facilities. They claim that this contradicts the Commission's order that the transmission providers must not forestall expansion when needed to ensure reliability.

MEUA says that the OATT is not explicit with regard to the ISO and transmission providers conducting grid expansion in response to a valid request for transmission service.

IPPNY is concerned that new interconnections to the grid require existing interface transfer capabilities to be maintained, and that the interconnecting party will have to pay for any upgrades necessary to maintain existing interface transfer capability. IPPNY argues that, if this is necessary, new generators are being prejudiced in favor of existing generators. They request that the Commission direct the Member Systems to make clear that new generators interconnecting to the grid will not be responsible for maintaining existing transfer capabilities.

The Member Systems, in response to IPPNY, assert that a "generator is responsible for ensuring that its interconnection with the grid does not reduce the transfer capability of the grid by degrading reliability at current transfer levels." [12] Further, Member Systems state that this standard does not concern the impact of net injections of energy by a newly connected generator on transfer capability, as this is accounted for in the ISO's dispatch and LBMP. The interconnection standard concerns generators whose mere interconnection reduces transfer capability, even if the net injections of energy are zero. The Member Systems acknowledge that this would be unusual, but it wants generators that have this impact on the grid to be responsible for modifying their interconnections to maintain interface transfer capability.

PECO claims that the silence in the tariff with regard to payment for facilities to eliminate adverse reliability impacts from an interconnection allows the ISO and transmission provider to deny an interconnection of a new generator to the grid. PECO wants the tariff modified so that the party wishing to be interconnected only pays for the needed facilities to meet the minimum reliability standards. PECO states that network upgrades should only be optional, and only should be considered and paid for by parties wishing to avoid congestion and obtain the associated TCCs.

Sithe recommends approval of the priority procedures for generator interconnection, but asks the Commission to reject any pre-determined cost responsibility for transmission upgrades associated with new interconnections. Sithe believes that the ISO OATT provisions implicitly suggest that generators who interconnect are responsible for any upgrades needed. Sithe believes that all market participants should jointly develop guidelines for cost responsibility with regard to new interconnections.

In its answer to the protests to the compliance filing, the Member Systems respond to many of these arguments. The Member Systems clarify that the Operating Committee does not have to approve the study of any transmission expansion requests by the New York Commission. The Member Systems respond to MI and MEUA that the New York ISO will respond to requests for transmission expansion through the process described in the OATT.

The Member Systems state that all customer requesting firm transmission service will receive it if they are willing to pay the applicable congestion charge. To the extent that customers wish to avoid paying congestion charges, they may request transmission expansion. By paying for an expansion, a customer would receive TCCs associated with the expanded capacity to offset congestion charges. [13]

Further, the Member Systems argue that PECO's concerns are unwarranted, stating that a customer wishing to interconnect to the system would be able to modify its proposal if the original proposal was found to have adverse reliability impacts. They state that customers requesting interconnection only pay the cost associated with the interconnection proposal, including costs in conjunction with the maintenance of reliability in the proposal. [14] The Member Systems state that their interconnection proposal corresponds to NEPOOL's minimum integration standard.

Commission Response

We find that the ISO OATT provides that a Member System will, at the ISO's request, use due diligence to expand or modify the applicable portion of the transmission system and that the revised transmission expansion provisions are consistent with or superior to the *pro forma* terms and conditions.

[61,384]

We do not agree with the intervenors that are concerned that the ISO OATT predetermines a customer's obligations for grid upgrades. Consistent with the *pro forma* tariff language, Member Systems have included provisions (Section 19.4) that require any completed facilities study to include a good faith estimate of a customer's cost of direct assignment facilities and its share of any required network upgrades. We find that this and the other provisions are consistent with or superior to the *pro forma* tariff.

With respect to the New York Commission's request for clarification, the ISO OATT [15] already states that the ISO will perform transmission reinforcement studies at the request of the New York Commission at no cost to the New York Commission. There is no requirement for any further committee approval to commence a facilities study.

In compliance with the January 27 order, Member Systems provided procedures for merchant generators to arrange for interconnection in circumstances where they will not be separately obtaining transmission service. While generally supportive, several intervenors seek clarification with respect to the interconnection of new generators and the prioritization of interconnection requests.

We find that Member Systems' clarifications on the interconnection issues are sufficient at this stage but also find that the ISO and market participants should jointly develop guidelines for cost responsibility with regard to new interconnections.

We find that Member Systems' proposal to prioritize impact studies for interconnection based on the date of submission is a reasonable approach and absent an alternative proposal we will accept this methodology.

Liability and Indemnification

In the January 27, 1999 order, the Commission directed Member Systems to revise the New York ISO OATT to adopt the indemnification provisions of the *pro forma* tariff, without modification.

Compliance Filing

Member Systems have adopted the *pro forma* tariff indemnification and liability provisions in the ISO OATT. They have not adopted these provisions in the ISO Services Tariff.

Intervenor Comments and Member Systems Response

HQ notes that, although the ISO OATT was revised to comply with the indemnification provisions of the *pro forma* tariff, the ISO Services Tariff maintains a gross negligence standard. HQ argues that the ISO OATT liability standard must also be used in the ISO Services Tariff.

Member Systems respond that the Commission required that only the liability and indemnification provisions of the ISO OATT be modified and argue that the *pro forma* tariff liability and indemnification provisions should not apply to the ISO Services Tariff. They maintain that it is inappropriate for the Commission to mandate a standard for liability for providing non-OATT services and that the ISO Services Tariff's gross negligence standard is consistent with New York law. They further argue that the Commission routinely allows parties in competitive markets to negotiate their own terms for commercial transactions, and that the Commission has approved the ISO New England's Tariff for Dispatch and Power Administration Services and the PJM Operating Agreement which utilize a gross negligence standard.

Commission Response

The Commission's *pro forma* liability and indemnification provisions apply to open access transmission services. Contrary to HQ's argument, the *pro forma* tariff indemnification provisions need not apply to the ISO Services Tariff, which does not contain open access transmission services. In this instance, the ISO Services Tariff's conforms with New York law, which governs power sales within the state. Therefore, we accept the Member Systems' revised liability and indemnification provisions in the ISO OATT and the ISO Services Tariff.

Transmission Rates

MEUA submitted a request for rehearing stating that the Commission erred in rejecting a single system, pool wide transmission rate. It states that the current proposal leaves too much control in the hands of Member Systems and recommends a single system-wide transmission rate.

This issue was discussed at length in the January 27 order, where the Commission approved the proposed pricing approach. MEUA has not raised any new arguments which warrant further consideration here and we find no reason to reach a different result in this case.

Transmission Losses

Under the proposal that we accepted, transmission customers would be responsible for the marginal losses associated with their transactions. Under the marginal loss proposal, revenue collected for losses will exceed the actual costs for losses. The excess revenue collected above costs will be offset against the scheduling

[61,385]

charge which is paid by all entities scheduling load in New York.

Requests for Rehearing and Member Systems Response

MEUA and Sithe seek rehearing of the Commission's acceptance of marginal losses. MEUA wants losses calculated based on average system-wide losses and recommends rejecting the marginal loss proposal since it over collects for losses that are refunded through the scheduling charge. MEUA claims that charging marginal losses to both energy market participants and bilateral market participants would lead to the participants in the bilateral market subsidizing participants in the energy market.

Sithe also objects to the marginal loss proposal unless the customers that overpay for losses are refunded the amount of their overpayment. Sithe argues that the refund through the scheduling charge is not appropriate for refunding loss overpayments. Sithe claims that this violates the fundamentals of rate making, legal precedent, the Federal Power Act, and Commission policy by not allocating the cost of losses based on a customers actual contribution to losses in the system.

The Member Systems respond that intervenors are incorrect that entities are "overcharged" for marginal losses. First, they argue that charging for marginal losses is economically correct in a competitive market. Second, if revenues were refunded to customers in the manner advocated by Sithe, those refunds would undermine the price signals and incentives that are provided by charging for marginal losses. The Member Systems maintain that the most reasonable way to refund excess revenues is through the scheduling charge. [16]

Commission Response

As we stated in our January 27 order, the use of marginal losses is a significant component of the LBMP pricing method we have already approved. [17] Under the Member Systems' proposal, the variable costs of transmission (congestion and losses) will be treated consistently under a marginal rate cost design. Marginal losses, like congestion costs, vary on the basis of the location of the generator and load. Thus, marginal losses help send efficient price signals to market participants. Marginal losses do not cause the bilateral market to subsidize the energy market; all participants face the marginal loss price signal and thus are treated similarly. We disagree that customers should receive a refund of a portion of their payments for marginal losses, since such refunds would inefficiently change the marginal loss price signal. We deny the requests for rehearing and note that the intervenors raise no new arguments on rehearing.

Energy Imbalance Service

Compliance Filing

The revised filing provides that for those parties taking service under the ISO Services Tariff, energy imbalances will be settled at the real-time LBMP. In essence, any deviations between the day-ahead schedule and real-time transactions are purchases from or sales to the ISO's real-time energy market at the applicable LBMP. [18] Generators whose real time production does not match their schedules also pay a regulation charge for the amount of the deviation. However, if the energy deviation is less than the tolerance level to be defined by the ISO, the energy deviation is set to zero.

For parties taking service only under the ISO OATT, energy imbalance charges will be settled as an energy imbalance service. If energy withdrawals are less than scheduled withdrawals, the transmission customer pays a charge equal to the greater of 150% of the real-time LBMP or $100/MWh. If the transmission customer's delivery exceeds the scheduled delivery, no payment will be made for the excess energy. These transmission customers may also be subject to regulation and frequency response charges.

Intervenor Comments and Member Systems Response

MEUA, Sithe, Coral/EPMI and IPPNY all complain about the different treatment of imbalances between the ISO Services Tariff and the ISO OATT. MEUA says that the imbalance charges in the OATT are higher than generally accepted, and the *pro forma* deviation bandwidth is missing from the imbalance charges. IPPNY wants the Commission to direct the Member Systems to include *pro forma* tariff terms regarding energy imbalance charges the OATT. It states that this different treatment between the two tariffs would force transmission customers to take service under the Services Tariff, contrary to the Commission's order. Coral/EPMI want the imbalance charges under the ISO Services Tariff and the OATT to be comparable, and they want all imbalances settled at the real-time LBMP. Sithe requests that the Commission order that OATT imbalances be settled at the real-time LBMP.

NEMA claims that the penalties for undergenerating--i n particular, the payments for

[61,386]

regulation service--are excessive. It claims that it is quite difficult for generators to be right on their Security Constrained Dispatch (SCD) base point. In order to counter this risk, NEMA argues that generators will alter their bids and affect market prices. [19] It proposes a penalty equal only to the market price for energy or a small bandwidth in which smaller penalties will be imposed.

The Member Systems respond that the Services Tariff and the OATT confer different obligations and benefits upon parties taking service under each of these tariffs. They cite PJM where there is differential treatment of imbalances that has been approved by the Commission. The Member Systems state that customers that take service only under the OATT should pay a penalty because it is necessary to ensure such customers do not unfairly lean on Services Tariff customers' generation resources. [20]

The Member Systems also respond to NEMA that regulation charges have already been approved by the Commission in the January 27 order, but they have now defined the tolerance level that was not in place previously. They claim that their approach is consistent with Order No. 888-A in that generators should be required to deliver their energy on schedule.

Commission Response

We will accept the Member Systems' proposal. Customers participating in the ISO Services Tariff pool their resources and operate a real-time market to account for imbalances. This is similar to the arrangement the Commission approved in the PJM Reliability Assurance Agreement. Customers that do not participate in the ISO Services Tariff cannot rely on these pooling arrangements and will be subject to the energy imbalance provisions of the ISO OATT.

We agree with the Member Systems that it is appropriate to assess regulation charges to generators which deviate from their energy schedules. Units which deviate from their energy schedules create a greater burden on suppliers of regulation service by forcing them to adjust their output to keep supply and demand balanced on the system. As more units deviate from the scheduled energy injections, the ISO will need to procure more capacity for regulation service. Thus, it is reasonable to assess regulation charges to those who cause the need for regulation.

The *pro forma* tariff provides for a deviation band of +/-1.5% of the scheduled transaction with a 2 MW minimum. Energy imbalances within the band are to be returned in-kind within 30 days. Energy imbalances outside of this deviation band are subject to charges proposed by the transmission provider and those charges are generally penalty rates intended to create an incentive for minimizing energy imbalances. The Member Systems have not shown that the energy imbalance provisions are consistent with the *pro forma* tariff. Therefore, we will require the Member Systems to incorporate the *pro forma* deviation band and transaction minimum in the ISO OATT.

Member Systems also propose a penalty charge for imbalances under the ISO OATT which is equal to the higher of 150% of the Real-Time LBMP at the point of delivery or $100/MWh. This charge is consistent with past Commission precedent concerning the penalty charges of other ISOs. [21] Therefore, we find Member Systems' proposed penalty charge level of 150% of LBMP to be reasonable. Further, we find that the proposed $100/MWh charge, which is equivalent to the 100 mills/kWh that we have routinely approved for emergency service, is also reasonable.

Voltage Support Charges

The Commission accepted the Member Systems' proposal for the ISO to pay the party with whom it contracts for voltage support and found that it was reasonable to expect that the contracting party would be the entity entitled to the output of the generator. The Commission also stated that it expected that the ISO would allow a non-utility generator (NUG) to participate in providing these services if the NUG believes that its contracts with purchasers permit it to contract directly with the ISO.

Requests for Rehearing

Sithe asks the Commission to direct the Member Systems to revise the tariff to allow NUGs with existing power purchase agreements to be able to contract directly with the ISO to provide, and be compensated for, reactive power and voltage support services. It argues that to allow otherwise would be discriminatory to NUGs vis-a-vis other generators who can contract with the ISO to provide these services.

Compliance Filing

For providers of voltage support service the ISO will pay each month one twelfth of the annual embedded cost for providing voltage

[61,387]

support. If the provider of voltage support is not an installed capacity provider, the monthly payment is equal to one twelfth of the annual embedded cost pro-rated by the number of hours the generator or synchronous condenser ran in that month. [22]

Rate Schedule 2 of the Member Systems' proposed Services Tariff provides that for NUGs selling power under power purchase agreements, the ISO shall contact the party purchasing energy under such an agreement for voltage support service. The ISO will compensate the holder of the agreement for the voltage support service provided. NUGs may receive payments for voltage support after the agreement has terminated or expired.

Intervenor Comments and Member Systems Response

Sithe urges the Commission to reject the portion of Rate Schedule 2 that would automatically preclude all NUGs operating under power purchase agreements from contracting with the ISO to sell reactive supply and voltage support. [23] Sithe argues that such automatic preclusion fails to conform to the January 27 order.

Sithe also asks the Commission to eliminate payment provisions for voltage support services that it views as discriminatory. [24] Sithe states that, under the proposed ISO Services Tariff, generators providing installed capacity receive higher payments for voltage support than those who are not. Sithe argues that generators providing voltage support, but not installed capacity are unlikely to fully recover the costs associated with voltage support provision.

In response, the Member Systems claim that they have complied with the Commission's directive to allow for the possibility that NUGs may be able to contract directly with the ISO. However, the Member Systems state that, in cases where the purchaser agrees to stipulate that the NUG should receive the payments, the Member Systems would not object to direct payments to the NUG. [25] Moreover, the Member Systems state that Sithe's arguments regarding generators providing voltage support, but not installed capacity, is misplaced here, since this was not an issue in the compliance filing and was already approved.

Commission Response

We agree with Sithe that NUGs should be allowed to contract on their own with the ISO for voltage support service where permitted under the terms of their power purchase agreements. The Member Systems state that in cases where the purchaser agrees to stipulate to the ISO that the NUG should receive the payments, the Member Systems would not object to direct payments to the NUG. We direct the Member Systems to revise the tariff accordingly.

We agree with the Member Systems that Sithe's protests regarding the differential payments for voltage support are misplaced as we have already approved this provision in the January 27 order. Moreover, we find it reasonable that providers of installed capacity receive the full embedded cost payment for voltage support since they are required, as providers of installed capacity, to follow the dispatch instructions of the ISO. A generator not providing installed capacity may offer these services only in the hours it chooses.

Grandfathered Agreements and Transition Plan

Requests for Rehearing and Clarification

NEMA asks the Commission to clarify that transmission customers with existing utility specific OATT reservations (regardless of when the customers took service under the utility specific OATT), be allowed to convert those reservations to the ISO OATT and thus obtain all of the benefits of the ISO OATT. NEMA argues this would ensure non-discriminatory open access for all transmission customers in New York. NEMA expresses concern that, if some transmission customers are forced to operate under a utility specific OATT, they would face rate pancaking and higher costs than other transmission customers.

Sithe and Selkirk ask the Commission to clarify that any transmission customer with an existing transmission agreement can take TCCs in lieu of its physical rights, but continue to pay the rates in accordance with the terms and conditions of the existing agreements. According to these intervenors, the January 27 order summarized the Member Systems' proposal as stating that those customers with existing agreements can either stay with the agreement, or convert their rights to TCCs and pay the associated transmission service charge (TSC) as defined in the tariff. Selkirk states that if the Commission's intention is to make the existing customer pay the TSC, and not the existing contract rate, it seeks rehearing on this issue.

[61,388]

Selkirk also requests clarification of ISO treatment of third-party wheeling agreements, and states that the January 27 order is inconsistent with the tariff concerning grandfathered agreements which allow the existing contract rates.

IPPNY requests the Commission to require the Member Systems to file a revised *pro forma* tariff that will implement retail access within 90 days of the January 27 Order. It states that this will help implement competition in New York, since it is IPPNY's understanding that half the load in New York will have retail access. Sithe and EPMI echo this sentiment and ask the Commission to require a filing by a firm date.

EPMI wants long-term firm service that exceeds a six-month period at a fixed price. EPMI argues that if TCCs are to be the basis for this long-term firm service then TCCs of greater than six months in duration must be offered so that the ISO tariff conforms to the *pro forma* tariff.

EPMI requests clarification that all transmission services must be available through existing agreements entered into under utility specific OATTs until the ISO assumes full operation of the grid. EPMI seeks this clarification to ensure that there will be no interruptions in open access to the New York system.

The Member Systems wish to clarify that a customer under an existing transmission agreement has three options: (1) it may continue taking service under the agreement and pay the contract rate; (2) it can take service under the agreement, and convert its physical rights to TCCs which will allow the customer the same flexibility as customers taking service under the ISO tariff, but it still pays the contract rate, not the TSC; and (3) it can terminate its existing agreement if it is allowed to do so and take service under the ISO tariff as a new customer, pay the TSC, but receive no TCCs in lieu of its physical transmission rights. The Member Systems state that they will include these options in their compliance filing.

Compliance Filing

The Member Systems had proposed to generically revise the charges under grandfathered contracts to include the ancillary service charges and incremental losses under the ISO OATT.

Attachment K of the OATT states that Third Party transmission wheeling agreements (Third Party TWAs) will remain in effect and a Third Party may: (1) retain the existing rights (Grandfathered Rights) subject to the provisions listed below; (2) convert the transmission rights to Transmission Congestion Contracts (Grandfathered TCCs); or (3) terminate the Third Party TWA (if terms allow). The provisions also require that each Third Party TWA will not be charged for losses or ancillary services under the ISO tariff until a Section 205 filing that provides for such charges is filed and the new rates become effective. In addition, the ISO OATT requires customers with existing transmission agreements, two weeks before the first auction, to indicate whether they will opt to elect to convert their existing transmission rights to TCC's or to take Grandfathered Rights.

Intervenor Protests and Member Systems Response

Sithe and MI also request that the Commission confirm that service under existing agreements' will be provided under preexisting rates, terms and conditions once the ISO becomes operational.

1st Rochdale believes that Member Systems who grandfather their own existing agreements establish barriers to entry for new transmission customers for comparable service. This is particularly true for the TSC which applies only to new entrants and non-grandfathered transactions.

MI state that transmission customers should not be required to provide an unconditional, irrevocable letter of credit to receive transmission service.

Commission Response

The Commission directed the Member Systems to adhere to the existing terms of existing transmission contracts until such time as the agreements are modified pursuant to Sections 205 or 206 of the FPA. Customers with existing transmission rights that elect to convert to TCCs will pay the tariff rates. The Commission determined that it would be inappropriate to generically increase the rates under existing bilateral agreements with respect to losses or any other rate component. In addition, we stated that we expected that the Member Systems would continue to grant requests for service under their individual tariffs and honor existing commitments until the date the ISO becomes effective. [26]

We are satisfied that the Member Systems' filing adequately addresses the treatment of existing contracts. It appears clear from the compliance filing that Member Systems will honor the existing rates, terms and conditions of existing agreements until such time as they

[61,389]

are modified under Section 205 or 206 of the FPA.

Moreover, Member Systems proposal to require the transmission customer to provide an unconditional and irrevocable letter of credit as security is consistent with the *pro forma* tariff, which provides that the transmission provider may require reasonable credit review procedures. [27] We therefore deny MI's request for the deletion of this requirement.

Transition Payments

The Commission generally approved the TSC, but reserved comment on the Transitional Charges until the ISO files details of the amounts and their effects on the TSC.

The Member Systems agreed to make Transition Payments to be determined by a formula in order to mitigate cost shifting among the members. The formula (Attachment H) identifies the components of the revenue requirement that will be used to determine each Member System's TSC for point-to-point and network transmission services.

The Member Systems' compliance filing does not provide the details and rate impacts associated with this. The Member Systems advise that it is premature to provide this data and they will provide data in a future filing. The Member Systems advise that the ISO must wait until after the first auction of TCCs before the Transitional Charges can be calculated along with their effects on the TSCs. The ISO will file Transition Payments, along with explanatory material, in the Spring of 2000. We note that Section H of the ISO Tariff provides that the transition period payment will be set to zero until the appropriate Section 205 filing is submitted to the Commission. We believe that it is reasonable for the Member Systems to defer these transition charges until after a filing under Section 205 is submitted to the Commission.

Recall of Energy Exports During Emergencies and Curtailments

Section 4.13 of the ISO Services Tariff allows for the interruption of purchases of energy in the day-ahead, ISO administered markets to serve load outside of the NYCA in order to maintain the appropriate reliability criteria in the NYCA or to avoid load shedding in the NYCA.

The ISO OATT has provided more detail regarding curtailment priorities and bid-based reductions needed in response to security violations. In short, non-firm service will be curtailed before firm service. For each type of service, reductions and curtailments will take place based upon decremental bids. These procedures appear in Attachment J of the OATT. However, the Member Systems have added a section in the body of the OATT (Section 13.6) summarizing its curtailment procedures needed to maintain reliability. In this summary, the OATT states that the ISO will follow the Lake Erie Emergency Redispatch (LEER) procedures and North American Electric Reliability Council Transmission Loading Relief (NERC TLR) procedures when applicable. Section 13.6 also states that the ISO reserves the right to curtail any firm service, at its discretion, in the event of an emergency that threatens reliability to the system. [28]

Intervenor Comments and Member Systems Response

IPPNY, Coral/EPMI, and Sithe ask the Commission to reject a provision in the ISO Services Tariff to recall sales from generators not committed to providing installed capacity to load outside of New York in order to prevent load shedding in New York. IPPNY believes that the ISO should only be able to recall these types of transactions if the transactions threaten reliability. It claims that this provision hampers competition and the development of broad regional energy markets. [29] IPPNY contends that, if generators in New York that provide installed capacity to load outside of New York face this provision, neighboring control areas could adopt similar policies. Coral/EPMI suggest a mechanism by which the ISO could offer to buy that energy instead of recalling it.

The Member Systems reaffirm the ISO's right to recall transactions in which generators providing installed capacity are involved. They also clarify that this recall applies only to generators that are providing installed capacity and the recall rights are a condition of eligibility for installed capacity. They reiterate the importance of this provision to maintain system reliability. [30]

Sithe asks for clarification on how the curtailment procedures in Section 13.6 of the OATT interact with the bid based curtailment procedures in Attachment J of the OATT.

Member Systems respond that the LEER procedures are reasonable, have been approved

[61,390]

by the Commission, and that this docket is not the appropriate venue for reviewing the LEER procedures. The Member Systems clarify that Section 13.6 reflects that: (1) transmission customers are obligated to follow ISO directions in the event of a Major Emergency state; (2) the ISO will follow NERC TLR procedures; and (3) the ISO will follow LEER procedures. They also state that Section 13.6 allows the ISO to proportionally allocate curtailments among network and point-to-point customers. The Member Systems note that a virtually identical proposal was approved for PJM. [31]

Commission Response

The Member Systems have clarified that they did not intend to recall energy produced by non-installed capacity generators serving external load. This clarification should satisfy IPPNY and other intervenors who ask the Commission to reject the provision allowing recall of energy from non-installed capacity when necessary to prevent load-shedding. We direct the Member Systems to add this clarification to the ISO Services Tariff.

We disagree with Sithe that there is ambiguity regarding how the curtailment procedures in Section 13.6 will interact with the bid-based curtailment procedures in Attachment J. We find the tariff to be clear.

Installed Capacity Requirement for LSEs

Requests for Rehearing

The New York Commission requests the Commission to clarify that LSEs, and not transmission customers, are responsible for meeting installed capacity requirements.

Compliance Filing

In its compliance filing, the Member Systems no longer seek to impose the installed capacity requirement upon transmission customers--the installed capacity requirement would be eliminated from the OATT. Instead, the requirement would be imposed specifically upon LSEs and placed in the Services Tariff.

The Member Systems also propose that the existing installed capacity requirements for the NYPP continue in effect until October 31, 1999, at which time the NYSRC's installed capacity requirements will become effective.

In their filing summary, Member Systems state that their proposal to impose an installed capacity requirement on all LSEs is justified in order to implement reserve sharing equitably. The Member Systems argue that it is not possible for the ISO to differentiate the reliability of service provided to end-users depending on whether the LSEs have provided installed capacity. Moreover, they argue, Commission precedent supports such a requirement, since the Commission has approved installed capacity requirements for LSEs in NEPOOL and PJM.

Commission Response

In the earlier order, the Commission rejected Member Systems' proposal to require all LSEs in the NYCA to satisfy installed capacity requirements as a condition of transmission service, questioned whether it would be appropriate to impose such a requirement outside the context of a pooling arrangement, and reserved judgement on Member Systems' proposal to require LSEs to secure installed capacity that satisfied locational requirements.

In the compliance filing, Member Systems have removed installed capacity requirements from the ISO OATT and incorporate these requirements into the ISO Services Tariff. Member Systems contend that it is reasonable to require all LSEs in the NYCA to satisfy an installed capacity requirement because industry reliability practices dictate that adequate generation reserves be maintained, it is an historical practice of the NYPP, and the NYSRC contemplates that this practice will be continued. Member Systems also contend that this requirement is being imposed in the context of a pooling arrangement because the ISO will be operating a real-time market under the ISO Services Tariff for the benefit of LSEs, which must be supported by installed capacity resources. Member Systems explain that, as in PJM, LSEs may avoid the installed capacity requirement by not electing service under the ISO Services Tariff. This satisfies the requirements of our order.

Determination of the Installed Capacity Requirement

The Member Systems have revised the filing so that if a customer is served by different LSEs over the course of a six-month period, each affected LSE's installed capacity requirement will be adjusted based on the LSE's share of energy supplied to the customer during the peak hour.

The ISO Services Tariff clarifies that the only locational installed capacity requirements that will be in effect when the ISO commences operations will be those currently in effect under retail access plans filed with the New York Commission and LIPA. However, the Member Systems have revised their filing to allow the ISO the authority to establish and implement additional locational installed capacity requirements.

Under the ISO Services Tariff, all LSEs serving load in the NYCA must provide installed

[61,391]

capacity in accordance with ISO requirements. In the first three years, LSEs found deficient of installed capacity will pay predetermined fines, based upon location, for kilowatts of capacity they are deficient. After three years, the fine is equal to three times the local levelized embedded cost of a gas turbine generator. Providers of installed capacity must abide by the ISO's rules, including a requirement to bid facilities either into ISO-facilitated energy markets or use facilities to serve load in the NYCA through bilateral transactions.

The actual installed capacity requirement for an LSE will be determined at the end of the capability period. If an LSE has not purchased enough installed capacity to meet its requirements, the ISO will allow any LSEs in this situation to avoid deficiency payments by purchasing installed capacity either from LSEs that had surplus installed capacity, or from a qualified installed capacity provider whose capacity is not already committed.

The ISO Services Tariff states the ISO will determine the amount of installed capacity that can be located outside the NYCA based upon NYSRC reliability criteria.

Intervenor Comments and Member Systems Response

The New York Commission states that it does not oppose the ISO's use of old NYPP rules at the start of ISO operations, but it would like new rules in place soon after commencement of operations.

NEMA argues that costs associated with loads served by different suppliers over different time periods can be shifted from an LSE that serves a load in a peak month to LSEs which serve the same load in months in which the peak in unlikely to occur. NEMA suggests that a monthly installed capacity market could alleviate the problem.

IPPNY and EPMI also ask the Commission to order the Member Systems to implement an installed capacity requirement that is known in advance. IPPNY claims that the proposed requirements leave LSEs in the position of not knowing how much installed capacity to procure until after the fact, since the requirement will be calculated based upon actual loads. Additionally, IPPNY and 1st Rochdale claim that the procedure for adjusting an LSE's load when a load switches LSEs under retail access is complicated and makes it difficult to know how much installed capacity will be needed. They further express concern that additional qualified installed capacity providers may not be available at the end of the capability period.

The Member Systems state that Coral and EPMI's protest regarding the uncertainty of the installed capacity requirement does not concern the adjustments undertaken to accommodate retail access, but rather, the determination of installed capacity requirements from the December 1997 filing. Since the compliance filing did not alter this aspect of the proposal, the Member Systems believe this protest should be dismissed as inappropriate for evaluating the compliance filing.

In response to NEMA, the Member Systems argue that installed capacity required to maintain reliability is also dependent upon load profiles, generator location and characteristics, maintenance schedules, and assistance from neighboring control areas. Therefore, any increase in load in any hour will change the installed capacity requirement to maintain a given level of reliability. The Member Systems also argue that NEMA's assertion that off-peak loads have no installed capacity responsibility is not defensible.

Coral and EPMI state that external installed capacity should not be grandfathered and that the Commission should allow the transmission capacity reserved for external installed capacity generators to be used for firm reservations. Coral and EPMI also claim that the Member Systems have provided no justification for limiting installed capacity from other control areas, nor has it justified, as ordered, any capacity benefit margin adjustments.

1st Rochdale is also concerned that the organizations responsible for reliability will impose unnecessary requirements and additional costs on LSEs.

The Member Systems claim that protests over limiting the amount of installed capacity outside of the control area is not timely as this aspect of the proposal was in the original filing. They further state that a failure to limit the amount of installed capacity from outside the NYCA could jeopardize the ability to provide reliable electric service in New York, and that allowing more installed capacity from outside NYCA would reduce inter-control area transfer capability that might be needed in the event of an emergency.

The Member Systems state that 1st Rochdale's request is not warranted and without rationale. They state that the Commission has already accepted procedures for determining reliability criteria.

Commission Response

In response to the Commission's concern that an annual determination of an LSE's installed capacity requirement may not reflect shifting load responsibility as retail access is implemented, the requirement will now be computed for a six-month capability period and apportioned among all LSEs serving the customer within the six-month period. We find that this

[61,392]

modification will ensure that, as a result of changes among suppliers during the year, the installed capacity requirement will not exceed the system requirements for reliability purposes.

Moreover, we reaffirm our decision in the January 27 order that the computation of the installed capacity requirement after the applicable period is reasonable in that LSEs will have the opportunity at the end of the period to purchase installed capacity to avoid deficiency charges. Moreover, the compliance filing, while allowing LSEs to purchase bilaterally any installed capacity needed at the end of a capability period, is silent on the possibility of an installed capacity auction being held for this purpose. As to locational installed capacity requirements, Member Systems state that, due to the physical configuration of the transmission system as well as the potential for localized transmission outages, it may be essential that installed capacity be located in particular areas of the state in order to maintain reliability. Member Systems state that these locational requirements may change over time as load conditions change. Member Systems contend that, while there is no explicit locational requirement in the existing NYPP arrangement, there is a *de facto* requirement since NYPP members' practice was to construct load in their service area or to construct transmission capability to deliver remote generation. Member Systems argue that, in a competitive environment, a locational requirement will provide price signals to ensure that resources are sited in locations that are deliverable to load in the NYCA. Member Systems point to New York City as an example of the need for locational installed capacity, and note that the New York Commission has imposed locational installed capacity requirements as a condition on new LSEs selling at retail in New York City until the ISO developed its own location requirements. Finally, Member Systems argue that PJM's installed capacity requirements are implicitly locational in that the installed capacity resource must be deliverable to load through firm transmission service.

A number of intervenors express concerns about the locational requirements, arguing that Member Systems have failed to justify any locational requirement or arguing that the specific locational requirements cannot be approved because they are not established.

We continue to have concerns about the locational requirement for installed capacity, which has not been an explicit requirement of any pooling arrangement, past or present, with the limited exception of the New York City and Long Island areas. Member Systems may be correct that the requirement to obtain firm transmission to reach installed capacity resources has effectively imposed a locational requirement in other pools in the past. However, currently, the ISO OATT provides no method for an LSE to secure a physical transmission path to a specific resource, and obtaining TCCs would not provide any reliability assurances equivalent to such a deliverability requirement. Member Systems' proposal also differs from the historical practice and current practice in PJM which does not change the locational requirements imposed on a LSE from time to time, *e.g.*, once a resource is obtained and accredited, it cannot be unaccredited for that LSE. We are also concerned that a locational requirement for installed capacity could affect the ability of specific generators to exercise market power due to their location. Indeed, we have approved localized market power migration rules for sales within New York City for this very reason. For these reasons, we will continue to reserve judgement on the imposition of locational installed capacity requirements that have not yet been designed or justified. We shall not disturb the locational requirements currently in place for New York City or Long Island.

Installed Capacity Market

The Commission's January 27 order directed the ISO to file a detailed proposal regarding the implementation of an installed capacity market.

Compliance Filing

In Section 5.12 of the ISO Services Tariff, the ISO is committed to running a bid-based auction for installed capacity upon the request of LSEs that wish to procure installed capacity in this manner. The ISO will establish the bidding rules. LSEs are permitted to engage in bilateral transactions for installed capacity outside of the auction.

Within the market structure, the ISO will make available capacity resources for a capability period, including resources necessary for locational installed capacity requirements. The market will establish separate market clearing prices for each locality and for the NYCA as a whole. LSEs bidding into the market will have the discretion to make the requests so that they may be able to satisfy their locational installed capacity requirements.

The ISO will enforce any Commission-approved market power mitigation measures.

Intervenor Comments

HQ and 1st Rochdale contend that the Member Systems have not filed a detailed proposal regarding the implementation of an installed capacity market as ordered in the January 27

[61,393]

order. They state that installed capacity should be available through a centralized market.

The Member Systems claim that HQ's assertion that a detailed proposal for an installed capacity market is misplaced. The Member Systems respond to HQ that the ISO will make a filing with respect to the details of locational installed capacity requirements in compliance with the January 27 order. When the ISO files on this matter, then parties will have a chance to evaluate the specific proposal. [32] Hence, the Member Systems conclude that they have complied with the January 27 order. [33]

The ISO, in a recent letter to the Commission, [34] adds that it will need approval of the details of the installed capacity auction soon after September 1, 1999. It requests this approval so it may conduct the installed capacity auction in mid-September for upcoming winter capability period.

Commission Response

We agree with HQ and 1st Rochdale that the Member Systems have not supplied what we consider a detailed installed capacity market proposal. However, in the January 27 order, the ISO, not the Member Systems, was directed to file this proposal. We have yet to receive such a proposal from the ISO on this matter. Moreover, we cannot in this order grant the ISO's recent request for approval of an installed capacity market proposal, since the only proposal before us lacks much detail. Therefore, we direct the ISO to file with the Commission a detailed proposal for an installed capacity auction market. Such a detailed proposal should include, but not be limited to, bidding rules and procedures, procedures for determining market clearing prices, and market power mitigation procedures.

Installed Capacity Requirement on Annual Basis

In the January 27 order, the Commission determined that the system's installed capacity needs are appropriately assessed on an annual basis because peak loads are the driving factor in determining those needs.

Requests for Rehearing

Sithe, MEUA, and EPMI filed requests for rehearing arguing that the annual installed capacity requirement should be changed to a monthly one. Sithe argues that the yearly requirement forces LSEs to reserve much more capacity than is needed during certain time periods. EPMI states that, since retail customers can change suppliers monthly, an LSE should be able to change its capacity requirement on a monthly basis. Sithe notes that the Commission has allowed monthly trading in NEPOOL.

Commission Response

We support the NY ISO's proposal to have separate winter and summer capability period requirements with adjustments made for LSE requirements when customers change suppliers. This proposal addresses the Commission's concerns that installed capacity requirements, on LSEs as a group, not exceed the system's total needs. Assessment of installed capacity on a winter/summer basis gives a more realistic picture of the installed capacity needs. Therefore, we deny the rehearing requests on this issue.

Generation Accreditation Criteria for Installed Capacity

In the January 27 order, the Commission set for hearing the reasonableness of criteria used to accredit generation for meeting the installed capacity requirement. The Member Systems have sought rehearing of the Commission's decision to set these criteria for hearing. The Member Systems argue that it was premature for the Commission to set the criteria for hearing, since the ISO has not yet established the criteria.

In response, IPPNY argues that the relevant question is whether availability should be based on a comparison of all generators available to the system as opposed to generators of the same type (generator classes). In addition, IPPNY and EPMI have objected to the Member Systems' proposal to establish availability standards based on generator classes, and ask the Commission to reject this proposal.

We continue to believe that the ongoing hearing is the most effective way to resolve whether the criteria used to accredit generation should be based on generator classes or all generators available to the system. We see no reason in this instance to delay pursuing whether the criteria should be based on generator classes or all generators available to the system.

Locational Based Marginal Pricing

MEUA requests rehearing of the Commission's acceptance of LBMP as a basis for congestion pricing and believes that the Commission's decision lacks sufficient reasoning. MEUA argues for an average embedded cost pricing system, and believes that transmission

[61,394]

pricing should be based solely on transmission-related costs. [35]

We will deny MEUA's request for rehearing, as MEUA has raised no new arguments here. As we have stated previously, we conclude that congestion pricing promotes more efficient trading and is more compatible with the type of competitive market mechanisms that we encourage. [36]

Minimum Generation and Start-Up Costs

The Commission accepted the Member Systems' proposal to recover certain start-up and minimum generation costs from all transmission customers.

Intervenor Comments and Member Systems Response

Intervenors argue that, while it may be reasonable for all transmission customers to pay for those costs for generators supplying ancillary services since they are a part of transmission service, it is not reasonable to charge all transmission customers start-up and minimum generation costs for those generators providing only energy. [37] They argue that, since energy is not a part of transmission service, bilateral customers who do not use the ISO's energy market should not be charged for these costs; only those customers who participate in the ISO energy market should be charged. Sithe and EPMI further argue that the costs associated with ancillary services should be passed through the rate schedules of the relevant ancillary services and not the scheduling charge.

The New York Commission asks the Commission to clarify that bidding of minimum generation and start-up costs should be included in the ISO's report evaluating its first year of market operations. In particular, the New York Commission is interested in the magnitude of the costs, the percentage of total costs to transmission customers, and potential alternatives.

The Member Systems respond that these intervenors seek a preferential benefit for bilateral loads by forcing entities that buy through the spot market to bear the costs of reliability. Member Systems state that it is not possible to determine what part of start-up and minimum load costs is attributable to energy versus ancillary services due to the simultaneous clearing of markets in the unit commitment process. Member Systems also argue that start-up and minimum load costs support redispatch to alleviate transmission constraints which benefits bilateral transactions as well. [38]

Commission Response

We deny the requests for rehearing on the allocation of start-up and minimum load costs. Most start-up and minimum load costs will be recovered in revenues from selling energy (and ancillary services) in the ISO's markets. Any remaining, uncovered start-up and minimum load costs will be recovered in the schedule 1 charge in the ISO OATT. We disagree with intervenors' argument that these residual start-up and minimum generation costs of units that supply energy but not ancillary services should be recovered solely from buyers in the ISO's energy market.

We also agree with the Member Systems that it is not possible to determine what portion of these costs supports loads served by the ISO's market versus for loads served by bilateral transactions. Therefore, we deny rehearing. We agree with the New York Commission that the magnitude of minimum generation and start-up costs should be addressed in the ISO's first year market evaluation report. We also direct the ISO to explore in that report alternative ways to allocate these costs.

Scheduling and Unit Commitment Issues

The Member Systems have made only one revision with respect to scheduling. The ISO Services Tariff allows transmission providers to request the dispatch of generators in order to preserve local reliability. The ISO evaluates these requests, and dispatches generators for local reliability on a least cost basis. [39]

Intervenor Comments and Member Systems Response

Although the ISO Services Tariff is silent on the issue, IPPNY, Coral/EPMI, and Sithe want clarification regarding the manner in which the Balancing Market Evaluation (BME) [40] will be run. Specifically, they seek clarification about whether it will be run on average load for the next hour (the average of the 12 5-minute dispatch intervals in the hour) or on the peak load expected for the hour (the highest of the 12 5-minute dispatch intervals in the hour). The intervenors claim that, if the peak load is used, then schedules will be determined that are not necessarily economic for the average conditions in the hour. This is especially

[61,395]

problematic for generators not on SCD [41] since they will not be able to adjust their generation accordingly and will not be paid for overgeneration.

Coral/EPMI further claim that the scheduling burdens for bilateral transactions are discriminatory relative to transactions that go through the pool market. First, they contend that specifying actual generator and load combinations is more restrictive than the *pro forma* tariff and prevents a party from scheduling transactions by simply specifying a set of points of injection and points of withdrawal. Second, Coral/EPMI states that LSEs going through the pool market can take long and short positions in the energy market, but those engaged in bilateral transactions cannot due to the restrictive scheduling restrictions. [42]

These intervenors also argue that there exists an incentive for LSEs participating in the pool market to engage in strategic behavior in the form of understating their demand in the day-ahead market to drive prices down. They claim that lifting the restrictions on bilateral transactions would force the price back to the level it would be in the absence of such an incentive.

MI and NEMA contend the transmission providers are allowed to require the commitment of additional generation, thereby altering the ISO's day-ahead schedule, to ensure reliability. [43] MI contends that this violates the ISO principle requiring that the ISO, rather than the transmission providers, is responsible for system reliability. NEMA argues that this provision violates Order No. 888 in that it violates the separation of merchant and transmission functions. NEMA concedes that reliability is a top priority and, if the provision remains, any such requests by transmission providers should be posted on the ISO's OASIS.

The Member Systems state that, because BME was not a part of the compliance filing, nor was it addressed in the January 27 order, it is beyond the scope of this proceeding. They believe that the BME should be conducted based upon the peak load in the hour to ensure that sufficient generation will be on hand to meet the expected peak load.

The Member Systems further argue that, although the ISO will have operational control of certain transmission facilities, transmission providers have an interest in the safe, reliable operation of the transmission assets that they still own. Moreover, the transmission providers will have more in-depth knowledge of operating conditions on their respective systems. Therefore, it is essential that the transmission providers be able to review the ISO's commitment of generating units, and to request that the ISO commit additional generating units for reliability reasons. The Member Systems state that any request by transmission providers for the commitment of additional generators by the ISO is subject to documentation and audit by the ISO. [44]

Commission Response

We reject Coral/EPMI's assertion that the scheduling burdens for bilateral transactions are discriminatory. All customers that wish to schedule bilateral transactions must do so in the same manner, so they are treated comparably; relative to the ISO administered market, the scheduling burdens are really no different. Generators injecting power into the systems must specify a point of injection, and LSEs must specify a point of withdrawal.

We disagree with Coral/EPMI's claim that firm service cannot be reserved more than one day in advance. While customer *schedules* will be established a day in advance, the *right* to firm service provided through TCCs or the payment of a congestion charge. The transmission rights proposed here (*i.e.*, TCCs) can be acquired well in advance of real-time. As discussed elsewhere in this order, TCCs initially can be purchased at auction for a term lasting from the beginning of the ISO markets' operation until May 1, 2000. Subsequent auctions will make TCCs available for terms up to 5 years.

We deny Coral/EPMI's request to order the ISO to change its bid submission deadline. We accepted the 5:00 am deadline in our January 27 order, and we see no reason why the 5:00 am deadline in New York would be detrimental to regional trading.

We accept the Member Systems answer regarding the commitment of generators to preserve local reliability. While the transmission providers will be able to request that the ISO commit additional generation units for reliability reasons, the final commitment decisions will rest with the ISO. Thus, the ISO will maintain responsibility for reliability. However, we also agree with NEMA that any such requests to commit generators not otherwise committed by the ISO in the day-ahead market should be posted on the ISO's OASIS. We direct the

[61,396]

Member Systems to revise the ISO Services Tariff accordingly. This openness should provide adequate scrutiny for such practices to help ensure this procedure is not abused by the transmission providers.

Disclosure of Bid Information

In the January 27 order, the Commission required the release of information about bids into the energy, ancillary services, and TCC markets 6 months from the time the bids have been submitted in order to help interested parties monitor the market.

Requests for Rehearing

Several intervenors ask the Commission to clarify that bid information from LSEs will also be released after six months. IPPNY believes the January 27 order was unclear on this issue. EPMI provides examples of potential strategic behavior by LSEs that could be revealed by disclosure of their bids.

The New York Commission asks the Commission to clarify that the New York Commission will have access to ISO data in its market monitoring and mitigation plan that the Commission ordered filed.

The Member Systems seek rehearing of the Commission's bid disclosure requirement. They state that the LBMP system is designed to create an efficient market and to encourage suppliers to bid marginal costs. Therefore, the Member Systems argue that the disclosure of bid information is disclosure of commercially sensitive information about generator costs. [45] They claim suppliers will not want this information disclosed to potential competitors.

The Member Systems argue that the disclosure of bids will encourage participants to leave the ISO-facilitated market in favor of bilateral transactions, which have no requirement to disclose cost information. The Member Systems believe that reducing the number of suppliers in the ISO markets will have detrimental effects on economic dispatch of the system, and lead to difficulties in balancing schedules and procuring spinning reserves and other ancillary services. Suppliers involved in bilateral deals will be reluctant to submit incremental and decremental bids, since that might reveal sensitive information. Instead, these suppliers would rely on default bids, or might provide bids which exceed their incremental cost. The Member Systems contend that this situation could lead to excessive price volatility and extreme variance in congestion. [46]

The Member Systems also argue that disclosure of TCC bids could allow auction participants to see who is bidding aggressively, and could enable participants to identify constraints for which there were not many TCC bidders and for which tacit agreements to reduce bids most likely would be successful. The Member Systems state that this potential for collusion from bid disclosure does not benefit consumers. [47]

Compliance Filing

The ISO Services Tariff submitted by the Member Systems in their compliance filing states that bid information will be released after 6 months. [48]

Intervenor Comments and Member Systems Response

IPPNY reiterates its view that bids from LSEs should be released as well.

PECO objects to the disclosure of bid information. PECO argues that use of "cost based bid data" combined with sophisticated methods for estimating fuel costs will allow construction of highly accurate models of a generator's heat rate, operating parameters, and other confidential cost information. PECO claims this information can lead to advantages for parties negotiating bilateral and power supply contracts. PECO also states that bidders may leave the ISO markets for bilateral markets, or would inflate bids to conceal this information, and lead to market power abuses. [49]

Member Systems reiterate their arguments set forth in their petition for rehearing and note PECO's concern that this will harm the market.

Commission Response

We deny the claims of the Member Systems and the protest of PECO, and we grant the clarification sought by intervenors. We reaffirm that bid information must be made public after 6 months, and we clarify that all bids including those of LSEs must be made public. [50] We will not require the names of bidders to be publicly revealed; however, the data should be posted in a way that permits analysts to track each individual bidder's bids over time.

As we stated in our January order, it is important for bid information to be released to the public, in order to permit interested parties to monitor the market. Moreover, we have permitted

[61,397]

the information to be kept confidential for six months to help prevent collusive behavior. The arguments offered by the Member Systems and PECO against bid disclosure are speculative and unconvincing. First, publicizing the bids will not give advantages to selected participants since the data will be available to every market participant. Second, the disclosure requirement will not cause participants to leave the ISO-administered markets. As long as the ISO's markets provide products and services at advantageous prices when compared to bilateral prices, we would not expect the participant to abandon the ISO's markets in light of a bid disclosure requirement. Third, we do not expect that a seller will inflate its bids above its costs in response to the bid disclosure requirement. By inflating its bids, the seller would run the risk that it would not be scheduled during periods when it would be profitable to operate.

We clarify that the New York Commission should receive the same information that the Commission receives from the ISO with respect to the ISO's monitoring and mitigation efforts.

Treatment of Generators

In the January 27 order, the Commission noted that under the Member Systems' proposal, internal suppliers, unlike external suppliers, were allowed to substitute energy from the LBMP market for their own energy in a bilateral transaction when the LBMP price is less than their decremental bids. The Commission directed the Member Systems to revise the ISO Tariff provisions in this regard in order to treat external suppliers the same as internal suppliers.

Requests for Rehearing

The Member Systems agreed to revise the ISO Tariff to allow external generators involved in bilateral transactions to replace their own scheduled energy with LBMP energy, if the LBMP is less than their decremental bid, in the day-ahead and hour-ahead markets. Still, the Member Systems claim that external generators cannot be treated identically with internal generators unless the external generator is dynamically scheduled. They state that the reason is that external generators that are a part of another control area cannot respond to the ISO's SCD signals every five minutes. These generators can only participate in the ISO market through fixed control area to control area schedules.

The Member Systems state that their filing does not prevent an external generator from becoming a part of the New York control area by installing the necessary metering and control capabilities.

Member Systems state that, if the Commission's order intended equal treatment of internal and external generators in real-time, they request rehearing on this matter.

Compliance Filing

The Member Systems have included changes in Attachment J of the ISO OATT that allow the substitution of energy from LBMP market in the day-ahead and hour-ahead. External generators would not be able to substitute energy from the LBMP market for their own energy in real-time. Again, the Member Systems argue real-time substitution is not possible unless the external generators are dynamically scheduled.

Intervenor Comments and Member Systems Response

MEUA believes that the Member Systems' proposal is not satisfactory and contend that external generators are still disadvantaged under the compliance filing. HQ claims that the Member Systems have not complied with the Commission's directive. It claims that only an internal generator is allowed to substitute energy from LBMP market for it own energy.

The Member Systems claim that HQ's and MEUA's protests are without merit. The Member Systems claim to have complied explaining how external generators can replace energy in the day-ahead and hour-ahead market, but only internal generators can replace that energy in real-time.

Commission Response

The Member Systems' proposal to allow equal treatment of internal and external generators in the day-ahead and hour-ahead markets--as outlined in the filing summary--would satisfy the Commission's directive if implemented. However, we disagree with the Member Systems that this treatment has been made explicit in Attachment J. We therefore direct the Member Systems to make explicit in Attachment J that external generators engaged in bilateral transactions will have the ability to substitute energy from the day-ahead and hour-ahead markets for their own energy. To do so, the Member Systems should follow the same format as in Section 2.0, p. 249 in Attachment J, which applies to internal generators.

At this time we shall not require the ISO to treat internal and external generators the same in real-time. We agree with the Member Systems that allowing external generators this flexibility in real-time requires dynamic scheduling, and we accept the Member Systems' explanation in their rehearing request that they do not preclude any generator from installing the proper equipment necessary for dynamic scheduling.

[61,398]

Failure to Pay Generators for Excess Generation

The Commission accepted the Member Systems' proposal not to compensate generators for generation delivered above scheduled generation or above generation requested by the ISO.

Requests for Rehearing

IPPNY argues that this practice will prevent intermittent generators such as wind, photovoltaics, and small hydro from participating in the ISO's energy market since they cannot be dispatched by SCD or automatic generating control signals. In support of its argument, IPPNY states that the LBMP system will itself induce proper behavior, since the LBMP will tend to decrease as a unit generates more power, thereby providing an incentive for a generator to reduce its output. EPMI and IPPNY also claim that paying for excess generation enhances reliability in two ways. First, it provides generators the incentive to provide their best estimate for maximum availability for the next day. If they are not paid for excess generation, IPPNY claims that generators will overstate their next day availability to avoid scheduling less than their real-time output. Second, IPPNY claims that paying for excess generation allows generators to respond to the need for additional generation in the case of a contingency such as loss of a line or a generator.

Commission Response

The Member Systems have proposed to pay nothing for uninstructed overgeneration as a disincentive to overgenerate. They argue that a strong disincentive is necessary for uninstructed overgeneration because overgeneration creates reliability risks. Specifically, they argue that overgeneration (but not undergeneration or unscheduled deviations in load) creates the risk that transmission limits may be violated before the grid operator is able to take corrective action. We have no basis to reject the Member Systems' reliability concerns on this issue and will deny, at this time, the rehearing requests of IPPNY and EPMI.

However, the New York ISO should evaluate whether the circumstances in New York merit the continued different treatment of uninstructed overgeneration once it has gained operational experience. In this regard, the Member Systems' proposal for New York treats uninstructed overgeneration differently from the ISOs operating real time energy markets in PJM, NEPOOL, and California. In these latter markets, most uninstructed generation faces the applicable real-time energy price.

As part of this evaluation, the ISO should examine whether the same pricing treatment should apply to all uninstructed overgeneration, regardless of the location of the generator or the transmission conditions, as the Member Systems propose. [51] The ISO should evaluate whether the reliability risks of certain undergeneration (for example, by generators located on the import side of a transmission constraint) are different from the risks of overgeneration, and if not, whether different pricing treatment is appropriate for overgeneration and undergeneration.

The ISO should also evaluate whether the LBMP price signals are sufficient to address any overgeneration problems, as intervenors argue. [52] The ISO should also evaluate whether harsher penalties than those proposed by the Member Systems should apply in limited circumstances where transmission limits are in imminent risk of being violated.

In addition, the ISO should consider market rules that accommodate the special operating characteristics of generators (such as wind, photovoltaic and hydro generators) that are unable to precisely forecast and schedule their energy production in advance. We direct the ISO to consult with stakeholders on these issues, and file a report on its conclusions and recommendations with the Commission one year after it begins market operations.

Ancillary Services

The Commission directed the Member Systems to include provisions for "cascading," *i.e.*, substituting higher quality ancillary services for lower quality ancillary services if it leads to a lower cost of procuring ancillary services.

Requests for Rehearing

The Member Systems ask for clarification or rehearing on the Commission's order to allow for the "cascading" of bids from higher quality services to lower quality services. The Member Systems state that their proposal already incorporates

[61,399]

a feature similar to "cascading," but which is more efficient than "cascading."

The Member Systems point out that under their proposed model, generators can simultaneously offer the same capacity into multiple product markets. They note that the markets for ancillary services clear simultaneously, not sequentially. Given these two features, the Member Systems contend that their method for the procurement of ancillary services is comparable or superior to "cascading" of ancillary service bids. Furthermore, the Member Systems state that their definitions for operating reserves implicitly gives the ISO the ability to substitute ancillary services. However, the Member Systems agree to add explicit language to confirm that the ISO's Security Constrained Unit Commitment (SCUC) program does substitute higher quality services for lower quality services.

Compliance Filing

The ISO Services Tariff clarifies that the SCUC program selects the least cost mix of energy and ancillary services. In doing so, the SCUC allows for the substitution of higher quality services for lower quality services. [53]

Intervenor Comments

There were no intervenor comments on cascading; however, the New York Commission states that Section 4.6 of the ISO Tariff filed in December 1997 has been deleted from the compliance filing and wants it reinstated into the ISO OATT. This section stated that the ISO is responsible for maintaining operating reserves and hence, system reliability.

The Member Systems agree to include the omitted Section 4.6 in the ISO OATT in an errata filing.

Commission Response

We accept the Member Systems' characterization that their simultaneous clearing of markets achieves the same result as the cascading that we directed. The Commission accepts the Member Systems' explanation in its rehearing requests, and we accept the inclusion of explicit language in its compliance filing stating that the ISO can substitute higher quality services for lower quality services.

We agree with the New York Commission that the provisions of Section 4.6 of the ISO Tariff filed in December 1997 have been omitted from the ISO OATT. We direct the Member Systems to reinstate Section 4.6 into the ISO OATT in order to make it clear that the ISO is responsible for the establishment of operating reserves and implementing the operating reserve requirement established by the NYSRC.

TCC Auction

In the January 27 order, the Commission directed the Member Systems to revise the TCC auction structure so that market participants will not know the percentage of transmission capacity to be auctioned in each round of the auction. [54] The Commission also directed the Member Systems to clarify how they would address the potential problem of oversubscription of grandfathered TCCs.

Requests for Rehearing

The Member Systems request rehearing of the Commission's requirement that the percentage of TCCs to be awarded in each round be kept confidential. The Member Systems believe that keeping this information from market participants will increase price volatility between rounds of the TCC auction, rather than decrease it. For example, if bidders overestimate the amount of transmission capacity to be auctioned off in a particular round, it may lead to artificially high prices due to bidders' inability to accurately forecast the transmission capacity offered for sale. They concede, however, that prices will vary somewhat from round to round due also to other factors such as participants modifying their bidding strategies as they receive more information from subsequent rounds.

The Member Systems state that the Commission's description of the auction process is not an accurate reflection of what was in the filing, and they explain how the auction should be described. They commit to clarify the description of the auction in their compliance filing and request that the Commission reconsider the auction process as more fully described in the compliance filing.

The New York Commission asks the Commission to clarify that the first year review include a discussion of the TCC auction procedures, especially the effect of not announcing the quantity of TCCs available before each round. The New York Commission worries that this feature may prevent a vibrant TCC market, and hence a vibrant wholesale and retail market.

Compliance Filing

The Member Systems' compliance filing revised the ISO OATT [55] so that the percentage of TCCs to be available in each auction round will not be announced in advance.

In addition, the Member Systems have proposed two types of auctions to be held during

[61,400]

the transition from the current power pool regime to the ISO regime. The Member Systems state that a transition is necessary due to temporary software limitations.

The first transitional auction for TCCs will be held six weeks before the start of ISO operations. This transitional auction will use a single round auction, because the software needed to conduct multi-round auctions cannot be developed in time for the first auction. All TCCs in the first transitional auction will have a term that expires on May 1, 2000.

The second transitional auction will be a multi-round auction and will coincide with the start of the Summer 2000 capability period. In this auction, the ISO will separately put up for bid TCCs of different, pre-established term lengths ranging from 6 months to 5 years.

When the necessary software is developed, the ISO will begin holding multi-round auctions where all available TCCs will be auctioned simultaneously. In this auction, each bidder can submit bids that specify any TCC term length that the bidder chooses. The Member Systems expect that the necessary software to conduct this type of auction will be completed for the Summer 2001 capability period.

In the event that the combined amount of existing transmission rights, grandfathered TCCs, and grandfathered rights exceed the physical transmission capacity in New York, the Member Systems propose a method of reducing these TCCs and rights so that the existing rights and TCCs match physical capacity. The ISO will use the auction software to reduce the allocation of TCCs so as to maximize the aggregate value of the reduced TCCs.

Intervenor Comments and Member Systems Response

The New York Commission requests clarification that revenues from TCC sales by transmission providers will be used to reduce the applicable TSC. It also requests clarification that transmission providers may bid into the TCC auctions. New York Commission believes that since transmission providers are the provider of last resort, they should be able to purchase TCCs in order to keep costs down to retail customers. [56]

The New York Commission generally supports the auction of long term TCCs, but it is concerned that over the long term, TCCs may confer market power comparable to ownership of generation. [57] It wants the Commission to institute a reporting requirement for TCC owners, in conjunction with the establishment of the ISO's market monitoring unit so that potential market power abuses may be evaluated. Specifically, the New York Commission believes buyers and sellers of TCCs should be required to report transactions to the market monitoring unit and New York Commission, and whether these TCCs were purchased through the secondary market or the auction.

In responding to the concerns of the New York Commission, the Member Systems clarify that TCC revenues will be used to offset TSC charges and that transmission owners can bid into the TCC auction.

The Member Systems also respond that ownership of TCCs themselves does not confer market power. They claim that since TCCs do not confer physical rights, it is not possible for holders of TCCs to withhold output from the market. [58] They further argue that if one assumes that TCCs can aid in the exercise of market power, then any other financial instrument could be used to accomplish the same goal. The Member Systems contend that any agency investigating potential market power derived from TCCs would have to look beyond primary ownership. The Member Systems cite various financial arrangements that have the same effect as selling TCCs. The Member Systems also believe that, if it is the New York Commission's intent to require more stringent reporting requirements on generators holding TCCs, that would impose a reporting burden on generators without the actual potential for the exercise of market power. [59]

HQ claims that the Member Systems have not complied with the Commission order for the ISO to reveal the buyer's identity when a secondary market transaction has taken place. It also wants the ISO to adopt settlement procedures with the actual owners of TCCs and not just with primary holders.

The Member Systems respond that HQ's protest is inappropriate since the Commission directed the ISO, rather than the Member Systems, to make the necessary changes. They further state that they this process would most likely only track the primary holders of TCCs since it would be quite difficult for the ISO to track transactions made by secondary holders. [60]

Selkirk and Sithe request the Commission to order that grandfathered customers be allowed to change their election of physical rights or TCCs after the first transitional TCC auction. Selkirk believes that, under the current proposal, the choice of TCCs versus physical rights is

[61,401]

one that is irreversible and wants the option to change its election between the transitional auction and the first initial auction. Selkirk claims that this option will allow transmission customers with existing contracts to gain market experience and determine whether holding TCCs or physical rights is more valuable before making a long term decision. It believes that this change will reduce the risk, or the perception of risk to market participants. Selkirk further argues that this will not hurt the operation of the TCC market.

The Member Systems agree to modify the OATT to permit parties to elect to convert their existing rights to TCCs any time before the Spring 2000 initial auction. However, it asserts that any such election would be irrevocable.

IPPNY believes the transitional auction should have multiple bidding rounds much like subsequent auctions. It contends that the problems cited by the Member Systems in single round auctions will materialize in the transitional auction.

The Member Systems reply that the transitional auction cannot have multiple rounds due to current software and resource limitations.

IPPNY, EPMI, and Sithe disagree with the Member Systems proposal to limit the amount of long term TCCs to no more than 35 percent of the available transmission capacity. They request that the Commission direct the ISO to choose the percentage of long term TCCs to be sold in the initial auctions.

With regard to the percentage of transmission capacity to be auctioned, the Member Systems respond that the Commission should reject the various intervenor requests for the following reasons: (1) the percentage only applies to the initial auction; (2) the percentage limits the consequences of "fire sales" which would adversely impact upon revenue that Member Systems would receive from the initial auction; (3) the percentage cap does not overly restrict the availability of long-term TCCs; and (4) in informal discussions with market participants, the main interest is in short-term TCCs. They state the need for the percentage ahead of time to compensate for the fact that the software needed to allow the market to determine the length of TCCs will not be ready by the Spring of 2000. [61]

The New York Commission agrees with the Member Systems that the percentages of transmission capacity to be auctioned in each round should be announced in advance to auction participants. New York Commission argues that failure to do so could depress auction prices.

1st Rochdale believes that there are many details about the TCC auction design that remain to be developed. It is concerned that feasible load flow analyses will not take into account changing resource patterns as markets develop. It claims that marketers must know the available transfer capability at key interfaces in order to know what transmission capacity is available.

1st Rochdale argues that revenues from TCCs should not be guaranteed in the event of a line derating or if a line goes down. It asks the Commission to order that Transmission Providers be responsible for capacity deratings, and to order an incentive compatible framework for transmission providers to avoid or respond promptly to line deratings and outages which can create congestion.

The Member Systems state that 1st Rochdale's concerns are unclear. They reiterate that TCC availability will be governed by a simultaneously feasible power flow. They further state that as the location of load changes within a load zone, the assumptions underlying the simultaneously feasible power flow will change to accommodate the load changes. Member Systems add that 1st Rochdale's concern regarding line derating is not timely or appropriate since this aspect of the tariff was approved by the Commission already.

Sithe asks for clarification as to whether TCC holders may reconfigure TCCs outside of the auction process as ordered by the Commission. Sithe argues that if reconfiguration is not allowed outside of the auction process, then the OATT is inferior to the *pro forma* tariff. [62]

The Member Systems state that Sithe's clarification about reconfiguration of TCCs outside of the auction process has been left to the ISO as directed in the January 27 Order.

Commission Response

We will grant the request for rehearing of the Member Systems and permit the ISO to announce in advance the percentage of TCCs to be awarded in each round. We are persuaded by the Member Systems and the New York Commission that announcing the percentage in advance will provide more information to market participants and encourage a more vibrant TCC market. We agree with the New York Commission that a discussion and evaluation of TCC auction procedures should be included in the first year review, and direct the ISO accordingly.

We accept the Member Systems' proposals for transition TCC auctions. We conclude that

[61,402]

the transitional features are reasonable in light of existing software limitations. We disagree with IPPNY that the first transitional auction must have multiple bidding rounds; as the Member Systems state, the necessary software will not be available in time to accommodate multiple bidding rounds for the first transitional auction.

We agree with the New York Commission that buyers and sellers of TCCs should be required to publicly report TCC transactions. Indeed, we required such reporting in our January 27 order. We agree with HQ that the Member Systems' compliance filing does not include such a reporting requirement. Therefore, we will direct the Member Systems to comply with this requirement.

In response to other New York Commission requests for clarification, we note that under the Member Systems' proposal as implemented in its compliance filing, revenues from TCC sales by transmission providers would be used to reduce the applicable TSC, and that any creditworthy entity, including a transmission provider, may bid for TCCs.

We are persuaded by the arguments of Sithe and Selkirk as to a one-time right to change their election, and we direct the Member Systems to permit grandfathered customers a one-time right to change their election of physical rights or TCCs after the first transitional TCC auction. This option will allow transmission customers with existing rights to gain market experience before making a permanent choice, while not hurting the operation of the TCC market. Moreover, all TCCs offered during the first transitional auction will expire in May 2000, while longer term TCCs (involving a longer commitment) will be auctioned later. In addition, the first transitional auction will have only a single round, so bidders will have less information about TCC prices than under the multi-round auctions held later.

We will deny the request of IPPNY and others that the ISO should be the entity to determine the percentage of long term TCCs to be sold in the second transitional auctions. We agree with the Member Systems that the percentage only applies to the initial auction and that the proposed percentage limits the consequences of "fire sales" of TCCs, which could adversely affect the revenue received by the transmission providers from the initial auction.

We will deny 1st Rochdale's request that revenues from TCCs not be guaranteed in the event of a line derating. As the Member Systems noted, the request is not timely since this aspect of the tariff was approved by the Commission in the January 27 order.

In response to Sithe's request for clarification regarding whether TCC holders may reconfigure TCCs outside of the auction process, we note that our January 27 order directed the ISO to explore a process where any party could request a reconfiguration of its TCCs. We also directed the ISO to include its findings and recommendations in the report due one year after its operations begin.

Market Based Rates

Requests for Rehearing

MEUA states that the Commission erred in approving market based rates without hearing, because there are disputed issues of material fact. [63] MEUA argues that the Member Systems' witnesses calculate that the wholesale markets in New York State would be highly concentrated, that the witnesses artificially reduce their calculated market shares by applying an inappropriate price test percentage, and that the Member Systems' proposal for congestion pricing will create multiple, small markets with market power. In addition, MEUA argues, market-based rates are premature because the Member Systems' Market Rate Plan would create many structural changes.

Commission Response

We will deny MEUA's request for rehearing. The January 27 order approved the application for market-based rates after thoroughly evaluating the Applicants' market power analyses, including their calculation of market shares. We concluded that most sellers in most markets would have market shares below 20 percent. While the analyses showed that a few sellers in some markets would have market shares above 20 percent, these analyses did not reflect the significant divestiture of generating assets that is underway in New York, nor the termination of Niagara Mohawk's purchases from independent power producers. We also noted other factors that would mitigate market power, such as the existence of generating capacity substantially in excess of ancillary service requirements.

D. *Other Issues*

LIPA

The Member Systems have requested assurances that LIPA's participation in the ISO would not adversely affect: (1) its use of publicly financed tax-exempt bonds; and (2) its non-jurisdictional status under Section 201(f) of the FPA. [64]

In its compliance filing, the Member Systems have proposed language in the OATT which

[61,403]

provides that LIPA will not be required to provide transmission service where the provision of such service would result in the loss of its tax-exempt status for its bonds. They have also proposed additional scheduling protocols and procedures to ensure their continued tax-exempt status in addition to revised tariff language to clearly recognize LIPA's non-jurisdictional status. Finally, the filing provides that if LIPA's tax-exempt status is jeopardized, LIPA will be able to withdraw from the ISO with 30 days notice.

We will accept the Member Systems' proposed language as described above. We note, however, that we cannot review LIPA's rates under the Section 205 just and reasonable standard, but will apply the comparability standard we use when evaluating non-jurisdictional, so-called "NJ" transmission tariffs to assure that the tariff rate is comparable to the rate LIPA charges itself and others. [65]

ISO Operating Manuals

In its request for rehearing, EPMI requests that the operating manuals be filed with the Commission along with the ISO's OATT, since these manuals directly affect the rates, terms, and conditions under which participants take transmission service, or participate in the ISO's markets.

Member Systems responds that manuals were not required to be filed with the Commission in PJM, but rather were required to be made available to the public. [66] The Member Systems state that the New York

ISO will make the manuals available to the public for inspection and will post draft and final manuals on its web site.

We are satisfied with the Member Systems' statements that the New York ISO will make the manuals available for public inspection and post the manuals on the internet.

Retail Access Tariff Provisions

In its request for rehearing, IPPNY states that the ISO may not be ready to accommodate retail access. Therefore, it requests that the retail access tariff provisions of the filing be filed within 90 days of the January 27 order.

We will not require any such action by the ISO. The ISO is proceeding in a reasonable manner and as quickly as possible in order to become operational and accommodate retail access in New York.

Market Administration Charge

The Member Systems have proposed a Market Administration Charge (MAC) in the ISO Services Tariff, which is designed to recover costs not recovered under the ISO OATT scheduling charge.

Sithe has questioned how the MAC will apply to sellers of services and how a rate that is developed using energy withdrawals as billing units will be applied to entities selling services to the ISO. Member Systems respond that market participants that sell services to the ISO will not pay the MAC; it states that the MAC will only be paid by those market participants taking service under the ISO Services Tariff in order to supply load in the NYCA and those purchasing from the LBMP markets to supply load outside the NYCA.

We are satisfied that the charges proposed by the MAC are reasonable and we will accept the MAC, as proposed by the Member Systems.

Transmission Bidding Report

In its request for rehearing, the Member Systems requested clarification as to which entity should submit the Transmission Bidding report. Member Systems note that Ordering Paragraph (L) in the January 27 order has the ISO submitting this report, but the body of the order has the Member Systems submitting this report. [67] We clarify that the ISO should submit this report.

NYPA Upgrades

The Member Systems ask that the Commission clarify that the costs associated with NYPA transmission upgrades will not be recovered solely under its TSC (which applies to only four NYPA customers directly connected to NYPA facilities), but rather primarily through the NYPA transmission adjustment charge (NTAC).

We agree with Member Systems' requested clarification. The TSC allows each transmission provider to recover their revenue requirement based on their system load. NYPA does not operate an integrated transmission system and its facilities are primarily used to serve load in the service areas of other transmission providers. In order for NYPA to recover its revenue requirement, Member Systems have proposed the separate NTAC charge that will be applied to the load of all ISO customers. Most of the costs associated with NYPA transmission facilities, including upgrades, will be recovered

[61,404]

through the NTAC. The NTAC allows NYPA to recover the cost of NYPA transmission facilities that are used to serve load located in service areas of other transmission providers.

Effective Dates

We approve the Member Systems' request for a first effective date of August 4, 1999, to permit the ISO to conduct the first TCC auction prior to the opening to the new market. [68] We accept the Tariffs and related New York ISO Agreements, with the modifications noted herein, to become effective on the day the ISO becomes operational. [69]

The Commission orders:

(A) The motion to intervene out-of-time by IEMO in Docket Nos. ER97-1523-000 , *et al.*, is hereby granted.

(B) The requests for rehearing and clarification are hereby granted in part and denied in part, as discussed in the body of this order.

(C) The Member Systems' compliance filing is hereby accepted, as modified, to become effective as discussed in the body of this order.

(D) The Member Systems are hereby directed to make a revised filing, with the modifications directed herein, within 30 days of the date of this order.

(E) The New York ISO is hereby directed to make a filing, as directed herein, with the Commission 30 days after the start of ISO operations.

(F) The Member Systems will be informed of rate schedule designations at a later date.

-- Footnotes --

[61,378]

Footnotes

1 *Central Hudson Gas & Electric Corp.*, *et al.*, 86 FERC ¶61,062 (1999).

2 The seven public utility Member Systems at the time of the original filing were Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (ConEd), Long Island Lighting Company (LILCO), 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 (Rochester G&E). Since the filing of Docket No. ER97-1523-000 , LILCO's transmission facilities were acquired by Long Island

[61,379]

Power Authority (LIPA) (which is not a public utility) and LIPA is now a party to the proceeding. *Long Island Lighting Company*, 82 FERC ¶61,129 (1998). The eighth Member System, the New York Power Authority, is not a public utility.

For ease of reading, however, we shall refer to all eight together as Member Systems or Transmission Providers.

3 *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888 , 61 *Fed. Reg.* 21,540, *FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996*¶31,036 (1996), *order on reh'g*, Order No. 888-A , 62 *Fed. Reg.* 12,274 (1997), *FERC Statutes and Regulations*¶31,048 (1997), *order on reh'g*, Order No. 888-B , 81 FERC ¶61,248 (1997), *order on reh'g*, Order No. 888-C , 82 FERC ¶61,046 (1998).

The June 30 order also conditionally approved certain proposed ISO procedures, such as the ISO Board and committee governance structure. However, the order directed the parties to negotiate and propose a revised committee voting structure. The order also deferred acceptance of the agreements filed by the Member Systems.

4 The request for market-based rate authorization was separately docketed as ER97-4234-000.

5 *Central Hudson Gas & Electric Co.*, 87 FERC ¶61,135 (1999) (April 30 order).

[61,380]

6 Ancillary service costs are recovered from parties taking service under the OATT.

7 These agreements include the ISO Agreement, the Agreement between the ISO and the Transmission Providers (ISO/TP Agreement), the New York State Reliability Counsel NYSRC) Agreement (ISO/NYSRC Agreement). Descriptions of these agreements can be found in our June 30 order.

We note that further revisions to these agreements may be necessary to reflect the final ISO governance procedures.

8 A subsequent request for an extension of time was granted by the Commission extending the date to file protests and interventions until June 11, 1999.

9 Selkirk, IPPNY, Coral Power, PECO Energy Co., the New York Commission and Constellation Power Source also filed to intervene in this proceeding. These parties have been admitted as intervenors previously in the underlying dockets to this proceeding. Therefore, we do not need to act here on their requests for intervention.

[61,381]

10 *See*18 C.F.R. §385.213 (a)(2) (1999).

11 On July 2, 1999, the Member Systems submitted a settlement on outstanding governance issues. We will not take action at this time on the ISO governance procedures as submitted in the April 30, 1999, compliance filing and instead defer these issues to a subsequent order in light of our April 30 order and the subsequent settlement filed by the Member Systems.

[61,383]

12 Member Systems response at 34 (Member Systems response).

13 Member Systems response at 16.

14 Member Systems response at 35.

[61,384]

15 *See* ISO OATT Section 19A.

[61,385]

16 Member Systems response at 4.

17 *See*86 FERC at p. 61,214 .

18 The exception is for real-time generations produced above the schedule without instruction from the ISO, for which the generator receives no payment.

[61,386]

19 NEMA protest at 5.

20 Member Systems response at 37-39.

21 For example, on July 22, 1998, the Commission accepted NEPOOL's compliance filing in which a penalty charge was established at a 200% level. *New England Power Pool*, 85 FERC ¶61,141 (1998).

[61,387]

22 These provisions are the same as in the previous filing that was the subject of the January 27 order.

23 Sithe protest at 22-23.

24 Sithe protest at 23-24.

25 Member Systems response at 76-77.

[61,388]

26 We note that we accept the Member Systems' description of grandfathered agreements and agree that we did not accurately describe the treatment of such agreements in our January 27 order.

[61,389]

27 The transmission provider may require the customer to maintain in effect, during the term of the service agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the tariff. Order No. 888-A at p. 30,514 (Section 11).

28 ISO OATT at 67.

29 IPPNY at 8.

30 Member Systems response at 42.

[61,390]

31 Member Systems response at 12.

[61,393]

32 Member Systems response at 59-60.

33 *Id.* at 27-28.

34 Status Report on Commencement of Operations by New York System Operator, Inc., July 7, 1999.

[61,394]

35 MEUA protest at 5.

36 *See*86 FERC at p. 61,223 .

37 *See*, *e.g.*, IPPNY at 7; Sithe at 13-15.

38 Member Systems response at 7-8.

39 *See* ISO Services Tariff at 55.

40 The BME assesses the bids submitted in the hour-ahead market and new bilateral schedules submitted hour-ahead in order to dispatch units in real-time. The dispatch minimizes the bid-production costs.

[61,395]

41 Generators not on SCD cannot respond to the ISO's computerized dispatch signals in real-time. These generators must be dispatched at a uniform level during the entire hour.

42 Coral/EPMI protest at 6. Some of the scheduling burdens cited by Coral/EPMI are the inability to reserve firm transmission service more than one day ahead and the 5:00 am deadline for the submission of bids and schedules for the day-ahead market.

43 MI protest at 16.

44 Member System response at 61-62.

[61,396]

45 Member Systems response at 9. Part of the bids submitted by generators includes technical information such as ramp rates and start-up times.

46 Member Systems request for rehearing at 10.

47 *Id.* at 11.

48 *See* Section 6.3 at 84 of the Service Tariff, and Attachment M at 301 of OATT.

49 PECO protest at 6-7.

50 We note that information on load forecasts and prices will be posted publicly on the ISO OASIS site.

[61,398]

51 For example, the ISO should evaluate whether there are reliability risks of overgeneration for generation located on the import side of a transmission constraint, and if not, whether the Member Systems' proposal is appropriate for such overgeneration. In addition, the Member Systems propose no penalty for uninstructed undergeneration.

52 The LBMP system creates market pricing incentives to signal sellers and buyers regarding their decisions in the day-ahead market as well as in real time. The Member Systems' proposal removes uninstructed overgeneration from the LBMP signal. Under the LBMP system, uninstructed overgeneration should lead to a lower LBMP which should be enough of an incentive to prevent uninstructed overgeneration.

[61,399]

53 ISO Services Tariff at 51-52.

54 ISO OATT, Attachment M at 296.

55 *See* OATT Section 3, Attachment M.

[61,400]

56 New York Commission at 8.

57 *Id.*

58 Member Systems response at 49.

59 *Id.* at 50-51.

60 *Id.* at 45.

[61,401]

61 *Id.* at 44-45.

62 Sithe protest at 29.

[61,402]

63 MEUA Request for Rehearing at 11-14.

64 16 U.S.C. §824 (1994).

[61,403]

65 *See New York Power Authority*, 82 FERC ¶61,078 (1998).

66 *See Pennsylvania-New Jersey-Maryland Interconnection*, 81 FERC ¶61,257, at p. 62,267 .

67 *See*, 86 FERC at p. 61,211 .

[61,404]

68 While this effective date contemplated that July 21, 1999 would be the cutoff date for grandfathered transmission contracts for the TCC auction, we note that this date may need modification if the ISO is unable to conduct the first TCC auction by August 4, 1999.

69 The Member Systems have requested this date to be September 1, 1999. We approve this date only if the New York ISO commences operation at that time.