D. MARKET MONITORING

D.1. Whether the ISO's role in market monitoring should be limited to data collection and monitoring only, but should not include an enforcement or police function? [Issue No. 631, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Enron and WPTF]

Proponents contend that the activities of the ISO's DMA[123] and Market Surveillance Committee ("MSC") should be limited to the gathering of information voluntarily provided by Market Participants[124] and the reporting of findings to the Commission. They contend that the ISO should have no role in the enforcement of rules against market abuse. *See* Joint Initial Brief on Issues D.1-D.4, at 4-5. Proponents offer three arguments in support of this contention: (1) that the Commission cannot delegate its enforcement authority to an entity such as the ISO; (2) that even if the Commission can delegate its authority, it must retain the authority to review enforcement actions, and it has not done so; and (3) that the ISO has failed to delete certain provisions from the ISO Tariff relating to enforcement as required by the Commission's orders. *See id.* at 7-11.

As an initial matter, the ISO notes that this issue is not ripe for decision. In its October 1997 Order, the Commission directed the ISO to file any proposed sanctions under Section 205 of the FPA (16 U.S.C. § 824d (1994)) prior to imposing such sanctions. October 1997 Order, 81 FERC at 61,553-54. The ISO has not, to date, made such a filing. As a result, the ISO has no authority to enforce rules against market abuse. Indeed, as discussed below in connection

123 The DMA was formerly known as the MSU – which is why the MMIP refers to it as the MSU. As discussed below in relation to Issue N.4, the ISO plans to modify its bylaws to reflect the name change.

124 Proponents' assertion that information gathering should be limited to information

with Issue D.2, the scope of the ISO response to incidents of market abuse is at this time limited to reports to the Commission and to identifying and proposing necessary market reforms. Regardless of whether the issue is ripe, however, Proponents' arguments are groundless.

Proponents' first argument rests on the flawed premise that the Commission has delegated its enforcement authority under the FPA to the ISO. It has done no such thing. Even when the ISO files, and gains approval of, sanctions to be imposed for market abuses, the Commission retains all of its statutory authority to enforce the terms of the FPA and the Commission's regulations. The Commission has not authorized the ISO to punish violations of the statutory or regulatory requirements, and the sanctions contemplated by the ISO Tariff would not do so. The Commission simply approved the provisions of the ISO Tariff that allow the ISO to enforce the *Tariff's* proscription of gaming and the exercise of market power in the markets that the ISO administers.

Indeed, the Commission has already responded on this subject to claims that permitting market administrators to impose sanctions constitutes an impermissible delegation of the Commission's authority. In the context of its order concerning RTOs, the Commission stated as follows: "We are not delegating our statutory authority and responsibility; however, we believe RTOs can help us understand and identify market problems. RTOs will be permitted to take actions only within specified parameters that are contained in a Commission-approved tariff." Order No. 2000-A, FERC Stats. and Regs., Regs. Preambles ¶ 31,092, at 31,380.

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voluntarily provided by Market Participants is discussed in connection with Issue D.4, below.

Even if the ISO's enforcement authority were a delegation of Commission authority, however, it would still be permissible. Proponents cite *R. H. Johnson & Co. v. SEC*, 198 F.2d 690 (2d Cir. 1952) in support of their second argument. *See* Joint Initial Brief on Issues D.1-D.4, at 9. The holding in *R. H. Johnson & Co.* was that, because the Securities and Exchange Commission retained the power to approve or disapprove rules of the National Association of Securities Dealers, the Securities Exchange Act of 1934 did not unconstitutionally delegate power to that association. Proponents contend that the MMIP contravenes this principle because it does not provide for Commission review of enforcement and sanctions decisions. They are wrong. First, as noted above, the Commission has made clear that the ISO may not impose sanctions until it has filed with the Commission the specific sanctions and the criteria for their imposition. Second, if the ISO imposes sanctions against an entity, that entity may contest the sanctions through the ISO's dispute resolution process as described in Section 13 of the ISO Tariff. The outcome of the dispute resolution process is subject to appeal to the Commission on the grounds that it violates law, the Commission's regulations, or the Commission-approved Tariff. *See* ISO Tariff, Section 13.4.1. Thus, the Commission retains in all instances ultimate decision-making power regarding sanctions for market abuse.

Proponents' final argument – that the ISO failed to comply with the Commission's October 1997 Order – fares no better. Proponents state that the Commission "did . . . strike down the provisions of the CAISO's tariff that allow its Governing Board or any unit within the CAISO to impose sanctions or take unilateral corrective action without first making the requisite section 205 filing."

Joint Initial Brief on Issues D.1-D.4, at 10-11. To the contrary, the Commission did not "strike down" any provisions of the Tariff. Rather, the Commission *approved* the concept of enforcement penalties, but directed the ISO to revise the Tariff to describe the penalties. *See* October 1997 Order, 81 FERC at 61,553-54. In other words, the Commission did not require that the ISO delete any provisions of the Tariff, but rather that it supplement them. Moreover, the Commission did not direct that those changes be included in the compliance filing to be made sixty days after commencement of operations (i.e., the June 1, 1998 Compliance filing); rather, the ordering paragraph cited by Proponents instructed the ISO to file the revisions regarding sanctions at least sixty days prior to the imposition of sanctions. *See* October 1997 Order, 81 FERC at 61,573; Joint Initial Brief on Issues D.1-D.4, at 10. Inasmuch as the ISO has imposed no market monitoring sanctions, it remains in compliance with the Commission's October 1997 Order.

Proponents also err in citing Tariff Sections 2.3.1, 2.3.2, 2.3.3, 2.3.4, 4.5.2, and 7.3 as provisions allowing the ISO to impose sanctions or penalties in a manner inconsistent with the October 1997 Order. *See* Joint Initial Brief on Issues D.1-D.4, at 11. As detailed below in connection with Issue D.2, these Tariff sections provide the ISO with no independent authority to impose sanctions.

In summary, nothing in the enforcement provisions of the MMIP constitutes an impermissible grant of authority to the ISO, and the ISO is in full compliance with the Commission's directives in this regard.

D.2. Does section 2 of the Market Monitoring and Information Protocol of the ISO Tariff ("MMIP") that allows the ISO to monitor the activities of Market Participants and take corrective and other action against what it believes to be "anomalous market behavior" provide the ISO with overbroad authority and deny market participants due process? [Issue No. 64, Docket Nos. EC96-19-008 and ER96-1663-009. Proponents - BPA, Dynegy, Enron, and WPTF]

Proponents assert that the market monitoring provisions of the ISO Tariff (1) violate the filed rate doctrine in that they fail to provide Market Participants with adequate notice of the conditions under which service is provided; and (2) violate the Commission's policy as expressed in *New York Independent System Operator, Inc., et al.*, 89 FERC ¶ 61,196 (1999), by failing to define improper market behavior clearly and narrowly. *See* Joint Initial Brief on Issues D.1-D.4, at 11-14. Proponents' arguments, however, are directed at straw men – types of authority that the ISO neither has nor claims. In reality, the ISO's market monitoring provisions authorize sanctions against Market Participants only for very specific conduct and are fully consistent with Commission policy.

Proponents assert that the MMIP provides the ISO with the authority to police "vaguely-defined, subjective behavior." Joint Initial Brief on Issues D.1-D.4, at 13. While the ISO believes that Sections 2.1.1.1 to 2.1.1.5 of the MMIP appropriately describe the behavior with which the DMA should be concerned, it is not necessary to review these provisions in detail because the basic premise of Proponents' argument – that the MMIP provides the ISO with authority to sanction Market Participants for such behavior – is flawed.

In the *New York Independent System Operator, Inc.* case which Proponents cite, the Commission rejected the authority of the New York ISO to impose, based on inadequately defined criteria, three specific sanctions on Market Participants: bid restrictions, an obligation to pay for Replacement Reserves, or a default bid. *New York Independent System Operator, Inc.*, 89 FERC at 61,602. The ISO, by contrast, has no comparable authority.

Proponents cite Sections 2.3.1, 2.3.2, 2.3.3, 2.3.4, 4.5.2, and 7.3 of the MMIP as the authority for the ISO to issue sanctions. *See* Joint Initial Brief on Issues D.1-D.4, at 11. None of these provisions actually refers to such authority.

Section 2.3.1 of the MMIP authorizes the DMA to investigate potential exercises of market power and to take action under Sections 4, 6, or 7 of the MMIP to institute corrective action. Section 4 of the MMIP allows the DMA to collect information and to *provide information and make recommendations* to the ISO, the ISO's CEO, the ISO Governing Board, regulatory agencies, and the MSC. There is no authority for sanctions other than for a failure to provide information. The propriety of this authority is discussed below in regard to Issue D.4. Section 6 of the MMIP provides the authority for the MSC to evaluate information and issue reports. There is no authority to issue or enforce sanctions. Section 7 of the MMIP authorizes the ISO Governing Board to modify procedures, recommend Tariff amendments, refer matters to regulatory authorities, and impose sanctions and penalties *that are permitted under the ISO Tariff approved by the Commission.* There is no independent authority to impose sanctions other than those specified elsewhere in the ISO Tariff.

Section 2.3.2 of the MMIP authorizes the DMA to fully investigate behavior, *make recommendations* on various matters to various entities, and publicize activities of Market Participants that may undermine the efficiency and competitiveness of the ISO Tariff. The propriety of the publication of information is discussed below in regard to Issue D.3. Section 2.3.2 of the MMIP authorizes no sanctions.

Section 2.3.3 of the MMIP authorizes the ISO to investigate gaming and to take actions with regard to necessary structural changes, Tariff amendments, or the proscription of specific behavior. It provides for arbitration proceedings regarding whether certain activities indicate evidence of gaming. Section 2.3.3 of the MMIP authorizes no sanctions.

Section 2.3.4 of the MMIP authorizes the MSU to *recommend* certain actions to the ISO's CEO or the MSC, who are in turn authorized to *recommend* those actions to the ISO Governing Board. The actions specified are all *market controls.* None involves sanctions against a specific entity.[125] More importantly, the actions are to be implemented if the ISO Governing Board approves them "*and when necessary obtains regulatory approval."* In other words, the ISO Governing Board can take no actions in response to the DMA recommendations for which it is not otherwise authorized by the ISO Tariff or law. Section 2.3.4 of the MMIP provides no independent authority to take action in response to market abuses.

Section 4.5.2 authorizes sanctions for a failure to provide information required by the DMA in its investigative capacity. These sanctions are thus for very specific behavior, and Market Participants have full notice regarding them. As previously noted, the propriety of this authority is discussed in connection with

[125] Proponents argue that Section 2.3.4 of the MMIP states that the actions are "not limited to" the specified list. *See* Joint Initial Brief on Issues D.1-D.4, at 6. Under the standard principle of interpretation *ejusdem generis*, however, the ISO's authority is limited to actions that are similarly market controls.

Issue D.4.

Also as noted above, Section 7.3 of the MMIP only authorizes sanctions that appear elsewhere in the ISO Tariff and that have been approved by the Commission. It provides no independent authority.

In summary, the argument of Proponents fails because its basic premise is flawed. The ISO's market monitoring procedures provide no authority for imposing sanctions on Market Participants for market abuses.

D.3. Does section 2.3.2 of the MMIP, which allows the ISO to publicize allegedly abusive activities or behavior of Scheduling Coordinators before a Commission finding of wrongdoing is reached, deny Scheduling Coordinators due process? [Issue No. 65, Docket Nos. EC96-19-008 and ER96-1663-009. Proponents - Enron and WPTF]

Perhaps in recognition of the fact that the constitutional guarantee of due process concerns only governmental actions,[126] Proponents do not argue that Section 2.3.2 of the MMIP violates due process. Rather, through contorted reasoning, they assert that it violates Commission policy. Proponents cite the Commission decision in *New York Independent System Operator, Inc.*, 89 FERC ¶ 61,196, as holding that the New York ISO is not required to publish every instance of market power and that the New York ISO should include, in confidential reports to the Commission, the names of any companies exercising market power. Proponents assert that the only way to give meaning to this decision is to conclude that the New York ISO is prohibited from publishing its findings concerning market abuse or gaming. *See* Joint Initial Brief on Issues D.1-D.4, at 14-16.

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[126] *See* Ronald D. Rotunda & John E. Nowak, Treatise on Constitutional Law § 17.2 (3d ed. 1999).

This interpretation, of course, requires one to believe that the Commission does not carefully distinguish between permitting certain actions and mandating them. Fortunately, in order to give meaning to the Commission's orders, one need not equate "not required" with "not allowed." By informing the New York ISO that it would not be required to publish every instance of market power, the Commission provided it with the authority to use its discretion to publish some instances of market power and keep others confidential. This decision is consistent with the plan submitted by the New York ISO, under which "all reports are submitted to the Board which *has the discretion* to take any steps necessary to protect confidentiality before general release." *New York Independent System Operator, Inc.*, 89 FERC at 61,602 (emphasis added). By further requiring that the New York ISO report instances of market abuse to the Commission in confidential reports, the Commission merely ensured that it would be informed of those instances that the New York ISO, *in its discretion*, kept confidential.

Moreover, Proponents' position lacks any policy justification. Proponents cite the damage that premature or inaccurate reports could inflict upon their business interests. Of course, they face similar exposure from public statements by any entity that suggests improper behavior. Proponents would be protected against such damage by the availability of civil remedies if the ISO were to intentionally or negligently defame it.[127] There is therefore no reason for the Commission to abandon its decision to permit the disclosure of instances of market power abuse or gaming.

[127] The ISO continues to believe that, in light of the public value of market monitoring activity, the appropriate standard is "willful misconduct." *See* ISO Initial Brief of the California Independent System Operator Corporation, Docket Nos. ER98-3760-000, *et al.* (Feb. 14, 2000), at 13-26; *New York Independent System Operator, Inc.*, 89 FERC at 61,604.

D.4. Are the informational demands contained in section 4.5 of the MMIP unjust and unreasonable? [Issue No. 66, Docket Nos. EC96-19-008 and ER96-1663-009. Proponents - Enron, WPTF, and Dynegy]

Relying heavily on the Commission's order in *New York Independent System Operator, Inc.*, 89 FERC ¶ 61,196, Proponents contend that the ISO's authority to collect market information for purposes of monitoring violates Commission policy because it is overly broad and mandates compliance. Joint Initial Brief on Issues D.1-D.4, at 16-17. Proponents are incorrect as to both contentions.

Proponents complain that Section 4.5.1 of the MMIP requires only that the information requested be potentially relevant to the inquiry. They contrast this requirement to the "List of Data" to be collected that the New York ISO filed with the Commission. *See id.*[128] Proponents neglect to note that in *New England Power Pool*, 85 FERC at 62,478, the Commission accepted the New England ISO's requirement that Market Participants provide it with "any information the ISO deems necessary to perform its obligations." Proponents also neglect to note that Section 4.1.2 of the MMIP requires that the ISO develop and refine "a detailed catalog of all the categories of data it will have the means of acquiring, and the procedures it will use (including procedures for handling confidential data) to handle such data." That list has been developed, and is published on the ISO Home Page.

Next, Proponents assert that the provision of information to the New York ISO is voluntary, and that the Commission "adopted a policy that is founded on

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[128] Contrary to Proponents' assertion, there is no indication that the Commission *required* that the "List of Data" be filed. Rather the Commission simply accepted the filing of the list. *New York Independent System Operator, Inc.*, 89 FERC at 61,603.

the essential proposition that the right to compel data from market participants is one that belongs only to the Commission itself." Joint Initial Brief on Issues D.1-D.4, at 17-18. Under the New York ISO Tariff, however, if a market participant refuses to provide information, the market participant and the New York ISO must attempt to negotiate compromises and confidentiality protections. If they are unable to do so, the issue will be subject to resolution through binding arbitration or judicial or regulatory proceedings. Proponents acknowledge this in a footnote, but fail to reconcile it with their assertion that only the Commission can enforce data collection requirements. *See* Joint Initial Brief on Issues D.1-D.4, at 17-18 & n.13.

Proponents correctly assert that under Section 4.5.2 of the MMIP, a failure to provide information can lead to sanctions. However, they neglect to point out that prior to the imposition of sanctions, the Market Participant must be provided an opportunity to respond in writing to explain the reason for the alleged failure. Second, they neglect to point out that, under Section 13 of the ISO Tariff, if the Market Participant wishes to contest the sanctions, it may institute dispute resolution proceedings. Under Section 13.2.1, these proceedings must begin with good faith negotiations to resolve this dispute. If the negotiations (and any mediation) fail, the Market Participant may demand arbitration under Section 13.3. If the Market Participant is dissatisfied with the results of the arbitration, it may appeal to the Commission under Section 13.4.1. In other words, (1) the ISO's procedures, in practice, are virtually indistinguishable from those of the New York ISO; and (2) the Commission retains the ultimate authority regarding the permissibility of information requirements.

Proponents have therefore failed to show that the ISO's information collection procedures violate Commission policy as set forth in the *New York Independent System Operator, Inc.* case or elsewhere. The Commission should approve the MMIP provisions without modification.

E. METERED SUBSYSTEMS

E.1. Has the ISO unreasonably delayed implementation of the Metered Subsystem concept and failed to fully and appropriately describe what an entity must do to operate as a metered subsystem, whether the ISO should establish specific target dates for implementation of the metered subsystem concept, or whether the Commission should remedy the ISO's failure to propose a workable Metered Subsystem, including providing for literal Self-Provision of Ancillary Services and the bidding and sale of Ancillary Services and Energy to the PX and ISO from a "System Unit."? Whether the definition of Existing Operating Agreement, in Appendix A to the ISO Tariff, should be modified to eliminate the requirement that the agreement must be entered into "prior to the ISO Operations Date." [Issue No. 2, Docket Nos. EC96-19-003 and ER96-1663-003 and EC96-19-029 and ER96-1663-030, Issue No. 71, Docket Nos. EC96-19-008 and ER96-1663-009, and Issue No. 377, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Numerous intervenors, including but not limited to, Turlock, SMUD, Pacific Gas & Electric Company ("PG&E"), and Los Angeles Department of Water and Power ("LADWP")]

As originally filed in the ISO/PX's Phase II filing in March 1997, the ISO Tariff included provisions under which an existing utility could qualify as a Metered Subsystem. The Metered Subsystem was envisioned as an alternative means for a vertically integrated utility system interconnected with the ISO Controlled Grid at a limited number of metered interfaces to continue to serve its customers and, at the same time, to participate in the ISO's markets.[129] This concept was not ready for implementation at start-up, however. Based on some parties' expressed interest in the Metered Subsystem concept, the Commission

[129] The ISO does not agree with contentions that the Metered Subsystem concept is necessary for such entities to participate in the ISO's Ancillary Services, Congestion Management, and Supplemental Energy markets. Any such contention is refuted by the fact that a number of publicly owned utilities in California are currently participating actively in those markets, even though the implementation of the Metered Subsystem concept has been delayed. The Metered Subsystem approach reflects only an alternative basis for participation by qualified entities which, for one reason or another, are not prepared to fully participate under the existing rules.

urged the ISO Governing Board "to consider this issue with a high priority." October 1997 Order, 81 FERC at 61,496.

Ever since the ISO commenced operations, it has endeavored, primarily through the Existing Rights Working Group, to develop the parameters of a Metered Subsystem concept that was acceptable to stakeholders and compatible with the ISO's protocols, market rules, and operating needs.[130] Those efforts have not been successful as yet. Recently, as part of the discussions concerning the development of a new methodology for the transmission Access Charge and mechanisms to encourage publicly owned utilities to place their transmission facilities and Entitlements under the ISO's Operational Control, Tariff language that would implement Metered Subsystems was finalized and included in the ISO's proposed Amendment No. 27, which was filed on March 31, 2000.

As Proponents concede, there has been progress on the Metered Subsystem issue (*see* Joint Initial Brief on Issue E.1, at 5); this is presumably why they have effectively abandoned the issue as framed above. A number of municipal utilities instead use their initial brief to criticize aspects of the Metered Subsystem components of the transmission Access Charge proposals and to criticize some of the existing ISO Tariff language on Metered Subsystems. Neither of these challenges is ripe for Commission review. These criticisms should be addressed in an intervention concerning Amendment No. 27.

First, this proceeding was established to enable parties to bring before the Commission issues relating to provisions of the ISO Tariff that took effect at the time of start-up or in one of the early Tariff amendments, and which the

[130] These efforts are described in the ISO's Initial Brief in the Unresolved Issues dockets at 29 n.20.

Commission did not address in its orders accepting those provisions or which the Commission addressed in rulings regarding which a party has filed a timely rehearing request. *See* April 1999 Order, 87 FERC ¶ 61,102. The criticisms of the Metered Subsystem aspects of certain transmission Access Charge proposals, however, are directed at provisions that are not currently part of the ISO Tariff and have just been reflected in a filing presented to the Commission on March 31, 2000. Amendment No. 27 provides a perfectly adequate forum for all parties to air any concerns regarding the Metered Subsystem provisions. No purpose would be served by the Commission's issuance here of what would amount to an advisory ruling on provisions pending in another docket.[131]

Second, the criticisms of the Metered Subsystems components of the transmission Access Charge proposals are not explained or developed in Proponents' initial brief. Indeed, they do not discuss any of the technical arrangements for Metered Subsystems reflected in the proposals, but instead focus on other aspects of the transmission Access Charge proposals (such as the allocation of certain ISO charges among all Market Participants and others relying on the ISO Controlled Grid).[132] They nevertheless attach to their initial brief a set of edits to the Metered Subsystem provisions of Amendment No. 27

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[131] *See, e.g., Transcontinental Gas Pipe Line Corp.*, 88 FERC ¶ 61,135, at 61,367-73 (1999) (Commission declined to issue clarification on issue that would arise, if at all, when new tariff filing is presented); *City of Tacoma, Washington*, 86 FERC ¶ 61,311, at 62,073 (1999) (issuance of advisory opinion would not be desirable or helpful and would not bind Commission in consideration of subsequent concrete proposal).

[132] Some of the proponents criticize the requirement in the transmission Access Charge proposals that an entity desiring Metered Subsystem status must become a Participating TO. Joint Initial Brief on Issue E.1, at 6. This provision is hardly remarkable in proposals that were developed to encourage entities to become Participating TOs. It is also consistent with the Commission's emphasis in Order No. 2000 on the development of mechanisms to encourage publicly owned utilities to participate in RTOs. *See, e.g.*, Order No. 2000, FERC Stats. and Regs, Regs. Preambles ¶ 31,089, at 31,024-25, 31,033-34.

that appear largely unrelated to anything discussed in the initial brief. Proponents' failure to support their proposed alternative provisions only underscores the inappropriateness of using this proceeding to address issues that are better resolved in the context of the ISO's Metered Subsystem proposal in Amendment No. 27.

Third, with respect to criticisms of current provisions in the ISO Tariff relating to Metered Subsystems, those provisions have never been implemented. *See Pacific Gas and Electric Co.*, 81 FERC at 62,475-77. The ISO's Metered Subsystem proposal reflects changes to the current Tariff provisions.[133] The review of Tariff provisions that the ISO has proposed to modify before they apply to a single entity is an unnecessary exercise. Again, the ISO's Metered Subsystem proposal has been submitted to the Commission, and parties are now able to present their views about the appropriate arrangements for the operation of Metered Subsystems in that proceeding. There is no need for the Commission to rule on poorly developed challenges to Tariff provisions that will only become operative when a new Participating TO executes a TCA.

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[133] For example, as LADWP notes, if the Metered Subsystem concept continues to rely on an "Existing Operating Agreement," the definition of such an agreement will have to be modified to reflect the fact that it was not in place as of the commencement of ISO operations. Joint Initial Brief on Issue E.1, at 11.

E.2. Is the amendment to section 2.5.24 of the ISO Tariff, that gives the ISO the ability to take direct control of the Metered Subsystem for any reliability reason even before it turns to other Ancillary Services bids, unreasonably broad in its scope of potential control, unjustly violative of Existing Conracts or unduly discriminatory as allowing the ISO to assume greater control over Metered Subsystems than any other type of Generating Unit, in contravention of section 5.1.3? [Issue Nos. 70 and 75, Docket Nos. EC96-19-008 and ER96-1663-009. Proponents - Turlock and SMUD]

SMUD and Turlock challenge portions of Section 2.5.24 of the ISO Tariff that give the ISO the authority, "if necessary to maintain ISO Controlled Grid reliability" or if the operator of a Metered Subsystem "does not conform with Good Utility Practice," to suspend Metered Subsystem control. This challenge, however, is not appropriately considered in the context of the present matter. As explained above in connection with Issue E.1, these provisions have never become operational and cannot become effective until an integrated Metered Subsystem proposal is accepted by the Commission. The appropriateness of this requirement can only be reviewed in connection with such filing, on the basis of a complete record, which does not exist in this proceeding.[134]

The provisions that SMUD and Turlock challenge, moreover, are appropriate mechanisms through which the ISO preserves its authority to operate the ISO Controlled Grid and to maintain the short-term reliability of the ISO Control Area. While the Metered Subsystem concept envisions the utility operating the Metered Subsystem as exercising first-line responsibility for operating its integrated facilities safely, in accordance with Good Utility Practice and in a manner that does not threaten the reliability of the ISO Controlled Grid,

[134] The untimeliness of this challenge is underscored by the fact that the provisions relating to the ISO's authority in these circumstances are modified substantially in the portions of Amendment No. 27 relating to Metered Subsystems, discussed in connection with Issue E.1, above.

the ISO retains ultimate authority as the Control Area operator and WSCC Security Coordinator. It must maintain the ability to take effective action if a Metered Subsystem operator fails to live up to these obligations. Preserving the ISO's ability to take appropriate action in these circumstances is consistent with its statutory obligations and the requirement under Order No. 2000 that an RTO have "exclusive authority for maintaining the short-term reliability of the grid that it operates."[135] These provisions ensure that the ISO preserves that authority, to be exercised in appropriately limited circumstances. SMUD and Turlock's concerns are unfounded and could jeopardize the reliability of the ISO's Control Area.

E.3. Whether the definition of Metered Subsystem, in Appendix A of the ISO Tariff, should be modified to eliminate the requirement that a Control Area operator operate its system in accordance with an Existing Contract? [Issue No. 2, Docket Nos. EC96-19-003 and ER96-1663-003, EC96-19-008 and ER96-1663-009, and EC96-19-029 and ER96-1663-030. Proponents - LADWP and Turlock]

LADWP and Turlock propose changes to the definition of a Metered Subsystem to delete the requirement that the Metered Subsystem rely on Existing Contracts. Joint Initial Brief on Issue E.3, at 4. Fundamentally, this issue is not ripe for a Commission ruling at this time. As explained above in relation to Issue E.1, the current Metered Subsystem provisions of the ISO Tariff have never become operational. The appropriateness of this requirement should only be reviewed in connection with the Metered Subsystem proposal that the ISO filed on March 31, 2000 as part of Amendment No. 27, on the basis of a complete record, which does not exist in this proceeding. Additionally, the ISO

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135 *See* Order No. 2000, FERC Stats. and Regs., Regs. Preambles ¶ 31,089, at 31,103.

notes that Amendment No. 27 proposes to delete the Existing Contract requirement.

E.4. Are the ISO's proposed amendments to section 2.5.20.3 of the ISO Tariff, which give the Metered Subsystem the ability to utilize a System Unit to participate in the procurement process of the ISO in relation to any Ancillary Service other than Regulation just and reasonable and not unduly discriminatory? Is the ISO's proposed amendments to the definition of Metered Subsystem, which eliminates the Metered Subsystem's right to bid Ancillary Services into the PX and Ancillary Services market just and reasonable and not unduly discriminatory? [Issue No. 248, Docket Nos. EC96-19-003 and ER96-1663-003, EC96-19-029 and ER96-1663-030, and EC96-19-035 and ER96-1663-036. Proponents - SMUD and Turlock]

SMUD and Turlock protest the alleged deletion from Section 2.5.20.3 of the ISO Tariff of reference to a Metered Subsystem's use of a "System Unit" to supply Ancillary Services. Joint Initial Brief on Issue E.4, at 2-3. The basis for this contention is unclear, since Section 2.5.20.3 currently includes the following sentence: "A MSS may utilize a System Unit to participate in the procurement processes of the ISO for Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve." ISO Tariff, Section 2.5.20.3. This language has been in Section 2.5.20.3 since start-up and SMUD and Turlock do not explain why it fails to satisfy their concerns.[136]

SMUD and Turlock also argue that Section 2.5.20.3 should be revised to specify that a System Unit can be used to provide Energy. Joint Initial Brief on Issue E.4, at 3. Section 2.5.20.3, however, is part of Section 2.5 of the ISO Tariff, which deals with Ancillary Services. With respect to the Dispatch of Ancillary Service capacity to supply Energy, no change is necessary, as the use

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[136] Some proponents raise what appears to be the same or a similar issue in connection with Issue E.1. *See* Joint Initial Brief on Issue E.1, at 8-9.

of a System Unit to supply Ancillary Services necessarily includes the supply of Energy from the Ancillary Service capacity accepted by the ISO. *See* ISO Tariff, Section 2.5.22.1. In any event, as discussed above in connection with Issue E.1, the provisions in Section 2.5.20.3 relating to the use of System Units by Metered Subsystems have never become operational and the ISO proposes to delete the provisions in Amendment No. 27. To the extent that SMUD and Turlock still have concerns about this provision as it may be modified in such filing, those concerns can be addressed in connection with that docket, on the basis of a complete record, which does not exist in this proceeding.

E.5. Should the ISO make Metered Subsystems available to Scheduling Coordinators and is its failure to do so while committing to provide incumbents with metered subsystems unduly discriminatory? [Issue No. 295, Docket Nos. EC96-19-003 and ER96-1663-003. Proponents - Enron and WPTF]

Enron and WPTF argue that all Scheduling Coordinators should be permitted to qualify as Metered Subsystems, regardless of whether the resources they seek to pool are located on a separate system and regardless of whether they operated vertically integrated utility systems in the past. Joint Initial Brief of WPTF and Enron on Issues A.6, B.5.f, E.5, L.1, and L.8, at 13-16. At the outset, this argument is premature. As explained above in connection with Issue E.1, the current Metered Subsystem provisions of the ISO Tariff have never become operational and cannot become effective until an integrated Metered Subsystem proposal is accepted by the commission. The appropriateness of the requirements a Scheduling Coordinator must satisfy to qualify as a Metered Subsystem should only be reviewed in connection with the Amendment No. 27

filing, on the basis of the proposal made in that filing and a complete record, which do not exist in this proceeding.

Moreover, these complaints really have nothing to do with the Metered Subsystem concept, but rather with Enron and WPTF's dissatisfaction with the structure of the ISO's markets. They want the ISO to accept bids for Ancillary Services and Supplemental Energy that do not specify the particular Generating Units or Loads that will supply the product. *Id.* at 15-16. The compatibility of such a "portfolio bidding" approach with the ISO's obligation as Control Area operator and WSCC Security Coordinator to verify the availability of the Ancillary Services it procures, and with its ability to maintain the short-term reliability of the ISO Controlled Grid, are complex questions that extend well beyond the proper design of Metered Subsystem provisions. The ISO explained in its Initial Brief in these proceedings why expansion of the Metered Subsystem concept to all Scheduling Coordinators, regardless of the technical arrangements of their resources, is inappropriate and inconsistent with the Commission's previous orders.[137] In particular, Enron and WPTF go too far when they assert that the Commission required the ISO to enable any Scheduling Coordinator to qualify as a Metered Subsystem operator. *See* Joint Initial Brief of WPTF and Enron on Issues A.6, B.5.f, E.5, L.1, and L.8, at 14. The Commission imposed no such requirement. Rather, it recognized that a Metered Subsystem operator must meet the ISO's technical requirements and that the implementation of those requirements is complex. October 1997 Order, 81 FERC at 61,496.

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[137] *See* Initial Brief of the California Independent System Operator Corporation, Docket Nos. ER98-3760-000, *et al.* (Feb. 14, 2000), at 30-31.

Further, a System Unit and Metered Subsystem, as defined in Amendment No. 27, do not provide WPTF and Enron with a vehicle to implement portfolio bidding. The proposed System Unit requires telemetry and communications to each individual Generating Unit or Participating Load. Additionally, the Generating Units and Loads constituting the System Unit must be in close physical proximity to each other such that the operation of the resources constituting the System Unit does not result in a significant difference in flows on the ISO Controlled Grid.

The ISO nevertheless has committed to study the feasibility of portfolio bidding and to discuss the results of that analysis with stakeholders as part of its consideration of market redesign proposals. That analysis will have to take into account the concern expressed by the Commission in Order No. 2000 that "a market design that favors large players (e.g., portfolio bidding) may create an incentive for consolidation and resulting market power problems."[138] At a minimum, consideration of the potential for portfolio bidding to exacerbate market power problems cautions against precipitous expansion of the Metered Subsystems concept as an improper means of implementing portfolio bidding.

[138] Order No. 2000, FERC Stats. and Regs., Regs. Preambles ¶ 31,089, at 31,218 (footnote omitted).

F. METERING

F.1. Is the language in ISO Tariff section 10.6.6.2 unduly restrictive because it grandfathers existing metering arrangements only for End Use meters? [Issue No. 473, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - Southern Cities]

As initially filed on March 31, 1997, the ISO Tariff language required metered entities (Section 10.2.4) and all End-Users (Section 10.6.4) to ensure that their meters are in conformance with Appendix J of the Tariff. Section 10.6.6.2 provided that all End-Use Meters in place as of the ISO Operations Date would be deemed to be certified. In the August 15, 1997 filing, the ISO separated metered entities into ISO Metered Entities ("ISOMEs") and Scheduling Coordinator Metered Entities ("SCMEs").[139] The ISO divided Article 10 of the ISO Tariff such that Sections 10.1 through 10.5 only applied to ISOMEs, and Section 10.6 only applied to SCMEs. However, Section 10.6 was the only section that explicitly grandfathered certification for End-Use Meters in place as of the ISO Operations Date. In the October 1997 Order, the Commission directed the ISO to amend Section 10.2.4 of the ISO Tariff to be consistent with PG&E's suggestion that End-Use Meters of ISOMEs should be grandfathered as well. October 1997 Order, 81 FERC at 61,516. The ISO made this revision in its June 1, 1998 Compliance filing.

Southern Cities contends that the language included in the June 1, 1998 Compliance filing is unduly limited. Initial Brief of Southern Cities on Issues F.1,

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[139] An ISOME includes any entity directly connected to the ISO Controlled Grid, including an End-User (other than an End-User that purchases all of its Energy from the UDC in whose Service Area it is located). Each ISOME is required to provide Meter Data by direct interface between the ISO's Meter Data acquisition and processing system and the ISOME's ISO-certified revenue quality meter or compatible meter data server. For ISOMEs, the ISO is responsible for the validation, editing, and estimation of the Meter Data in order to produce Settlement Quality Meter Data. In contrast, for SCMEs it is the responsibility of the Scheduling Coordinator to validate, edit, and estimate the Meter Data and provide the Settlement Quality Metered Data to the ISO. The Scheduling Coordinator must ensure that the metered entities it represents adhere to the requirements and standards for metering facilities set by the Local Regulatory Authority or, in the event that the Local Regulatory Authority has no such requirements, to the requirements of the ISO.

K.2, N.1.a, and N.1.b, at 7. Southern Cities argues that the ISO has not identified "any legitimate reason for excluding the metering arrangements for wholesale customers from the grandfathering provision" and that the "grandfathering provision should apply to all metering arrangements that were in place and considered adequate as of the ISO Operations Date." *Id.* As an alternative, Southern Cities proposes to add language to Section 10.6.6.2 of the ISO Tariff stating that "[p]rior to directing the addition of meters and metering system components where metering arrangements are not deemed certified, the ISO shall give due consideration to whether the expected benefits of such equipment are sufficient to justify the costs of such equipment." *Id.* at 7-8.

The ISO believes that the June 1, 1998 Compliance filing properly limited grandfathering only to the meters of End-Use Customers and that Southern Cities failed to preserve this issue by seeking rehearing of this determination. Given the ISO's market administration responsibilities as well as its role as the Control Area operator, it is reasonable for the ISO to require uniform, non-discriminatory data acquisition processes. The ISO metering standards are reasonable. Moreover, if compliance with those standards presents an undue hardship to a particular Market Participant, that entity is free to seek an exemption from compliance. Furthermore, the ISO notes its understanding that the current metering arrangements of Southern Cities are in compliance with the ISO's requirements.

In the October 1997 Order, the Commission noted that Turlock (not Southern Cities) contended that Section 10 of the ISO Tariff gave the ISO unnecessary authority over metering facilities and data acquisition and that "historical operation of the utilities should be respected." October 1997 Order, 81 FERC at 61,514. In response, the Commission stated that it "reject[s] Turlock's recommendations. Under the new model, the ISO will not only operate as the control area operator, but it must also perform billing and settlement functions." *Id.* at 61,516. No rehearing was filed with respect to the determination in the October 1997 Order that only the meters of End-Use Customers should be grandfathered.

Contrary to Southern Cities' assertions, there are "legitimate" reasons for not extending the grandfathering described above to wholesale meters. As Ms. Deborah A. Le Vine, the ISO's Director of Contracts & Compliance, testified in Docket No. ER98-1499-000:

> The ISO believes that metering requirements should be applied, to the extent feasible, in a uniform, non-discriminatory manner. . . . Such an approach facilitates the automation of the ISO's settlement and billing process. Automation of the meter data prevents shifting of administrative costs to participants that comply with the ISO's metering requirements from those facilities that do not. If the unit does not supply settlement quality data to the ISO or allow for direct polling in accordance with the ISO's metering standards, it causes the ISO to perform manual "work arounds" which are time consuming and resource intensive.[140]

As Ms. Le Vine further explained:

> Currently, the ISO processes almost 600,000 settlement line items per month for approximately 20 million MWH per month of transactions with gross billings of between $200 to $650 million. The ISO has been working to automate settlement entries, including metering, and the validation process. Given the volume and complexity of the transactions and the need to ensure timely and accurate settlements, the ISO must require uniform standards for gathering and reporting of metering data.[141]

In that same proceeding, Mr. Mark Morosky, the ISO's Manager of Metering and Meter Data Acquisition System ("MDAS") Operations, noted with respect to the costs of compliance with the ISO's metering requirements that: (1) the ISO certified meter costs approximately $2,500; (2) installation costs will

[140] Prepared Supplemental Direct Testimony of Deborah A. Le Vine on Behalf of the California Independent System Operator Corporation, Docket Nos. ER98-1499-000, *et al.* (filed Feb. 26, 1999), at 4.

[141] *Id.* at 9.

vary for different facilities;[142] (3) independent third-party inspection by a certified ISO metering inspector should cost approximately $1,000; and (4) ISO communications circuit and networking equipment lease costs are approximately $240 per month.[143] These latter costs are likely to decrease as the ISO develops secure techniques to poll the meters over the Internet.[144]

Section 13 of the MP outlines a process by which applicants can request and the ISO will consider requests for either temporary or permanent exemptions from the ISO's metering requirements where compliance with the requirements would be unnecessary, impractical, or uneconomic. In evaluating whether or not to grant an exemption, the ISO considers such factors as: (1) does the exemption request compromise the accuracy and integrity of the meter data or system; (2) does the exemption affect the speed or integrity of the communication system; (3) are the ISO requirements unnecessary, impractical, or uneconomic for the ISO Metered Entity; and (4) whether the request is for a temporary or a permanent exemption.[145]

Section 13.3 of the MP requires that the ISO confirm receipt of an application for an exemption within three Business Days and decide whether or not to grant the exemption within forty-five Business Days (unless the ISO makes a request for additional data more than forty days after the application, in which case the ISO must render a decision seven days after receiving the data). The

[142] Factors may include the configuration of the unit and whether or not the Generator can undertake the work itself. For facilities that rely on internal engineering resources for the electrical work and to prepare the design documents and schematics, the costs for installation and configurations can be limited to the cost of existing engineering staff time. If a Generator relies solely on engineering consultants, the cost may be higher, depending on the specifics of the contract. The ISO will assist in providing technical support, further decreasing installation costs.

[143] Prepared Direct Testimony of Mark Morosky on Behalf of the California Independent System Operator Corporation, Docket Nos. ER98-1499-000, *et al.* (filed Feb. 19, 1999), at 7-8.

[144] *Id.* at 8.

[145] *Id.* at 10-11.

ISO has generally taken far less than the forty-five days to act on these applications.[146]

There is a distinction between the number of potential meter upgrades that would be required for wholesale customers such as Southern Cities and the number that would be required for each and every End-Use Customer in California. The ISO metering requirements should not present an undue hardship for wholesale customers such as Southern Cities. However, if the burden of compliance is unreasonable, Southern Cities may seek an exemption.

Furthermore, the ISO believes that the current metering configurations for each of the cities that together constitute Southern Cities are satisfactory and that there are appropriate meters and metering procedures in place on each line from SCE to Southern Cities. Accordingly, Southern Cities' issue may be moot.

F.2. <u>Should section 10.2.2 and section 5.1.1 of the Metering Protocol ("MP") be modified so that the ISO would not be permitted to impose additional metering requirements except to the extent such additional facilities are necessary to permit the ISO to fulfill obligations with respect to the ISO Controlled Grid. [Issue Nos. 40 and 53, Docket Nos. EC96-19-008 and ER96-1663-009. Proponents - Southern Cities and CAC]</u>

Unresolved Issues Nos. 40 and 53 were raised by Southern Cities in comments in Docket Nos. EC96-19-006 and ER96-1663-007 in November 1997. Pursuant to the Commission's September 11, 1998 Order in Docket No. ER98-3760-000, *California Independent System Operator Corporation*, 84 FERC at 62,048, Southern Cities identified these issues as remaining in dispute.[147] As reflected in Attachment C to the Report on Outstanding Issues filed in this matter on March 11, 1999, Southern Cities and

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[146] *Id.* at 11.

[147] See the Report on Outstanding Issues filed in the Unresolved Issues dockets on March 11, 1999, at Appendix B.

the ISO reached a proposed settlement based on the following changes to the ISO Tariff:

- Changes to Section 10.2.2 of the ISO Tariff as follows: The ISO may require ISO Metered Entities to install, at their cost, additional meters and relevant metering system components, including real-time metering, at ISO specified Meter Points or other locations as deemed necessary by the ISO, in addition to those connected to or existing on the ISO Controlled Grid at the ISO Operations Date, including requiring the metering of transmission interfaces connecting Zones. <u>In directing the addition of meters and metering system components that would impose increased costs on an ISO Metered Entity, the ISO shall give due consideration to whether the expected benefits of such equipment are sufficient to justify such increased costs.</u> ISO Metered Entities, at their cost, shall install and maintain, or cause to be installed and maintained, metering equipment and associated communication devices at ISO designated Meter Points to meet the requirements of this Section 10 and the ISO metering protocols. Nothing in this Section 10 shall preclude ISO Metered Entities from installing additional meters, instrument transformers and associated communications facilities at their own cost.

- Changes to Section 5.1.1 of the Metering Protocol of the ISO Tariff as follows: The ISO has authority under Section 10.2.2 the ISO Tariff to require an ISO Metered Entity to install Metering Facilities in addition to those Metering Facilities on the ISO Controlled Grid at the ISO Operations Date. <u>In directing the addition of meters and metering system components that would impose increased costs on an ISO Metered Entity, the ISO shall give due consideration to whether the expected benefits of such equipment are sufficient to justify such increased costs.</u> An ISO Metered Entity may not commence installing those additional Metering Facilities until the ISO has approved its Proposal for Installation.

Southern Cities continues to “consider the addition of the foregoing language to MP 5.1.1 and ISO Tariff § 10.2.2 to provide an acceptable resolution of this issue.” Joint Initial Brief of EPUC/CAC and Southern Cities on Issue F.2, at 9. While the ISO believes that these Tariff provisions are just and reasonable as filed and that no additional changes are necessary, the ISO continues to support the compromise reached with Southern Cities. However, the additional changes requested by EPUC/CAC are unwarranted.

First, as noted above with respect to Issue A.3.a, the ISO believes that EPUC/CAC lacks standing to pursue this issue. EPUC/CAC was accorded the same opportunity as the other participants to identify specific issues to be included in the matrix that would serve as the basis for further proceedings in this case and declined to do so. EPUC/CAC also failed to file an intervention and protest in response to either the ISO's June 1, 1998 Compliance filing (in which the ISO's protocols, including the MP, were filed) or July 15, 1998 Clarification filing. In its April 1999 Order, the Commission found that where EPUC/CAC had failed to intervene or protest in prior proceedings it would not require the ISO to recategorize issues that had been withdrawn. April 1999 Order, 87 FERC at 61,423. The same rationale should apply to issues that have been settled when EPUC/CAC does not contend that it is being prejudiced by the revised language but instead seeks to expand the scope of the original issue. Accordingly, the Commission should accept the revisions agreed to by Southern Cities and the ISO and reject EPUC/CAC's belated attempt to seek additional changes.

Second, even if it has standing to raise its "additional concerns," EPUC/CAC's contention that "[i]f the ISO Controlled Grid is deemed to extend beyond the point of interconnection of a Qualifying Facility (QF) operation with the ISO transmission system, *i.e.*, to some point 'behind the meter' there is a problem" (Joint Initial Brief of EPUC/CAC and Southern Cities on Issue F.2, at 3) repeats an argument that has been rejected by the Commission. EPUC/CAC's assertion that the ISO's right to monitor Generating Unit performance should not extend beyond the interconnection point between the Generating Unit and the ISO Controlled Grid was explicitly rejected by the Commission in the October 1997 Order:

> We find that the restrictions proposed by EPUC/CAC to be inappropriate and unworkable. Restricting the right to monitor to the point of interconnection will severely restrict the acquisition of

> any meaningful information on generation performance particularly with respect to ancillary services.

October 1997 Order, 81 FERC at 61,514. EPUC/CAC never sought rehearing of this determination and should not be able to reargue this issue.[148]

The Commission's conclusion that the ISO must have data regarding Generating Unit operations beyond the point of interconnection is well-founded. To carry out its responsibilities as the Control Area operator to prevent and respond to emergencies, the ISO must have information regarding the current status of Generating Units. Telemetry of metering data enables the ISO Operators to know in real time whether or not units are on-line and whether they are fully loaded, only partially loaded, or unloaded. This information is of critical importance in order to control power levels in specific locations and in specific situations.

Take for example the situation of a facility with three 80 MW Generating Units having auxiliary system requirements of 10 MW. Assume further that this facility directly serves 20 MW of End-Use Customer Load and is self-providing Ancillary Services. If the only data received by the ISO is from a meter at the point of interconnection, the ISO lacks sufficient information to verify the Generator's ability to supply its Ancillary Service bids and to meet its Control Area responsibilities. For example, if the meter at the interconnection point reads 50 MW any of a variety of situations may be occurring, such as:

- One of the units may be operating, serving End-Use Customer Load of 20 MW, and have no excess ability to bid into the ISO's markets or provide increased output in an emergency.
- One of the units may be operating, serving End-Use Customer Load of 10 MW, with the ability to bid additional MW into the ISO Markets or provide increased output in an emergency.

[148] The Commission has a long-standing policy against the relitigation of issues. *See Alamito Company*, 41 FERC ¶ 61,312, at 61,829 (1987), *reconsideration denied*, 43 FERC ¶ 61,274 (1988). *See also Central Kansas Power Company, Inc.*, 5 FERC ¶ 61,291, at 61,621 (1978).

- Two of the units may be operating.
- Three of the units may be operating.

There are numerous other combinations of units and Loads that can be hypothesized. This underscores the fact that it is necessary and appropriate for the Control Area operator to have data on the operating status of Generating Units within the ISO Control Area.

Third, EPUC/CAC argues that "vague provisions" of the ISO Tariff "could allow the ISO's inappropriate and unlawful extension of its authority to order metering or any other obligation upon either the generator or the load comprising QF operation." Joint Initial Brief of EPUC/CAC and Southern Cities on Issue F.2, at 3. They maintain that "[n]ot only is there an imposition of costs for the metering obligations, but there is an impact upon the possible operation of the QF facility to meet its operating obligations to its host." *Id.* at 8. Unexplained is the causal connection as to how the provision of meter data will adversely affect operations. In its discussion above concerning Issue B.5.b, the ISO explained how Generators including QFs are protected under the ISO Tariff with respect to the ISO's Dispatch authority.

The reality is that EPUC/CAC is concerned that the meter data needed by the ISO for system operation will at some point in the future be used to allocate additional costs such as the GMC. As provided for by a currently effective GMC settlement, the GMC is charged to all Scheduling Coordinators in proportion to their metered Demand and exports, with three exceptions:

(1) 50% of the volumes flowing over the ISO Controlled Grid pursuant to Existing Contracts are excluded;

(2) "Qualified Loads" are excluded; and

(3) volumes located within the Service Areas of municipal and governmental utilities in the ISO Control Area, served by

> Generation located within that same utility's Service Area, are excluded.[149]

Qualified Loads are Loads served by QF Energy that is generated on or distributed by the QF generator through private property or over dedicated distribution facilities solely for the QF's own use, the use of its tenants, or the use of up to two other corporations located on adjacent property. ISO Tariff, Appendix F, Schedule 1. The basis upon which the GMC is assessed may change, of course, depending on the outcome of the filing that the ISO is required to make to become effective on January 1, 2001. *See California Independent System Operator Corporation*, 87 FERC ¶ 61,304. EPUC/CAC is simply trying to limit its members' potential exposure to these costs by eliminating the database which would be used in determining the GMC assessment. The Commission, however, has deemed it prudent to defer consideration of GMC allocation issues until the ISO completes further unbundling studies: "In view of the fact that the ISO still has neither the computer capability nor the data to make its unbundling proposal at this time, we continue to believe that it would not make sense to establish a hearing until the ISO has produced an unbundling study." *California Independent System Operator Corporation*, 87 FERC at 62,230.

Fourth, EPUC/CAC improperly claims that these metering issues are being addressed in Docket Nos. ER98-997-000 and ER98-1309-000, concerning the QF PGA. Joint Initial Brief of EPUC/CAC and Southern Cities on Issue F.2, at 3. EPUC/CAC states that Sections 5.1.1 and 10.2.2 of the ISO Tariff "can be

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149 The Commission accepted the GMC settlement in Docket Nos. ER98-211-000*, et al. California Independent System Operator Corporation*, 83 FERC ¶ 61,247 (1998). As originally filed, the settlement anticipated that the ISO would file a new GMC methodology by December 31, 1998. In October 1998, the ISO filed for a six-month extension of the settlement formula. The Commission accepted this proposal, subject to refund. *California Independent System Operator Corporation*, 85 FERC ¶ 61,433 (1998), *order on reh'g*, 87 FERC ¶ 61,023 (1999). On April 30, 1999, the ISO filed Amendment No. 16 to the ISO Tariff requesting a further extension of the current GMC methodology through December 31, 2000. The Commission has accepted Amendment No. 16, subject to the Commission's determination on the ISO's GMC filing to become effective on January 1, 2001. *California Independent System Operator Corporation*, 87 FERC ¶ 61,304 (1999).

read to require metering of load or generation behind the point of [the] interconnection meter" and that "[t]his is in fact what the ISO is urging in the QF PGA proceeding." *Id.* at 8. These contentions are incorrect.

Attachment 2 contains the testimony of CAC that has been filed in the QF PGA case. This testimony contains no discussion of metering. To the contrary, the only issues identified by CAC in its testimony are: (1) only the cogenerator's output which is available to fully participate in the market like a merchant plant, should be subjected to the ISO Tariff and protocols; (2) the cogenerator must be allowed greater flexibility in the scheduling of outages; (3) the ISO should not be permitted, by amending its Tariff and protocols, to unilaterally amend the PGA negotiated with a cogenerator; and (4) the cogenerator should be allowed to terminate its PGA without Commission approval.[150]

As discussed above with respect to Issue B.5.a, the PGA covers such matters as certification requirements and data collection requirements relating to major incidents, including System Emergencies that affect System Reliability. The PGA also includes an acknowledgment that the reliability of the ISO Controlled Grid depends on the Participating Generator's compliance with the ISO Tariff. Accordingly, it is an agreement that addresses both a Generating Unit's participation in the ISO's markets and its role in the ISO's operation of the ISO Control Area in a safe and reliable manner in accordance with Good Utility Practice and applicable standards for Control Area operation. The PGA does not set forth the ISO's metering requirements.

Moreover, EPUC/CAC fails to mention the *pro forma* Meter Service Agreements for ISO Metered Entities and Scheduling Coordinators that were recently accepted by the Commission as part of an uncontested Offer of

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[150] *See* Prepared Direct Testimony of James A. Ross on Behalf of the Cogeneration Association of California, Docket Nos. ER98-992-000, *et al.* (filed Oct. 20, 1998), at 2. Docket Nos. 98-997-000 and ER98-1309-000 were later severed from the primary PGA docket.

Settlement. *California Independent System Operator Corporation*, 90 FERC ¶ 61,186 (2000). Pursuant to Section 3.1 of each of the Meter Service Agreements, "[t]he parties agree they will comply with the provisions of Section 10 of the Tariff and the Metering Protocol of the ISO Tariff." The Offer of Settlement preserves the right of the owner of an individual project to make a filing pursuant to Section 206 of the FPA to argue that the ISO's metering requirements are unjust and unreasonable as applied to that CAC project or any other specific Generating project only in the event that: (1) the costs exceed a certain threshold, (2) the ISO and the project owner cannot agree on what actions can be taken to reduce the costs of compliance, and (3) the ISO does not grant the project an exemption from the metering requirements in accordance with the procedures in the ISO Tariff.[151]

Fifth, EPUC/CAC repeats its arguments regarding ISO jurisdiction and QF independence. *See* initial briefs concerning Issues A.3.a, A.3.c, B.3.c, B.5.b, B.5.c, B.5.i, and B.5.j. With regard to EPUC/CAC's misplaced assertion that "the ISO is seeking to impose requirements as though QF load is part of its Control Area and part of its Firm Load Obligations," this issue is discussed in relation to Issue O.3, below. In one sentence, EPUC/CAC states that "loads served by QF generation are not loads placed on the ISO Controlled Grid or the electrical system." Joint Initial Brief of EPUC/CAC and Southern Cities on Issue F.2, at 7. Two sentences later, EPUC/CAC recognizes that "[i]f the load requires standby service in the event of a generator outage, standby service is secured from a supplier, typically the local distribution company utility . . . ." *Id.* at 7-8. EPUC/CAC fails to note that in this latter instance, the UDC is providing the backup supply utilizing the ISO Controlled Grid, and the Regulation procured by

[151] Offer of Settlement, Sections 1.7.2 and 1.7.3. A copy of the Offer of Settlement is provided as Attachment 10.

the ISO to fulfill its obligations as Control Area operator, for the benefit of the Load typically served by the QF generation.

EPUC/CAC offers no basis to modify Section 10.2.2 of the ISO Tariff and Section 5.1.1 of the MP beyond the revisions agreed to by Southern Cities and the ISO. EPUC/CAC's focus in its initial brief on operations behind the meter is misplaced. EPUC/CAC seeks the benefits of ISO participation – selling power into the ISO's markets, scheduling deliveries over the ISO Controlled Grid, and obtaining the reliability benefits of the ISO's Control Area operations – without providing necessary data to the ISO and without contributing to the ISO's costs. The Commission has previously recognized that the restrictions proposed by EPUC/CAC are "inappropriate and unworkable." October 1997 Order, 81 FERC at 61,514. EPUC/CAC has provided no basis for questioning this conclusion.

F.3. Whether the Metering Protocol should describe the powers and authority of the ISO in the event of a party's failure to comply with the ISO's audit or test procedures in order to consistently define the authority of the ISO? [Issue No. 140, Docket Nos. EC96-19-006, EC96-19-007, EC96-19-008, ER96-1663-007, ER96-1663-007, and ER96-1663-009. Proponent - TANC]

TANC contends that the MP improperly fails to include the remedies available to the ISO in the event that an entity fails to comply with the ISO audit and test requirements, and that the ISO's practice of including remedies in the individual metering agreements effectively denies Market Participants the ability to monitor the ISO's practices. Initial Brief of TANC on Issue F.3, at 2 and 13-14. TANC worries that such agreements are numerous and subject to change. *Id.* at 14.

The ISO does not oppose TANC's proposal that penalties and sanctions associated with failure to comply with ISO audit and test requirements should be delineated in the ISO Tariff. Both the ISO's *pro forma* Meter Service Agreement for Scheduling Coordinators and the *pro forma* Meter Service Agreement for ISO

Metered Entities note that they are subject to the ISO Tariff.[152] To date, the ISO has not developed penalties and sanctions for failure to comply with an audit or test requirement pertaining to metering equipment.

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[152] *See* Section 3.1 of both the Meter Service Agreement for Scheduling Coordinators and the Meter Service Agreement for ISO Metered Entities. The settlement agreement containing these two agreements was accepted by letter order dated February 24, 2000, 90 FERC ¶ 61,186.

G. <u>OUTAGES</u>

G.1. <u>Whether sections 2.3.1.1.4, 2.3.3.1, and 2.3.3.5 of the ISO Tariff are reasonable? [Issue No. 409, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - PG&E and CAC]</u>

This issue has been withdrawn. Joint Initial Brief of PG&E and SDG&E on Unresolved Issues, at 2.

G.2. <u>Should the ISO's reasons for rejecting a requested Maintenance Outage or requested change to an Approved Maintenance Outage provided pursuant to section 2.3.3.5.3 of the ISO Tariff be provided for information purposes only, or should affected parties be permitted to challenge the ISO's determination after-the-fact in order to provide guidance for future determinations involving similar conditions, and does the ISO's amendment to section 2.3.3.5.3 fail to properly implement the directive from the Commission's October 30, 1997 Order? [Issue No. 446, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - TANC and Southern Cities]</u>

Proponents' criticisms regarding the ISO's proposed modification to Section 2.3.3.5.3 of the ISO Tariff, as filed in the June 1, 1998 Compliance filing, are unfounded. The ISO's proposed modification to Section 2.3.3.5.3 comports with the Commission's directive and intent by providing that an Operator may request after-the-fact explanation of ISO instructions; and by clarifying that such a request is for informational purposes and, as the Commission stated, does not undermine the ISO's authority. *See* October 1997 Order, 81 FERC at 61,512. Nothing in the ISO's filed language can be construed to limit "the flow of useful information between Operators." *See id.* Thus, contrary to Proponents' assertions (*see* Joint Initial Brief on Issue G.2, at 4), Section 2.3.3.5.3 is entirely consistent with the October 1997 Order. The ISO is and always has been willing to consider whether, on a prospective basis, it needs to change the policies and circumstances under which it cancels or reschedules a planned transmission maintenance outage. Further, nothing in the proposed Tariff language prevents an entity that questions the validity of an ISO order from pursuing available remedies under the ISO Tariff or before the Commission.

G.3. Should section 2.3.3.6.1 of the ISO Tariff be modified to establish a time frame within which the Operator must provide written justification for refusing a request for a Maintenance Outage. Issue No. 519, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - CAC]

In its comments on the Offer of Settlement filed in this proceeding on December 1, 1999, MWD noted that it had achieved a negotiated resolution of Unresolved Issue No. 519, but that another party "desires to litigate the issue."[153] MWD stated that "based upon its understanding that the ISO remains willing to honor its settlement offer, [MWD] will not address such issues in its Initial Brief."[154] EPUC/CAC, the party that desired to litigate the issue, has withdrawn its advocacy. Joint Initial Brief on Issue G.3, at 1.

The negotiated resolution of Unresolved Issue No. 519 was to be in accordance with the following proposed settlement terms:

> Changes to Section 2.3.3.6.1 of the ISO Tariff as follows: The Operator may: (1) refuse the request; (2) agree to the request; or (3) agree to the request subject to specific conditions. The Operator, acting in accordance with Good Utility Practice, shall make every effort to comply with requests by the ISO Outage Coordination Office. In the event that the Operator refuses the ISO's request, it shall provide to the ISO Outage Coordination Office: oral notice by no later than the end of the next business day and ~~it shall provide~~ written justification for its position within five (5) business days ~~to the ISO Outage Coordination Office~~.

The ISO remains willing to settle the issue in accordance with these previously proposed terms.

[153] Comments of The Metropolitan Water District of Southern California on the Offer of Settlement of the California Independent System Operator Corporation, Docket Nos. ER98-3760-000, *et al.* (Dec. 21, 1999), at 4.

[154] *Id.*

H. PORTFOLIO BIDDING

Does the ISO's prohibition of portfolio bidding for inter-zonal access, Ancillary Services, and Supplemental Energy discriminate against in-area non-incumbents and create inefficiencies in the market? [Issue No. 294, Docket Nos. EC96-19-003 and ER96-1663-003. Proponents - Enron, WPTF, and Dynegy]

Proponents assert that "[t]he zonal model that was contemplated during stakeholder discussions provided for the treatment of resources within a zone as being at the same virtual location. The ISO Tariff also unnecessarily limits the ability of new market participants to flexibly bid for inter-zonal transmission access." Joint Initial Brief on Issues B.2.e and H, at 2-3. They claim that the ISO should therefore be directed to implement portfolio bidding on a zonal basis. *Id.* at 3.

The ISO does not believe that zonal portfolio bidding should be implemented at this time. First, the ISO Governing Board has already approved a study concerning the development of this functionality as part of the ISO's continuing market redesign initiatives. The Board, however, believed that other elements of the redesign should take precedence and that budgetary and resource constraints would delay implementation of portfolio bidding beyond the year 2000. Since that time, the list of high-priority tasks that the ISO and interested stakeholders must address has increased to include the comprehensive review of the ISO's Congestion Management process, as well as consideration of the compatibility of the ISO's structure and functions with the requirements of Order No. 2000 and the development of plans to address any inconsistencies. Consideration of zonal portfolio bidding should not displace any of these high-priority issues.

Second, the Commission has ordered the ISO to assess "the design of a comprehensive replacement congestion management approach . . . with input from all stakeholder groups, as well as from the Market Surveillance Committee."

California Independent System Operator Corporation, 90 FERC at 61,013-14. Therefore, an approval or acceptance by the Commission of Proponents' proposals at this time could interfere with the stakeholder process that the Commission has ordered the ISO to initiate. And because it is not clear exactly what reforms may be made to the current Congestion Management model, holding Proponents' recommendations in abeyance pending the outcome of the stakeholder process would avoid the potential for any significant mismatch between any new model and Proponents' recommendations.[155]

Third, the Commission has identified both reliability and market power concerns associated with portfolio bidding. For example, in Order No. 2000 the Commission recognized that portfolio bidding is inappropriate for resources needed to control the transmission system and maintain reliability, and that a transmission system operator must be able to determine both the quantities and locations of Generating Units supplying such things as ancillary services. Order No. 2000, FERC Stats. and Regs., Regs. Preambles ¶ 31,089, 31,141. The Commission is also concerned about the market power implications of portfolio bidding. In Order No. 2000, the Commission stated that "since large players are more likely to cause market power problems, a market design that favors large players (e.g., portfolio bidding) may create an incentive for consolidation and resulting market power problems." *Id.* at 31,218.

For the foregoing reasons, the ISO respectfully requests that the Commission deny Proponents' request that the ISO be directed to implement

[155] The ISO also notes that the majority of stakeholders assign a very low priority to implementation of portfolio bidding. In fact, stakeholders placed portfolio bidding in last place among the eleven potential changes identified as part of the ISO's Market Redesign 2000 process. *See* Memorandum to Market Issues/ADR Committee re Market Redesign 2000 (Nov. 10, 1999), at 3, available at <http://www.caiso.com>. With so many other major market redesigns and assessments in process, the ISO should not be required to expend resources on implementing portfolio bidding at this time.

zonal portfolio bidding at this time, and defer consideration of this issue until after the ISO has filed its revised Congestion Management protocols.

I. PX

I.1. Whether the changes to the ISO Schedules and Bids Protocol and Scheduling Protocol in Amendment No. 7 that describe priorities for Reliability Must-Run Generation and Existing Contract rights are unjust and unreasonable as applied to the PX. [Issue No. 267, Docket Nos. EC96-19-023 and ER96-1663-024. Proponent - PX]

This issue has been withdrawn. *See* Letter from J. McGrew to Secretary Boergers, Docket Nos. ER98-3760-000, *et al.* (Feb. 14, 2000).

I.2. Does the ISO Tariff fail to provide the appropriate degree of separation between the ISO and the PX, and does the ISO Tariff accord the PX preferential treatment with respect to GMMs. [Issue No. 296, Docket Nos. EC96-19-003 and ER96-1663-003. Proponents - Enron and Coral]

Enron alleges that the ISO Tariff treats the PX more favorably than other Scheduling Coordinators. Initial Brief of Enron on Path 15 and PX-Preference Issues at 2. Enron identifies three areas in which it claims that the ISO and the PX have failed to separate their functions: (1) Sections 21.2.1 and 21.2.2 of the ISO Tariff regarding the use of forecast GMMs; (2) communication between the ISO and PX market monitoring units; and (3) the use of the PX's day-ahead and hour-ahead Energy prices in pricing of the ISO's out-of-market Dispatch calls. *Id.* at 18-20. Enron's concerns are unfounded.

In its filing concerning Amendment No. 13 to the ISO Tariff, the ISO noted that the ISO is not integrally linked to the PX.[156] The ISO proposed the elimination of at least 30 definitions in the ISO Tariff to clarify "that the PX will not be treated differently than other SCs." The ISO does not accord the PX preferential terms.

Section 21 of the ISO Tariff was added by Amendment No. 5. It set the GMM to 1.0 for scheduling purposes. The expectation was that once the ISO had been in operation and there had been greater experience, the ISO would

[156] *See* Transmittal Letter for Amendment No. 13 filing, Docket No. ER99-896-000 (Dec. 11, 1998), at 11.

allow Scheduling Coordinators to use forecasted GMMs. There also was a recognition that the PX needed to develop the software necessary to process forecasted GMMs.[157] The Commission accepted this filing in an order dated March 30, 1998. *California Independent System Operator Corporation*, 82 FERC ¶ 61,327.

It is important to note that since the ISO Operations Date, all Scheduling Coordinators – not just the PX – have utilized the unity loss factor of 1.0 for scheduling purposes. Implementation of the use of forecasted GMMs was delayed due to year 2000 computer concerns and the need to implement additional changes. The PX has developed the software necessary in order to use forecasted GMMs. Accordingly, it is expected that all Scheduling Coordinators, including the PX, will implement the use of forecasted GMMs at the same time.

With regard to Enron's second concern, the Commission has specifically endorsed cooperation between the market monitoring units of the ISO and the PX:

> We find the division of monitoring responsibility between the PX and ISO, with each monitoring the markets it administers, to be acceptable. However, given the substantial overlap between the markets administered by the ISO and PX, it is important that coordination between the two compliance divisions occur. The filing states that the ISO and PX expect to coordinate their operations and to share information. We agree with SMUD that coordination is critical to successful market surveillance and we strongly encourage them to coordinate their operations and to share information.

October 1997 Order, 81 FERC at 61,552. Thus, the Commission appropriately recognized that the market monitoring responsibilities of both the PX and the ISO would be compromised if their respective market monitoring units were denied

[157] *See* Transmittal Letter for Amendment No. 5 filing, Docket Nos. EC96-19-018 and ER96-1663-019 (Mar. 3, 1998), at 4-5.

access to necessary data in the possession of the other organization. Enron failed to seek rehearing of this determination.[158]

With regard to the use of the average of certain day-ahead and hour ahead PX prices in establishing an *alternative* payment option for OOM calls, Enron's complaints are both beyond the scope of this proceeding and groundless. First, Enron fails to mention that the use of the PX prices in establishing the out-of-market payment was approved by the Commission in its order on Amendment No. 23 to the ISO Tariff. *See California Independent System Operator Corporation*, 90 FERC at 61,014-15. Enron did not seek rehearing of that order and should not be permitted to use this proceeding to engage in a collateral attack on that determination. Second, Enron overlooks the fact that under the ISO Tariff, as revised by Amendment No. 23, resources are given the choice of either (1) continuing to receive the current pricing for ISO Dispatch orders (the Hourly Ex Post Price) or (2) employing the new payment option that includes, if applicable, a payment for market capacity, market Energy, verifiable start-up fuel costs, and gas imbalance charges. The PX prices are not utilized under the first option.

In sum, Enron's claims that the ISO treats the PX more favorably than other Scheduling Coordinators are procedurally defective and substantively without merit. The Commission approved the use of a unity GMM of 1.0 for scheduling purposes as put forth in Amendment No. 5 to the ISO Tariff. Moreover, this factor has been utilized by all Scheduling Coordinators, not just the PX. Further, in the October 1997 Order, the Commission found that cooperation between the ISO and PX market monitoring units was "critical to

[158] The only issue addressed in Enron's request for clarification concerning the October 1997 Order was whether the Commission's grant of market-based rate authority should extend to Adjustment Bids and Supplemental Energy bids submitted by PG&E, SCE, and SDG&E. *See* Request of Enron Power Marketing, Inc. for Clarification, Docket Nos. EC96-19-009, *et al.* (Dec. 1, 1997), at 3-4.

successful market surveillance," and Enron never sought rehearing of this determination. Finally, Enron should not be permitted to use this proceeding to collaterally attack the out-of-market payment provisions approved by the Commission in its order on Amendment No. 23.

J. SCHEDULING

J.1. Should section 24 of the ISO Tariff requiring Scheduling Coordinators to schedule and bid within the physical capability of their generating unit's physical constraints be a permanent requirement of the ISO Tariff or should this requirement be eliminated? [Issue No. 197, Docket Nos. EC96-19-021 and ER96-1663-022. Proponents - MWD and the PX]

In Amendment No. 6 to the ISO Tariff,[159] the ISO proposed a temporary Section 24 requiring Scheduling Coordinators for Generators to schedule and bid within the physical capability of the Generating Unit concerned. Section 24.2 made the following change to the SBP:

> **SBP 2.3** The Generation section of a Balanced Schedule, and any associated Adjustment Bids, must accurately reflect the physical capability of each Generating Unit identified in the Schedule (including each Generating Unit's ability to ramp from one hour to the next.) For example, a 500 MW Generating Unit specified with a ramp rate of 2MW/min and an operating point of 100 MWh for the current operating hour is not physically capable of generating 300 MWh in the next hour. Likewise, Adjustment Bids submitted for a Generating Unit, applicable to a particular operating hour, should be physically achievable within the applicable operating hour.[160]

Initial briefs concerning this provision were filed by MWD and the PX. Joint Initial Brief on Issue J.1. These parties, however, take contrary views with respect to Section 24.2. MWD argues that this section should be made a permanent feature of the ISO Tariff. *Id.* at 2. The PX contends that the provision should be eliminated. *Id.*

[159] Amendment No. 6 was filed in Docket Nos. EC96-19-021 and ER96-1663-022 on March 23, 1998. The Commission accepted the amendment in *California Independent System Operator Corporation*, 82 FERC ¶ 61,327 (1998), subject to refund, further Commission orders, and the conditions and modifications discussed therein.

[160] The ISO notes that consistent with the Offer of Settlement accepted by the Commission in this matter on February 14, 2000, 90 FERC ¶ 61,178, the temporary provision in Section 24 of the ISO Tariff has been eliminated and the changes therein have been incorporated into Section 2.3 of the SBP. Section 1.4 of the Offer of Settlement provides, however, that these changes were not meant to prejudice the future disposition of issues which were not settled, such as Unresolved Issue No. 197.

Both MWD and the PX correctly note that when the ISO filed Amendment No. 6, the ISO stated that it was concerned about the lack of adequate economic incentives to counteract imbalances that may result from staging implementation of the sub-hour Settlement Period. The ISO also stated that it would seek termination of this interim Tariff section and propose permanent measures to address reliability when it filed a comprehensive ISO Tariff amendment implementing a sub-hour Settlement Period pursuant to the ISO staging plan.[161] MWD is concerned that not requiring Scheduling Coordinators to submit realistic schedules creates gaming opportunities, exacerbating the ISO's Intra-Zonal Congestion Management problems. *Id.* at 5. The PX notes that the ISO's "CONG" software does not have the capability to maintain the physical feasibility of schedules during Congestion Management and argues that it is not reasonable to require Scheduling Coordinators to submit schedules that cannot be preserved.[162]

While the ISO has not as yet implemented a sub-hour Settlement Period, MWD's comment that the ISO has not proposed any new approaches (*id.* at 4) is in error. As MWD itself recognizes, the ISO has announced that, to address current market incentives for uninstructed deviations, it will be proposing a 10-minute settlement period to better align with 10-minute Dispatch of Imbalance Energy resources supplying real-time Energy that have existed since start-up in April 1998. *Id.* The ISO proposes to implement 10-minute Dispatch at the same

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[161] Joint Initial Brief on Issue J.1, at 3-4 & n.3, *citing* "Temporary Changes Respecting Physical Constraints on Schedules," in Attachment A to Transmittal Letter for Amendment No. 6 filing, Docket Nos. EC96-19-021 and ER96-1663-022 (Mar. 23, 1998).

[162] Joint Initial Brief on Issue J.1, at 6. The PX also claims that the "ISO software has no validation to confirm that schedules submitted have conformed with the physical feasibility rule and further has no penalties for those that do not conform." *Id.* at 7. The PX is incorrect. The ISO does have the capability of identifying units that have bid outside of their physical capabilities. Moreover, the ISO does have the authority to take action in response to a failure to conform to Dispatch instructions or a failure to pass an availability test. *See, e.g.*, ISO Tariff, Sections 2.5.22.11 and 2.5.26.

time as electronic Dispatch and 10-minute settlements. Ten-minute settlements of Uninstructed Imbalance Energy will allow more accurate and timely price signals regarding the Imbalance Energy market.

While MWD characterizes this proposal as "subject to significant stakeholder skepticism and criticism," *id.*, the ISO has attempted through a series of implementation workshops and meetings to enhance Market Participants' understanding of the proposed changes, to incorporate stakeholder input, and to address stakeholder concerns. After taking further public comments at the February 24, 2000 ISO Governing Board meeting, the Governing Board passed a resolution that ISO management is to move forward with the 10-minute market development, with an expected implementation date of August 1, 2000. *See* <http://www.caiso.com/pubinfo>. At the March 22, 2000 ISO Governing Board meeting, the Governing Board voted to continue with its February 24, 2000 resolution. *See id.*

Accordingly, the ISO believes that further consideration of this issue should take place in the context of its upcoming filing with respect to its 10-minute settlement proposal.

J.2. Should the ISO Tariff address the nature and scope of a Scheduling Coordinator's responsibilities to the Eligible Customers it serves? [Issue No. 504, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - MWD]

MWD argues that the ISO Tariff should be amended to include a "standard of care" provision for the relationship between Scheduling Coordinators and their Eligible Customers, along the lines of what currently exists between the ISO and Market Participants in Section 14.1 of the ISO Tariff. Initial Brief of MWD on Issue J.2, at 1-2. MWD notes that while the Scheduling Coordinator Application Protocol ("SCAP") describes the Scheduling Coordinator-customer relationship as one of agency,[163] there is no further requirement that the Scheduling Coordinator maintain standards of fiduciary responsibility towards its Eligible Customers. *Id.* at 4.

The ISO has no desire to come between Scheduling Coordinators and their customers, and there is no need for the Commission to place the ISO in that position. Eligible Customers and Scheduling Coordinators should be free to negotiate specific terms and conditions of service and allocation of liability. The ISO market structure anticipates competition between Scheduling Coordinators for the right to secure Eligible Customers. This competition may be thwarted if the ISO Tariff dictates *pro forma* terms. Moreover, the relationship between Scheduling Coordinators and End-Use Customers is a matter for the state public utilities commission to determine, not the ISO. Accordingly, MWD's request should be denied.

J.3. <u>Whether the ISO has unreasonably delayed implementation of the ability of market participants to utilize more than one scheduling coordinator at a single meter? [Issue No. 90, Docket Nos. EC96-19-006, EC96-19-007, EC96-19-008, ER96-1663-007, ER96-1663-008, and ER96-1663-009, and Issue No. 383, Docket Nos. EC96-19-035 and ER96-1663-036. Proponents - Dynegy, Turlock, and CAC]</u>

As filed, the ISO Tariff prohibited Market Participants from utilizing the services of more than one Scheduling Coordinator. The Tariff also prohibits more than one Scheduling Coordinator from using a single meter. Indeed, the ISO's scheduling software was not originally designed to track information on more than one Scheduling Coordinator per meter. It was believed that such a

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163 Section 5.2 of the SCAP reads in pertinent part as follows:

> The SC Applicant confirms that all of the parties which it represents as SC Customers have granted it all necessary agency authority, whether actual, implied, or inherent, to enable the SC to perform all of its obligations under the ISO Tariff.

feature would inject a high level of variability (multiple allocations varying by hour per meter), and would complicate the tracking of ISO and Scheduling Coordinator responsibilities for purposes of disputed statements, good faith negotiations, and Alternative Dispute Resolution. Indeed, the ISO lacks the ability to schedule and Dispatch practical components of multiple Scheduling Coordinator bids on individual meters available in each operating hour. The changes to the scheduling, Dispatch, and settlement systems of the ISO and the Scheduling Coordinators necessary to accomplish such functioning would be significant and costly.

However, in its October 1997 Order, the Commission directed the ISO to begin work to enable multiple Scheduling Coordinator capability. The Commission stated as follows:

> [W]e direct the ISO to coordinate efforts with all interested Scheduling Coordinators in the development of rules for allocating trades through a single meter. . . . The ISO must be involved in these efforts in order to ensure that whatever rules are developed are consistent with the ISO's scheduling, metering and other protocols.

October 1997 Order, 81 FERC at 61,509. While the Commission described this as "a critical priority for the ISO," it also recognized that "the ability of a customer to utilize more than one Scheduling Coordinator depends on the development of the proper software and development by Scheduling Coordinators of rules for the allocation of trades through a single meter." *Id.*

The ISO sought rehearing on two grounds: first, that it would be more efficient for Market Participants to coordinate use of the meter; and second, that it would be "impossibly complex to track arrangements that could change as much as hourly, and allocation schemes that could be structured in any number of ways by a creative and dynamic market."[164]

In its July 15, 1998 Clarification filing, the ISO deleted Section 2.1.1 from the ISO Tariff, which contained the prohibition against Market Participants utilizing more than one Scheduling Coordinator. Because the ISO's systems have not yet changed, however, the ISO Tariff still does not permit more than one Scheduling Coordinator to utilize a single meter. *See* SCAP 2.3.

Proponents claim that the ISO has unreasonably delayed implementing the necessary modifications to allow Market Participants to be represented by multiple Scheduling Coordinators at a single meter. *See* Joint Initial Brief on Issue J.3, at 2-3. Proponents request that the Commission direct the ISO to set an implementation date for procedures allowing Market Participants to trade through more than one Scheduling Coordinator. *Id.* at 4. The ISO Tariff does, however, allow for inter-Scheduling Coordinator trades of Energy and Ancillary Services obligations.

As described below, the ISO continues to believe that the significant costs required to develop the software modifications to allow Market Participants to utilize more than one Scheduling Coordinator at a single meter do not justify the potential benefits. There are other, more cost-effective ways to associate the Dispatch of a Generating Unit with two or more accounts, including contractual agreements, inter-Scheduling Coordinator trades, and utilization of separate channels on a single meter.

In April 1998, the ISO held a meeting to obtain input from Market Participants regarding its prioritization plan, which is a comprehensive matrix of the projects related to improving grid reliability, market operations, and the

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[164] *See* Request for Rehearing, Motion for Stay and Motions for Clarification of the California Independent System Operator Corporation, Docket Nos. EC96-19-009 and ER96-1663-010 (Dec. 1, 1997), at 4.

settlement process. As described in the Staging Plan No. 4 filed on July 22, 1998, Market Participants were asked both to prioritize the projects identified by the ISO and to identify any additional projects. Allowing multiple Scheduling Coordinators per meter was one of approximately thirty additional suggestions.[165] In the Staging Plan, the ISO noted it would work with other Market Participants to consider and prioritize these additional suggestions.[166]

The ISO's Market Redesign Team continued to work with Market Participants to develop a plan for market improvements. These efforts included the Ancillary Services redesign stakeholder process that culminated in the filing of Amendment No. 14 in March 1999 and the more recent Market Redesign 2000 process. For example, on September 29, 1999, Mr. Kellan Fluckiger, the ISO's Chief Operations Officer, gave a presentation at a stakeholder meeting summarizing the ISO's priorities for Market Redesign 2000. In a request sent by electronic mail to Market Participants on October 4, 1999, the ISO asked for comments on the list.[167] Significantly, the ability of Market Participants to utilize multiple Scheduling Coordinators at a single meter was not identified as a priority.

Modifying the ISO's systems to allow Market Participants to utilize more than one Scheduling Coordinator at a single meter will be extremely costly.[168] Moreover, there is a concern that these significant costs will be borne by all

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165 *See* Submission by California Independent System Operator Corporation of Revised Staging Plan No. 4, Docket Nos. EC96-19-000 and ER96-1663-000 (July 22, 1998), at Exhibit B.

166 *See id.* at 5-6.

167 A copy of the electronic mail including the list of priority items is provided as Attachment 11.

168 Proponents' initial brief does not identify the specific technical changes to the ISO's scheduling system that Proponents are requesting, and does not provide a list of the types of scenarios that Proponents wish the scheduling system to be able to handle. However, some types of scheduling system modifications (such as the ability to process hourly varying Scheduling Coordinator allocations on thousands of meters, with no limit on the number of Scheduling Coordinators that can be allocated to a single meter) may be technically impractical.

Market Participants through an increase in the ISO's GMC, though this modification may benefit only a few particular entities.

In addition, the ISO continues to believe that the significant costs required to develop the software and process changes needed to implement the multiple Scheduling Coordinator modification do not justify the potential benefits, especially in view of the geometric increase in system complexity these changes may entail. The ISO believes that there are other, more cost-effective ways to associate the Dispatch of a generator with two or more accounts. For example, if two or more Market Participants each wish to work through a different Scheduling Coordinator at a single meter, they can enter into contractual agreements among themselves whereby the single invoice rendered by the ISO for that meter can be allocated among them in any way they desire. Another example is that PG&E has worked with the Independent Energy Producers Association, the PX, and the ISO to develop an Enabling Agreement to permit QFs that have Power Purchase Agreements with PG&E to sell their excess energy to third parties, including the ISO. This agreement, approved by the CPUC by Resolution E-3625 (August 5, 1999), allocates billing and settlement responsibility while still utilizing the PX as the Scheduling Coordinator for the meter. A similar result could be reached via inter-Scheduling Coordinator trades. Any of these approaches would be much less costly to implement and potentially more robust than the software changes requested by Proponents, thus potentially reducing the risk of market failure, and certainly reducing the costs the ISO must pass on to Market Participants, not just those that benefit, via the GMC.

Given the low priority assigned to the multiple Scheduling Coordinator modification by Market Participants, the likely technical difficulty (or even impossibility) of implementing the modification, and the availability of more cost-effective alternatives, the ISO has devoted its resources to other, high-priority tasks ordered by the Commission and requested by Market Participants pending rehearing on the multiple Scheduling Coordinator modification. The ISO believes that the Commission should permit the ISO to continue with its current prioritization of tasks, and in the meantime provide the Commission with a technical report proposing a more robust and cost-effective approach to achieving the results sought by Proponents through their multiple Scheduling Coordinator modification proposal.

For the foregoing reasons, the ISO respectfully requests that the Commission deny the relief requested by Proponents. Instead, the Commission should permit the ISO to (1) continue with other, high-priority modifications instead of diverting resources to the multiple Scheduling Coordinator modification, which has been assigned a low priority by Market Participants; and (2) evaluate the best approach for achieving the results desired by Proponents, with a report due to the Commission on the results of the ISO's evaluation.

J.4. Does the limitation in section 2.5.22.4.1 of the ISO Tariff on the capability of market participants to withdraw Supplemental Energy bids unreasonably bind a generator to an ISO obligation without any compensation? [Issue No. 374, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - LADWP]

Section 2.5.22.4.1 of the ISO Tariff provides that Supplemental Energy bids must be submitted to the ISO no later than 45 minutes prior to the operating hour and cannot be withdrawn after 45 minutes prior to the Settlement Period. The bid price information is placed in merit order in a database for use in the real-time Dispatch of balancing Energy. The ISO may Dispatch the bid-associated resource at any time during the Settlement Period. This is a reasonable design for a mechanism whose job it is to ensure that consumers do not suffer in any way from the inevitable imbalances in projected Load and dedicated supply as well as from the more drastic imbalances that can occur because of unexpected outages of large Generators.

LADWP, as a potential bidder into the Supplemental Energy market, appears to believe that such bidders should be free to withdraw their bids at any time prior to the bids being accepted, so that they can re-market their generating capacity as they see fit. *See* Initial Brief of LADWP at 3-4. Because a bid in the Supplemental Energy market is accepted concurrent with its Dispatch as balancing Energy, LADWP effectively seeks to be able to withdraw its bid and associated resource at any time prior to its Dispatch. This would transform the balancing Energy mechanism from the safety net it currently is designed to be, into a very risky operation. Dispatchers would not know from second to second how much supply is available to "zero out" a real-time imbalance. Designing a balancing mechanism such as the one LADWP suggests is not in the public interest, certainly not at this point in the development of a competitive retail Energy market.

LADWP argues that it is unfair to bind it to its offer because it is not being compensated for holding its offer open. *See id.* at 4. LADWP later undercuts this argument by pointing out that suppliers will add into their bids the cost associated with the risk of not having the bid accepted. *See id.* Nevertheless, LADWP concludes that this pricing is not efficient. In response to LADWP's arguments, the ISO notes that there is nothing inherently unfair about a market that effectively requires an offeror to make its offer irrevocable for a reasonable period of time without direct compensation. Indeed, many markets for the sale of goods work this way. Second, the ISO agrees with LADWP that bidders will try to build into their bids the costs associated with their risk, i.e., the possibility that their resources will not be Dispatched during the Settlement Period in which they are bid. However, the ISO believes that this is a reasonable way to structure the mechanism. Generators not wishing to take this risk are under no obligation to participate in the Supplemental Energy market.

K. SETTLEMENTS

K.1. Whether the review and notification of errors periods for Preliminary Settlement statements are unreasonable and otherwise impinge on rights to challenge billing errors for the full term of any applicable statute of limitations? [Issue No. 59, Docket Nos. EC96-19-010, EC96-19-011, ER96-1663-011, and ER96-1663-012. Proponent - Cities / M-S-R]

Section 11.6.1.2 of the ISO Tariff provides as follows:

> Each Scheduling Coordinator should have a period of eight (8) Business Days from the issuance of a Preliminary Settlement Statement during which it may review the Preliminary Settlement Statement and notify the ISO of any errors. No later than fifty-one (51) Business Days after the Trading Day to which it relates, the ISO shall issue a Final Settlement Statement to each Scheduling Coordinator for that Trading Day.

In its initial brief, Cities/M-S-R expresses the concern that the review and notification of errors periods for Preliminary Settlement Statements required by Section 11.6.1.2 will be transformed into a statute of limitations. Cities/M-S-R is concerned that parties will thereby be prevented from asserting just claims as to ISO service after the initial period, rather than after the appropriate period of limitations has tolled. Initial Brief of Cities/M-S-R at 16.

As Cities/M-S-R acknowledges, it made substantially the same argument in the recent Amendment No. 22 proceeding (Docket No. ER99-4545-000) with regard to Section 11.6.3 of the ISO Tariff. Initial Brief of Cities/M-S-R at 16-17. Section 11.6.3, in turn, relates to an ISO Tariff provision that is parallel to Section 11.6.1.2: Section 11.6.1.3. Section 11.6.1.3, approved in the Amendment No. 22 proceeding, reads as follows:

> Each Scheduling Coordinator shall have a period of ten (10) Business Days from the issuance of the Final Settlement Statement during which it may review the Incremental Changes on the Final Settlement Statement and notify the ISO of any errors. No later than twenty-five (25) Business Days from the date of issuance of

> the Final Settlement Statement, the ISO shall incorporate any required corrections in a subsequent Preliminary Settlement Statement.

In the Amendment No. 22 proceeding, Cities/M-S-R raised the issue of whether a "ten day notice period for disputes of incremental changes on final settlement statements will not be transformed into a ten day statute of limitations." *California Independent System Operator Corporation*, 89 FERC at 61,686. The Commission found that there was no danger of the ten-day notice provision becoming a statute of limitations, as the ISO Tariff would still allow Scheduling Coordinators to bring a dispute in front of the ISO Governing Board "at any time." *Id.*[169] The same reasoning holds here; thus, Cities/M-S-R's fears are groundless. No clarifying language was needed for Section 11.6.1.3 or Section 11.6.3, and no such language is needed here.

K.2. <u>Is the process for collecting default amounts under Settlement and Billing Protocol § 6.9 (c) unjust and unreasonable. [Issue No. 309, Docket Nos. EC96-19-008 and ER96-1663-009. Proponent - Southern Cities]</u>

Southern Cities contends that the ISO's method of collecting on defaulted debts, as described in Section 6.9(c) of the SABP, is not just and reasonable. Rather than having the amounts owed by defaulting debtors be paid by the ISO Creditors whose payments to the ISO were due on the day of the debtors' default, Southern Cities argues that such costs should be recovered from all Market Participants. Initial Brief of Southern Cities on Issues F.1, K.2, N.1.a, and N.1.b, at 8-9.

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[169] On December 27, 1999, the Cities of Santa Clara and Palo Alto filed their Motion for Clarification or, In the Alternative, Request for Rehearing, in the Amendment No. 22 proceeding. However, they did not raise the Section 11.6.1.3 issue. Moreover, the City of Redding and M-S-R did not join in that motion nor did they file their own motion for rehearing.

Section 6.9(c) of the SABP reads as follows:

SABP 6.9 Replenishing the ISO Reserve Account Following Payment Default

If the ISO has debited the ISO Reserve Account as provided in SABP 6.7.2 then:

(c) If after taking reasonable action the ISO determines that the Default Amount (or any part) and/or default interest referred to in SABP 6.10.5 cannot be recovered, such amounts shall be deemed to be owing by those Market Participants who were ISO Creditors on the relevant Payment Date and shall be accounted for by way of a charge in the next Settlement Statements of those ISO Creditors. Such charge shall be credited to the Reserve Account.

First, it is important to note that the appropriate standard is that a ratemaking provision must be reasonable, not necessarily the best possible alternative.[170] Second, the basis for Section 6.9 of the SABP is found in the section of the SABP it references, 6.7.2 ("Use of ISO Reserve Account"). Section 6.7.2 calls for the ISO to debit the Reserve Account when necessary to effect payment to the ISO Creditors. Third, the ISO Clearing Account, through which the ISO settles all daily transactions, must be "returned to zero" at the end of each day. Therefore, Creditors must be "charged" for defaults to return the account to zero. This being the case, it is not unreasonable that the ISO, after it has "taken reasonable action" as described in Section 6.9(c) of the SABP, yet has been unable to recover the default amount in any other manner, charges the default amount to ISO Creditors, for whose benefit the amount was removed from the Reserve Account in the first place.

[170] *See, e.g., New England Power Co.,* 52 FERC at 61,336.

L. TRANSMISSION PRICING AND LOSSES

L.1. Is the ISO's use of Hour-Ahead Generation Meter Multipliers ("GMM") and ex post GMMs an unreasonable condition of service or harmful to the market? [Issue No. 493, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Enron and WPTF]

WPTF and Enron claim that the ISO's use of hour-ahead and Ex Post GMMs is an unreasonable condition of service because it subjects transmission users to commercial uncertainties and unknown costs over which they have no control. Joint Initial Brief of WPTF and Enron on Issues A.6, B.5.f, E.5, L.1, and L.8, at 16. In addition, WPTF and Enron assert that the use of Ex Post GMMs exacerbates the problem because transmission users are unable to determine the consequences of their purchasing decisions in advance, contrary to the filed rate doctrine. *Id.* at 17-18. They urge the Commission to direct the ISO to use GMMs calculated in advance of the daily pre-scheduling process. *Id.* at 18.

WPTF and Enron are incorrect in their assertions, for at least three reasons. First, the Commission has approved ex post losses pricing for California as well as for the New York ISO. Second, the ISO's approach comports with the filed rate doctrine. Third, as an ISO stakeholder process has determined, the current system entails a low risk of harm while at the same time providing for more accurate price signals and reducing the amount of UFE allocated to Load and exports.

(1) The Commission Has Approved Ex Post Losses Pricing.

In its October 1997 Order, the Commission expressed concern regarding the extent to which the ISO's losses estimates would differ from actual marginal Transmission Losses and the assignment of losses to individual participants.

The Commission directed the ISO to conduct a study evaluating the effects of the ISO's proposal for calculating and assigning Transmission Losses to individual Scheduling Coordinators against a method that assigns each Scheduling Coordinator the full marginal Transmission Losses associated with its actual scheduled transactions. *See* October 1997 Order, 81 FERC at 61,522. The ISO filed its report on December 1, 1999, in Docket No. ER00-703-000. On September 27, 1999, the ISO filed Amendment No. 22 to the ISO Tariff which, among other things, proposed a new model to calculate Transmission Losses. In order to reduce the inaccuracy of assigned Transmission Losses, the new model proposes to calculate Transmission Losses through the use of real-time power flows. The Commission accepted this proposal, subject to the outcome of the Unresolved Issues proceeding. *See California Independent System Operator Corporation*, 89 FERC at 61,685-86. Moreover, the Commission has considered this issue in the context of the New York ISO and has accepted a similar proposal.[171]

(2) The ISO's Approach Comports With the Filed Rate Doctrine.

WPTF and Enron argue that the ISO's losses methodology is "contrary to the central purpose of the filed rate doctrine, namely, to enable purchasers to know in advance the consequences of their purchasing decisions." Joint Initial Brief of WPTF and Enron on Issues A.6, B.5.f, E.5, L.1, and L.8, at 18. Contrary to WPTF and Enron's contention, however, the filed rate doctrine simply "'forbids

[171] *See Central Hudson Gas & Electric Corp.*, 86 FERC at 61,213-14. As does the ISO in California, the New York ISO uses ex post calculations, based on actual system power flows and conditions, to determine the losses charged to market participants. *See* New York Independent System Operator Open Access Transmission Tariff, Attachment I – LBMP Calculation Method, p.1.

a regulated entity to charge rates for its services other than those properly filed with the appropriate federal regulatory authorities.'"[172] As such, the filed rate doctrine and the rule against retroactive ratemaking serve the same purpose.[173] WPTF and Enron have not alleged, nor could they, that the ISO's losses pricing methodology has not been on file with the Commission at all times when it was being used to calculate losses. Finally, their argument proves too much. Many electricity pricing components in many contexts depend on real-time events and conditions that cannot be fully predicted ahead of time. Examples include Congestion costs (which may vary with real-time grid power flows) and certain Energy costs (which can be affected by unexpected Generating Unit outages). If the filed rate doctrine required that transmission users be given perfect knowledge of future costs associated with their market decisions, a large portion of pricing methodologies currently in use (and especially those depending to some degree on market forces) would have to be invalidated.

(3) The ISO's Approach is a Reasonable Result of a Stakeholder Process.

While the analysis presented by WPTF and Enron takes into account only the interests of a certain class of transmission users, the ISO's losses calculation approach balances the interests of all California ISO Market Participants. The SIT began a stakeholder process in November 1998, which culminated in the ISO's current losses calculation methodology. This process took into account

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[172] *Western Resources, Inc. v. FERC*, 72 F.3d 147, 149 (D.C. Cir. 1995), *quoting Associated Gas Distributors v. FERC*, 893 F.2d 349, 354 (D.C. Cir. 1989).

[173] *Western Resources*, 72 F.3d at 151. *See also Transwestern Pipeline Co. v. FERC*, 897 F.2d 570, 577(D.C. Cir. 1990).

Enron's input, as well as that of many other stakeholders. The stakeholders favored the current process for two reasons: (1) the risk of the harms of which WPTF and Enron complain is low, and (2) use of actual system conditions in calculating losses results in more accurate price signals and reduces the amount of UFE allocated to Load and exports.

(i) <u>Low Risk Of Harm</u>

The ISO believes that WPTF and Enron are exaggerating the risks of the ISO's approach to Transmission Losses. First, the ISO does not agree that ex ante losses estimates are disseminated too late to be taken into account in purchasing decisions. The ISO calculates estimated GMMs beginning two days before the Trading Day for which losses are being calculated, and continuously updates this calculation to reflect changing system conditions. These calculations are promptly posted on WEnet. *See* ISO Tariff, Section 7.4.2.1. Thus, Market Participants are provided with the ISO's best estimates of actual losses for the Trading Day in question well in advance of that Trading Day, and certainly in enough time to formulate purchasing decisions.

Second, as stakeholders in the SIT process have recognized, WPTF and Enron greatly exaggerate the potential for changes in "grid topology" that can have significant unforeseen impacts on their actual losses liabilities. While such system events can occur, wide divergences between actual and estimated losses resulting from causes outside the control of transmission users will be rare. This is because the events giving rise to such divergences, such as major unplanned transmission line outages, are themselves rare.

Third, while Transmission Owners may have “control” over certain variables affecting losses, they have no incentive to manipulate these variables to increase losses for transmission users. Transmission Owners do not obtain increased revenues or other competitive advantages if transmission users on their systems are assessed higher losses. (For example, losses revenues are collected by the ISO, not the Transmission Owners.) On the contrary, Transmission Owners have substantial *dis*incentives to incur events such as line outages. First, the applicable Transmission Owner will incur any OOM costs related to a specific outage of a transmission facility. Second, an outage may interfere with the Transmission Owner’s ability to serve its own customers, including native Load customers, and may become grounds for a regulatory investigation and penalty. Finally, the ISO exercises Operational Control over the transmission grid. *See generally* ISO Tariff, Section 2.3. Thus, it seems highly unlikely that Transmission Owners will use their limited “control” over system variables to inflate losses incurred by transmission users.[174]

(ii) Advantages of the ISO’s Approach

WPTF and Enron ignore the advantages of the ISO’s approach to estimating and calculating losses, though these have been recognized by the other stakeholders in the SIT process. Indeed, both equity and economic efficiency commend the use of this approach.

WPTF and Enron have not disputed that calculating losses ex post based on real-time power flows is more accurate than calculating them based on the

[174] In fact, transmission users have more “control” over the magnitude of losses than Transmission Owners. As described below, they can cause their actual deliveries of electricity to the grid to deviate from scheduled deliveries, thus changing the power flows that affect the losses calculations.

forward schedules submitted by Scheduling Coordinators. Because Scheduling Coordinator Loads and electricity deliveries to the grid often vary from their forward schedules, actual power flows are often different from ex ante projected power flows, with concomitant effects on Transmission Losses.[175] Thus, if the ISO were to use estimate calculated "well in advance" of the actual Trading Day to calculate Market Participants' loss responsibilities, the result would often be substantial deviations between actual losses on the system and losses recognized and allocated to the appropriate Market Participants. Such inaccuracies would have two negative effects.

First, because UFE is partly a function of the difference between real and calculated losses, the amount of UFE in the system would likely increase. Under the ISO Tariff, the cost of UFE is allocated to Load and exports, while losses are allocated to Generators. Thus, as recognized by stakeholders in the SIT process, in the absence of accurate calculations of losses, costs may be shifted to Load and exports that should properly be borne by Generators. Obviously, it is inequitable to shift costs that should be borne by one group of Market Participants onto another group, especially when the reason for such cost-shifting is simply an unwillingness to use real, as opposed to estimated, data in the calculation of a particular cost component.

Second, WPTF and Enron's proposal would distort losses price signals to Generators. The ISO Tariff allocates responsibility for losses to Generators in order to provide them with incentives to make economically efficient siting and sales decisions. The rationale for this is that Generators who pay losses will

175 Such effects on Transmission Losses are caused by the fact that transmission line losses are sensitive to line loadings, and such loadings are in turn determined by power flows.

locate their plants closer to Load and will favor sales to nearby customers in order to minimize their transmission line loss liabilities.[176] By so doing, such Generators will minimize the amount of power lost as a result of line losses.

However, if the magnitude of actual losses deviates significantly from the losses for which such Generators are held accountable, these price signals will be distorted. Such a result would undercut the Commission's policy of economic efficiency in ISO pricing generally and in losses pricing in particular. *See, e.g., California Independent System Operator Corporation*, 89 FERC at 61,685-86.

(4) Conclusion.

For the foregoing reasons, the ISO respectfully requests that the Commission reject WPTF and Enron's proposed changes to the ISO's losses methodology, and that the Commission approve the losses methodology.

L.2. Whether the Default Usage Charge is insufficiently detailed, unreasonable, or discriminatory, and whether the existing Default Usage Charge should be rejected and replaced by a charge that reflects the zonal price differential based on an adjusted Market Clearing Price determined from actual generation bids? [Issue No. 205, Docket Nos. EC96-19-017 and ER96-1663-019, EC96-19-021 and ER96-1663-022, and ER98-3760-000. Proponents - HIPG, Enron, WPTF, DWR, and the PX]

The ISO disagrees with WPTF and Enron that the Default Usage Charge ("DUC") is insufficiently detailed, unreasonable, and discriminatory. *See* Joint Initial Brief on Issue L.2, at 6-7. The DUC-related scheduling system modifications developed and implemented by the ISO last year are fully consistent with Section 7.3.1.3.2 of the ISO Tariff. The ISO's DUC methodology

[176] Note that "closer" and "nearby" are used here in a technical sense. Thus, for example, it may make economic sense for a Generator to move closer to a Load served over a highly loaded line, though it may be farther away from a Load served over a lightly loaded line.

is a reasonable method for establishing the price for the use of congested transmission paths when economic Adjustment Bids are not available.

WPTF and Enron argue that the DUC constitutes an unreasonable penalty on Scheduling Coordinators that choose not to or cannot submit voluntary Adjustment Bids. *Id.* at 5-7. Their argument largely relates to the current inability of Scheduling Coordinators to submit Adjustment Bids on inter-Scheduling Coordinator trades. *See id.* at 6-7. Inter-Scheduling Coordinator trades of Adjustment Bids would enable Scheduling Coordinators that do not control physical resources in a Congestion Zone to designate the Congestion price they are willing to pay to utilize a particular constrained inter-zonal path. Inter-Scheduling Coordinator trades of Adjustment Bids would enable Scheduling Coordinators to avoid playing the role of "price-taker" for inter-zonal transmission access. At its March 2000 meeting the ISO Governing Board directed ISO management to implement inter-Scheduling Coordinator trades of Adjustment Bids for the summer of 2000. The ISO is currently scheduled to implement inter-Scheduling Coordinator trades of Adjustment Bids in late August 2000.

WPTF and Enron also argue that the DUC should be replaced by an alternative mechanism that would charge a DUC that is determined by the real-time price for the path. *See id.* at 10. This argument should be rejected. First, as it stands today, the ISO cannot determine a real-time Energy price differential at each Inter-Zonal Interface. The ISO can and does establish separate zonal real-time or Imbalance Energy prices internal to the ISO Control Area. This practice is known as "Splitting BEEP," whereby the ISO segregates the Energy bids available in the ISO's BEEP stack by zonal location.

As the ISO noted in its proceedings concerning Amendment No. 4 to the ISO Tariff,[177] a methodology for establishing a DUC that relies on the Imbalance Energy price in the Zones on either side of a congested interface is subject to gaming. Under WPTF and Enron's proposal, Generators would have an incentive not to submit Adjustment Bids. In such circumstances, similar to the concerns raised as to Amendment No. 4, a thin Adjustment Bid market and reliance on the Real Time Market to establish the Congestion price may artificially inflate zonal clearing prices in forward Energy markets. Therefore, WPTF and Enron's alternative approach should be rejected.

The PX raises concerns that the ISO's calculation of the DUC is not always consistent with zonal marginal costs in those Zones where there exist sufficient bids to make the calculation of a zonal marginal cost possible. *See id.* at 7-8. The PX asserts that the ISO's process for determining the DUC has on many occasions failed to support marginal cost pricing in the PX. In September 1999 the ISO implemented scheduling system changes that modified the DUC calculation. The ISO believes that the modifications to its scheduling system address the PX's concerns. Moreover, even prior to the modifications, the ISO manually corrected the DUC calculation to comport with the zonal marginal price methodology. The PX recommends that the Commission require the ISO to calculate and impose the DUC as proposed in Appendix A of the initial brief on this issue. *Id.* at 11. Based on an examination of the PX's proposal and informal discussions with the PX, the ISO believes that the ISO's modifications

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177 Amendment No. 4 was submitted on March 3, 1998 in Docket Nos. EC96-19-017 and ER96-1663-018. The Commission issued an order on the amendment in *California Independent System Operator Corporation*, 82 FERC ¶ 61,327.

address the deficiencies identified by the PX. The ISO requests that the Commission defer ruling on this particular matter pending further discussions between the ISO and the PX to determine if the revised DUC software does in fact address the concerns raised by the PX.

DWR raises concerns that the creation of Zone 26 and the potential application of the DUC to Zone 26 may significantly increase costs to DWR. *Id.* at 8-10. DWR raise no specific concerns about the ISO's DUC methodology other than that the costs incurred for use of the transmission paths into and out of Zone 26 may be high. DWR raises no substantive issues concerning the ISO's DUC methodology and therefore has established no basis for its requests that the Commission institute an investigation of the DUC. Therefore, DWR's request should be rejected.

L.3. <u>With respect to the ISO's Neutrality Adjustment</u>:

a. <u>Is the ISO's Neutrality Adjustment sufficiently defined and should it be included as a formula rate in the ISO Tariff?</u>

b. <u>Should there be a cap on the amounts that can be collected?</u>

c. <u>What items are properly included in the Neutrality Adjustment?</u>

d. <u>How should the charges be allocated?</u>

<u>[Issue Nos. 204, 208, 229, and 304, Docket Nos. EC96-19-021 and ER96-1663-022, and Issue No. 403, Docket No. ER98-3760-000. Proponents - Dynegy, Southern Cites, Cities / M-S-R, and City of Vernon, California ("Vernon")]</u>

Proponents make four arguments concerning the ISO's neutrality adjustment. First, they assert that the neutrality adjustment should not be accepted as a formula rate in the ISO Tariff, because the ISO has not disclosed to stakeholders the data inputs used to calculate the neutrality adjustment.

Joint Initial Brief on Issue L.3, at 3. Second, Proponents argue that if the Commission does allow a formula treatment, it should place a cap of two mills per kWh on the amounts that can be collected, and once the cap is reached the ISO should be required to file with the Commission a proposal to collect additional amounts. Proponents claim that a cap is appropriate because it "will allow certain flexibility" in assessing the charges related to the neutrality adjustment, which are numerous and difficult to verify. *Id.* at 3-4. Third, Proponents assert that the ISO should prepare a report on the neutrality adjustment and its proposed allocation of related charges, because a more detailed allocation methodology is appropriate. *Id.* at 4. Fourth, Proponents argue that costs related to UFE should be excluded from the neutrality adjustment with regard to municipal utilities. Proponents' reasoning is as follows: (1) UFE mainly involves distribution-related costs; (2) municipal utilities bear all of their own UFE-related costs and do not cause the UFE charges which arise from retail service outside their systems; (3) therefore, municipal utilities will be improperly double-charged if assessed an "inapplicable amount of UFE costs" through the neutrality adjustment. *Id.*

As discussed below, Proponents' criticisms fail to withstand scrutiny. The neutrality adjustment is a reasonable means of settling cash imbalances. Moreover, in the revised transmission Access Charge filing, which was filed on March 31, 2000 in Amendment No. 27, the ISO is proposing that total annual charges levied under the neutrality adjustment, as described in Section 11.2.9 of the ISO Tariff, will not exceed $0.095/MWh, applied to gross Loads in the ISO Control Area and total exports from the ISO Controlled Grid unless approved by the ISO Governing Board. In addition, the ISO has already committed to study potential actions that can be taken to reduce the neutrality adjustment. Finally, the question of the proper allocation of UFE costs is discussed in connection with Issue L.5, below.

Proponents are correct that the original intent of the neutrality adjustment was to collect for cash imbalances due to rounding. *See* Joint Initial Brief on Issue L.3, at 5. In Amendment No. 6 to the ISO Tariff the ISO filed to expand the items included in the neutrality adjustment. The ISO noted that additional cash imbalances were identified during testing and market simulations conducted prior to the ISO Operations Date. As identified by the ISO in Amendment No. 6, such imbalances were the result of the following:

- Control Area inadvertent Energy interchanges that are the result of the fact that import and export Schedules at the tie-points are "deemed" delivered. Due to the multiple Schedules at each tie it is not possible to disaggregate hourly flows and assign them to specific Schedules. In actuality, while Schedules are "deemed" satisfied, aggregate imbalances do exist at the ties due to inadvertent flows.

- Real-time Inter-Zonal Congestion can result in cash imbalances. Real-time Inter-Zonal Congestion requires the ISO to Dispatch resources in the importing and exporting Zones and to the extent that payments do not match, imbalances will result.

- Transmission Losses are components of both Import Deviation and UFE. Losses for import deviations are calculated based on scheduled imports. However, losses for UFE are calculated based on actual deliveries at the tie points. Therefore, two different losses quantities are calculated. Any difference between the two results in a cash neutrality mismatch.

- Imbalances in forward market Schedules can occur when the sum of scheduled Generation, imports, Loads, exports and inter-Scheduling Coordinator trades is not zero yet falls within the ISO's 1-20 MW Balanced Schedule deviation tolerance; and

- Differences that may result from the settlement of instructed and uninstructed deviations. Under the ISO's market design, resources are paid different amounts for deviations from Schedules instructed by the ISO and deviations from Schedules that were not instructed (uninstructed) by the ISO.[178]

In Amendment No. 22, the ISO proposed and the Commission accepted additional revisions to Section 11.2.9 of the ISO Tariff. *See California Independent System Operator Corporation*, 89 FERC at 61,686-87. The ISO stated that as an entity that collects no monies on its own account (except for operating expenses), the ISO's role in the settlement process is primarily as a clearinghouse for Market Participants.[179] The ISO noted that, in most cases, when a Scheduling Coordinator disputes a Preliminary Settlement Statement and the dispute is granted, the ISO adjusts for the disputed amount in all Scheduling Coordinator Final Settlement Statements for the applicable period, but that, when the dispute is denied and the Scheduling Coordinator pursues the options of good faith negotiation or Alternative Dispute Resolution ("ADR") procedures, the ISO may find itself in the position of owing additional monies to that Scheduling Coordinator, to be paid for by other Scheduling Coordinators, or of receiving additional revenue from that Scheduling Coordinator, to be credited to other Scheduling Coordinators. In Amendment No. 22, the ISO was authorized to allocate amounts payable by or to the ISO pursuant to good faith negotiations or the ADR process to other Scheduling Coordinators through the neutrality adjustment. *California Independent System Operator Corporation*, 89 FERC at 61,686-87.

Proponents contend that the neutrality adjustment should not be accepted as a formula rate. Joint Initial Brief on Issue L.3, at 3. Proponents argue that a

[178] Amendment No. 6 filing, Docket Nos. EC96-19-021 and ER96-1663-022 (Mar. 23, 1998), at 70-71.

[179] Funds that the ISO receives from one Market Participant are passed on to another Market Participant or Participants. Changes in a charge to one Scheduling Coordinator require offsetting changes in charges or credits to other Scheduling Coordinators.

formula rate can only be approved if "the formula can clearly be applied and the data which comprise the inputs to the formula are easily and accurately identifiable." *Id.* at 7. However, it should be noted that all the cases Proponents adduce in support of this proposition involve the rates of investor-owned utilities. In contrast to these entities, however, the ISO is a non-profit customer service organization whose role in the settlement process is primarily as a clearinghouse for Market Participants. Consequently, any charges or credits accruing to the ISO must somehow be passed through to the Market Participants. The only question is how such pass-through should be accomplished.

In fact, the ISO *has* provided a "formula that can clearly be applied," as well as "data which comprise the inputs" for the neutrality adjustment. Thus, the ISO has precisely defined the charges/credits that will be added together to equal the neutrality adjustment. *See* ISO Tariff, Section 11.2.9. Each of these charges/credits is in turn a residual resulting from the computation of a quantity whose computation is precisely expressed in the ISO Tariff (i.e., Inter-Zonal Congestion, losses, etc.). The result of the application of this addition has been a precise dollar amount calculated for each month. The results of the calculation of the neutrality adjustment for each of the months in 1999 are shown in Table 1, below.

However, Proponents apparently wish the ISO to do more. They do not argue with the proposition that the ISO can and should pass through charges and credits to Market Participants. Instead, they appear to demand that the ISO eliminate all residuals in its calculations of various quantities, and allocate each dollar to the appropriate Market Participant. Joint Initial Brief on Issue L.3, at 16-17. Proponents do not consider whether a system that chases down and accounts for every last dollar of Congestion, losses, inadvertent interchange Energy, UFE, and Schedule deviation cost can be technically feasible or cost-effective. In fact, such a system, even if it could be constructed, would result in Market Participants paying far more to reimburse the ISO for its operational costs than they are now. The ISO has formulated its neutrality adjustment with as much precision as to computation and data as is possible under the current system. It is worth noting that the Commission has approved similar residual charges spread over classes of Market Participants. *See, e.g.*, *New England Power Pool*, 87 FERC ¶ 61,045, 61,193 (1999); *New England Power Pool*, 85 FERC ¶ 61,379, 62,463 (1998).

Finally, the residual amounts spread on a pro rata basis among Market Participants by the neutrality adjustment are small when compared to the market costs at issue. For example, as shown in Table 1, below, the average monthly neutrality adjustment for 1999 was less than $900,000. The amount was never more than 0.7% and typically well below 0.5% of the ISO's gross monthly billings.

Table 1
Neutrality Adjustment 1999 (millions)

Month	Neutrality (Million)	Gross Dollars (Million)
January-99	$ 0.24	$ 242
February-99	$ 0.54	$ 189
March-99	$ 0.39	$ 243
April-99	$ 0.07	$ 299
May-99	$ 1.23	$ 279
June-99	$ 1.44	$ 229
July-99	$ 0.95	$ 403
August-99	$ 2.43	$ 504
September-99	$ 2.18	$ 477
October-99	$ 2.63	$ 783
November-99	$ -2.34	$ 595
December-99	$ 0.79	$ 450

Proponents also argue that there should be a cap of two mills per kWh on the amounts collected through the neutrality adjustment and state that the ISO should be required to file with the Commission any proposal to collect neutrality adjustments in excess of the established limits. *See* Joint Initial Brief on Issue L.3, at 10-12. It would be inappropriate to subject the ISO, an entity that serves as a clearinghouse for Market Participants, to such a “hard cap” on the recovery of neutrality adjustments.

In Amendment No. 27, as part of the revised transmission Access Charge methodology, the ISO has proposed that total annual charges levied under the neutrality adjustment, as described in Section 11.2.9 of the ISO Tariff, will not exceed $0.095/MWh, applied to gross Loads in the ISO Control Area and total exports from the ISO Controlled Grid, unless the ISO Governing Board reviews the basis for the charges above that level and approves the collection of charges above that level for a defined period and the ISO provides at least seven days’ advance notice to Scheduling Coordinators of the determination of the ISO Governing Board.

As explained above, the ISO does not believe that an absolute cap on the neutrality adjustment is appropriate. The ISO is a cash-neutral entity. To the extent that Market Participants are responsible for paying certain costs, the ISO must be able to allocate such costs to Market Participants and collect the full amount. The ISO believes that its proposal is superior to a requirement that it be forced to make a separate Section 205 filing to account for unanticipated increases in the neutrality adjustment. Under the ISO’s proposal in Amendment No. 27, stakeholders are fully informed of the amount of any increase in the neutrality adjustment and the basis for such an increase. To the extent that they disagreed with the ISO Governing Board’s decision that it is appropriate to recover these costs through the neutrality adjustment, they would be free to challenge that determination before the Commission.

Proponents request that the Commission order the ISO to prepare an analysis that identifies with specificity the level of the neutrality adjustments, the utilities in whose Service Area these costs are being incurred, the categories of cost, and a proposal for an equitable allocation of the costs. Joint Initial Brief on Issue L.3, at 17. The ISO notes that it has already committed, as part of the Unresolved Issues settlement concerning the resolution of Unresolved Issue No. 243, to undertake a review of what actions can be undertaken to reduce the neutrality adjustment. The ISO is to publish the results of its review and provide interested parties with an opportunity to comment on the report. The ISO is currently preparing the report.

Proponents also repeat their arguments as stated in relation to Issue L.5, that UFE should be excluded from the neutrality adjustment with regard to municipal utilities. *See* Joint Initial Brief on Issue L.3, at 13. Proponents' reasoning is as follows: (1) UFE mainly involves distribution-related costs; (2) municipal utilities bear all of their own UFE-related costs and do not cause the UFE charges which arise from retail service outside their systems; (3) therefore, municipal utilities will be improperly double-charged if are assessed an "inapplicable amount of UFE costs" through the neutrality adjustment. *Id.*

It is not clear to the ISO whether Proponents assume that UFE is included in the neutrality adjustment or whether they have concerns about the Transmission Losses calculation related to UFE. In any case, the issue is discussed in relation to Issue L.5, pertaining to whether UFE should be allocated to municipal entities. As stated in connection with Issue L.5, the calculation and allocation of UFE have been improved since the ISO Operations Date. In addition, the ISO Tariff clearly requires UFE to be calculated for each UDC

Service Area. Any entity meeting the definition of a UDC can qualify for a separate UFE calculation for its Service Area by signing a UDC Agreement with the ISO.

In sum, Proponents have not demonstrated that the neutrality adjustment is unjust or unreasonable. While the ISO is preparing a report that is intended to identify additional improvements that can be made to reduce these charges, Proponents have not justified modification of the current ISO Tariff provisions.

L.4. <u>With regard to Metered Subsystems, Existing Contracts, or non-converted transmission contracts, should SP 4.2.1(c) and SBP 2.2.2 be revised to recognize that transmission losses may be dealt with by a scheduling party's system according to existing protocols in use for those contracts and not according to ISO protocols? [Issue No. 80, Docket Nos. EC96-19-008 and ER96-1663-009 and Issue No. 347, Docket Nos. EC96-19-006, EC96-19-008, ER96-1663-007, and ER96-1663-009. Proponents - SMUD and MWD]</u>

Proponents raise two issues with respect to the calculation of losses. First, they argue that, with respect to a Metered Subsystem, the GMM, which is the mechanism through which the ISO determines the amount of Demand that can be served by a Generator, after losses on the ISO Controlled Grid are taken into account, should be calculated "at the perimeter of the MSS" or of the Scheduling Coordinator that represents the customer operating as a Metered Subsystem. Joint Initial Brief on Issue L.4, at 2-3. They also argue that, where a Scheduling Coordinator represents an entity with Existing Rights or "Non-Converted Transmission Contracts," the same principle should apply and, in addition, the ISO should calculate losses based on the contract that gave rise to those rights, rather than in accordance with the methodology in the ISO Tariff. *Id.* at 3. They propose changes to Section 4.2.1(c) of the SP to implement these positions.[180]

(1) GMMs for Metered Subsystems.

The first proposed change is both premature and unnecessary. As the ISO explains elsewhere in this brief, and as the Commission has recognized, the Tariff and technical provisions required to implement the Metered Subsystem concept have, until recently, been under development. The ISO is proposing comprehensive Metered Subsystem provisions as part of the revised Access Charge methodology that was filed on March 31, 2000 in Amendment No. 27. It would be inappropriate to address one aspect of the rules governing Metered Subsystems – the responsibility of a Scheduling Coordinator representing the Metered Subsystem for losses on the ISO Controlled Grid – on a piecemeal basis.

Moreover, Section 7.4.2 of the ISO Tariff already provides that "[a]ll Generating Units supplying Energy to the ISO Controlled Grid at the same electrical bus shall be assigned the same Generation Meter Multiplier." Section 4.2.2(a) of the SP similarly specifies that GMMs will be calculated "at each Generating Unit and Scheduling Point." A Scheduling Point is defined as a location at which the ISO Controlled Grid is connected to transmission facilities that are outside the ISO's Control Area. *See* ISO Tariff, Appendix A, definition of "Scheduling Point." If Generating Units within a Metered Subsystem are not connected at the same point relative to the ISO Controlled Grid, there is no reason why that difference should not be captured in the ISO's calculation of Transmission Losses. The ISO Tariff thus already provides the means for

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[180] In their initial brief, Proponents mistakenly reference Section 4.1(c) of the SP, which does not exist. *See* Joint Initial Brief on Issue L.4, at 2-3.

applying the GMM to the point of Interconnection between the Metered Subsystem and the ISO Controlled Grid when it is appropriate to do so. The first change proposed by Proponents is therefore unnecessary.[181]

(2) Losses for Schedules Using Existing Contracts.

Proponents' second proposal is also unfounded and unnecessary. They would inappropriately interject the ISO into the relationship between a Scheduling Coordinator and the entities it represents in two ways. First, the ISO would have to determine the following: (i) which such entities have "existing operating agreements which provide for absorbing of internal losses within its system"; (ii) what constitutes the "system" of each such entity; and (iii) which locations on the ISO Controlled Grid represent the "perimeter" of that system. Second, they would require the ISO to determine these things whenever a Scheduling Coordinator represents an entity with a contract that provides for Existing Rights or Non-Converted Rights[182] and has loss provisions that differ from those applicable under the ISO Tariff.

There is no need for the ISO to step into either role. In the first case, as noted, the ISO Tariff requires the ISO to calculate GMMs for Generating Units and Scheduling Points. When all Generating Units that supply Energy for a

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[181] Even if a change were necessary and appropriate, the specific language proposed by SMUD and MWD still should not be used. That language uses ambiguous terms that are not defined and uses terms used elsewhere in an inconsistent manner. For example, their language speaks of "imports and exports" by a Metered Subsystem or an entity with an existing operating agreement to describe the transmission of Energy for use within the ISO's Control Area, when the ISO Tariff generally uses those terms to refer to the transmission to or from locations in other Control Areas.

[182] SMUD and MWD refer to "Non-converted Transmission Contracts," which is not a defined term in the ISO Tariff. The ISO presumes they intended to refer to "Non-Converted Rights," which are Existing Rights that are not converted to ISO transmission service when the entity holding the rights becomes a Participating TO. In Amendment No. 27, the ISO has proposed to eliminate the concept of Non-Converted Rights.

schedule using Existing Rights are located at the same Scheduling Point and have the same effect on flows on the ISO Controlled Grid, they will have the same GMM. There is no need to introduce a whole set of new terms and concepts into the ISO Tariff and a new set of obligations on the ISO. With respect to the second point, the ISO Tariff appropriately provides that the ISO will allocate losses among all Scheduling Coordinators, using the GMM methodology, whether or not each Scheduling Coordinator represents entities with Existing Contracts. When a contract between the Scheduling Coordinator and the entity it represents uses a different means of assigning loss responsibility to the customer, that difference can and should be resolved bilaterally between the parties. That is the approach reflected in Section 2.4.4.4.4.5 of the ISO Tariff, which specifically provides that the Transmission Losses provisions of Existing Contracts will remain in force and, "[t]o the extent that Transmission Losses . . . requirements associated with Existing Rights or Non-Converted Rights are not the same as those under the ISO's rules and protocols, the ISO will not charge or credit the Participating TO for any cost differences between the two . . . ." The ISO simply provides the parties with the loss calculations under the ISO Tariff and it is then up to the parties to settle any difference among themselves. *Id.*

The changes to Section 4.2.1(c) of the SP that Proponents recommend would conflict with clear provisions of the ISO Tariff and undermine completely the principle they reflect: to avoid infringing on rights under Existing Contracts, the ISO should apply its Transmission Losses methodology consistently, without regard to the terms of those contracts, and let the parties resolve any difference between the ISO's Transmission Losses methodology and the corresponding provisions of their contracts. Proponents' alternative approach would require the ISO to recognize those differences in its assignment of Transmission Losses, which would effectively allocate any differences (positive or negative) to *other* Scheduling Coordinators. This would inappropriately spread the obligations and rights under Existing Contracts to entities that are not parties to them. Proponents identify no reason for involving the ISO or other Market Participants in the resolution of issues arising under bilateral contracts.

L.5. Are the ISO's unaccounted for energy ("UFE") charges in accordance with the ISO Tariff, and not unjust, unreasonable or unduly discriminatory or preferential; should the ISO Tariff be clarified or revised? [Issue No. 321, Docket No. EC96-19-003 and ER96-1663-003, Issue No. 362, EC96-19-000 and ER96-1663-000, EC96-19-003 and ER96-1663-003, and EC96-19-029 and ER96-1663-030, Issue No. 402, Docket Nos. ER98-3760-000 and EC96-19-029 and ER96-1663-030, Issue No. 423, Docket Nos. EC96-19-029 and ER96-1663-030, Issue Nos. 459,[183] and Issue No. 550, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - DWR, MWD, Vernon, PG&E, and Southern Cities]

Improvements to the Calculation of UFE

As detailed below, the ISO's UFE charges are made in accordance with its Tariff. Moreover, the calculation and allocation of UFE have been improved since the ISO Operations Date. One improvement has been the identification and recommendation of a methodology to better differentiate transmission-level UFE from distribution-level UFE, and to allocate it on the basis of cost causation. Therefore, only small amounts of distribution-level UFE cost are in today's UFE charges. Further, the ISO Tariff clearly requires UFE to be calculated for each

[183] Issue No. 459 is not associated with a prior docket.

UDC Service Area. Any entity meeting the definition of a UDC can qualify for a separate UFE calculation for its Service Area by signing a UDC Agreement with the ISO. In addition, Proponents[184] are incorrect in asserting that the components of cost that are recoverable through UFE charges "are almost totally inapplicable" to Proponents as transmission-level customers, and in asserting that the ISO has been "imposing" UFE charges on them as if they were "components of the retail load of Southern California Edison" (*see* Joint Initial Brief on Issue L.5, at 2-3). The ISO's approach to the charging of UFE costs is just, reasonable, not unduly discriminatory, and should not be changed.

(1) <u>The ISO's UFE Charges are Made in Accordance With its Tariff.</u>

The ISO Tariff provides that UFE on the ISO Controlled Grid is to be calculated separately for each UDC Service Area and for each Settlement Period. *See* ISO Tariff, Appendix A, definition of "Unaccounted for Energy." UFE is defined as the difference in Energy between the net Energy delivered into the UDC Service Area (adjusted for UDC Service Area Transmission Losses) and the total metered Demand within the UDC Service Area (adjusted for distribution losses). *Id.* If there is a difference, the difference is attributable to meter measurement errors, power flow modeling errors, Energy theft, statistical Load profile errors, and distribution loss deviations. *Id.* In addition, UFE is treated as Imbalance Energy. ISO Tariff, Section 11.2.4.3. It is allocated to each Scheduling Coordinator based on the ratio of its metered Demand (including exports to neighboring Control Areas) within the relevant UDC Service Area to

[184] The ISO's discussion of this issue uses "Proponents" to refer to Southern Cities and Vernon. The ISO recognizes that PG&E was also a proponent regarding this issue, and will treat PG&E's arguments separately.

total metered Demand within the UDC Service Area. *Id.* UFE is included in the settlements for Imbalance Energy for each Settlement Period. *Id.*

The inclusion of specific provisions regarding UFE in the ISO Tariff was first proposed by the Joint Commentors in Docket Nos. EC96-19-003 and ER96-1663-003 on June 6, 1997. In response, the ISO included a new definition of UFE as well as provisions regarding the allocation of UFE in its "Restated and Amended Tariff," which it filed on August 15, 1997. In the October 1997 Order, the Commission found that "the ISO Tariff assignment of UFE losses is reasonable." The Commission noted that the distribution loss component "should arguably not be assigned" to Scheduling Coordinators that schedule only at the transmission level, but also observed that "quantification of this single component may not be feasible." October 1997 Order, 81 FERC at 61,522. Indeed, prior to the start of operations the ISO considered the idea of differentiating transmission-related UFE from distribution-related UFE. However, the cost to achieve this was found to be prohibitive, because there are over 800 points of Interconnection between the ISO Controlled Grid and the UDC distribution systems. Even so, as discussed below, the calculation of UFE has improved such that little distribution-level UFE is now being incorporated into UFE charges. The Commission made clear in the October 1997 Order that Scheduling Coordinators, including Scheduling Coordinators that schedule only at the transmission level, should bear a share of all other components of UFE "because they are attributable to overall system conditions and do not lend themselves to any reasonable alternative assignment methodology." *Id.*

(2) The Processes for the Calculation and Allocation of UFE have Been Improved Since the ISO Operations Date.

As described below, UFE costs were substantial during the first months following the ISO Operations Date. A UFE Project Team was organized to investigate the source of these high costs. It discovered that they were largely caused by transmission-level meter data management errors. These errors were corrected and the accounts of Scheduling Coordinators were retroactively settled. UFE calculations and allocations have also been improved through a SIT initiative. UFE charges are now minimal unless errors are made in their calculation. If errors are made, they are corrected. Accounts are retroactively settled for significant errors.

In July 1998, the ISO initiated the UFE Project[185] in response to growing Market Participant concern about the magnitude and financial impact of UFE. System UFE was much higher than expected from April through September 1998. It was running between 4% and 6% of total Load and export in the ISO Controlled Grid. Within the UDC Service Areas, UFE ranged as high as 15%, and as low as –10%, of total Load and export. The UFE Project ultimately identified significant Generation and Load meter data errors that accounted for about 3 million MWhs and $75 million in UFE charged between April 1 and December 31, 1998. Much of the problem was associated with the submission of Logical meter data by Scheduling Coordinators for the non-Participating TOs. Non-Participating TOs are typically municipalities and federal power marketing

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[185] The goal of the UFE Project was to investigate the unexpectedly high UFE, determine its cause, and fix any identified problem. The ISO worked with all the Scheduling Coordinators on this project.

agencies that have Existing Contracts with Participating TOs. Logical meter data is calculated for the pseudo-Generation and pseudo-Loads used to model and schedule the uses of Existing Rights to or from non-Participating TOs, for purposes of charging UFE, Imbalance Energy, and other market Settlement costs. Other sources of UFE error included erroneous meter data from intra-zonal metering at Midway Substation, and data from a few Generation Units which were improperly mapped in the wrong UDC Service Area, inclusive of one unit at San Onofre Nuclear Generating Station. All these errors were corrected, and Scheduling Coordinator accounts were retroactively adjusted to reflect the corrections. ISO System UFE ran between plus and minus 1% of total Load and export from September 1998 through July 1999.[186]

In addition to discovering UFE errors, participants in the UFE Project also identified three areas where the calculation and allocation of UFE could be improved. These included (1) an improved model for calculation of Transmission Losses, (2) more accurate allocation of Transmission Losses among UDC Service Areas, and (3) a methodology to better differentiate transmission-level UFE from distribution-level UFE and allocate it on the basis of cost causation. These issues were subsequently addressed and resolved, as discussed below, in the SIT[187] process with the Market Participants.

First, as a result of the recommendations made in the SIT process, the ISO is improving its calculation of Transmission Losses by replacing its present

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[186] Other technical issues arose after this period, and were in turn corrected, as described below.

[187] The SIT was established by the ISO to work with Market Participants to resolve concerns about settlement issues.

power flow model with a new one by the end of 2000. The ISO's current model was derived from the WSCC's power flow model and uses scheduled Load. Using scheduled, rather than actual, Load introduces a source for error in the calculation of Transmission Losses. In particular, if scheduled Load is lower than actual Load (as has been the case in the past on the ISO Controlled Grid), Transmission Losses are understated and UFE is overstated. The new ISO power flow model will use real-time power flow data. This change will improve the accuracy of Transmission Losses calculations.

Second, the ISO has implemented a new Transmission Losses allocation methodology that allows it to more accurately allocate Transmission Losses among UDC Service Areas. The new model allocates Transmission Losses, calculated for each transmission line segment, directly to the respective UDC Service Areas. Previously, the ISO calculated total ISO Controlled Grid Transmission Losses and then allocated them among UDC Service Areas, on essentially a pro rata basis.

Finally, the SIT participants[188] recommended that each of the three UDCs in the ISO Controlled Grid (i.e., SDG&E, SCE, and PG&E) insert an engineered distribution-related UFE factor into their Distribution Loss Factor ("DLF"), which is charged to the UDC's retail customers in their retail rates. This methodology would effectively move distribution-related UFE from the ISO's overall UFE calculation and apply it directly to retail metered data, i.e., to the rates of the investor-owned utility "causing" any distribution-related UFE. The ISO

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[188] DWR was a participant in the SIT process and, originally, one of the proponents concerning Issue L.5. However, DWR has not joined in the brief on this issue. (DWR and the MWD are proponents as to Issue O.1.b, which also relates to UFE.)

understands that SDG&E and SCE have already rolled this "grossed-up" DLF into their retail rates, but that PG&E is still considering implementation, which would require CPUC approval.

(3) Proponents Have Little to Object to Regarding UFE Charges.

Once all the changes recommended in the SIT process are implemented, UFE charges will include little if any distribution-related UFE. Furthermore, UFE charges should be minimal, unless errors are made. The changes sought by Proponents would not eliminate any such errors. *Cf.* Joint Initial Brief on Issue L.5, at 4-5. Errors are more likely to be eliminated by increased participation in the ISO. For example, from August 21 through December 31, 1999, the ISO experienced another spike in UFE. The UFE Project team determined that the primary causes were Logical metering difficulties and a transposition of the Load and Generation channels of a replaced transmission substation meter. Logical meter-related errors can be dramatically reduced if non-Participating TOs join the ISO Controlled Grid, and all Generation and Load meters are read directly. Additionally, "better" allocation methods are not going to affect any future spike in UFE caused by meter data management errors.

The ISO has consistently shown that it will investigate every instance of a jump in UFE, fix any problems identified, and correct accounts to rectify errors. Proponents have no grounds to complain that "the impacts of avoidance of [substantial computational UFE] errors are presently unknown." *See id.* at 4. Proponents should not be shielded from ISO UFE charges.

(4) <u>The ISO Tariff Clearly Requires UFE to be Calculated for Each UDC Service Area and It Should Not Be Changed.</u>

The ISO Tariff clearly requires UFE to be calculated for each UDC Service Area. *See* ISO Tariff, Appendix A, definition of "Unaccounted for Energy." Thus, any entity that qualifies as a UDC and establishes a formal relationship with the ISO through a UDC Operating Agreement will have its UFE separately calculated for its Service Area.[189] An entity can qualify as a UDC if it: (1) owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, (2) provides regulated retail electric service to Eligible Customers, and (3) provides regulated procurement service to those End-Use Customers who are not yet eligible for direct access or who choose not to arrange services through another retailer. *See id.*, Appendix A, definition of "UDC."

Proponents argue that "there is no requirement in the ISO Tariff that a UDC Agreement be a requisite for UDC classification." Joint Initial Brief on Issue L.5, at 10. Proponents are mistaken. In order for a qualifying UDC to establish a formal relationship with the ISO, it must enter into a UDC Operating Agreement. *See* ISO Tariff, Section 4.1.1. Section 4 of the ISO Tariff describes the nature of the relationship between the ISO and UDCs, including UDC Operating Agreements, the coordination of Maintenance Outages, UDC responsibilities,

[189] Section 11.2.4.3 of the ISO Tariff provides that "the ISO will calculate UFE on the ISO Controlled Grid, *for each UDC Service Area*." (Emphasis added.) In addition, the definition of UFE in Appendix A of the ISO Tariff reads as follows:

> UFE is the difference in Energy, *for each UDC Service Area* and Settlement Period, between the net Energy delivered into the UDC Service Area, adjusted for UDC Service Area Transmission Losses . . . and the total metered Demand within the UDC Service Area adjusted for distribution losses . . . .

(Emphasis added.)

System Emergencies, electrical emergency plans, System Emergency reports, the coordination of expansion or modifications to UDC facilities, and information sharing. Section 4.1.1 provides that the ISO "shall not be obliged to accept Schedules, Adjustment Bids or bids for Ancillary Services which would require Energy to be transmitted to or from the Distribution System of a UDC directly connected to the ISO Controlled Grid unless the relevant UDC has entered into a UDC Operating Agreement." The UDC Operating Agreement is the vehicle by which the UDC and the ISO agree to reciprocal, enforceable rights, responsibilities, and obligations. The UDC Operating Agreement establishes a contractual relationship between the ISO and the UDC, and requires the UDC to comply with the provisions of Section 4 of the Tariff, other applicable sections of the Tariff, and the relevant ISO protocols. In the absence of Commission jurisdiction over UDCs, there is no other way than by contract to bind UDCs to the UDC responsibilities outlined in the Tariff.

Proponents argue that the ISO has been "imposing UFE charges" on Proponents (except for the City of Anaheim) "as if they were components of the *retail* load" of SCE. Joint Initial Brief on Issue L.5, at 3 (emphasis in original). This is an incorrect and unjustified characterization of the UFE the ISO charges to the Scheduling Coordinators for Proponents. Unless Proponents establish formal relationships with the ISO as UDCs – through the execution of UDC Operating Agreements – the ISO has no recourse under its Tariff except to charge Proponents' Scheduling Coordinators a pro rata share of the UFE calculated for the UDC Service Area within which they otherwise reside. Proponents argue that this treatment is incorrect because each of them meets the Tariff definition of a UDC and each of their distribution systems meets the Tariff definition of a Service Area. *See id.* at 9-10. Proponents can remedy their "treatment" by the ISO if they wish to. Proponents merely need to execute UDC Operating Agreements.

In a somewhat contradictory argument, Proponents say that they cannot execute UDC Operating Agreements because (except for the City of Anaheim) they are not "directly connected to the ISO Controlled Grid." *See id.* at 10. Apparently, Proponents assume that the phrase "directly connected to the ISO Controlled Grid" in Section 4.1.1 of the ISO Tariff differs significantly in meaning from the phrase "owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid" in the Tariff's definition of UDC. There is no basis for this assumption by Proponents. Their position that they are eligible to be UDCs under the ISO Tariff but ineligible to execute UDC Operating Agreements with the ISO under the ISO Tariff is neither logical nor supported by the Tariff. In short, Proponents are trying to establish that they are entitled to the benefits of being UDCs within the ISO system without having to accept the responsibilities of being UDCs within the ISO Control Area. That is, Proponents want to have their UFE charges calculated separately for their Service Areas, but they do not want to undertake the responsibilities set out in the UDC Operating Agreement and Section 4 of the ISO Tariff. This would be discriminatory, and is an incorrect, unfair, and unacceptable characterization of the Tariff.

<u>Transmission Losses</u>

PG&E notes that it has requested the Commission to order the ISO to file a supplemental report on the pre-Amendment No. 22 Transmission Losses methodology in place prior to February 1, 2000. Joint Initial Brief on Issue L.5, at 11-12. PG&E appears to desire this information to support its argument (which it has made previously) that the Commission should order the ISO to apply retroactively the new losses methodology filed in Amendment No. 22. The Commission has already twice rejected PG&E's retroactivity argument. As the Commission stated in its order concerning the ISO's Amendment No. 22 compliance filing:

> [A]lthough the previous method had been accepted as an interim measure, the Commission did not intend to apply a successor method retroactively. The Commission did not accept the interim method subject to refund or subject to future orders. Moreover, while PG&E characterizes the amounts at ISO had incorrectly applied its transmission loss methodology and was charging an incorrect rate; rather, it objects to the method of calculation, which was in fact the approved filed rate. Thus, there is no basis for requiring retroactive application of the new loss methodology.

California Independent System Operator Corporation, 90 FERC ¶ 61,315, slip op. at 7-8 (2000) (footnote omitted). Given that the Commission does not intend to reconsider the retroactivity issue for a third time, the report that PG&E requests is unnecessary.

Conclusion

In summary, the ISO charges UFE in accordance with its Tariff. The Tariff's UFE provisions are just, reasonable, and not unduly discriminatory. Moreover, the improvements made to the calculation and allocation of UFE since the ISO Operations Date, and the ISO's correction of UFE errors, have eliminated the real objection underlying Proponents' position in this case.

L.6. With respect to Settlement and Billing Protocol ("SABP"), Appendix A, section 3.2, should "metered consumption be changed to "metered Demand"? [Issue No. 89, Docket Nos. EC96-19-008 and ER96-163-009. Proponent - SMUD]

Appendix A of the SABP describes the computation of the GMC, setting forth a formula for determining the GMC charge for each Scheduling Coordinator (Section A 2.2) and defining the terms used in the formula (Section A 3). One of those terms, $Qcharge_j$, stands for the quantity to which the GMC is applied and is defined as the "monthly metered consumption" of the Scheduling Coordinator j, for which the charge is being calculated.

SMUD contends that the phrase "monthly metered consumption" should be changed to "monthly Demand," because it is uncertain about what is included in "consumption." Initial Brief of SMUD on Issue L.6, at 2. There is, however, no basis for confusion. Appendix A of the SABP implements the GMC formula, which is found in Schedule 1 to Appendix F of the ISO Tariff. That formula provides a definition of "monthly metered consumption." *See* ISO Tariff, Appendix F, Schedule 1 (defining the term as the aggregate of "Other Metered Consumption" and "Existing Contract Deliveries," which are also defined as part of the GMC formula). The specific terms were agreed upon as part of the GMC settlement that the Commission approved in Docket Nos. ER98-211-000, *et al.* *See California Independent System Operator Corporation, et al.*, 83 FERC ¶ 61,247. Because the provision that SMUD challenges in Appendix A of the SABP is defined in the GMC formula, no modification is necessary or appropriate.

L.7. Should less costly alternatives to transmission expansion identified in ISO Tariff section 3.2.1.2 be priced at the greater of a cost-based rate or the revenues foregone (*i.e.*, the opportunity cost) in providing them. [Issue No. 356, Docket Nos. EC96-19-000 and ER96-1663-000 EC96-19-003 and ER96-1663-003. Proponent - DWR]

DWR explains that this issue was intended to explore the implementation of Section 3.2.1.2 of the ISO Tariff, which concerns less costly alternatives to transmission expansion. Initial Brief of DWR at 40. DWR acknowledges in its initial brief that the issue of implementation of Section 3.2.1.2 has been overtaken by the ISO's efforts to clarify the long-term planning process through Amendment No. 24 (Docket No. ER00-866-000). That amendment has now been withdrawn and returned to a stakeholder process. Accordingly, DWR asserts that the issue of the implementation of Section 3.2.1.2 should not be decided here, but instead should be deferred for consideration in the reinstated stakeholder process on long-term grid planning. Initial Brief of DWR at 41.

The ISO agrees with DWR that given the comprehensive revaluation of long-term grid planning, which will encompass evaluations of less costly alternatives to transmission expansion,[190] there is no need to pursue the issue regarding the implementation of Section 3.2.1.2 in this proceeding.

Rather than being satisfied with this deferral and accepting an open consideration of the issue in the reinstated stakeholder process, DWR requests the Commission to issue "guidance" to the ISO in its consideration of the issue. Initial Brief of DWR at 41-45. This request for "guidance," however, is nothing

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190 *See* Notice of the California Independent System Operator Corporation to Withdraw Amendment No. 24 to the ISO Tariff – Revised Long-Term Grid Planning Process – and Request to Terminate Proceedings, Docket No. ER00-866-000 (Feb. 4, 2000), at 1-2.

more than an effort by DWR to place a tight fence around the consideration of the issue. DWR effectively seeks to have the Commission dictate the resolution of the issue by making the use of off-peak transmission rates the top priority for consideration.

Limiting the stakeholder process as requested by DWR is inappropriate. The whole purpose of a stakeholder process is to allow all parties to present and discuss in an open forum all potential issues and solutions. Having the Commission limit the scope of discussion as requested by DWR would defeat the primary purpose of the stakeholder process, and preclude those opposing DWR's position from having an opportunity to present their views. Such a result would also be directly contrary to the decision of the Commission in Order No. 2000 not to dictate the outcome of RTO collaborative processes. The Commission has established the ground rules and principles to which RTOs must adhere, but permits each RTO the flexibility to develop the type of solution that best fits its market.[191] That is precisely what the ISO intends to do in its stakeholder process on long-term grid planning – examine all alternatives and develop the best solution in the circumstances. Adopting DWR's request would only serve to prevent the ISO and its stakeholders from accomplishing that goal.

In addition, it would be premature and inefficient for the Commission to limit the ISO's consideration of the issue as DWR requests. During the stakeholder process, DWR, just like all other parties, will be able to present its view on the appropriateness of time-of-use rates. There will be a full opportunity for DWR to present its position, and for those who oppose it to respond. The end

[191] *See* Order No. 2000, FERC Stats. and Regs., Regs. Preambles ¶ 31,089, at 31,038.

result of the process may be to develop a solution that is both consistent with Order No. 2000 and acceptable to DWR. In that case, the issue will be moot. Given this eventuality, it would be inefficient for the Commission to opine on the proper resolution of the issue before the parties have had an opportunity even to discuss it. DWR's request to have the Commission issue guidance should therefore be denied.

L.8. Is the ISO's failure to permit discounting in its wheeling-out rates arbitrary and unreasonable, resulting in transmission service that is substantively worse than the quality of service contemplated by Order No. 888? [Issue No. 492, Docket Nos. EC96-19-029 and ER96-1663-030]. Proponents - Enron and WPTF]

WPTF and Enron contend that the Commission should order the ISO to amend its existing non-discountable Wheeling Access Charge to permit discounting. They propose that Section 7.1.4.1 of the ISO Tariff be amended, consistent with Order No. 888's *pro forma* tariff language on discounting, to establish a price cap, rather than a fixed charge, that can be discounted. Initial Brief of WPTF and Enron on Issues A.6, B.5.f, E.5, L.1, and L.8, at 19. WPTF and Enron claim that the ISO's refusal to discount locks Generation in California, leading to artificially lower prices. This market distortion, they claim, will have a long-term, detrimental effect on all Market Participants other than Transmission Owners, who benefit from lower prices. *Id.*

The ISO disagrees that its current rate structure will have a detrimental effect on Market Participants. The ISO's proposal gives all Generators access to the entire ISO Controlled Grid through the payment of a single Access Charge. Moreover, the Commission has never required transmission providers to offer discounted transmission rates for a particular service. October 1997 Order, 81 FERC at 61,505. Finally, the Commission was not convinced that the ISO's regional transmission pricing proposal, as compared to discounted but pancaked rates, would lock Generation in California. *Id.* at 61,506.

As discussed previously, challenges to the ratemaking principles of the ISO Tariff were required to be raised in a petition for rehearing of the October 1997 Order. Section 313(a) of the FPA, 16 U.S.C. § 825*l*(a) (1994), provides that a party aggrieved by a Commission order must file an application for rehearing within 30 days after the order is issued to preserve its right to review. WPTF and Enron did not seek rehearing and should be precluded from raising the issue now. *Cf. Transcontinental Gas Pipe Line Corp.*, 66 FERC at 61,764-65.