B. DISPATCH / CONGESTION MANAGEMENT / OVERGENERATION

B.1. Is the ISO properly managing Path 15?

Background

Path 15 is a transmission path owned by PG&E that generally extends from PG&E's Los Banos Substation to a point of Interconnection with the transmission facilities of SCE at the Midway Substation. Path 15 is also an Inter-Zonal Interface between the ISO's NP15 and ZP26 Congestion Management Zones. Prior to the commencement of ISO Operations, PG&E executed many Existing Contracts over Path 15. Path 15 is one of the most heavily utilized transmission paths on the ISO Controlled Grid, and there is often Congestion on the path, a situation which has been complicated by the numerous Existing Contracts with transmission service rights over this path. This path, and the levels of Congestion experienced on it, have been a matter of concern for Market Participants prior to the California restructuring efforts. Pursuant to the ISO Tariff, various FERC orders, and the TCA between the ISO and Participating TOs,[30] transmission priorities for Path 15 under Existing Contracts are established by information and operating instructions provided to the ISO by PG&E, the Participating TO for Path 15.

In proposed Amendment No. 3 to the ISO Tariff, filed on February 25, 1998 in Docket Nos. EC96-19-016 and ER96-1663-017, the ISO attempted to clarify priorities on Path 15 in light of the operating instructions for that path which PG&E had provided to the ISO shortly before the ISO Operations Date. A number of parties with Existing Contracts on Path 15 opposed Amendment No. 3 on the grounds that the operating instructions reflected in Amendment No. 3 would leave inadequate capacity to serve Existing Contracts. The Commission rejected Amendment No. 3, noting that "its main concerns are that the ISO has not adequately demonstrated that the proposed transmission priority on Path 15 is supported by an Existing Contract, was clearly presented and approved by the ISO Board, or that Amendment No. 3 was the product of prior stakeholder discussions or understanding." *California Independent System Operator Corporation*, 82 FERC ¶ 61,312, 62,242-43 (1998) ("March 27, 1998 Order"). The Commission directed "all affected parties" to "negotiate a resolution to this issue." *Id.* at 62,243.

In a TCA compliance filing made on February 20, 1998 in Docket No. ER98-1971-000, the ISO submitted a revised TCA intended to meet the requirements put forward by the Commission in the October 1997 Order. Included in this filing was a "Supplement to Appendix A" relating to the transmission priority over Path 15, as well as proposed changes to TCA Appendix B, delineating the Participating TOs' Encumbrances on Path 15. Numerous intervenors opposed this aspect of the TCA compliance filing on the grounds that the proposed Supplement to Appendix A and changes to Appendix B would afford PG&E priority over other third parties for the use of transmission capacity on Path 15. The Commission rejected this proposed priority over Path 15 without prejudice to further filings addressing these issues,

[30] The TCA contains, in Appendix B, a list of the Encumbrances for each Participating TO. These Encumbrances include such items as Existing Contract obligations.

consistent with its order on Amendment No. 3. *California Independent System Operator Corporation*, 82 FERC ¶ 61,325 (1998) ("March 30, 1998 Order"). The question of transmission priority on Path 15 arose again in the context of Amendment No. 7 to the ISO Tariff. In that proceeding, the Commission accepted Tariff amendments concerning transmission priority of Existing Contracts, but, consistent with the Commission's order on Amendment No. 3, stated that "we again direct the ISO to work with the affected parties with Existing Contracts to continue to resolve the details of this issue . . . ." *California Independent System Operator Corporation*, 83 FERC ¶ 61,209, 61,922 (1998) ("May 28, 1998 Order").

On June 1, 1998, the ISO submitted a further compliance filing, amending the TCA to bring that agreement in compliance with the October 1997 and March 30, 1998 Orders. The June 1, 1998 Compliance filing included revisions to Reference No. 54 in Appendix B of the TCA for PG&E that specifically addressed transmission priorities for Path 15. Several parties submitted motions to intervene and comments in Docket No. ER98-1971 in response to the June 1, 1998 Compliance filing, arguing that the revised Appendix B still failed to preserve the rights and priorities, under Existing Contracts, of entities other than PG&E to transmission capacity on Path 15.[31] The ISO filed an Answer to these comments on September 3, 1998, explaining that, consistent with Commission orders and ISO Tariff provisions mandating that the ISO have no role in

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[31] Enron, the proponent of issues concerning Path 15 in the Unresolved Issues proceeding, filed a motion to intervene in Docket No. ER98-1971 on August 5, 1998, but did not file substantive comments in that proceeding.

interpreting Existing Contracts, the ISO had accepted revisions to the TCA concerning Existing Contract priorities over Path 15 as provided by PG&E, the Participating TO, and noting that the ISO expected that any parties with concerns about the Path 15 transmission priority information provided by PG&E would exercise their rights to raise such concerns when the revised TCA was filed with the Commission. This is exactly what occurred in that proceeding.

On February 11, 1999, the ISO filed with the Commission further revisions to Appendix B of the TCA, consisting of changes to Reference No. 54 of PG&E Appendix B, based on information provided to the ISO by PG&E.[32] The revisions were the result of the negotiations called for in the Commission's March 27, 1998 and May 28, 1998 Orders. The revised portion of Appendix B includes explicit references to the negotiated operating instructions for Path 15. In addition, PG&E provided the ISO with its "Path 15 Operating Instructions for Existing Encumbrances Across the Path 15 Interface" as Exhibit B-1 to PG&E Appendix B, in order to avoid any potential ambiguity in Reference No. 54.

On March 3, 1999, the Coalition of New Market Participants ("CNMP"), of which Enron is a member, filed an intervention and protest in Docket No. ER99-1770. In its protest, CNMP argued, *inter alia*, that the revised Appendix B filing did not convey the "real" operating instructions by which transmission priority would be determined;[33] that all Market Participants did not

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[32] This filing was assigned Docket No. ER99-1770-000.

[33] Motion to Intervene and Protest of Coalition of New Market Participants, Docket No. ER99-1770-000 (Mar. 3, 1999), at 4.

have the opportunity to participate in the Appendix B negotiations;[34] and that the filing allowed PG&E too much control over Path 15.[35]

The ISO filed an Answer to the comments (and CNMP protest) in Docket No. ER99-1770 on March 18, 1999, explaining, *inter alia*, that the February 11 filing was the product of negotiation by the interested parties;[36] that the ISO has no authority to interpret Existing Contracts;[37] and that it is proper for the ISO to follow operating instructions provided to it by Participating TOs.[38] On April 19, 1999, in response to a letter from Commission Staff, the ISO filed in Docket No. ER99-1770-001 additional documents that PG&E had provided to the ISO concerning Existing Rights over Path 15. These documents included sheets, in a template format established by the ISO for the submission of information on transmission service rights, that contain contract-specific information on the quality of transmission service available under Existing Contracts for Path 15; daily, hourly, and real-time scheduling rights; points of receipt and delivery; and effective and termination dates for Existing Contracts that have transmission rights on Path 15. In addition, the ISO filed spreadsheets that provide certain information on curtailment procedures in connection with these contracts. The Commission accepted the ER99-1770 compliance filing, as

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[34] *Id.* at 7.

[35] *Id.*

[36] Motion for Leave to File Answer and Answer of the California Independent System Operator Corporation to Motions to Intervene, Comments, and Protest, Docket No. ER99-1770-000 (Mar. 18, 1999), at 5.

[37] *Id.* at 8-9.

[38] *Id.* at 9.

supplemented, in a letter order issued on June 17, 1999. *California Independent System Operator Corporation*, 87 FERC ¶ 61,312 (1999). CNMP requested rehearing of this order on July 19, 1999, and the Commission issued a tolling order on August 10, 1999 regarding this request. No further action has occurred in Docket No. ER99-1770.[39]

a. <u>Is the provision of the ISO Tariff that affords higher priority on congested pathways such as Path 15 to conditional firm service under existing contracts than such service had prior to the start of ISO operations anticompetitive or unduly discriminatory to new market entrants? [Issue No. 489, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Enron and Coral Power, LLC ("Coral")]</u>

Enron[40] contends that the ISO is improperly managing Path 15, arguing that the ISO allows Existing Rights holders with conditional firm rights to enjoy a higher priority than they had prior to the start of the ISO. Enron argues that this results in additional costs to entities that do not have Existing Contracts with transmission rights for Path 15. Enron also contends that the process by which the operating instructions which determine the transmission priority for Existing Contracts on Path 15 were developed was faulty; Enron claims that entities that were not parties to Existing Contracts, such as Enron, did not have the opportunity to participate in the discussions and negotiations. Initial Brief of Enron on Path 15 and PX-Preference Issues at 8. Enron argues that this process was contrary to the Commission's directions in the March 27, 1998 and May 28, 1998 Orders that all "affected parties" participate in these negotiations.

[39] Enron acknowledges that the issues it raises in the instant proceeding are essentially the same issues it has raised in Docket No. ER99-1770. *See* Initial Brief of Enron on Path 15 and PX-Preference Issues at 4 n.1.

Id. In addition, Enron complains that entities that are not parties to such Existing Contracts continue to be deprived of information necessary to evaluate how access to Path 15 is awarded. *Id.* at 9. According to Enron, the Commission should require the ISO to "post sufficient information to allow independent verification of how Path 15 (and other inter-zonal interfaces) is being managed in light of Existing Contracts uses." *Id.*

Enron's contentions are baseless. They ignore the ISO's clearly established role with respect to the implementation, as opposed to the interpretation, of Existing Contracts. They also ignore the fact that Market Participants have already been provided with ample information, both in FERC filings and in Operating Procedures posted on the ISO Home Page, about how Path 15 and other paths are to be managed. Moreover, as Enron itself recognizes, it has made the same arguments in another proceeding, and the Commission has declined to act on those arguments. For the reasons explained below, the Commission should reject these same arguments in the instant proceeding.

As an initial matter, the ISO notes that Enron has identified no "provision of the ISO Tariff" that affords higher priority to entities with Existing Contracts for conditional firm service on Path 15 than such entities had prior to the commencement of ISO operations. In fact, the crux of Enron's claim is that instructions given to the ISO by PG&E for implementing Existing Contracts with transmission rights over Path 15 are inconsistent with Section 2.4.4.5 of the ISO

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[40] The other members of the CNMP did not brief the Path 15 issue.

Tariff. Enron cites the following excerpt from that Tariff provision several times: "Existing Rights and Non-Converted Rights will enjoy the same relative priorities vis-à-vis new, ISO-provided transmission uses, as they would under the Existing Contracts and the FERC Order 888 tariffs." *See, e.g.*, Initial Brief of Enron on Path 15 and PX-Preference Issues at 5. This excerpt is from the first two sentences of Section 2.4.4.5, which reads in full as follows:

> The ISO will implement the provisions of Section 2.4.4.4 in its Scheduling Protocol. The objective will be to ensure that under the ISO rules and protocols, Existing Rights and Non-Converted Rights will enjoy the same relative priorities vis-à-vis new, ISO-provided transmission uses, as they would under the Existing Contracts and the FERC Order 888 tariffs.

This provision therefore must be read in concert with Section 2.4.4.4.1 of the ISO Tariff, which addresses the ISO's treatment of Existing Contracts, including rights under Existing Contracts for conditional firm transmission service:

> For the purposes of Section 2.4.4, Existing Rights and Non-Converted Rights fall into one of three general categories: firm transmission service, non-firm transmission service, and conditional transmission service. The parties to an Existing Contract shall notify the ISO which Existing Rights and Non-Converted Rights fall into each category, through the operating instructions described in Section 2.4.4.5.1.1. The parties to an Existing Contract shall also be responsible to submit to the ISO any other necessary operating instructions based on their contract interpretations needed by the ISO to enable the ISO to perform its duties.

These two sections are part of a carefully structured framework set forth in the ISO Tariff, and approved by the Commission, concerning the treatment of Existing Contract transmission service rights. Under this framework, Existing Contract transmission priorities for Path 15 are to be established by information and operating instructions negotiated by the parties to those Existing Contracts and provided to the ISO by PG&E, the Participating TO for Path 15. The Commission explicitly approved this framework in the October 1997 Order: "[I]t is reasonable for the ISO to rely on the operating instructions of the Participating TO. The Participating TO is the entity most familiar with performing the operating instructions on a day-to-day basis under the existing contract."

October 1997 Order, 81 FERC at 61,473.

The ISO Tariff not only establishes this framework, but also describes the process by which disputes concerning operating instructions for Existing Contracts are to be resolved. Section 2.4.4.4.1.1 of the ISO Tariff, for example, states as follows:

> The ISO will have no role in interpreting Existing Contracts. The parties to an Existing Contract will, in the first instance, attempt jointly to agree on any operating instructions that will be submitted to the ISO. In the event that the parties to the Existing Contract cannot agree upon the operating instructions submitted by the parties to the Existing Contract, the dispute resolution provisions of the Existing Contract, if applicable, shall be used to resolve the dispute; provided that, until the dispute is resolved, and unless the Existing Contract specifies otherwise, the ISO shall implement the Participating TO's operating instructions.

This framework is also reflected in various provisions of the TCA, which dictates how the ISO and each Participating TO will discharge their respective duties and responsibilities.[41]

Far from blindly accepting the dictates of a single Market Participant in this regard, as Enron would have it (*cf.* Initial Brief of Enron on Path 15 and

[41] *See, e.g.*, TCA, Section 6.4.2 (governing the operational protocols for facilities placed under the ISO's Operational Control that are subject to Encumbrances, including Existing Contracts); *id.*, Section 13 (establishing that Sections 2.4.3 and 2.4.4 of the ISO Tariff will apply to the treatment of transmission facilities of a Participating TO placed under the Operational Control of the ISO which are subject to transmission service rights under Existing Contracts).

PX-Preference Issues at 9), the ISO has carried out the instructions of the Commission and the dictates of the ISO Tariff responsibly with respect to transmission service rights for Path 15 under Existing Contracts. The current operating instructions for Path 15 were negotiated by all parties to Existing Contracts with transmission service rights over Path 15, in accordance with the procedures described in Section 2.4.4.4, *et seq.* of the ISO Tariff. These negotiations were described in substantial detail in the ISO's filings in Docket No. ER99-1770. In fact, this is an instance where the process worked exactly as contemplated by the Commission. The ISO implemented the operating instructions provided by the Participating TO while the parties to the Existing Contracts resolved disputes concerning the interpretation of those contracts through negotiations.

Enron objects that, as an entity that is not a party to those Existing Contracts, it was not afforded an opportunity to participate in those discussions. *See* Initial Brief of Enron on Path 15 and PX-Preference Issues at 13-14. There is nothing in Section 2.4.4.4, *et seq.* of the ISO Tariff that suggests that other non-parties are entitled to interject themselves into the resolution of a dispute concerning the operating instructions to implement an Existing Contract. Moreover, contrary to Enron's claims, there is nothing in the Commission's March 27, 1998 and May 28, 1998 Orders that would require that non-parties have a role in negotiating the resolution of the transmission priority over Path 15 under Existing Contracts. Those orders address concerns raised by the parties *to such Existing Contracts* that prior versions of the operating instructions for

Path 15 developed by PG&E would leave inadequate capacity to serve their Existing Rights. In its March 27, 1998 Order the Commission stated that "[w]e urge all affected parties . . . to negotiate a resolution to this issue." March 27, 1998 Order, 82 FERC at 62,243. However, this statement was clarified in the May 28, 1998 Order, where the Commission noted that "we again direct the ISO to work with the affected parties *with Existing Contracts* to continue to resolve the details of this issue within the framework proposed by the ISO." May 28, 1998 Order, 83 FERC at 61,922 (emphasis added). Enron therefore has no basis for its arguments that the process by which the Existing Contract operating instructions for Path 15 were developed was faulty.

Enron's initial brief makes clear that its real complaint is with the negotiated interpretation of various agreements that pre-dated ISO operations, as reflected in the revised Path 15 operating instructions. Specifically, Enron objects to the curtailment priority afforded to "SCE's, SDG&E's and PG&E's rights under the Pacific Intertie Agreement" under the negotiated operating instructions for Path 15. Initial Brief of Enron on Path 15 and PX-Preference Issues at 6. Enron claims that even the Converted Rights of those Participating TOs for Path 15 should be afforded a higher priority for new firm use of Path 15 than the various Existing Rights and Non-Converted Rights for transmission over Path 15. Such a result is not mandated by Order No. 888,[42] and would be inconsistent

[42] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. and Regs. Jan. 1991-June 1996, Regs. Preambles ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. and Regs. III, Regs. Preambles ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997),

with the resolution of transmission rights over Path 15 negotiated by all parties to the relevant agreements.

Enron contends that the ISO has taken too much of a "hands-off" approach to the management of Path 15 and finds fault with the ISO's "assertion" that the ISO should have no role in interpreting Existing Contracts. *Id.* at 9. As described above, that "assertion" is nothing more or less than the language of Tariff provisions explicitly approved by the Commission. The ISO is not bound to "blindly accept" operating instructions that are plainly contrary to an Existing Contract, but where there is room for interpretation, it is to take no active role in that interpretation. For example, if an Existing Contract provided for 10 MW of firm transmission service over a given transmission path, the ISO would not be bound to accept operating instructions negotiated by the parties to that contract that directed the ISO to reserve 50 MW of capacity for that Existing Contract. In the case of the many Existing Contracts with transmission rights over Path 15, however, there was a substantial need for interpretation and therefore negotiation; the ISO believes that it is wholly appropriate to implement the operating instructions negotiated by PG&E and the other parties to those contracts. This is especially true because those operating instructions were accepted by the Commission.

Entities such as Enron were given a forum to raise issues about the Existing Contract operating instructions for Path 15. Those instructions were incorporated into the amendment to the TCA filed in Docket No. ER99-1770.

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81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *appeal pending*.

That filing was publicly noticed, and all interested Market Participants (not just those that are parties to Existing Contracts for Path 15) were given the opportunity to comment on or protest that filing. Enron did just that. As a member of CNMP, Enron raised all the issues it has raised again in this proceeding, including the claim that it improperly was excluded from participation in the negotiation of the operating instructions in question. Enron had a fair opportunity to have its arguments heard. Nonetheless, the Commission found it appropriate to accept the negotiated revisions to the Path 15 operating instructions in Docket No. ER99-1770.

Enron's claim that it lacks access to sufficient information as to how Path 15 is being managed (*see id.* at 15-16) is simply not true. The documents filed in Docket No. ER99-1770 included operating instructions that include tables of curtailment priorities; template sheets with contract-specific information on the quality of transmission service available under Existing Contracts for Path 15; information about daily, hourly, and real-time scheduling rights; points of receipt and delivery; information about effective and termination dates for Existing Contracts that have transmission rights on Path 15; and spreadsheets with further information on curtailment procedures in connection with these contracts. In addition, various operating instructions describing the ISO's management of Path 15 are publicly posted on the ISO Home Page. These include Operating Procedure No. S-302, "Scheduling the Use of Existing Transmission Contract Rights," which includes five pages of details on scheduling and curtailments over Path 15, including Section XI that specifically addresses Path 15 managers, and which was posted on September 2, 1999. Also posted is Operating Procedure No. S-319, "Real-Time Path 15 South to North Flow Mitigation Procedure"; this was posted on October 7, 1999 and made effective as of January 15, 1999. Finally, the individual Existing Contracts for transmission service over Path 15 that are jurisdictional transmission service agreements are on file with the Commission.

The Commission should recognize that, in its initial brief, Enron attempts to bolster its case by taking out of context statements made in prior ISO filings. For example, Enron cites a portion of the ISO's Amendment No. 3 filing to support the proposition that the ISO currently improperly grants Existing Rights holders "higher priority" on Path 15. *See* Initial Brief of Enron on Path 15 and PX-Preference Issues at 5-6. In fact, the language quoted was a portion of the ISO's filing describing the "Effect of Tariff Amendment [No. 3] on Other Market Participants." That language therefore specifically related to the Amendment No. 3 Tariff revisions concerning transmission priority for "Eligible Regulatory Must-Run Generation" and "Eligible Regulatory Must-Take Generation" proposed in that amendment. Those Tariff revisions were rejected by the Commission in its March 27, 1998 Order.

Similarly, Enron notes that, in the Amendment No. 3 filing, the ISO identified software issues related to Path 15. *See id.* at 6. Based on this reference, Enron suggests that the ISO's software may currently be unable to "properly handle" conditional firm transmission rights. As the transmittal letter for the Amendment No. 3 filing makes clear, however, the ISO, in February 1998, was simply requesting authority to stage functionality of certain features relating to curtailments on Path 15, pending the installation and testing of software being developed for implementation by the start of ISO operations. Specifically, the ISO explained that, until software changes were completed, it would be forced to use manual "work-arounds" for curtailments on Path 15, and that such manual work-arounds would not allow the ISO to curtail in exactly the manner specified in PG&E's original Existing Contract operating instructions for Path 15.[43] The ISO explained that the work-arounds would be a "short-term solution (which may, in fact, not be used at all if software installation and testing are completed as scheduled)."[44] These software delays have long since been resolved. The ISO's filings in Docket No. ER99-1770 (as well as Operating Procedure No. S-302) make clear that the ISO now manages curtailments for transmission service over Path 15 scheduled pursuant to Existing Contracts in accordance with the operating instructions negotiated between PG&E and the other parties to such contracts. The statements from the ISO's Amendment No. 3 filing cited by Enron therefore have nothing to do with the issues being addressed in the instant proceeding.

[43] *See* Transmittal Letter for Amendment No. 3 filing, Docket Nos. EC98-19-016 and ER96-1663-017 (Feb. 25, 1998), at 11-12.

[44] *Id.* at 11.

b. Has the ISO improperly allowed PG&E to retain operational control over Path 15 in violation of its tariff? [Issue No. 488, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Enron and Coral]

Enron contends that the ISO has allowed PG&E to retain an inappropriate level of operational control over Path 15, "notwithstanding that the purpose of the CAISO is to assume operational control previously exercised by the Transmission Owners in order to prevent the Transmission Owners from exerting market power." *See* Initial Brief of Enron on Path 15 and PX-Preference Issues at 10. Enron claims that the ISO has allowed PG&E to maintain the authority over Path 15 that the company enjoyed prior to the creation of the ISO, to the detriment of Market Participants.

Most of these arguments are repetitions of Enron's claims that the operating instructions for Path 15 were improperly developed and that the ISO has failed to comply with Section 2.4.4.5 of the ISO Tariff. The ISO has responded to these claims in the portion of this brief addressing Issue B.1.a, above.

Enron also contends that the ISO has deferred the day-to-day calculation of Available Transfer Capacity ("ATC") for new firm uses on Path 15 to PG&E, placing PG&E in "complete control over access to a commercially significant transmission path in California." *See* Initial Brief of Enron on Path 15 and PX-Preference Issues at 13. This is simply not the case. The ISO calculates and posts ATC information for Path 15, and other interregional interfaces, based on the current Operational Transfer Capacity ("OTC") of the relevant path, less any Committed Uses for Existing Contracts. This is a necessity due to the varied and complex Existing Contracts with transmission rights over Path 15. Moreover, PG&E's performance of this function for Path 15 is the direct outcome of the operating instructions negotiated by the parties with Existing Contracts for that path, in accordance with the ISO Tariff and Commission orders. The fact that the Committed Uses information for Path 15 is provided to the ISO through this procedure in no way demonstrates that the ISO has abdicated its responsibility to calculate ATC for Path 15. In actuality, the ISO has found that PG&E, as the Existing Contract facilitator, has provided more new firm use availability than if the ISO were solely managing the path, because PG&E is in a better position to interpret Existing Contracts.

Further, despite Enron's claims to the contrary (*see id.* at 14-15), the ISO also has retained the independent responsibility for implementing schedules and curtailments over Path 15. Specific procedures by which the ISO fulfills this function are set forth in the publicly posted Operating Procedure No. S-302. A review of that procedure, as well as of the ISO's filings in Docket No. ER99-1770, provides ample detail on the interaction between the ISO and PG&E.

In essence, Enron claims that it is improper for the ISO to allow PG&E to have an active role in implementing aspects of the Path 15 operating instructions that derive from PG&E's contracts.[45] However, provisions of the ISO Tariff accepted by the Commission, in addition to requiring the ISO to follow the

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45 Enron also suggests that the Path 15 operating instructions are somehow contrary to Order No. 888's ISO Principle No. 1, which states that the governance of an independent system operator should be independent of any one class of participants, including transmission owners. *See* Initial Brief of Enron on Path 15 and PX-Preference Issues at 12. Since Enron offers no discussion of the ISO's governance or of how that governance might relate to the process by which parties to Existing Contracts negotiated operating instructions for Path 15, this statement is inexplicable at best and obfuscatory at worst.

operating instructions developed by parties to Existing Contracts (including Participating TOs), also provide for the Participating TOs themselves to exercise such operating instructions in some circumstances. Section 2.4.4.5.1.2 of the ISO Tariff provides as follows:

> To the extent that the operating instructions [developed by the parties to the Existing Contracts] can be exercised independently of the ISO by the parties to the Existing Contracts and the results forwarded to the ISO, the operating instructions shall be exercised by the Participating TOs, and the outcomes forwarded to the ISO. The determination of whether the operating instructions can be "exercised independently of the ISO by the parties to the Existing Contracts" shall be made using the same procedures described in Section 2.4.4.4.1.1.

As discussed above, the procedures described in Section 2.4.4.4.1.1 were followed with respect to the development of the Path 15 operating instructions, including the designation of PG&E as Existing Contract Path 15 manager. That being the case, it is wholly appropriate under the ISO Tariff for PG&E to independently implement aspects of the operating instructions for Path 15.

All of the arrangements described in the operating instructions for Path 15 accepted by the Commission, in Docket No. ER99-1770, as well as in Operating Procedure No. S-302, are consistent with the ISO Tariff and all applicable Commission orders. Moreover, none of those arrangements alter the fact that it is the ISO that maintains Operational Control over Path 15. Nothing in Enron's initial brief provides any evidence to the contrary. The Commission should therefore reject Enron's arguments on this issue.

B.2. With respect to inter-zonal congestion management:

a. Has the ISO complied with the Commission's October 30, 1997 Order, 81 FERC ¶ 61,122 at 61,479, to make publicly available to Market Participants its Inter-zonal congestion management algorithm? Should the ISO have to make available to Scheduling Coordinators its congestion management software and transmission database, and is the ISO's refusal to provide this information to Scheduling Coordinators unjust and unreasonable? [Issue No. 537, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - City of Redding, California, City of Santa Clara, California, and the M-S-R Public Power Agency ("Cities / M-S-R"), and Palo Alto, MWD, Enron, WPTF, and DWR]

In the October 1997 Order, the Commission directed the ISO "to make publicly available the algorithm that it uses to manage Inter-Zonal Congestion." October 1997 Order, 81 FERC at 61,479. Proponents claim that the ISO has failed to comply with this directive. In fact, the ISO has made the Inter-Zonal Congestion Management algorithm available on the ISO Home Page.[46] The ISO has also posted additional information explaining the implementation of this algorithm.[47]

Proponents claim, however, that posting the algorithm and explanatory material is not enough. In addition to the algorithm employed in Inter-Zonal Congestion Management, they argue that the ISO must also make available the software program, documentation, network database, and other materials it uses to *operate* the algorithm. Joint Initial Brief on Issue B.2.a, at 6. This claim goes

[46] A paper setting forth the algorithm for Inter-Zonal Congestion Management, as well as other information, may be found at <http://www.caiso.com/marketops/technical>. A copy of this paper is attached to this brief as Attachment 3.

[47] *See* Ziad Alaywan, *Facilitating the Congestion Management System in California*, available at <http://www.caiso.com/aboutus/articles> and attached to this brief as Attachment 4.

well beyond any requirement imposed in the October 1997 Order and was not made in any request for rehearing of that Order. It is therefore untimely. This claim also exceeds the requirements the Commission has imposed on other ISOs that employ computer-based dispatch models to develop Congestion charges. *Cf., e.g., Pennsylvania-New Jersey-Maryland Interconnection, et al.*, 81 FERC ¶ 61,257, 62,256 (1997).

Moreover, the additional requirements that Proponents now ask the Commission to impose are inappropriate and unnecessary. First, the ISO has obtained the proprietary computer software that it employs for Congestion Management under license from an outside vendor. Publication of that software would violate the ISO's confidentiality obligations under its contract with the vendor. Second, the Commission has imposed other requirements on the ISO to enable Market Participants to ascertain the Usage Charges for which they will be responsible. Under the ISO Tariff, when the ISO determines that Scheduling Coordinators' Preferred Day-Ahead Schedules will result in Inter-Zonal Congestion, the ISO provides to each Scheduling Coordinator a Suggested Adjusted Schedule to relieve the Congestion, together with advisory information about the Usage Charges that Scheduling Coordinators may incur in using the constrained Inter-Zonal Interface. ISO Tariff, Section 2.2.8.2. The Commission also requires the ISO to advise Scheduling Coordinators of the amount of Inter-Zonal Congestion that would result from the Preferred Schedules. *See* October 1997 Order, 81 FERC at 61,479. This information enables Scheduling Coordinators to determine the Usage Charges for which they would be responsible before they are bound to Final Day-Ahead Schedules. In contrast, the additional information that Proponents seek would not improve their ability to predict Usage Charges or to verify the ISO's calculation, because that calculation necessarily depends upon the full complement of bids submitted by Scheduling Coordinators. Even Proponents recognize that those bids cannot be immediately disclosed without violating Market Participants' confidentiality expectations. *See* Joint Initial Brief on Issue B.2.a, at 6.

In these circumstances, the Commission's requirement that the ISO disclose its Inter-Zonal Congestion algorithm only was an appropriate application of the "rule of reason," under which the Commission determines which of the infinitude of contracts, rules, and practices affecting charges for jurisdictional service must be filed under Section 205 of the FPA (16 U.S.C. § 824d (1994)). *Cf. Public Service Co. of Colorado*, 67 FERC ¶ 61,371, 62,267 (1994).

b. <u>Whether section 10.3 of the Scheduling Protocol ("SP") addressing Congestion Management and pricing is sufficiently detailed to provide Market Participants with adequate information to determine in advance, the cost of a particular schedule? [Issue No. 116, Docket Nos. EC96-19-006, EC96-19-007, EC96-19-008, ER96-1663-007, ER96-1663-007, and ER96-1663-009. Proponent - Transmission Agency of Northern California ("TANC")]</u>

TANC contends that Section 10.3 of the SP provides insufficient information to enable Market Participants, including those unfamiliar with the ISO's Congestion Management processes, to determine Inter-Zonal Congestion costs in advance. Initial Brief of TANC at 5. Section 10.3 of the SP does not stand alone, however. The provision itself cross-references one of the subsections of Section 7.3.1 of the ISO Tariff. Section 7.3.1 provides over six pages of detail describing the calculation of Usage Charges. Additional detail is set forth in Appendix E to the Settlement and Billing Protocol ("SABP"). TANC provides no support for its claim that all of this information must be repeated or explicitly cross-referenced in Section 10.3 of the SP. Neither does TANC support its assertion that additional information about the development of Usage Charges is required to enable a Market Participant to compute Congestion costs for which it may be responsible. In fact, the Commission requires the ISO, during the Day-Ahead scheduling process, to provide information to Scheduling Coordinators to advise them of expected Usage Charges as well as expected amounts of Inter-Zonal Congestion, based on Preferred Schedules. *See* October 1997 Order, 81 FERC at 61,477. TANC has not even attempted to explain why this information is insufficient. Its demand that Section 10.3 of the SP be expanded should accordingly be denied.

c. <u>Whether adjustment bids left standing after the close of the Hour-Ahead market should be converted into supplemental energy bids? [Issue No. 461, Docket No. ER98-3760-000. Proponents - the Utility Reform Network and Utility Consumers Action Network ("TURN / UCAN") and Southern Cities]</u>

Proponents assert that prior to the ISO's July 15, 1998 Clarification filing, Section 4 of the Schedules and Bids Protocol ("SBP") provided that Adjustment Bids left standing after Congestion Management would be converted to Supplemental Energy bids, and that the ISO reversed that policy in the Clarification filing without explanation. Joint Initial Brief on Issue B.2.c, at 3. Proponents are mistaken. Although the ISO intended in August 1997 to convert remaining Adjustment Bids to Supplemental Energy bids, and so informed the Commission (*see* October 1997 Order, 81 FERC at 61,476), the ISO modified that program prior to filing any implementing provisions. Thus, Section 4 of the SBP, as filed on October 31, 1997, reads in part as follows:

> These Adjustment Bids will *not* be transformed into Supplemental Energy bids. However, these Adjustment Bids are treated as standing offers to the ISO and may be used by the ISO in the Real Time Market for the sole purpose of managing Intra-Zonal Congestion.

(Emphasis added.) Under the ISO's market design, the Imbalance Energy market is distinct from Congestion Management. Adjustment Bids are determined by the value that a Scheduling Coordinator assigns to a particular combination of resources. The ISO does not believe that these factors should influence the establishment of the Ex Post Price that is paid or charged in the Imbalance Energy market. The ISO will, of course, be reviewing the role of Adjustment Bids in its comprehensive evaluation of Congestion Management reform.[48]

d. Whether the ISO has improperly restricted Adjustment Bids with respect to inter-Scheduling Coordinator trades? [Issue No. 398, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent – TURN / UCAN]

TURN/UCAN contends that the ISO should be required to accept Adjustment Bids in connection with inter-Scheduling Coordinator trades, and to adjust such Schedules in accordance with the Tariff provisions governing Inter-Zonal Congestion Management. Initial Brief on Issues B.2.d, B.8, and N.4, at 2. The ISO does not dispute the value of Adjustment Bids in connection with

[48] *See* Transmittal Letter for Motion for Clarification or, In the Alternative, Request for Rehearing, and Request for Expedited Consideration of the California Independent System Operator Corporation, Docket No. ER00-555-000 (Feb. 7, 2000), at 2-3 (discussing the ISO's response to the Commission's order on Amendment No. 23, *California Independent System Operator Corporation*, 90 FERC ¶ 61,006).

inter-Scheduling Coordinator Energy Trades. The ISO Governing Board has recently approved the implementation of procedures to allow inter-Scheduling Coordinator trades in the Congestion Management process through the submission of Adjustment Bids. Numerous stakeholders believed that this would be an important feature to implement between now and the time the ISO completes its stakeholder process on Congestion Management reform and implements the results of the process. Thus, at the ISO Governing Board meeting held on March 22, 2000, the Board authorized ISO management to implement inter-Scheduling Coordinator trades of Adjustment Bids as soon as possible.

e. <u>Is the 3000-bus model adopted by the ISO for prices and decisions on inter-zonal access anticompetitive, unjust or unreasonable, or should the ISO adopt a simplified commercial 15-bus model, which treats all resources within a zone identically on a zonal basis? [Issue No. 298, Docket Nos. EC96-19-003 and ER96-1663-003. Proponents - Enron and WPTF]</u>

Proponents suggest in their initial brief that a 30-bus model for Inter-Zonal Congestion Management should replace the ISO's current model. They propose that the ISO implement portfolio bidding on a zonal basis by Scheduling Coordinators. Proponents believe these changes would make the ISO's Congestion Management methodology simpler, more efficient, and more transparent. Joint Initial Brief on Issues B.2.e and H, at 2-3.

However, as Proponents also recognize, the Commission has already 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; Joint Initial Brief on Issues

B.2.e and H, at 5. Proponents' proposal regarding a 30-bus model will be considered in that context. Moreover, an approval or acceptance by the Commission of Proponents' suggestions at this time would short-circuit or frustrate altogether the stakeholder process that the Commission has ordered the ISO to initiate. And because it is unclear exactly what form a potential replacement for the current Congestion Management model may take, implementing Proponents' suggestions could result in a significant mismatch between any new Congestion Management model and the model Proponents have suggested.

For the foregoing reasons, the ISO respectfully requests that the Commission deny Proponents' proposal that the ISO be directed to modify its zonal Congestion Management approach as requested, thus allowing the stakeholder process ordered by the Commission to move forward effectively. Proponents have an opportunity to participate in that stakeholder process, and the ability to promote their views in this forum. In addition, if the issue is still being considered by the time the ISO is to report back to the Commission on the outcome of the stakeholder process, then Proponents can present their concerns to the Commission.

B.3. <u>With respect to intra-zonal congestion management:</u>

a. <u>Has the ISO properly complied with the Commission's October 30, 1997 Order at page 61,478, regarding the filing of specific practices and procedures it uses to manage Intra-Zonal Congestion, including an explanation of pricing and billing for Intra-Zonal Congestion? [Issue No. 535, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Cities / M-S-R and Palo Alto, MWD, and DWR]</u>

Proponents assert that the ISO has failed to comply with the Commission's directive cited in the issue statement. Proponents concede that the ISO has filed a series of amendments regarding the management of

Intra-Zonal Congestion. *See* Joint Initial Brief on Issue B.3.a, at 1-2. Nonetheless, they make three arguments to support their claim that the ISO has failed to comply. First, they assert that the Tariff provisions remain "murky," citing the Commission's recent decision that the ISO lacks the authority to call resources out-of-market when market bids are available for Dispatching units to address Intra-Zonal Congestion. Second, they cite the ISO's failure to comply with a recommendation that it substitute "Participating Generators" for the term "resources" in Section 7.2.6.2. Finally, they allege that the ISO failed to comply with the Commission's order that it revise the ISO Tariff to provide for informing Market Participants whether Imbalance Energy bids are used for system balancing or to manage Intra-Zonal Congestion. *See id.* at 3-7.

Proponents fail, however, to consider the context of the Commission's October 1997 Order. There the Commission was addressing a provision of the ISO Tariff that stated simply that the ISO would manage Intra-Zonal Congestion using existing Operating Procedures and standard industry practices. *See* October 1997 Order, 81 FERC at 61,478. Thus, the Commission did not find the ISO Tariff ambiguous or lacking in specificity; rather, it found that there were simply no provisions laying out the practices and procedures for Intra-Zonal Congestion Management. As the ISO identified in its July 15, 1998 Clarification filing, it subsequently filed amendments adding Sections 7.2.6.2 and 7.2.6.3 to the ISO Tariff, as well as Sections 7.4 and 8.4 to the Dispatch Protocol ("DP"), which set forth the ISO's practices and procedures for the real-time management of Intra-Zonal Congestion, including the provisions regarding charges and payment. Proponents are therefore simply wrong when they state that the ISO never made any clarifying change to its Tariff in response to the Commission Order. *See* Joint Initial Brief on Issue B.3.a, at 3-4.

Proponents' assertions do not contradict the simple fact that the ISO did incorporate the procedures for management of Intra-Zonal Congestion into the ISO Tariff. They point to the ISO's belief that it was entitled, under the ISO Tariff, to disregard certain Supplemental Energy bids in managing Intra-Zonal Congestion, as evidence that the Tariff provisions are ambiguous. *See id.* However, the Commission found that the ISO was in error and the provisions were unambiguous. *See California Independent System Operator Corporation*, 90 FERC at 61,010-11. More importantly, one cannot reasonably equate a dispute regarding the interpretation of Tariff language with a finding that language is not in compliance with a Commission order.

Proponents' second assertion, that the ISO failed to comply with Proponents' recommendation that it substitute "Participating Generators" for the term "resources" in Section 7.2.6.2 of the ISO Tariff (*see* Joint Initial Brief on Issue B.3.a, at 4-5), is no better evidence that the ISO has disregarded Commission orders. There is simply no relationship between the October 1997 Order and Proponents' recommended revision (of language that did not even exist when the Commission issued the order). Moreover, Proponents' recommendation is substantively flawed. Section 7.2.6.2 states that the ISO will use its authority to Redispatch resources if Adjustment Bids and Imbalance Energy bids are exhausted. By its own terms, this section is limited to resources that the ISO has the authority to Dispatch. It does not pretend to define or expand that authority. Proponents' suggestion, however, would significantly limit the ISO's authority, and would hamper the management of Intra-Zonal Congestion, by limiting Dispatch to only Participating Generators, and excluding Loads (e.g., pumps), imports and exports of Supplemental Energy, and non-Participating Generators.

Proponents' third assertion, that the ISO failed to comply with the Commission's July 30, 1999 order[49] (*see id.* at 6-7), is irrelevant to the ISO's compliance with the October 1997 Order. In addition, it is simply wrong. On November 19, 1999, in Docket No. ER99-3301, the ISO filed the modification specified in the July 30, 1999 order. The Commission accepted the ISO's compliance filing on January 13, 2000. *California Independent System Operator Corporation*, 90 FERC ¶ 61,025 (2000).

Finally, even assuming *arguendo* that Proponents had provided evidence that the ISO failed properly to comply with the October 1997 Order regarding the filing of Congestion Management practices and procedures, the issue is now moot. As Proponents acknowledge (*see* Joint Initial Brief on Issue B.3.a, at 5), the Commission has directed the ISO to undertake a comprehensive evaluation of Congestion Management redesign. This redesign will, of course, be embodied in amendments to the ISO Tariff. Proponents may participate in the stakeholder process leading up to these amendments and, if they believe that the amendments are poor policy or insufficiently specific, they have the ability to raise their concerns in the stakeholder process. In addition, they may protest the amendments when they are filed. However, Proponents' efforts to predetermine the outcome of this stakeholder process now are misguided.

b. Whether the ISO failed to properly implement the Commission's October 30, 1997 Order at 61,478, with respect to the deletion of sections 2.5.22.8, 7.2.1.4.2, and 7.3.2 of the ISO Tariff? [Issue No. 536, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Cities / M-S-R and Palo Alto]

Proponents assert that the Commission's October 1997 Order directed the ISO to delete a number of sections of the ISO Tariff related to Intra-Zonal

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[49] *California Independent System Operator Corporation*, 88 FERC ¶ 61,146 (1999).

Congestion Management, including Sections 2.5.22.8, 7.2.1.4.2, and 7.3.2. They note that the ISO's June 1, 1998 Compliance filing did not delete these sections, and argue that the ISO has therefore failed to comply with the October 1997 Order. *See* Initial Brief of Cities/M-S-R and Palo Alto at 9-10. Proponents fail to explain the full context of the Commission's order.

In the October 1997 Order, the Commission directed the ISO to delete the sections in question not because it substantively rejected them, but because the ISO was not ready to implement them. It informed the ISO that it would need to refile the sections when it was ready to implement them. *See* October 1997 Order, 81 FERC at 61,478. As discussed in relation to Issue B.3.a, above, subsequent to the October 1997 Order, the ISO filed Tariff amendments setting forth its Intra-Zonal Congestion practices, procedures, and protocols. As a result, by the time the Compliance filing was made, the ISO was ready to implement Sections 2.5.22.8, 7.2.1.4.2, and 7.3.2. The ISO therefore simply amended Section 2.5.22.8 to be consistent with the Intra-Zonal Congestion practices, procedures, and protocols that were being implemented. It would have exalted form over substance to require the ISO to delete the sections at that time. Proponents had as great an opportunity to protest the amended substance of the provisions at the time of the Compliance filing as they would have if the ISO had refiled the provisions.

Indeed, Proponents have taken the opportunity to protest the substance of amended Section 2.5.22.8 at this time. These protests are without merit. Proponents argue that the Tariff language in question, which states that the ISO will under certain circumstances exercise its authority to Redispatch resources, could be read as an expansion of the ISO's authority. *See* Initial Brief of Cities/M-S-R and Palo Alto at 11-12. However, the language specifies no additional authority. By its own terms, it merely sets forth one circumstance in which the ISO will exercise authority that it is given by *another* Tariff provision or contract. There is no reason to require an additional amendment to this already clear provision.

Proponents' real concern appears to be the scope of the ISO's authority over Generators that are not Participating Generators. The ISO notes that in the initial brief on Issue B.5.c, the proponents on that issue recognize that the ISO should not be "limited to being able to call on *participating* generators to respond to potential or actual emergencies." Joint Initial Brief on Issue B.5.c, at 6 (emphasis in original). In addition, the ISO has under certain circumstances exerted indirect authority over non-Participating Generators. For example, UDCs are required under Section 4.4 of the ISO Tariff to comply with ISO directions concerning the management of System Emergencies. If a Generator is not a Participating Generator, but does have a contractual relationship with a UDC under which the UDC has authority to Redispatch the Generator, the ISO could direct the UDC to do so in the case of a System Emergency. Moreover, the ISO's authority to Dispatch both Participating and non-Participating Generators is consistent with the Commission's conclusion with regard to the Redispatch authority of an RTO. In its Order No. 2000, the Commission concluded "that the RTO must have the right to order the redispatch of any generator connected to the transmission facilities it operates, if necessary for the reliable operation of the transmission system." Order No. 2000, FERC Stats. and Regs., Regs. Preambles ¶ 31,089, 31,104.

Finally, this issue is now moot. As Proponents acknowledge, the Commission has directed the ISO to undertake a comprehensive redesign of its Congestion Management procedures. Initial Brief of Cities/M-S-R and Palo Alto at 12-13. This redesign will, of course, be embodied in amendments to the ISO Tariff. Proponents may participate in the stakeholder process leading up to these amendments and, if they believe that the amendments inappropriately expand the ISO's authority, they have the ability to voice their concerns in the stakeholder process. In addition, they may protest the amendments when they are filed.

c. <u>Does Section 2.5.22.8 of the ISO Tariff give the ISO excessive authority in managing intra-zonal congestion by extending its control over the dispatch of non-participating generators? [Issue No. 530, Docket No. ER98-3760-000. Proponents - MWD, SMUD, and CAC]</u>

Proponents argue that Sections 2.5.22.8 and 7.2.6.2 of the ISO Tariff expand the ISO's authority to Redispatch Generators to resolve Intra-Zonal Congestion. *See* Joint Initial Brief on Issue B.3.c, at 2-3. As the ISO has explained in relation to Issue B.3.b., above, these Tariff sections provide the ISO with no authority beyond that otherwise provided in the Tariff or in other agreements. Although the instant issue refers to the Dispatch of non-Participating Generators, Proponents appear to be concerned with Generators that have not bid into the ISO's markets and with QFs. However, non-Participating Generators are Generators that have not bid into the ISO's markets and have not executed a PGA.

The Commission, in its order on Amendment No. 23 to the ISO Tariff, has already concluded that the ISO does not have the authority to call resources out-of-market when market bids are available for calling upon Participating Generators to address Intra-Zonal Congestion in real time. *See California Independent System Operator Corporation*, 90 FERC at 61,011-14. If Proponents merely seek affirmation of the Commission's rulings, there is no "unresolved issue" here.

If Proponents are instead contending that the ISO's authority, under Section 5.1.3, to direct the Redispatch of a Participating Generator in the case of an actual or threatened real-time emergency does not extend to addressing real-time Intra-Zonal Congestion when bids are unavailable, then adoption of their position would significantly threaten the reliability of the ISO Controlled Grid. Unresolved Intra-Zonal Congestion, in and of itself, would present a System Emergency. If the Adjustment Bids and Imbalance Energy bids that can resolve the Intra-Zonal Congestion are insufficient, then there is a very real threat of a System Emergency that the ISO can avoid only by going outside the market. As the Commission has stated, "[t]here is no dispute that the ISO currently has the authority to direct any Participating Generator to change its dispatch when the ISO deems it necessary *to protect system reliability.*" *Id.* at 61,010 (footnote omitted) (emphasis added). The ISO must retain the authority to Dispatch Participating Generators when necessary to address that concern.

One of the proponents, EPUC/CAC, puts forth arguments regarding QFs (*see* Joint Initial Brief on Issue B.3.c, at 8-11) which are equally unfounded. These arguments are addressed in relation to other issues including, for example, Issues A.3.a, A.3.c, and B.5.b.

B.4. <u>With respect to Overgeneration:</u>

a. <u>Does the ISO Tariff, particularly section 2.3.4, allow the ISO to order reductions for Overgeneration by entities that are operating in balance and/or did not cause the Overgeneration problem in an unjust, unreasonable, or discriminatory manner, and is section 2.3.4.4 of the ISO Tariff, which provides that the ISO can mitigate real time Overgeneration by requiring all Scheduling Coordinators to make pro rata cuts in their Generation or imports, contrary to the requirements in the Commission's October 30, 1997 Order that those who cause Overgeneration problems be responsible for alleviating those conditions and contrary to the Commission's directive to honor Existing Contracts? [Issue No. 213, Docket Nos. EC96-19-0021 and ER96-1663-022, and Issue Nos. 366, 472, and 505, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Enron, WPTF, Southern Cities, DWR, SMUD, CAC, and TANC]</u>

In its October 1997 Order, the Commission rejected a plan under which certain Overgeneration conditions (i.e., circumstances in which the Generation that was required to operate for regulatory, contractual, or other reasons exceeds Demand) would be managed during the Day-Ahead scheduling process through adjustments to the Schedules submitted by certain Scheduling Coordinators, including some whose Schedules did not contain excess Generation. The Commission concluded that the requirement that each Scheduling Coordinator's Schedule be balanced between Load and Generation should apply during Overgeneration conditions. October 1997 Order, 81 FERC at 61,526.

Accordingly, the ISO deleted provisions of the ISO Tariff relating to the management of Overgeneration in forward markets through adjustments to Schedules in forward markets. Thus, the ISO Tariff does require each Scheduling Coordinator to match its Generation to its Load in the Schedules it submits to the ISO, even during Overgeneration conditions. In Amendment No. 6, the ISO proposed amendments to Section 2.3.4 of the ISO Tariff to detail how it would address Overgeneration situations that arise in real-time operations, even though Scheduling Coordinators have submitted Balanced Schedules. Essentially, the ISO endeavors to reduce Overgeneration by calling upon decremental bids that Scheduling Coordinators have submitted for the reduction of Generation and imports, and the increase in Demand, by advising Scheduling Coordinators of the situation and advising them that the price of real-time Energy had been reduced to zero or to a negative amount, and by exporting Energy to other Control Areas. Only if these measures are insufficient to reduce the excess real-time Generation will the ISO resort to non-economic measures, by directing pro rata reductions in Scheduling Coordinators' Generation and exports, proportional to the Load they serve and, if necessary, ordering reductions in the output of specific resources.[50]

Proponents do not challenge the first steps of this process, but contend that the non-economic reduction measures violate the Commission's directive that Overgeneration conditions should be absorbed only by those Scheduling Coordinators who contribute to the problem. *See* Joint Initial Brief on

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[50] *See* Transmittal Letter for Amendment No. 6 filing, Docket Nos. EC96-19-021 and ER96-1663-022 (Mar. 23, 1998), at 13-16.

Issue B.4.a, at 3-7.

First, they argue that the provision for pro rata curtailments in Section 2.3.4.4 inappropriately requires Scheduling Coordinators that do not have excess Generation in their portfolios to contribute to alleviating other Scheduling Coordinators' Overgeneration. *See id.* at 3-5, 6-7. This provision was put in place to guard against the possibility that insufficient decremental bids would be available to address Overgeneration. This concern, however, was substantially reduced by the addition, as part of Amendment No. 13, of the capability for Scheduling Coordinators to submit negative priced Imbalance Energy bids. *See California Independent System Operator Corporation*, 86 FERC ¶ 61,122, 61,420-21 (1999). Now, when Overgeneration conditions prevail, the real-time Energy price can be negative, requiring Scheduling Coordinators who provide excess Energy in real time to pay the ISO. This causes those Scheduling Coordinators who contribute to real-time Overgeneration to pay the associated costs whenever possible. Consequently, the ISO has determined that it no longer requires the authority (which it has never exercised) to direct pro rata curtailments to manage Overgeneration. The ISO would accordingly agree to the deletion of Section 2.3.4.4 of the ISO Tariff.

Second, some of the proponents argue that Section 2.3.4.5 gives the ISO too much discretion in authorizing the ISO to issue mandatory Dispatch instructions for the reduction of Generating Unit output or exports when other measures to manage Overgeneration are insufficient. They would require the ISO to submit procedures to guide its exercise of this authority. Joint Initial Brief on Issue B.4.a, at 6. This argument is unfounded. If Overgeneration conditions are left unaddressed in real-time operations, reliability will suffer because the ISO will be unable to meet its responsibility as Control Area operator to match Generation and Load. When other means of eliminating the Overgeneration are unavailable, the ISO must have the flexibility to address the System Emergency that would otherwise be created. If the ISO cannot issue Dispatch instructions to Generating Units in these circumstances and rely on their adherence to those instructions, "the ISO will be unable to effectively manage and control the ISO Controlled Grid." October 1997 Order, 81 FERC at 61,456-57.[51] Plainly, the ISO may not use this authority arbitrarily, but must issue Dispatch instructions that are designed to alleviate the Overgeneration condition being experienced. No written procedure could identify the particular Generating Units, or combinations thereof, that would be Dispatched to address all of the circumstances in which Overgeneration could occur. Moreover, any such procedure would go into the kind of detail that is inappropriate and unnecessary for a tariff. Finally, the ISO notes that, since the implementation of negative Imbalance Energy bids (in particular, negative decremental bids in which the ISO is paying entities not to generate), it has not had to avail itself of the authority reserved under Section 2.3.4.5. Nevertheless, because that provision simply restates the ISO's authority to issue Dispatch instructions to avert a threatened System Emergency or real-time operating problem, it should remain in the ISO Tariff.

[51] *See also California Independent System Operator Corporation*, 90 FERC at 61,010-11 (ISO can issue Dispatch instructions when resources are unavailable to manage Intra-Zonal Congestion).

b. <u>Whether Section 10.2 of the Scheduling Protocol fails to comply with the October 30, 1997 Order by failing to adopt and implement procedures for allocating transmission capacity on a pro-rata basis for each Scheduling Coordinator when the ISO reduces a Scheduling Coordinator's Generation due to insufficient transmission capacity. [Issue No. 437, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - TANC]</u>

In the October 1997 Order, the Commission directed the ISO "to clarify the procedures that will be used when allocating transmission capacity on a *pro rata* basis. In particular, the Tariff should specify whether the ISO will maintain balanced schedules for each Scheduling Coordinator when it reduces a Scheduling Coordinator's Generation due to insufficient transmission capacity." October 1997 Order, 81 FERC at 61,485. Section 10.2 of the SP accordingly describes the process of Inter-Zonal Congestion Management. It specifies, among other things, that pro rata adjustments in real time to Scheduling Coordinators' portfolios will only be made if Adjustment Bids are exhausted before Congestion is eliminated, and will exclude Schedules that rely on transmission service under Existing Contracts. SP 10.2(d). It also states that "[e]ach SC's portfolio will be kept in balance . . . after adjustments." SP 10.2(b).

TANC does not contend that Section 10.2 of the SP fails to address its substantive concerns. Instead, TANC asserts that this section cannot constitute compliance with the October 1997 Order, because it was not black-lined in the ISO's June 1, 1998 Compliance filing and because it is included in the SP, rather than in the ISO Tariff. *See* Initial Brief of TANC at 6-7. Neither assertion has merit.

First, the reason that changes to Section 10.2 of the SP were not black-lined in the ISO's June 1, 1998 Compliance filing is that the whole provision was developed to provide the procedure required by the Commission in the October 1997 Order. At the time the October 1997 Order was issued, the ISO had not filed the ISO protocols with the Commission. *See* October 1997 Order, 81 FERC at 61,441-42. The submission of a provision of the SP that had not previously been filed presents no need or opportunity for black-lining, and plainly constitutes compliance with the Commission's directive.

Second, subsequent to the October 1997 Order, the Commission required the ISO to file all of the ISO protocols with the Commission. *Pacific Gas and Electric Co., et al.*, 81 FERC ¶ 61,320, 62,471 (1997). The SP, including Section 10.2 of the SP, is thus part of the ISO's rate schedule on file with the Commission and can only be changed through a filing submitted under Section 205 of the FPA (16 U.S.C. § 824d (1994)). TANC has identified no practical difference between including the Inter-Zonal Congestion Management procedure in the SP and including it in the ISO Tariff. TANC's demand that the procedure be shifted should accordingly be rejected.

c. Are the changes in Amendment No. 6 to the ISO Tariff regarding Overgeneration management and giving native Load an implicit priority in Congestion Management inconsistent with prior Commission Orders (regarding, inter alia, Existing Contracts) or unduly discriminatory and otherwise unreasonable? [Issue Nos. 198, 199, and 266, Docket Nos. EC96-19-021 and EC96-1663-022. Proponents - Enron, WPTF, DWR, TANC, Turlock Irrigation District ("Turlock"), Cities / M-S-R, SMUD, and the California Power Exchange ("PX")]

On March 23, 1998, the ISO filed Amendment No. 6 to the ISO Tariff to address a number of issues that had arisen during the first coupled market demonstration test, and which had to be resolved before the imminent commencement of ISO operations. The Commission accepted Amendment No. 6, subject to further orders, in *California Independent System Operator Corporation*, 82 FERC ¶ 61,327 (1998). Proponents raise two distinct issues with respect to Amendment No. 6. Some of the proponents challenge the provisions of Amendment No. 6 relating to the real-time management of Overgeneration conditions. *See* Joint Initial Brief on Issue B.4.c, at 3-5. That issue is addressed in the ISO's discussion of Issue B.4.a, above. One of the proponents, the PX, challenges provisions giving Load an implicit priority in Congestion Management. *See id.* at 5-7. The ISO responds below regarding this latter issue.

In Amendment No. 6, the ISO explained that its coupled market demonstration test had revealed a potential problem with its Congestion Management process. When there were insufficient Adjustment Bids to relieve Congestion, the ISO's Congestion Management ("CONG") software called for curtailments of both Load and Generation. The CONG software implements curtailments by using implicit Adjustment Bids assigned to Load and Generation that do not submit actual Adjustment Bids. When actual Adjustment Bids are used up, the software calls for adjustments by other Load and Generation on the basis of these implicit Adjustment Bids. Before Amendment No. 6, the software assigned the same implicit Adjustment Bid level to Load and Generation. In this respect, the software did not take into account the fact that Load is relatively less flexible than Generation and so may not achieve the assumed level of reduction, leaving the Congestion unrelieved even if it were chosen. To remedy this problem, the ISO modified the software to assign a higher implicit Adjustment Bid level to Load than to Generation, so that the software would call first for curtailments by Generation that had not submitted a lower Adjustment Bid. The revised levels of implicit Adjustment Bids were reflected in Section 4.6 of the SBP.[52]

The PX challenges this modification to Section 4.6, arguing that it could require a Generator to supply more Energy than it has offered to supply, even if it is unable to do so. *Id.* at 6. The PX fails to note, however, that the Commission approved the deletion of the table of Adjustment Bid values in Section 4.6 from the SBP as part of its order on Amendment No. 21. *See California Independent System Operator Corporation*, 89 FERC ¶ 61,169, 61,511 (1999). The PX is thus complaining about a provision of the ISO Tariff that no longer exists and that is no longer an issue at this time.

[52] *See* Amendment No. 6 filing, Docket Nos. EC96-19-021 and ER96-1663-022 (Mar. 23, 1998), at 36-38. As revised, Section 4.6 of the SBP established $700/MWh as the implicit Adjustment Bid assigned to Load and $600/MWh as the implicit Adjustment Bid for Generation and exports. *See id.* at 39-40.

Further, even if Section 4.6 had not been eliminated, the substance of the PX's objection is unfounded. First, implicit Adjustment Bids are assigned by the ISO's CONG software only to resources that do not submit Adjustment Bids. A Generator can avoid the effects the PX complains of by submitting Adjustment Bids that the ISO can use in Congestion Management.

Second, the PX is complaining about a circumstance that has little or nothing to do with Amendment No. 6. Whenever insufficient Adjustment Bids are available to the ISO for Congestion Management, the ISO must call for adjustments to the output of resources to ensure that portions of the ISO Controlled Grid are not overloaded. This could require some resources to operate at higher levels than they would prefer, while the output of other resources is curtailed, depending upon their location relative to the constraint. The ISO has determined, based on experience during the coupled market demonstration test, that Load is relatively less responsive to curtailment directives issued by the ISO, requiring the ISO to rely primarily on adjustments by Generating Units to relieve Congestion. The reflection of the reduced responsiveness of Load in the ISO's CONG software, as described in Amendment No. 6, was simply a recognition of reality, which the ISO *must* take into account if it is to manage Congestion effectively.[53]

In other words, whether or not the ISO took account of this difference between Load and Generating Units in its software, when Adjustment Bids were not available to relieve Congestion, the ISO's operators would still have to select

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[53] *See id.* at 36-37.

those resources upon whose adjustment they could rely to address the problem. Based on the ISO's experience with the responsiveness of Load, they would have to turn to Generating Units. The only consequence of removing the implicit Load Preference from the ISO's software would be that the ISO's operators would be forced to disregard the software's selection of resources to be adjusted in Congestion Management, and make the selections manually. Such a process would be administratively burdensome, and would have no corresponding benefits for Generators or any other Market Participants.

The PX also complains that the ISO did not include resources outside of the Control Area among the resources whose output could be adjusted to manage Congestion when Adjustment Bids are exhausted. *See* Joint Initial Brief on Issue B.4.c, at 7. However, Amendment No. 6 assigned an implicit priority only to Loads within the ISO Control Area. To the extent that the ISO can require a resource outside its Control Area to increase output to manage Congestion, doing so would not substitute for a reduction in Load or increase in Generation within the ISO Control Area. When the inter-Control Area interface is congested, such an adjustment would *increase* Congestion, not decrease it. Consequently, the Commission should reject Proponents' proposals.

B.5. With respect to the ISO's dispatch authority:

a. Is section 5 of the ISO Tariff unduly discriminatory because it requires a PGA for schedulers of Ancillary Services from within the ISO Controlled Grid, but Amendment No. 10 does not require a PGA for generation provided from outside the ISO Control Area? [Issue No. 245, Docket Nos. EC96-19-035, ER96-1663-036. Proponent - Turlock]

Turlock contends that Section 5 of the ISO Tariff is unduly discriminatory because it requires a PGA for those who would sell Ancillary Services to the ISO from within the ISO Controlled Grid, but not for those who sell Ancillary Services from outside the ISO's Control Area. Initial Brief on Issue B.5.a, at 2. Turlock's claim is without merit.[54]

Turlock states that it would like to supply Ancillary Services to the ISO but that it has encountered a barrier to entry: the execution of a PGA. *Id.* at 3-4. Turlock does not question the technical standards for determining categories of Ancillary Services or establishing the quantities of Ancillary Services and Imbalance Energy to be purchased by the ISO on behalf of the Market Participants. Moreover, the requirements that Turlock challenges apply to *all* Generating Units located within the ISO Control Area. Thus, although it couches its claims in terms of discrimination, Turlock in fact seeks an exemption from requirements that apply generally to all Generating Units in the Control Area. Turlock bases its claims on the fact that Generating Units located in other Control Areas (i.e., "System Resources") are not required to execute a PGA, but can participate in the ISO's markets as System Resources. *Id.* at 5. Simply stated,

[54] Turlock notes that this issue is also currently pending in Docket No. EL99-93-000, and that the Commission has set the issue for hearing but has held the hearing "in abeyance pending settlement judge procedures." *See* Joint Initial Brief on Issue B.5.a, at 3 n.1. Turlock offers to withdraw the initial brief on Issue B.5.a if it "achieve[s] success in its complaint docket or in its settlement negotiations." *Id.* Turlock, however, should be bound by the Commission's determination on this issue – whether it be in the Unresolved Issues dockets or in Docket No. EL99-93-000 – regardless of whether the issue is decided in Turlock's favor, and regardless of whether the matter is settled.

Turlock's position is that Generating Units located within the ISO's Control Area, which it owns or for which it has a contractual entitlement, must be treated like System Resources, rather than like other Generating Units in the Control Area.

Contrary to Turlock's assertions, the ISO's requirements are appropriate for all Generating Units in the ISO's Control Area that desire to participate in the ISO's markets, regardless of their ownership. They are necessary to enable the ISO to fulfill its obligations to maintain the ISO Control Area safely and reliably. Further, Turlock's claims that these requirements prohibit them from participating in the ISO's Ancillary Services and Imbalance Energy markets are unfounded and are refuted by the fact that other full-service municipal utilities are currently participating in the ISO's markets under PGAs.

(1) A Generator Does Not Give Up Effective Control of Its Generating Unit by Executing a PGA.

The PGA is applicable to Generators who wish to participate in the ISO's markets by submitting Schedules and bids through a Scheduling Coordinator. 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 includes an acknowledgment that the reliability of the ISO Controlled Grid depends on the Participating Generator's compliance with the ISO Tariff.[55] Thus, the PGA 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.

[55] A copy of the *pro forma* PGA is provided as Attachment 5.

Execution of a PGA does not equate with a loss of control jeopardizing a municipal utility's ability to operate as a vertically integrated, or full-service, provider. To the contrary, the organizing principle of the ISO's markets is to give greater flexibility to Market Participants, while preserving the ISO's ability to ensure that reliability is preserved.

First, the owner of a Generating Unit retains the flexibility to determine whether, and on what economic terms, to participate in the ISO's markets. The execution of a PGA does not require a municipality (or any other Market Participant) to bid the resource into any of the ISO's markets.[56] The Scheduling Coordinator representing the Generating Unit is responsible (subject, presumably, to the direction of the Generator) for submitting Schedules and bids to the ISO, reflecting the quantities and prices it desires to supply, into the ISO's Ancillary Services, Congestion Management, and Imbalance Energy markets. A Generator can, working with its Scheduling Coordinator, address particular operational requirements through the Schedules and bids it submits. If, for example, Turlock would be exposed to a substantial loss or other risk due to curtailing (or having to increase) power production, it should submit bids that place a very high cost to the market for changing their output. Because the ISO's markets are conducted on an hourly basis, a Scheduling Coordinator has the flexibility to specify a different set of capability options for its unit from hour to hour.

[56] In its response to Turlock's complaint in Docket No. EL99-93-000 (filed October 7, 1999), the ISO provided the Affidavit of Trent A. Carlson ("Carlson Affidavit"). A copy of this affidavit is provided as Attachment 6. In the affidavit, Mr. Carlson explains that Scheduling Coordinators are free to bid (or not bid) their resources as they wish. *See* Attachment 6, Carlson Affidavit, ¶ 13. For the purposes of its markets, the ISO is only interested in the capability of the Generating Unit that is scheduled or bid to the ISO; the ISO's market structure does not recognize any Generating Unit capability that is not identified through a Schedule or bid.

Second, it is important to remember that neither the ISO Tariff nor the execution of a PGA would require Turlock to relinquish the benefits of its Existing Contracts.[57] It could sign a PGA and participate in the ISO's markets, *without* "joining" the ISO.[58] Moreover, the execution of a PGA for sales of excess capacity and Energy does not require Turlock to serve its customers through purchases in the ISO's markets.

Third, while the ISO does have the authority to order a Generating Unit to increase or decrease Generation to alleviate Congestion (such as overloads and voltage problems), provide balancing Energy, satisfy reserve requirements, and manage Overgeneration, it may do so only as a Control Area operator to take action to avoid or resolve an operating emergency. Attachment 6, Carlson Affidavit, ¶ 12. This "markets first" philosophy is stated clearly in the ISO Tariff:

> The ISO plans to obtain the control over Generating Units that it needs to control the ISO Controlled Grid and maintain reliability by purchasing Ancillary Services from the market auction for these services. When the ISO responds to events or circumstances, it shall first use the generation control it is able to obtain from the Ancillary Services bids it has received to respond to the operating event and maintain reliability. Only when the ISO has used the Ancillary Services that are available to it under such Ancillary Services bids which prove to be effective in responding to the problem and the ISO is still in need of additional control over Generating Units, shall the ISO assume supervisory control over other Generating Units. It is expected that at this point, the operational circumstances will be so severe that a real-time system problem or emergency condition could be in existence or imminent.

ISO Tariff, Section 5.1.3. Similarly, with respect to real-time Intra-Zonal Congestion Management, the ISO is required under its Tariff to use "available

57 *See id.*, ¶ 11. For example, execution of a PGA does not subject the scheduled uses of an Existing Contract to Usage Charges under the ISO's Congestion Management protocols. *Id.*

58 The execution of the PGA does not require an entity to (1) execute a TCA and transfer Operational Control of its facilities to the ISO; or (2) "convert" its Existing Contracts to new firm uses for the benefit of all ISO participants. *See* ISO Tariff, Section 2.4.4.2.

Adjustment Bids, and Imbalance Energy bids, based on their effectiveness and in merit order, to minimize the cost of alleviating Congestion." *Id.*, Section 7.2.6.2. Only "[i]n the event no Adjustment Bids or Imbalance Energy bids are available, [will] the ISO . . . exercise its authority to direct the redispatch of resources . . . ." *Id.*[59] Any uncertainty regarding the limits of the ISO's authority in these areas was resolved by the Commission's January 7, 2000 order with respect to the ISO's proposed Amendment No. 23, *California Independent System Operator Corporation*, 90 FERC ¶ 61,006. In that order, the Commission stated that [t]here is no dispute that the ISO currently has the authority to direct any Participating Generator to change its dispatch when the ISO deems it necessary to protect system reliability." *Id.* at 61,010 (footnote omitted). The Commission then noted that

> [t]here is nothing in the ISO Tariff that suggests that the ISO can disregard market bids that have the physical ability to meet the ISO's needs and to either direct those same bidding generators to perform at a different price (the OOM price) or dispatch a generating unit that has not bid into the market.

Id. at 61,011.

The ISO, as the operator of a Control Area, is required to secure the required amounts of Ancillary Services to satisfy WSCC criteria and NERC standards. The WSCC defines a Control Area as an area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling Generation to maintain its interchange schedule with other Control Areas, and contributing to frequency regulation of the interconnection.

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[59] This section was revised by the Unresolved Issues settlement which the ISO filed on December 1, 1999 and which the Commission approved by letter order dated February 24, 2000, *California Independent System Operator Corporation*, 90 FERC ¶ 61,178 (2000).

Attachment 6, Carlson Affidavit, ¶ 14. As the ISO does not operate generating facilities of its own, it must rely on the Generating Units in its Control Area for the resources that enable it to meet its Control Area responsibilities and thereby to ensure the reliable operation of the grid, when the markets fail to provide the necessary Energy and in the locations where they are needed. The PGA is the mechanism through which the ISO obtains the necessary rights to direct the operation of Generating Units for this purpose.

(2) Other Municipalities Have Executed PGAs and Are Participating in the ISO's Markets.

Turlock's contention that execution of a PGA is unduly discriminatory (Initial Brief on Issue B.5.a, at 3) is not only inconsistent with the provisions of the ISO Tariff, but also it is directly contradicted by the ISO's actual experience. The Cities of Anaheim and Pasadena, California are full-service, publicly owned utilities. Both have executed PGAs, and both are actively participating with their Generating Units' excess capacity in the ISO's markets, while continuing to provide reliable service to their own customers.[60] DWR has also executed a PGA and is an active participant in the ISO's markets.[61]

Additional municipalities are also already participating in the ISO's markets for Ancillary Services, transmission Congestion relief, and Imbalance Energy. The Cities of Azusa, Banning, Riverside, and Vernon, California, and DWR, have entered into Scheduling Coordinator Agreements with the ISO,[62] as

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[60] The City of Anaheim's PGA was accepted by letter order dated November 9, 1998 in Docket No. ER98-1912-001. The City of Pasadena's PGA was accepted by letter order dated September 14, 1999 in Docket No. ER99-3617-000.

[61] This PGA was accepted by order dated September 8, 1998 in Docket No. ER98-2115-000, subject to the outcome of Docket No. ER98-992-000.

[62] These agreements were accepted in Docket Nos. ER99-716-000, ER99-715-000, ER98-1887-000, ER98-1008-000, and ER98-2899-000, respectively.

has the Modesto Irrigation District ("Modesto").[63] As Scheduling Coordinators, these utilities can submit Schedules and bids to the ISO and participate in the ISO's markets as buyers and sellers.

It is not the ISO's requirements that have prevented Turlock from making sales from its Generating Units in the ISO's markets, but rather Turlock's own insistence on linking such participation to the resolution of other issues in a specific manner: through the adoption of a Metered Subsystem concept that limits its responsibility for the payment of ISO-related costs. See discussion of Issue E.1, below.

(3) <u>The Different Requirements for Participation in the ISO's Ancillary Service Market Between Entities Located Inside the ISO's Control Area and Those Outside the Control Area Are Reasonable.</u>

Turlock recognizes that the ISO does not require resources outside its Control Area to execute a PGA before participating in the ISO's Ancillary Services and Imbalance Energy markets, but instead has allowed them to participate as a "System Resource." Initial Brief on Issue B.5.a, at 5. Turlock's implication that Generating Units within the ISO's Control Area are indistinguishable for reliability purposes from suppliers outside the Control Area is completely unfounded, and is contrary to WSCC criteria and NERC standards. Turlock disregards the function of Control Areas, which are the basic mechanism through which the reliability of the interconnected electric grid is maintained, and the manner in which the ISO and other Control Area operators fulfill that responsibility. To match Generation and Load within its Control Area within the small tolerances specified under WSCC reliability criteria, the ISO must have the ability to direct the operations of Generating Units within its Control Area and

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[63] The Scheduling Coordinator Agreement with Modesto was filed in Docket No. ER98-2948-000 and accepted by the Commission on June 4, 1998.

must acquire data on Loads within the Control Area. The ISO simply does not require that degree of control with respect to external resources since these resources, and associated Load responsibility, are the responsibility of other Control Areas.

Commission precedent recognizes that it is not undue discrimination to impose different responsibilities on differently situated entities. Moreover, Turlock's claim of preferential treatment with respect to Generators located outside the ISO's Control Area fails to recognize corresponding limitations that have been placed on these participants. Finally, Turlock fails to recognize that it has another option available to it should it desire to participate in the ISO's markets in a manner equivalent to System Resources: Turlock could establish its own Control Area or Control Areas, fulfill all of the associated responsibilities, and certify the delivery of its own System Resources to the ISO Control Area.

(i) <u>It is Consistent with the ISO's Responsibilities as the Control Area Operator for Maintaining Reliability to Impose Different Conditions on Generators Within the Control Area from Those Required of Generators Outside the Control Area</u>

Turlock does not operate its own Control Area. It is the ISO that performs this function. The Control Area requirements derive from the standards and criteria established by NERC and WSCC, and go far beyond providing, or contracting for the provision of, Energy and capacity as a vertically integrated company. Some of the additional obligations and responsibilities of a Control Area operator include, but are not limited to, the following:

- frequency control (continuous balancing of Control Area load, Generation, and interchange) and time-error correction;

- managing and eliminating OTC violations (and reporting OTC violations to WSCC);
- maintaining an adequate supply of Operating Reserves (and reporting Operating Reserve violations to WSCC);
- minimizing Area Control Error ("ACE") (and reporting results to WSCC);[64]
- managing Loop Flow;
- managing inadvertent interchange (and reporting status to WSCC); and
- meeting WSCC criteria and NERC standards (including the responsibilities associated with WSCC Reliability Management System reporting and NERC Standard Compliance reporting).

Attachment 6, Carlson Affidavit, ¶ 15.

Turlock complains of a supposed double standard, because Scheduling Coordinators for resources outside the Control Area need report only "net" transfers of power into or out of the ISO Control Area, while Scheduling Coordinators for entities inside the Control Area need to do more. Initial Brief on Issue B.5.a, at 5. This complaint fails on three grounds. First, it has nothing to do with the ability of Turlock to participate in the ISO's markets as a *seller*. As explained above, Turlock could execute PGAs and, through the same Scheduling Coordinator, schedule excess capacity and Energy with the ISO and make sales in the ISO's Ancillary Services and Imbalance Energy markets. Second, the requirements that all Loads within the Control Area be reported to the ISO applies uniformly to all Scheduling Coordinators serving such Loads. No special demands are imposed on Turlock. Notably, Turlock does not allege that it has been disadvantaged relative to other utilities serving Loads in the ISO's Control

[64] ACE is the instantaneous difference between the actual and scheduled interchange of a Control Area and includes a component for frequency bias. *See* <http://www.nerc.com>, at "Glossary of Terms" section.

Area. Third, contrary to Turlock's assertions, the ISO is not discriminating against participants located within its Control Area in requiring them to submit gross Load data. The ISO must have this information in order to comply with WSCC and NERC requirements.

As Mr. Carlson explains in his affidavit, the ISO, as Control Area operator, must have available Ancillary Service capacity in amounts based on WSCC criteria for its Load responsibility. Attachment 6, Carlson Affidavit, ¶ 14(b). The WSCC defines load responsibility as a "*Control Area's* firm load demand plus those firm sales minus those firm purchases for which reserve capacity is provided by the supplier." *Id.* (emphasis added). To determine its Load responsibility, and therefore its Ancillary Service requirements, the ISO needs accurate data on Generation and, for the ISO's Control Area, Load and interchange with other Control Areas. Without this information, the ISO's ability to fulfill its Control Area responsibilities, and therefore to ensure the reliability of the Control Area and interconnection, are compromised.[65]

The requirement that utilities serving Demand within the ISO's Control Area submit gross Load data to the ISO is therefore integral to the ISO's responsibilities as Control Area operator. In contrast, the ISO is not responsible for maintaining adequate reserves for Demands external to its Control Area even when the supplier schedules transactions on the ISO Controlled Grid. The ISO only requires accurate data regarding interchange schedules with other Control Areas. The distinction between the Load reporting requirements (i.e., Control

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[65] In his affidavit, Mr. Calson notes that Control Area Load, in real time, is calculated as the difference between Generation and net interchange (i.e., Load = Generation - Net Interchange, with exports being positive). Attachment 6, Carlson Affidavit, ¶ 15(c). He explains that the extent to which generator output is *not* monitored by the Control Area Energy Management System is the extent to which Control Area Load is underestimated; and that the extent to which Load is underestimated is the extent to which Ancillary Services are insufficiently provided to cover total Load responsibility. *Id.*

Area Load responsibility) applicable to internal and external Loads is therefore reasonable and appropriate.

The fact is that there are significant distinctions between Generating Units and System Resources. For example, real-time deviations by Generating Units located inside the ISO's Control Area contribute to the ISO's ACE while similar deviations by resources outside the ISO Control Area do not.[66] Also, because they are located in other Control Areas, transactions involving System Resources are scheduled as Control Area interchange. Such interchange schedules are not applicable for Generating Units within the ISO's Control Area, whether or not they are System Units. *Id.*, ¶ 14(g).

The ISO is responsible for the real-time balance of Loads and resources within the ISO Control Area, while resources located outside the ISO's Control Area are the responsibility of other Control Area operators. As Mr. Carlson stated:

> For those resources located outside of the Control Area, Scheduling Coordinators have the additional burden of arranging interchange schedules with their host utility and the ISO. As with all interchange schedules, this is required so that each Control Area can assure that it is meeting its Control Area requirements and that the proper arrangements have been made with respect to transmission (*e.g.*, in the case of delivering Ancillary Services, the

[66] In his affidavit, Mr. Carlson cites the following example: Assume that one of Turlock's generating facilities, which had been producing 120 MW, trips and is disconnected from the system. The ISO's ACE then changes by this amount (plus the changes in system losses that will have occurred due to the disconnection of the Generation). At the scan rate of the ISO's Energy Management System ("EMS"), Participating Generators providing Regulation (i.e., enabled Automatic Generation Control) would be issued control signals to adjust their output for the 120 MW deficiency. To return the Regulation units back to their preferred operating points, the ISO would then call on resources, in price merit order, from the real-time balancing Energy market. Assuming further that Turlock had its Generation monitored by the ISO's EMS, the ISO would have also detected the cause of the ACE excursion. If Turlock did *not* have its Generation being monitored by the ISO's EMS, the disconnection of the Generation would have still caused ACE to change by the same amount; the only difference would be that the ISO would not have any information on what event occurred or where (unless Turlock's operators were to provide the information to the ISO Control Area operators). Attachment 6, Carlson Affidavit, ¶ 15(d).

transmission must be firm). With respect to Ancillary Services, this represents another burden associated with System Resources. Suppliers of Ancillary Services from System Resources are required to certify to the ISO ". . . their ability to deliver the service to the point of interchange with the ISO Control Area (including with respect to their ability to make changes, or cause such changes to be made, to interchange schedules during any interval of a Settlement Period at the discretion of the ISO)." Tariff section 2.5.7.4.2. Without such certification, System Resources are ineligible to supply Ancillary Services to the ISO. Generators within the ISO Control Area, whether represented by individual Generating Units, Physical Scheduling Plants or, in the future, System Units, are not certified in this manner since they are subsumed within the ISO and the ISO is responsible for them as the Control Area operator in accordance with its Tariff that incorporates WSCC criteria and NERC standards. The ISO certifies these internal resources on a basis reflecting the fact it is able to call on the capacity held in reserve at any time during the hour without having to coordinate such actions with one or a number of other Control Area operators.[67]

(ii) Commission Precedent Recognizes That Treating Differently Situated Entities Differently Does Not Constitute Undue Discrimination

The Commission has frequently recognized that it is not unreasonable to impose different requirements on differently situated entities. There is no absolute rule as to what constitutes undue discrimination. Rather, the Commission has stated that this question must be evaluated on a case-by-case basis.[68] There is a long line of court and administrative decisions evaluating

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[67] *Id.* and the Exhibit to the Carlson Affidavit. With respect to transactions that involve Wheeling Through or Wheeling Out of the Control Area, the Commission's landmark Order No. 888 recognized that there are differences between entities serving Load within the Control Area and entities Wheeling Through the Control Area. Order No. 888, FERC Stats. and Regs. Jan. 1991-June 1996, Regs. Preambles ¶ 31,036, at 31,715-16. Internal Loads are subject to real-time deviations. In contrast, inter-Control Area transactions are scheduled with the Control Area operators being responsible for delivering the scheduled amounts. *See* Order No. 888-A, FERC Stats. and Regs. III, Regs. Preambles ¶ 31,048, at 30,230.

[68] *See, e.g., Southern California Edison Co.*, 46 FERC ¶ 61,052, at 61,243 (1989) ("[T]he particular showing required [to prove undue discrimination] will necessarily turn upon the facts of each case, including the characteristics of the customer class involved and the service requested, as well as myriad other potentially relevant factors.)".

what distinguishing factors prevent entities from being considered "similarly situated," a threshold question for a possible finding of undue discrimination.[69] For example, in *Town of Norwood v. FERC*, 587 F.2d 1306, 1312 (D.C. Cir. 1978), the Court found that the level of a customer's risk aversion and bargaining power constituted a difference of sufficient significance to warrant disparate rate treatment.

The ISO's responsibilities as a Control Area operator and WSCC requirements impose different requirements on entities operating within the Control Area. Turlock is not similarly situated to resources outside the Control Area. Having different requirements for Market Participants serving internal Load and external Load does not constitute undue discrimination.[70]

Moreover, missing from Turlock's claims of undue discrimination is any recognition that the ISO Tariff currently places certain limitations on bidding by System Resources into the ISO markets – restrictions that are not placed on Participating Generators within the ISO Control Area. These restrictions include a limitation on the total amount of the ISO's requirements for Regulation, Spinning Reserve, and Non-Spinning Reserve that can be supplied from resources outside the ISO's Control Area.

The ISO Tariff specifically authorizes and requires the ISO to take the geographic dispersion of its sources of Ancillary Service capacity into account in

[69] "[U]ndue discrimination can only occur when two similarly situated customers are treated differently, and there is no justification for the differing treatment." *PacifiCorp Electric Operations and Arizona Public Service Co.*, 54 FERC ¶ 61,296, at 61,855 (1991), *citing Cities of Newark, et al. v. FERC*, 763 F.2d 533, 546 (3d Cir. 1988); *Cities of Alexandria v. FPC*, 55 F.2d 1020, 1027-28 (D.C. Cir. 1977); *St. Michaels Utilities Comm'n v. FPC*, 377 F.2d 912, 915 (4th Cir. 1967).

[70] For example, in *Pacific Gas & Electric Company*, 88 FERC ¶ 63,007, at 65,075 (1999), Judge Stephen Grossman concluded that "distribution-only" service within the ISO Control Area "would have numerous effects on the ISO grid, and can not be performed in isolation from the ISO grid."

procuring its Ancillary Service requirements.[71] It is plainly appropriate for the ISO to retain the discretion to ensure that the geographic mix of Ancillary Service resources is appropriate to maintain reliability.[72] Absent that flexibility, the ISO could find itself required to buy greater quantities of Ancillary Service capacity to provide the requisite level of reliability.[73]

Based on these considerations, the ISO initially decided that a 25 percent limit on acquisition from external resources struck a reasonable and appropriate balance between reliability concerns and the desirability of increasing the range of suppliers who could participate in the ISO's Spinning Reserve and Non-Spinning Reserve markets. The Commission accepted this limitation. May 1999 Order, 87 FERC at 61,819. After further study and operating experience, the limitation has been raised to 50 percent for Spinning and

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[71] Section 2.5.4 of the ISO Tariff states as follows:

> For each of the Ancillary Services, the ISO shall determine the required locational dispersion in accordance with ISO Controlled Grid reliability requirements. These standards shall be used as guidance only. The actual location of Ancillary Services on a daily and hourly basis shall depend on the location spread of Demand within the ISO Control Area, the available transmission capacity, the locational mix of Generation, and historical patterns of transmission and Generation availability.

[72] As the Commission recognized in Order No. 2000 with respect to an RTO's provision of Ancillary Services, an RTO must have the authority to determine the quantities *and locations* for Ancillary Services. *See* Order No. 2000, FERC Stats. and Regs., Regs. Preambles ¶ 31,089, at 31,141.

[73] In November 1998, the ISO's Chief Operating Officer explained in a memorandum the factors that were taken into account in establishing a limit on the acquisition of Ancillary Services from external resources. Principal factors cited included the following: (1) the feasibility of achieving the required response time from resources in adjacent Control Areas; (2) the problem that, absent a ceiling, all Operating Reserves could potentially be scheduled on a single tie, which would obviously violate the geographic dispersion requirement of the ISO Tariff; (3) the effect of the loss of an inter-area tie on reliability would be multiplied since both Energy scheduled across the tie and Reserves scheduled across the tie would be lost; (4) instances in which Scheduling Coordinators did not comply in a timely manner with ISO requests for Energy from imports of Operating Reserve capacity; and (5) at present, the ISO's scheduling system gives Energy deliveries higher priority than Ancillary Service deliveries when both are using the same inter-area tie. As a result, when the inter-tie is curtailed, all Ancillary Services scheduled on the tie may be eliminated, compounding the problem created by the curtailment. A copy of the memorandum in which these factors were discussed is provided as Attachment 7.

Non-Spinning Reserves.[74] In its published standards, the ISO has established an initial limit of 25 percent, as it had done initially with respect to imports of Spinning and Non-Spinning Reserves. In addition, the Commission has accepted the ISO's proposal in Amendment No. 25 to facilitate imports of Regulation. *See California Independent System Operator Corporation*, 90 FERC ¶ 61,316, slip op. at 3-5 (2000).

Turlock's allegations of undue discrimination also fail to recognize that there are certain corresponding disadvantages to operating as a System Resource under the ISO Tariff. In contrast, the ISO has continuously attempted to balance its responsibilities to maintain the safe and reliable operation of the grid with a desire to enhance participation in its nascent market structure. The Commission has supported these efforts by recognizing that it is appropriate for the ISO to recognize differences between resources located within the ISO's Control Area and those located in other Control Areas.

Turlock desires its Generating Units to be treated in a manner equivalent to that of a System Resource. Initial Brief on Issue 5.B.a, at 5. Yet, there is nothing in the ISO Tariff that limits Turlock's ability to create a new Control Area. Turlock can, if it is willing to assume Control Area obligations, have its Generation treated as System Resources and scheduled as interchange with the ISO's Control Area.

The ISO does not advocate this approach. Regional integration would best be served by the combination of existing Control Areas, not the creation of new ones. The ISO notes that its own creation involved the combination of three

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[74] Concerning the 25 percent import limitation, the Commission stated that it would not require that limitation to be filed, and that it saw "no need to restrict the ISO's ability to adjust the level of imports as its reliability concerns are met." May 1999 Order, 87 FERC at 61,819. Thus, the Commission placed no constraints on the ISO's ability to raise the import limitation to, e.g., 50 percent.

formerly separate Control Areas. Also, the City of Pasadena, which had operated as a Control Area for many years, recently decertified its Control Area, executed a Utility Distribution Company Operating Agreement with the ISO, and became part of the ISO Control Area. Attachment 6, Carlson Affidavit, ¶ 16. Nevertheless, the availability of this option underscores the nature of the relief sought by Turlock: to receive the benefits of participating in the ISO's markets as a separate Control Area without taking on the associated responsibilities or incurring the associated costs.

(4) Conclusion.

Based on the pleadings submitted in this matter, the Commission should determine that Turlock's contention of undue discrimination is without merit and suspend the need for further action with respect to Turlock's complaint in Docket No. EL99-93-000.

b. Whether the ISO's authority over Market Participants in Sections 2.3.1.2.1, 2.3.1.2.2 and 2.3.4 of the ISO Tariff should be limited to emergency conditions under Market Participants' contracts or other arrangements? [Issue No. 228, Docket Nos. EC96-19-021 and ER96-1663-022 and Issue No. 443, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - TANC, Cities / M-S-R, and CAC]

Proponents contend that Sections 2.3.1.2.1 and 2.3.1.2.2 of the ISO Tariff are "over broad" and that Market Participants "also should not be subject to ISO orders and instructions that are unrelated to the services they provide to, or receive from, the ISO." Joint Initial Brief on Issue B.5.b, at 4. They argue that the ISO should not force Market Participants to violate, or be denied the benefit of, Existing Contracts absent a System Emergency. *Id.* They also contend that QF operations were not contemplated in the development of the ISO Tariff, that there are operations for which curtailment of thermal supply would pose safety concerns, and that terms and conditions to address QF operational concerns are being considered in Docket Nos. ER98-997-000 and ER98-1309-000. *Id.* at 5-6. Proponents propose the specific modifications noted in the following table.[75]

Revisions Proposed by TANC	Revisions Proposed by EPUC/CAC
2.3.1.2.1 **Comply with Operating Orders Issued.** With respect to this Section 2.3.1.2, all Market Participants <u>with</u> *in* <u>respect to services provided to, or received from,</u> the ISO *Control Areas* shall comply fully and promptly with the ISO's operating orders, unless such operation would impair public health or safety <u>or cause the Market Participant to fail to honor Existing Contracts</u>. For this purpose ISO operating orders to shed Load shall not be considered as an impairment to public health or safety.	2.3.1.2.1 **Comply with Operating Orders Issued.** With respect to this Section 2.3.1.2, all Market Participants within the ISO Control Areas shall comply fully and promptly with the ISO's valid operating orders, unless such operation would impair public health or safety. <u>Unless the ISO has declared an emergency to exist, an ISO operating order shall not be valid if it impairs the ability of a qualifying facility, as defined by federal law, to satisfy either thermal obligations or obligations pursuant to an existing power purchase contract in accordance with Section 5.1.5.</u> For this purpose ISO operating orders to shed Load shall not be considered as an impairment to public health or safety.
2.3.1.2.2 **Implementation of Instructions**. All Market Participants shall respond to ISO instructions with no more delay than specified in the response times set out in the ISO Protocols, <u>with respect to services provided to, or received from the ISO, unless such operation would impair public health or safety or cause the Market Participant to fail to honor Existing Contracts.</u>	No change.

The ISO Tariff, as clarified by the Commission's orders, already strikes a careful balance between the rights of entities with Existing Contracts and the ISO's responsibilities as the Control Area operator. The proposed modifications to the ISO Tariff suggested by Proponents are unnecessary.

Contrary to Proponents' assertions, no Market Participants, including non-Participating Generators, are subject to ISO operating orders and

[75] Joint Initial Brief on Issue B.5.b, at 6-7.

instructions that are unrelated to the services they provide to, or receive from, the ISO. It is incumbent on all Scheduling Coordinators, whether submitting schedules and bids on behalf of an Existing Rights holder, a QF, or some other facility subject to contractual or regulatory restrictions, to protect the interests of the Generating Units through the Energy Schedules that they submit to the ISO, and to protect the quantities and prices that they bid into the ISO's Ancillary Services, Adjustment Bids, and Supplemental Energy markets. Because the ISO markets are conducted on an hourly basis, a Scheduling Coordinator has great flexibility to specify a different set of capability options for its resources from hour to hour.

The Commission's order regarding Amendment No. 23 provided explicit guidance as to restrictions on the ISO's authority with respect to bids:

> Section 5.1.3 and other sections of the ISO Tariff which describe the situations in which the ISO has the authority to direct generators that have not bid into the market to dispatch their resources are clearly limited to situations when the supply that has bid into the market is less than the amount needed to physically satisfy the ISO's need, e.g., the supply that has bid cannot be dispatched due to transmission constraints. There is nothing in the ISO Tariff that suggests the ISO can disregard market bids that have the physical ability to meet the ISO's needs and to either direct those same bidding generators to perform at a different price (the OOM price) or dispatch a generating unit that has not bid into the market.

California Independent System Operator Corporation, 90 FERC at 61,011.

Additionally, all Generators, including QFs, are free to specify both a "minimum operating limit" and any operating "limitations" applicable to their Generating Unit.[76] This allows the facility to indicate to ISO operating personnel any technical operating restrictions on the ability of the Generating Unit to curtail or deliver power to the ISO.

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[76] *See* Attachment 1.

As described in relation to Issue A.3.a, EPUC/CAC's claim that QF operations were not contemplated under the ISO Tariff is incorrect. In recognition of the fact that cogenerators and other QFs have pre-existing contractual commitments under power purchase agreements ("PPAs") executed prior to the creation of the ISO, the ISO Tariff also requires the ISO to honor the terms of those PPAs for "Regulatory Must-Take Generation" identified as such by a local regulatory authority. In the course of the creation of the ISO, the relevant local regulatory authority – the Public Utilities Commission of the State of California ("CPUC") – declared that such "Regulatory Must-Take Generation" includes QFs with PPAs executed prior to December 20, 1995. Section 5.1.5 of the ISO Tariff requires the ISO to honor the terms of those "existing PPAs" to the extent that the ISO is presented with "operating instructions" that describe the operating constraints of those PPAs. Thus, a cogenerator may also protect its operational commitment to its industrial process through the submission to the ISO of "operating instructions" regarding the operational constraints of its "existing PPA" that are inconsistent with the ISO Tariff.

Only in the event that "the ISO has not received bids from generators that must operate in order to resolve a real-time system problem [does] the ISO [have] the authority to issue dispatch orders." *California Independent System Operator Corporation*, 90 FERC at 61,009-010. Thus, it was appropriate for the Commission to find as follows with respect to Section 2.3.1.2.1:

> We find that the requirement that participants comply with all ISO orders except those that would result in impairment to public health and safety to be reasonable. With regard to intervenor concerns about potential damage to their facilities, we note that the ISO will follow good utility practice in operating the system and will comply with all NERC, WSCC and other reliability criteria.

October 1997 Order, 81 FERC at 61,456. Although TANC sought rehearing of this determination, it has presented no arguments in its initial brief warranting reversal of the determination.

The ISO's authority under its Tariff is consistent with the Commission's ISO Principles, as adopted in Order No. 888. In Order No. 888, the Commission stressed the importance of an ISO's retaining and exercising "the primary responsibility in ensuring short-term reliability of grid operations."[77] The Commission recognized that "[t]he ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system, especially when transmission constraints limit trading," though it should rely, where possible, on market mechanisms.[78] In addition, the ISO's authority is consistent with requirements that apply to RTOs under Order No. 2000, in which the Commission stated that an RTO must have "exclusive authority for maintaining the short-term reliability of the grid that it operates."[79] The Commission also stated that "for reliability purposes, the RTO should have full authority to order the redispatch of any generator, subject to existing environmental and operating restrictions that may limit a generator's ability to change its dispatch."[80]

The ISO disagrees that the broad policy issues associated with the ISO's Dispatch authority under the ISO Tariff are at issue in Docket Nos. ER98-997-000 and ER98-1309-000, which concern the PGAs for two QFs and a possible *pro forma* QF PGA. As the ISO has noted in relation to Issue B.5.a, the

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77 Order No. 888, FERC Stats. and Regs. Jan. 1991-June 1996, Regs. Preambles ¶ 31,036, at 31,731.

78 *Id.*

79 Order No. 2000, FERC Stats. and Regs., Regs. Preambles ¶ 31,089, 31,103.

80 *Id.* at 31,104.

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, Proponents have failed to demonstrate that the provisions of Sections 2.3.1.2.1 and 2.3.1.2.2 are unjust or unreasonable. To the contrary, these are necessary provisions, consistent with the Commission's recognition that RTOs must have "some control over generation." The ISO Tariff provides appropriate protections respecting the Existing Contracts, operating instructions, and bids of Market Participants.

c. Does the ISO unjustly and unreasonably exercise authority to control the operations of non-participating Generators, and should section 2.3.2.7 of the ISO Tariff be revised to added the word "Participating" before the word "Generators" to reflect the specific Generators to which this section should apply? In addition, should sections 5.1.3, 5.2.1, 5.2.3, 5.3, 5.4 and 5.7.3 of the ISO Tariff, which provide the ISO with authority over, and control of, all Generators, be revised to limit the ISO's authority to Participating Generators? [Issue Nos. 444 and 448, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - TANC, SMUD, and CAC]

Proponents "do not believe that sections 2.3.2.7 and 5.1.3 *et al.* should be revised to limit the ISO's authority to Participating Generators." Joint Initial Brief on Issue B.5.c, at 2. For this reason, they "request that the Commission direct the ISO to comply with its Order in Docket No. ER00-555-000 with respect to Section 5.1.3" and to amend "the remaining relevant subsections in Section 5 of the ISO Tariff to include the word 'Participating' before the word 'Generators' . . . ." *Id.* at 5-6. Proponents fail to identify the subsections to which they refer.

The ISO believes that the Commission's decision with respect to Amendment No. 23 and Proponents' recognition that "the ISO should not be limited to being able to call on *participating* generators to respond to potential or actual emergencies," *id.* at 6 (emphasis in original), have essentially resolved the issue in dispute. Therefore, no further clarifications are necessary.

Proponents' request that the ISO be directed to comply with this order (*id.* at 5) is redundant. The ISO must already comply with the order on Amendment No. 23, just as it will have to comply with any orders issued in this proceeding.

No modifications are necessary with respect to the specific Tariff sections that Proponents list in their initial brief. The ISO notes that Sections 5.2.1 and 5.2.3 pertain to Reliability Must-Run Units. Bilateral agreements are executed for each of these units, with the ISO specifying their responsibilities. Moreover, Proponents fail to demonstrate that Sections 5.4 and 5.7.3 of the ISO Tariff are unjust or unreasonable and thus in need of revision. These provisions of the ISO Tariff are as follows:

> 5.4 Generator Performance Standard.
>
> Participating Generators shall, in relation to each of their Generating Units, meet all applicable WSCC standards including any standards regarding governor response capabilities, use of power system stabilizers, voltage control capabilities and hourly Energy delivery. Unless otherwise agreed by the ISO, a Generating Unit must be capable of operating at capacity registered in the ISO Controlled Grid interconnection data, and shall follow the voltage schedules issued by the ISO from time to time.
>
> 5.7.3 Coordination of Critical Protective Systems.
>
> Generators shall coordinate with the ISO, Participating TOs and UDCs to ensure that ISO Controlled Grid Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with Generator's Participating TO's and UDC's protective systems.

This is not a case of the ISO "tread[ing] all over the agreements that formed the foundation upon which the subject ISO Tariff sections were based" Joint Initial Brief on Issue B.5.c, at 4. To the contrary, these are appropriate provisions designed to foster reliable interconnected operation in accordance with Good Utility Practice.

In addition to Proponents' recommendations, one of the proponents, EPUC/CAC, states that the Commission should "clarify the proper interpretation of that language to properly proscribe the ISO's authority." *Id.* at 6-7. EPUC/CAC offers no specific recommendations in this regard. Instead, it largely repeats its description of the ISO's jurisdiction and QF independence. *See id.* at 8-9. The ISO has discussed these concerns in response to other issues, including, for example, Issue A.3.a, A.3.c, and B.3.c.

d. <u>Has the ISO improperly eliminated section 7.2.5.2.6 of the ISO Tariff? [Issue No. 593, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - Dynegy]</u>

This issue has been consolidated with Issue B.9. Initial Brief of Dynegy at 9-10.

e. <u>Does section 7.2.5.2.7 unreasonably allow the ISO to curtail Generation and Demand of Non-Participating TOs using resources that are not bid into the ISO markets if Adjustment Bids do not alleviate Congestion on the Inter-Zonal interface? [Issue No. 254, Docket Nos. EC96-19-003 and ER96-1663-003. Proponent - SMUD]</u>

Section 7.2.5.2.7 of the ISO Tariff provides as follows:

> If inadequate Adjustment Bids have been submitted to schedule Inter-Zonal Interface capacity on an economic basis and to the extent that scheduling decisions cannot be made on the basis of economic value, the ISO will allocate the available Inter-Zonal Interface capacity to Scheduling Coordinators in proportion to their respective proposed use of that capacity as indicated in their Schedules and shall curtail scheduled Generation and Demand to

> the extent necessary to ensure that each Scheduling Coordinator's Schedule remains balanced.

SMUD believes that Section 7.2.5.2.7 "gives the ISO unreasonable control over SMUD's resources." SMUD alleges that this provision "appears to allow the ISO to curtail scheduled Generation and Demand of any Scheduling Coordinator ('SC'), whether or not they are participating in the ISO's markets, if Adjustment Bids do not alleviate congestion on the Inter-Zonal interface." Initial Brief of SMUD on Issue B.5.e, at 2. SMUD fears that all of the Load it is scheduling, "even that load of a non-Participating TO that remains behind-the-meter," is subject to curtailment. According to SMUD, "[t]he ISO can only assert authority over resources in order to remedy a pending or existing system emergency after first using procured ancillary services that are ineffective in managing the problem." *Id.* at 3.

In responding to SMUD's contentions it is important to clarify the terminology to being used. SMUD speaks of "participat[ion] in the ISO markets." *Id.* at 2. However, Section 7.2.5.2.7 does not pertain to participation in the ISO markets, i.e., bids offered into the ISO's Ancillary Services, Adjustment Bids, or Supplemental Energy markets; the requirement that the ISO respect those bids has been discussed above in relation to Issue B.5.b. Instead, Section 7.2.5.2.7 concerns the situation in which the market mechanisms have failed to alleviate Inter-Zonal Congestion and the ISO must adjust the scheduled delivery of power over the ISO Controlled Grid in order to maintain voltages and transmission facility loadings to within reliable limits.

Two forms of transmission service are scheduled over facilities within the ISO Controlled Grid. First, transmission service is scheduled for what the ISO terms "new firm uses." "New firm uses" refers to any transmission scheduled by the ISO that is not scheduled pursuant to the terms of Existing Contracts that grant transmission service rights and that were in existence on the ISO Operations Date, March 31, 1998. In addition, the ISO schedules transmission service used pursuant to such Existing Contracts.

Scheduling Coordinators are responsible for submitting, on behalf of Market Participants, transmission schedules to the ISO for any Energy to be transmitted into, out of, or through the ISO Controlled Grid. The process for scheduling “new firm use” transactions is as follows. Scheduling Coordinators must submit initial Preferred Schedules for new firm uses for consideration in the Day-Ahead transmission market by 10:00 A.M. on the day before the operating day for which transmission is to be scheduled. Scheduling Coordinators may also submit Adjustment Bids that are used by the ISO to adjust Preferred Schedules if there is Congestion, i.e., if there is insufficient ATC to implement all Day-Ahead Preferred Schedules simultaneously. After 10:00 A.M., the ISO runs its Congestion Management process. Based on that process, if there is Congestion, by 11:00 A.M. the ISO provides Suggested Adjusted Day-Ahead Schedules for Energy to all Scheduling Coordinators that submitted Preferred Day-Ahead Schedules as well as information on the price for Congestion over the congested paths. Scheduling Coordinators are then given the opportunity to submit Revised Day-Ahead Schedules and to partially revise Adjustment Bids (Scheduling Coordinators may revise Adjustment Bid quantities but not prices) by 12:00 noon on the day prior to the operating day. Final Day-Ahead schedules, reflecting any adjustments from the Revised Day-Ahead Schedules and the second iteration of the Congestion Management process (if necessary), are sent to Scheduling Coordinators by 1:00 P.M.

Scheduling Coordinators may submit Preferred Schedules for new firm uses for consideration in the Hour-Ahead transmission markets to the ISO any time after Day-Ahead Final Schedules are published, but by no later than two hours prior to each operating hour. Scheduling Coordinators may submit Adjustment Bids that are used by the ISO to adjust Hour-Ahead Preferred Schedules if there is Congestion. Each hourly market is run independently. There is no provision to allow Scheduling Coordinators to revise their Hour-Ahead Preferred Schedules prior to the ISO publishing final Hour-Ahead Schedules if Congestion is present. If the ISO is required to use Adjustment Bids to adjust Schedules for new firm use transactions, the ISO's costs for use of the Adjustment Bids are allocated to the Scheduling Coordinators using the congested path, in proportion to their Schedules. If there are insufficient Adjustment Bids available to allow requested new firm use transactions to go forward, the ISO will adjust all Schedules to ensure that Schedules do not exceed ATC on the congested path. If there are insufficient Adjustment Bids over the congested path and if there are no Firm Transmission Rights ("FTRs") being exercised, the ISO will adjust new firm use schedules on a pro rata basis.

In addition, a Market Participant can obtain FTRs. An FTR is a contractual right that entitles the holder of the FTR to receive a portion of Congestion revenues over a specific interface. This provides a level of financial protection against any additional costs for scheduling transmission over that interface that an FTR holder might incur when Congestion is present. In addition, if Day-Ahead Congestion cannot be relieved solely through the use of Adjustment Bids submitted with Day-Ahead Schedules, and the ISO has to make pro rata curtailments of Day-Ahead Schedules to manage the Congestion, the ISO will curtail Schedules that do not have an associated FTR before it curtails any Schedules that do have an associated FTR. If further reductions are necessary, after all Schedules without an associated FTR have been cut, remaining new firm use Schedules with FTRs will be cut on a pro rata basis. FTRs are made available by the ISO in auctions to be conducted annually. The first auction was conducted in November 1998. FTRs can also be acquired in secondary markets. The process just described reflects the fact that there is a physical scheduling priority associated with FTRs in the Day-Ahead Market. However, this scheduling priority does not exist in the Hour-Ahead Market or in real time. As a result, FTRs operate only as financial transactions in the Hour-Ahead Market or in real time.

Moreover, the ISO is required to honor Existing Contracts. The process for scheduling is constrained by the terms and conditions of the Existing Contracts. Since the ISO cannot interpret Existing Contracts, it must rely on instructions provided by Participating TOs. These Existing Contracts generally reflect the scheduling timelines that were in effect prior to the ISO's assuming Operational Control of the ISO Controlled Grid. Under those prior scheduling timelines, it was usual for entities to submit "pre-schedules" for transmission, generally by 2:00 P.M. on the last Business Day before the operating day for which transmission was to be scheduled. Due to this fact, transmission schedules for holders of Existing Rights are usually not submitted to the ISO until the afternoon of the day before transmission is to be scheduled, which falls within the timeframe for the ISO's "Hour-Ahead" scheduling, i.e., between 1:00 P.M. on the day prior to the operating day up to two hours prior to the operational hour in question. Thus, to assure that the provisions of Existing Contracts are honored in the Day-Ahead scheduling process, the ISO must assume that all Existing Rights will be exercised, and the ISO reserves capacity for Existing Rights using this assumption.

While pre-scheduling is usual, pre-scheduling is not always required by Existing Contracts. Some transactions for transmission service under Existing Contracts can be scheduled as late as 20 minutes before they are to occur. Moreover, even where pre-scheduling is required, many instructions related to

Existing Contracts allow changes to pre-scheduled transactions after the Hour-Ahead scheduling process.

The ISO's pro rata curtailment of Balanced Schedules is a reasonable approach to resolving transmission constraints. This same methodology was adopted by the Commission in its *pro forma* Open Access Transmission Tariff in Order No. 888:

> We intended and continue to believe that curtailment on a pro-rata basis is appropriate for curtailing the transactions that substantially relieve the constraint . . . [and] we are clarifying the curtailment provision of the tariff to explicitly allow the transmission provider discretion to curtail the services, whether firm or non-firm, that substantially relieve the constraint. Of course, any curtailment must be made on a non-discriminatory basis, including curtailment of the transmission provider's own use of the transmission system.[81]

Moreover, Section 7.2.5.2.7 must be read in conjunction with the other provisions of the ISO Tariff that respect the Existing Rights entities such as SMUD have under their pre-existing transmission agreements. As described in Section 2.4.4.5 of the ISO Tariff:

> The ISO will implement the provisions of Section 2.4.4.4 in its Scheduling Protocol. The objective will be to ensure that under the ISO rules and protocols, Existing Rights and Non-Converted Rights will enjoy the same relative priorities vis-à-vis new, ISO-provided transmission uses, as they would under the Existing Contracts and the FERC Order 888 tariffs. Under the ISO Scheduling Protocol:
>
> 2.4.4.5.1.1 Existing scheduling rules, curtailment priorities and any other relevant terms and conditions associated with the scheduling and day-to-day implementation of transmission rights will be documented in sets of operating instructions provided to the ISO by the parties to the Existing Contracts. The documentation of these operating instructions, and disputes related to these operating instructions, will be handled in accordance with the terms of Section 2.4.4.4.1.1.

[81] Order No. 888, FERC Stats. and Regs. Jan. 1991-June 1996, Regs. Preambles ¶ 31,036, at 31,749 (footnote omitted).

Thus, in determining which Schedules to curtail, the ISO will respect the instructions of the Participating TOs with respect to Existing Contracts. *See also* the discussion concerning Issue B.4.b, above.

Accordingly, SMUD's proposed revisions to Section 7.2.5.2.7 of the ISO Tariff are unnecessary. The ISO must have a means to resolve Inter-Zonal Congestion in situations where market bids are insufficient. The ISO's approach respects priorities under Existing Contracts, and its pro rata curtailment of the scheduling of Balanced Schedules is consistent with Order No. 888.

f. Is the ISO's ability to redispatch a Scheduling Coordinator's portfolio on an involuntary basis through out-of-market payments (under which the ISO pays only its real-time prices) punitive and confiscatory? [Issue No. 494, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Enron and WPTF]

WPTF and Enron request that the Commission "(i) limit the CAISO's authority to impose 'out-of-market' orders on market participants to those situations necessary to address legitimate System Emergencies; and (ii) order the CAISO to replace its compensation scheme with one that fully compensates Scheduling Coordinators for their costs when they are involuntarily redispatched." Joint Initial Brief of WPTF and Enron on Issues A.6, B.5.f, E.5, L.1, and L.8, at 12. As the ISO will show, WPTF and Enron are improperly using this proceeding to make a collateral attack on the Commission's order on Amendment No. 23. Moreover, their first proposal would threaten the reliability of the California transmission system, while their second proposal creates an undue risk of overpayment by the ISO for Supplemental Energy, with resulting inefficiencies.

(1) Collateral Attack on the Commission's Order Approving Amendment No. 23.

In its order on Amendment No. 23 to the ISO Tariff, the Commission approved the scope of the ISO's out-of-market Dispatch authority and the pricing mechanism that WPTF and Enron dispute here.[82] With regard to the payment option, the Commission stated as follows:

> We will accept the ISO's proposed alternative payment option. While this pricing method may, on some occasions, result in payments that are higher than necessary to address concerns that rates equal out-of-pocket costs, and may, on other occasions, result in payments that fail to consider all opportunity costs (such as the untimely release of hydro generation), the ISO's proposal is a pragmatic approach to addressing generators' concerns which uses payment methods based, to the extent possible, on market data.

California Independent System Operator Corporation, 90 FERC at 61,015. Neither WPTF nor Enron requested rehearing of the Commission's order.[83] The scope of the Unresolved Issues proceeding only concerns issues relating to (1) the original ISO Tariff filings, (2) Amendments Nos. 1-7 thereto, and (3) the Clarification and Compliance filings. *See* the ISO's Report on Outstanding Issues, Docket Nos. ER98-3760-000, *et al.* (Mar. 11, 1999), at 6-7. WPTF and Enron's present assertions constitute an impermissible collateral attack on the Commission's Amendment No. 23 order and are thus beyond the scope of this proceeding. For this reason alone, they should be rejected.

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[82] *California Independent System Operator Corporation*, 90 FERC at 61,014-15. Amendment No. 23 also proposed additional out-of-market authority for the ISO; however, the Commission rejected this portion of the amendment, leaving the ISO with the out-of-market authority and pricing mechanism that WPTF and Enron attack here.

[83] Enron raised similar issues in Docket Nos. EC96-19-029 and ER96-1663-020, regarding the ISO's June 1, 1998 Compliance filing; however, neither Enron nor WPTF raised the issues on rehearing in response to the Commission's Amendment No. 23 order. In fact, Dynegy was the only party to ask for rehearing on either of the issues addressed here in response to the Amendment No. 23 order, and it requested rehearing only on the pricing mechanism. *See* Answer of Dynegy Power Marketing, Inc. to Motion for Clarification of the California Independent System Operator Corporation, Docket No. ER00-555-000 (Feb. 22, 2000), at 2-3. Although Dynegy is a member of WPTF (*see* <http://www.wptf.org>), the ISO contends that WPTF is still barred from raising these issues here, since WPTF is a party that is separate and distinct from Dynegy. Moreover, in its initial brief WPTF states that "[t]he positions taken by WPTF herein do no necessarily represent the positions of its members." Joint Initial Brief of WPTF and Enron on Issues A.6, B.5.f, E.5, L.1, and L.8, at 5 n.1. The ISO notes that Dynegy, a separate participant in this proceeding, elected *not* to be a proponent regarding this issue.

(2) The ISO's Authority to Invoke Out-Of-Market Dispatch.

WPTF and Enron argue that "[w]hen the CAISO orders redispatch for purposes other than reliability, it acts as a Poolco, which is not the California model. . . . By contrast, under the CAISO model, as envisioned by the stakeholders, market participants have the freedom to refrain from bidding." Joint Initial Brief of WPTF and Enron on Issues A.6, B.5.f, E.5, L.1, and L.8, at 11. WPTF and Enron assert that the ISO's out-of-market authority in effect forces Market Participants to submit Supplemental Energy bids, because otherwise Market Participants face the risk of an involuntary Dispatch at the allegedly inadequate out-of-market prices. *Id.* at 11-12.

WPTF and Enron mischaracterize the ISO's out-of-market Dispatch authority, and propose to change it in a way that could prove disastrous for the California transmission system. Contrary to their claims, the ISO Tariff *does* limit out-of-market Dispatch to system reliability concerns, and even then out-of-market Dispatch is used *only* after other options have been exhausted. Consistent with the ISO's responsibility to safeguard short-term reliability, the ISO will generally use its authority to exercise supervisory control over resources participating in its markets only when a *real-time* system problem or emergency either exists or could occur in the absence of ISO action, and available market bids are either exhausted or would not be effective to resolve the problem. *See* ISO Tariff, Sections 2.3.2.2 and 2.3.2.3. When the ISO requires resources in one of these circumstances, it will rely on resources with which it has RMR Contracts before Dispatching other resources. The ISO expects to rely on its authority to issue Dispatch orders to non-RMR resources that have not submitted bids, rarely; but the ISO must have the authority to do so if it is to meet its responsibility to safeguard short-term reliability.

Second, the ISO remains strongly committed to the market principles cited by WPTF and Enron as underlying the ISO Tariff. *See* Joint Initial Brief of WPTF and Enron on Issues A.6, B.5.f, E.5, L.1, and L.8, at 11-12. These principles, however, do not require the ISO to ignore situations in which market bids that can be used to respond effectively to a system reliability problem or emergency are unavailable. Rather, they direct the ISO, in addressing system reliability problems, to look *first* to the resources voluntarily made available by Market Participants, and only after these are exhausted is the ISO to look to Generating Units, Curtailable Demands, and System Resources, which may serve to alleviate the condition that threatens reliability.

Third the ISO's authority to Redispatch resources is consistent with the Commission's ISO Principles, as adopted in Order No. 888 and reaffirmed in Order No. 2000. In Order No. 888, the Commission stressed the importance of an ISO's retaining and exercising "the primary responsibility in ensuring short-term reliability of grid operations."[84] The Commission recognized that "[t]he ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system, especially when transmission constraints limit trading," though it should rely, where possible, on market mechanisms.[85] The Commission reached similar conclusions in Order No. 2000. The Commission stated that an RTO must have "exclusive authority for maintaining the short-term reliability of the grid that it operates."[86] The RTO should also be able to exercise operational control over generation facilities if

[84] Order No. 888, FERC Stats. and Regs. Jan. 1991-June 1996, Regs. Preambles ¶ 31,036, at 31,731.

[85] *Id.*

[86] Order No. 2000, FERC Stats. and Regs., Regs. Preambles ¶ 31,089, at 31,103. *See generally id.* at 31,092-106 (describing aspects of short-term reliability).

necessary to maintain reliability, though generally market mechanisms should be allowed to operate.[87] Notably, the Commission stated that "for reliability purposes, the RTO *should have full authority to order the redispatch of any generator*, subject to existing environmental and operating restrictions that may limit a generator's ability to change its dispatch."[88]

The ISO's out-of-market authority is critical to the ISO's ability to fulfill this important function. The Commission is obviously aware that once the transmission system reaches a full-fledged emergency condition, it may not be possible to resolve the emergency without loss of service, economic harm, damage to property, and even injury to persons. It would be a foolish trade-off to let WPTF and Enron's demand for ideological purity on the Poolco-versus-ISO distinction compromise the practical need to guard against the occurrence of potentially disastrous System Emergencies.

(3) The ISO's Pricing Mechanism.

In support of their protest against the ISO's pricing mechanism for out-of-market Dispatch, WPTF and Enron list examples of types of "externality" costs that they believe will not be compensated under this mechanism. These include such things as take-or-pay penalties, pollution penalties, and maintenance costs. *See* Initial Brief of WPTF and Enron on Issues A.6, B.5.f, E.5, L.1, and L.8, at 10. WPTF and Enron also argue that market resources will be forced to bid into the Supplemental Energy markets to avoid the risk that they will be under-compensated if they fail to do so. *Id.* at 10-11.

WPTF and Enron's criticism of the ISO's out-of-market pricing mechanism is a result of their interests as sellers of Supplemental Energy, and ignores the

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87 *Id.* at 31,104.

88 *Id.* (emphasis added).

broader interests of all Market Participants. The out-of-market pricing mechanism that WPTF and Enron attack was finalized after a full stakeholder process, and was approved by the ISO Governing Board, which represents a broad spectrum of Market Participants, as well as End-Use Customers. The Commission subsequently approved the pricing mechanism. *See California Independent System Operator Corporation*, 90 FERC at 61,014-15.

As explained further below, there were concerns that such a cost-based approach would encourage bid withholding behavior that could artificially inflate prices in ISO markets. The ISO instead sought to develop an alternative payment option based on market indicators that would be expected to greatly reduce the possibility that Generators would be Dispatched at a loss. In addition, the ISO's pricing mechanism ensures that Generators will have the opportunity to recover certain specific costs, including fuel start-up costs and daily gas imbalance charges, in addition to compensating for both capacity and Energy at prices tied to equitable market indicators. The ISO believes that this is a fair approach, which substantially reduces the possibility that Generators will be required to operate at a loss in those situations when they are called out-of-market. As noted above, the Commission agreed with the ISO and thus approved the pricing mechanism, stating as follows:

> We will accept the ISO's proposed alternative payment option. While this pricing method may, on some occasions, result in payments that are higher than necessary to address concerns that rates equal out-of-pocket costs, and may, on other occasions, result in payments that fail to consider all opportunity costs (such as the untimely release of hydro generation), the ISO's proposal is a pragmatic approach to addressing generators' concerns which uses payment methods based, to the extent possible, on market data.

California Independent System Operator Corporation, 90 FERC at 61,015.

Some intervenors in the proceedings on Amendment No. 23 were concerned that the potential for overpayment gave Generators an incentive to withhold bids from the market in the hopes that they would be Dispatched out-of-market at rates substantially higher than the market price. The ISO's pricing mechanism represents a compromise between concerns about under-compensation, and other concerns about overpayment.

Finally, the ISO is not unsympathetic to the concerns of participating Generators who believe that, under certain conditions, the Commission-approved rates are not sufficient. On March 24, 2000, the ISO announced that it would commence a stakeholder process to facilitate the development of a third payment option to address these concerns. The first stakeholder meeting was held on April 5, 2000. Depending on its outcome, that process may yield an amendment to the ISO's current rate structure for out-of-market Dispatch.

For the foregoing reasons, the ISO requests that the Commission reject WPTF and Enron's proposed changes to the sections of the ISO Tariff establishing the ISO's out-of-market Dispatch authority and out-of-market pricing mechanism.

g. <u>With respect to section 10.2.8 of the Dispatch Protocol ("DP"), should the ISO be required to file reports notifying the Commission whenever the ISO calls a System Warning or Emergency and, if so, should such a report contain information regarding any out-of-market generators it was required to dispatch? [Issue No. 621, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - Dynegy]</u>

Dynegy contends that the ISO should be required to disseminate information setting forth the reasons for all system warnings or System Emergencies called by the ISO either in regular reports to the Commission or in postings on the ISO Home Page. Initial Brief of Dynegy at 11. Dynegy states that the ISO has already agreed to disclose information for calling OOM Generation under the draft OOM protocol. In particular, Dynegy expresses its concern that it was subject to five OOM calls in January. *Id*. at 11-12.

Dynegy's contentions are unfounded. First, it is important to recognize that ISO declarations of system warnings or System Emergencies are already disseminated to all Market Participants by electronic mail. No additional purpose would be served by requiring the ISO to compile a report for the Commission. A copy of the relevant ISO procedure, Procedure E-504, is supplied as Attachment 8. This procedure states that "Alert, Warning, and Emergency Notices are sent to all Market Participants simultaneously . . . ." Attachment 8, Procedure E-504, at 1. The ISO will issue an Alert Notice when, in the Day-Ahead Market, the Operating Reserve is forecast to be less than the WSCC Minimum Operating Reliability Criteria ("MORC") Minimum. *Id*. at 2. A Warning Notice is issued when, in the Hour-Ahead market, reserve is forecast to be marginal or less than the MORC Minimum. *Id*. at 2-3. An Emergency Notice is issued when "it is clear that an Operating Reserve shortfall is unavoidable, or when in real-time operations, the Operating Reserve is forecast to be less than the ISO minimum." *Id*. at 3. Pursuant to the Offer of Settlement in the instant proceeding, Alert Notice and Warning Notice have been added to the Master Definitions Supplement, Appendix A to the ISO Tariff.

Second, Dynegy correctly notes that in the ISO's draft out-of-market procedure the ISO has offered to post information on out-of-market calls. Initial Brief of Dynegy at 11. Nevertheless, for purposes of seeking a resolution of this issue, the ISO will agree to implement the reporting provisions of the draft procedure. Under these provisions, by the tenth Business Day of each month, the ISO would publish on the ISO Home Page a summary of out-of-market calls made during the previous month. The summary for each Zone and each type of call would contain the following: (1) the hours during which calls were made, (2) the total MWh called, and (3) the cost of the total MWh called. Third, the OOM calls to Dynegy in January 2000 were due to the outage of an RMR unit that the ISO would have otherwise Dispatched.

The ISO believes that the information provided to Market Participants concerning Alert Notices, Warning Notices, and Emergency Notices, together with the additional commitment to post data on OOM calls, provides the requisite information to enable Market Participants to monitor the ISO's actions. Requiring reports to the Commission would serve no additional purpose.

h. <u>Should the ISO be required to clarify in section 7.3.2 of the ISO Tariff, regarding the ISO's authority to redispatch a Scheduling Coordinator's resources, that it will operate in a manner consistent with section 2.3.2.3.1 of the ISO Tariff? [Issue No. 595, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - Dynegy]</u>

This issue has been withdrawn. Initial Brief of Dynegy at 12.

i. Does DP 8.1.1 unreasonably permit the ISO to issue a dispatch order for a generator without the generator's having submitted a bid that has been accepted and made final, or until such time as the ISO has otherwise exhausted all market mechanisms provided to it under the ISO Tariff, and thus must call a System Emergency? [Issue No. 611, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Dynegy and CAC]

Proponents contend that Section 8.1.1 of the DP[89] "is overbroad and has the effect of authorizing the ISO to dispatch Generating Units to meet real-time imbalances and to relieve Congestion without regard to whether a Generating Unit has submitted a bid that has been accepted" by the ISO. Joint Initial Brief on Issue B.5.i, at 2. They recognize that "[t]he Commission addressed a very similar issue in Docket No. ER00-555-000," which concerns the ISO's proposed Amendment No. 23. *Id.*

As noted with respect to Issue B.5.c, the ISO believes that the Commission's order on Amendment No. 23 is dispositive on this issue. In that order the Commission determined that "[t]here is nothing in the ISO Tariff that suggests that the ISO can disregard market bids that have the physical ability to meet the ISO's needs," and that

> Section 5.1.3 and other sections of the ISO Tariff which describe the situations in which the ISO has the authority to direct generators that have not bid into the market to dispatch their resources are clearly limited to situations when the supply that has bid into the market is less than the amount needed to *physically* satisfy the ISO's need, e.g., the supply that has bid cannot be dispatched due to transmission constraints.

[89] Section 8.1.1 of the DP is titled "Responsibility of the ISO in Real Time Dispatch." It provides as follows:

> During real time Dispatch, the ISO will be responsible for dispatching Generating Units, Curtailable Demands and Interconnection schedules to meet real time imbalances between actual and scheduled Demand and Generation and to relieve Congestion, if necessary, to ensure System Reliability and to maintain Applicable Reliability Criteria.

California Independent System Operator Corporation, 90 FERC at 61,011 (emphasis in original).

Proponents contend that "[t]he same rationale applies to DP 8.1.1." Joint Initial Brief on Issue B.5.i, at 3. The ISO does not disagree. With respect to Proponents' immediately following statement that "[t]he ISO does not have authority to dispatch a Generating Unit that has not bid into the market" unless there is a System Emergency (*id.*), the ISO presumes that Proponents are not questioning the ISO's ability to manage Congestion. As the ISO has explained in relation to Issue B.3.c, if Proponents' contention is that the ISO's authority, under Section 5.1.3, to direct the Redispatch of a Generator in the case of an actual or threatened real-time emergency does not extend to addressing real-time Congestion, then adoption of their position would significantly threaten the reliability of the ISO Controlled Grid. Unresolved Congestion, in itself, would present a System Emergency. If the ISO Adjustment Bids and Imbalance Energy bids that can resolve the Congestion are not available as market mechanisms, then there is a very real threat of a System Emergency that the ISO can avoid only by going outside the market. As determined in the order on Amendment No. 23, the ISO can make out-of-market calls on Generators when necessary to resolve transmission constraints.

Accordingly, Proponents' proposal to include a cross-reference to Section 5.1.3 of the ISO Tariff in the first sentence of Section 8.1.1 of the DP is too narrow. The ISO's authority under this provision is guided not only by Section 5.1.3 but by other Tariff provisions as well. For example, under Section 4.4 of the Tariff, UDCs are required to comply with ISO directions concerning the management of System Emergencies. Given the guidance provided in the order on Amendment No. 23 which properly recognizes the need to interpret the Tariff as a whole,[90] Proponents' recommended change is inappropriate.

One of the proponents, EPUC/CAC, contends that the cross-reference to Section 5.1.3 is insufficient. *Id.* at 4. EPUC/CAC repeats its arguments concerning the historical perspective of QFs. *Id*. *See also* EPUC/CAC arguments in the initial briefs concerning Issues A.3.a, A.3.c, B.3.c, B.5.b, and B.5.c. EPUC/CAC states that Section 8.1.1 of the DP does not consider either safety or operational considerations of QFs. *Id*. at 6. The ISO has addressed these concerns in connection with Issue B.5.b. First, Market Participants are expected to protect their interests by means of the values specified in their bids. This provides ample flexibility as those values may be changed by Scheduling Coordinators on an hourly basis. Second, QFs are able to submit operating instructions to the ISO designed to address exactly the type of safety concern identified by the QFs. The ISO is sensitive to the need to operate in a safe and reliable manner in accordance with federal, state, and local regulations. While cogenerators have specific concerns, all generators (fossil-fueled units, hyroelectric units, and nuclear facilities) operate within specific safety restrictions in conformance with environmental and other requirements that must be respected. As the Commission recognized in Order No. 2000, "for reliability purposes, the RTO should have the full authority to order the redispatch of any generator, subject to existing environmental and operating restrictions that may

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90 As the Commission has described:

> In construing what a tariff means, certain general principles apply. One looks first to the four corners of the entire tariff, considers the entire instrument as a whole, giving effect so far as possible to every word, clause and sentence, and attributes to the words used the meaning which is generally used, understood, and accepted.

Columbia Gas Transmission Corp., et al., 27 FERC at 61,166.

limit a generator's ability to change its dispatch." Order No. 2000, FERC Stats. and Regs., Regs. Preambles ¶ 31,089, 31,104.

The ISO does not believe the revisions to Section 8.1.1 of the DP which have been proposed are appropriate. The Commission has already addressed this issue in its order on Amendment No. 23. Moreover, Market Participants are expected to protect their interests by means of the values specified in their bids. This provides ample flexibility as those values may change on an hourly basis. In addition, QFs, like all other generators, are able to submit operating instructions to the ISO designed to address exactly the type of safety concern identified by the QFs.

j. <u>Is the ISO's dispatch authority under DP 9.1.1 and 9.5 overbroad? Should DP 9.1.1 be modified to clarify that this provision is subject to other applicable Tariff requirements respecting Existing Contracts, and should DP 9.5 be modified to limit the ISO's authority to dispatching units in the event of an actual System Emergency? [Issue No. 335, Docket Nos EC96-19-006 and ER96-1663-007 and EC96-19-008 and ER96-1663-009, and Issue No. 617, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - MWD, Dynegy, and CAC]</u>

Proponents claim that Sections 9.1.1 and 9.5 of the DP may be interpreted in a manner that "contravenes" Section 5.1.3 of the ISO Tariff by granting the ISO improper authority over the Dispatch of Generation and Loads that have not bid into the ISO's Ancillary Services or Imbalance Energy markets. Joint Initial Brief on Issue B.5.j, at 2. Specifically, Proponents state that Section 5.1.3 "did not envision that the CAISO would utilize its authority to dispatch generators that did not bid into the ISO market for economically motivated reasons or for congestion management purposes." *Id.* at 3. For these reasons, they suggest that the ISO insert in Sections 9.1.1 and 9.5 of the DP a cross reference to Sections 5.1.3 and 5.1.5 of the ISO Tariff. *Id.* at 4. Proponents also note that the ISO's authority to

direct the operation of Generating Units is subject to the terms and conditions of Existing Contracts. Finally, one of the proponents, EPUC/CAC, reiterates arguments it has raised previously (see for example the discussions concerning Issues B.5.b, B.5.c, and B.5.i) regarding special concerns of QFs.
See Joint Initial Brief on Issue B.5.j, at 4-6.

The revisions suggested by Proponents are unwarranted. Sections 9.1.1 and 9.1.5 of the DP operate in conjunction with Section 5.1.3 and other provisions of the ISO Tariff to give the ISO the necessary authority to manage real-time operations and maintain the reliability of the ISO Controlled Grid, with due respect given to Existing Contracts. Proponents' contention that ISO's authority to issue Dispatch orders to avoid or relieve a System Emergency should not extend to the relief of Congestion, even in the absence of available market bids, is unfounded. If Generation and Load were not adjusted to relieve the overloading, the Congestion would create a "real-time system problem," as described in Section 5.1.3 of the Tariff, that the ISO is directed and empowered to remedy.

In normal circumstances, the ISO obtains the Energy it needs to balance Loads and resources in real time (i.e., Imbalance Energy), and for reliable operation of the ISO Controlled Grid, from Energy that resources have bid into the ISO's Real Time Markets, from capacity that has been selected in the Ancillary Services markets, or from RMR units (e.g., to satisfy local area requirements). Recourse to markets, however, is not always feasible. Deficiencies of Imbalance Energy bids may arise from market anomalies, which can occur anytime, or from capacity shortages (such as have been experienced in California during periods of high Load in summer months and during natural gas curtailments in winter months). Even when bids do offer sufficient quantities, as is likely in shoulder or off-peak months, bids may not be available from resources that could be adjusted to respond effectively to the ISO's needs because of transmission outages or other local area problems. The ISO Tariff therefore permits the ISO in certain circumstances to issue operating orders to Generating Units, Curtailable Demands, and System Resources[91] that have not bid into the relevant ISO markets. *See, e.g.*, ISO Tariff, Sections 5.1.3, 5.6.1, and 7.2.6.2. These circumstances include the following:

- where there is a deficiency of Ancillary Service Energy bids and of Supplemental Energy bids;
- where there is an absence of Adjustment Bids and Imbalance Energy bids that can be effective in resolving adverse system conditions (e.g., due to locational requirements); or
- where there is an imminent or existing real-time system problem or System Emergency.

The ISO remains strongly committed to the "markets first" principle. The ISO clearly recognizes the Commission's admonition in its order on Amendment No. 23 that "[t]here is nothing in the ISO Tariff that suggests that the ISO can disregard market bids that have the physical ability to meet the ISO's needs . . . ." *California Independent System Operator Corporation*, 90 FERC at 61,011. The ISO is also fully cognizant of its responsibility to respect Existing Contracts.

The "markets first" principle, however, does not require the ISO to ignore situations in which market bids are unavailable for use in responding effectively to a system problem or emergency. Rather, the principle directs the ISO to look *first* to the resources voluntarily made available by Market Participants, as reflected in their bids, to obtain the resources necessary to preserve the reliability of the ISO Controlled Grid. But where the bids voluntarily submitted to the

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91 System Resources are defined as "[a] group of resources located outside the ISO Control Area capable of providing Energy and/or Ancillary Services to the ISO Controlled Grid." ISO Tariff, Appendix A, definition of "System Resource."

market and the resources available to the ISO under RMR Contracts will not enable the ISO to maintain the reliability of the ISO Controlled Grid in real-time operations, the ISO must issue operating orders to Generating Units, Curtailable Demands, and System Resources, which may serve to alleviate the condition that threatens reliability.

The ISO's authority to issue operating orders in these circumstances is clear. Section 5.6.2 of the ISO Tariff directs the ISO to respond to an actual, imminent, or threatened System Emergency "where practicable, [by] utiliz[ing] Ancillary Services which it has the contractual right to instruct," before issuing instructions to a Participating Generator. Subject to this direction, however, Section 5.6.1 of the Tariff authorizes the ISO

> to instruct a Participating Generator to bring its Generating Unit on-line, off-line, or increase or curtail the output of the Generating Unit and to alter scheduled deliveries of Energy and Ancillary Services into or out of the ISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent or threatened System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency.

Section 5.1.3 of the Tariff similarly authorizes the ISO to assume Operational Control over Generating Units when "operational circumstances [are] so severe that a real-time system problem or emergency condition could be in existence or imminent" and Ancillary Services bids effective to address the problem are unavailable. Transmission Congestion, left unmitigated, represents one such "real-time system problem." Section 7.2.6.2 of the ISO Tariff accordingly states that "the ISO will exercise its authority to direct the redispatch of resources" to manage Intra-Zonal Congestion in the absence of effective incremental or decremental bids.

Proponents contend that the authority to issue Dispatch orders to avoid or relieve a System Emergency should not extend to the relief of Congestion.

Joint Initial Brief on Issue B.5.j, at 3. This claim is unfounded in several respects. First, it ignores the fact that the ISO's authority to Redispatch resources is not limited to System Emergencies, as defined in the ISO Tariff.[92] As noted above, Section 5.1.3 of the Tariff authorizes the ISO to assume supervisory control of a Generating Unit where necessary to respond to an actual or threatened "real-time system problem." Transmission Congestion in real-time operations qualifies as a "real-time system problem." Congestion is not simply an economic phenomenon. In real time, Congestion represents circumstances such as the overloading of lines and other elements of the transmission grid. If Generation and Load were not adjusted to relieve the overloading, the Congestion would create a real-time system problem that the ISO is directed and empowered to remedy.

Moreover, even if the ISO's Redispatch authority were limited to situations qualifying as System Emergencies, real-time Congestion would still qualify. If real-time overloads are not relieved, elements of the grid will fail, leading to equipment damage and service interruptions. In other words, real-time Congestion represents an "abnormal system condition which requires immediate . . . action to prevent loss of Load [or] equipment damage," i.e., a System Emergency. There is no reason to exclude System Emergencies arising from real-time Intra-Zonal Congestion from the scope of the ISO's authority to Redispatch resources where necessary to preserve reliability.

[92] A System Emergency is defined as "[c]onditions beyond the normal control of the ISO that affect the ability of the ISO Control Area to function normally including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system elements which might result in cascading outages or to restore system operation to meet the minimum operating reliability criteria." *Id.*, definition of "System Emergency."

Proponents' position with respect to the ISO's Redispatch authority for Congestion is inconsistent with the Commission's findings in its order on Amendment No. 23. In that order, the Commission expressly recognized that

> [t]here is no dispute that the ISO currently has the authority to direct any Participating Generator to change its dispatch when the ISO deems it necessary to protect system reliability. For example, if the output available from generators bidding into the imbalance and ancillary services markets is inadequate to serve load and *manage congestion*, the ISO can direct an idle Participating Generator to start up and deliver energy to meet the ISO's needs.

California Independent System Operator Corporation, 90 FERC at 61,010-11 (emphasis added) (footnote omitted).

The recognition in the Tariff of the ISO's authority to Redispatch resources is consistent with the Commission's ISO Principles, as adopted in Order No. 888. There, the Commission stressed the importance of an ISO's retaining and exercising "the primary authority in ensuring short-term reliability of grid operations." Order No. 888, FERC Stats. and Regs. Jan. 1991-June 1996, Regs. Preambles ¶ 31,036, 31,731. The Commission recognized that "[t]he ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system, especially when transmission constraints limit trading," though it should rely, where possible, on market mechanisms. *Id.* The Commission reaffirmed these conclusions in Order No. 2000:

> Some commenters appear to confuse the reed to redispatch generators to maintain reliability with the need to take specific actions to relieve congestion. Commenters generally agree that the RTO should have clear authority to order redispatch for reliability purposes. However, for congestion management, we conclude here that the RTO should attempt to rely on market mechanisms to the maximum extent practicable. We recognize, of course, that there may be times when even well-functioning markets will fail to provide the RTO with the options it needs to alleviate a specific instance of congestion. *In those cases, the RTO must have the*

> *authority to curtail one or more transmission service transactions that are contributing to the congestion.*

Order No. 2000, FERC Stats. and Regs., Regs. Preambles ¶ 31,089, 31,127 (emphasis added). The Tariff provisions described above are integral to the ISO's ability to fulfill this critically important ISO function.[93]

With regard to the additional concerns raised by EPUC/CAC, the ISO has previously shown in this Answering Brief, in relation to Issue A.3.a, that the claim that QF operations were not contemplated under the ISO Tariff is incorrect.[94] The ISO also has explained that QF Generators are able to submit operating instructions to the ISO designed to address exactly the type of safety concern identified by EPUC/CAC. Again, the ISO disagrees that the broad policy issues associated with the ISO's Dispatch authority under the ISO Tariff are at issue in Docket Nos. ER98-997-000 and ER98-1309-000, which concern the PGAs for two QFs and a possible *pro forma* QF PGA. As noted in regard 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.

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[93] Contrary to the claims of Proponents (Joint Initial Brief on Issue B.5.j, at 3), nothing in the current provisions of the ISO Tariff contravene the ISO's commitment to honor Existing Contracts, including Interconnection Agreements. The ISO will exercise the authority that it otherwise has – subject to any limits imposed by Existing Contracts – to issue Dispatch instructions to resolve operating problems that must be addressed in real-time operations.

[94] In recognition of the fact that cogenerators and other QFs have pre-existing contractual commitments under PPAs executed prior to the creation of the ISO, the ISO Tariff also requires the ISO to honor the terms of those PPAs for "Regulatory Must-Take Generation" identified as such by a local regulatory authority. In the course of the creation of the ISO, the relevant local regulatory authority, the CPUC declared that such "Regulatory Must-Take Generation" includes QFs with PPAs executed prior to December 20, 1995. Section 5.1.5 of the ISO Tariff requires the ISO to honor the terms of those "existing PPAs" to the extent that the ISO is presented with "operating instructions" that describe the terms of those PPAs. Thus, a cogenerator may also protect its commitment to its industrial process through the submittal to the ISO of "operating instructions" regarding the terms of its "existing PPA" that are inconsistent with the ISO Tariff.

When properly considered in the context of the entire ISO Tariff,[95] Sections 9.1.1 and 9.5 of the DP do not vest undue authority in the ISO. The Commission has found that these provisions, and indeed the ISO Tariff as a whole, do not vest the ISO with the authority to disregard bids. However, Proponents are incorrect in suggesting that Section 5.1.3 of the ISO Tariff and other Tariff provisions do not authorize the ISO to Redispatch resources to resolve Congestion in the absence of available bids.

k. <u>Does DP 9.4.1 provide the ISO too much discretion to shut down a generating unit. [Issue No. 618, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Dynegy and CAC]</u>

Unresolved Issue No. 618 was raised by Dynegy in comments in Docket Nos. EC96-19-029 and ER96-1663-030 concerning the ISO's June 1, 1998 Compliance filing. 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, Dynegy identified this issue as remaining in dispute.[96] As reflected in Attachment C to the Report on Outstanding Issues filed in the instant proceeding on March 11, 1999, Dynegy and the ISO reached a proposed settlement based on the following changes to the ISO Tariff:

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[95] As the Commission has described:

> In construing what a tariff means, certain general principles apply. One looks first to the four corners of the entire tariff, considers the entire instrument as a whole, giving effect so far as possible to every word, clause and sentence, and attributes to the words used the meaning which is generally used, understood, and accepted.

Columbia Gas Transmission Corp., et al., 27 FERC ¶ 61,089, at 61,166 (1984).

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

Revise DP 9.4.1(h) to read as follows:

Generators must: . . .
(e) respond to a Dispatch instruction issued for the shut down of a Generating Unit <u>in accordance with DP 10.2.8</u>, within the time frame stated in the instruction.

Dynegy continues to support the proposed settlement as a mutually agreeable resolution of this issue. Joint Initial Brief on Issue B.5.k, at 2. While the ISO believes that this Tariff provision was just and reasonable as filed and that no changes are necessary, the ISO continues to support the compromise reached with Dynegy. However, the additional changes requested by EPUC/CAC are unwarranted.

As explained 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 serve as the basis for settlement discussions. EPUC/CAC declined to do so. Moreover, unlike most of the entities that identified issues, EPUC/CAC failed to file a timely intervention and protest in response to the ISO's June 1, 1998 Compliance filing, in which the DP was filed for Commission acceptance. In its April 28, 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. *California Independent System Operator Corporation*, 87 FERC at 61,423. The same rationale should apply to issues that have been settled, where 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 Dynegy and the ISO, and should reject EPUC/CAC's belated attempt to seek additional changes.

EPUC/CAC states that the existing Tariff provisions fail to properly consider the particular safety concerns related to operation of the thermal energy host facility. Joint Initial Brief on Issue B.5.k, at 3. To the contrary, as discussed above in relation to Issue A.3.a, all Generators, including QFs, are free to specify both a "minimum operating limit" and any operating "limitations" applicable to their Generating Unit.[97] This allows the facility to indicate to ISO operating personnel any technical operating restrictions on the ability of the Generating Unit to deliver power to the ISO. Moreover, as the Commission recognized in its October 1997 Order:

> We find that the requirement that participants comply with all ISO orders except those that would result in impairment to public health and safety to be reasonable. With regard to intervenor concerns about potential damage to their facilities, we note that the ISO will follow good utility practice in operating the system and will comply with all NERC, WSCC and other reliability criteria.

October 1997 Order, 81 FERC at 61,456. Accordingly, the existing Tariff and *pro forma* agreements address the safety concerns expressed by EPUC/CAC.

B.6. <u>With respect to the ISO's communications with Generators:</u>

a. <u>Whether the ISO properly complied with the Commission's October 30 Order with respect to its modifications to sections 2.5.6.2 and 2.5.22.10 of the ISO Tariff. [Issue No. 541, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - CAC]</u>

EPUC/CAC has withdrawn its advocacy of this issue. Joint Initial Brief on Issue B.6.a. Unresolved Issue No. 541 was originally raised by Cities/M-S-R and settled in accordance with the resolution of Issue B.6.b (Unresolved Issue No. 586).[98] As discussed in the next section, EPUC/CAC has withdrawn its

[97] *See* Attachment 1.

[98] *See* Comments of the Cities of Redding, Santa Clara and Palo Alto, California, and the M-S-R Public Power Agency, Docket Nos. ER98-3760-000, *et al.* (Dec. 21, 1999), at 3.

opposition to that issue as well and the ISO agrees to modify the ISO Tariff in accordance with the proposed settlement terms.

b. <u>Whether section 2.5.6.2 improperly permits the ISO to determine unilaterally which method of communication with the generator is appropriate. [Issue No. 586, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - Dynegy and CAC]</u>

Dynegy correctly notes that it reached a proposed settlement with the ISO concerning a proposed modification to Section 2.5.6.2 of the ISO Tariff. Initial Brief of Dynegy at 12. Evidently, CAC has withdrawn its opposition to the proposed terms. *Id.* at 13. The ISO reiterates that it is willing to modify the Tariff in accordance with the proposed revision to the third sentence of Section 2.5.6.2 of the ISO Tariff, as reflected in Dynegy's initial brief.

c. <u>With respect to DP 3.4.4:</u>

(1). <u>Should the ISO be prohibited from imposing penalties, fines or sanctions as long as a generator is abiding by the terms of its contract with the ISO?</u>

(2). <u>If the ISO bypasses the Scheduling Coordinator and communicates directly with the generator, should neither the Scheduling Coordinator nor the generator be subject to penalties? [Issue No. 607, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - Dynegy]</u>

Dynegy argues that Section 3.4.4 of the DP is "superfluous and irrational." Initial Brief of Dynegy at 3. Dynegy finds the provision irrational because it applies penalties against a Scheduling Coordinator when a Generator fails to respond or inadequately responds to an ISO request. Dynegy states that since the Scheduling Coordinator might not have any relationship with the Generator apart from that described in the Scheduling Coordinator Agreement ("SCA"), the Scheduling Coordinator should not be penalized for the Generator's shortcomings. Dynegy considers the provision to be superfluous because the failures and incorrect actions of Generators are already subject to penalties in the PGA. *See id.*

This provision is neither superfluous nor irrational. As Section 3.4.3 of the DP makes clear, communication normally takes place between the ISO and the Scheduling Coordinator, rather than the Generator. It is then the responsibility of the Scheduling Coordinator to pass on instructions to the Generator immediately. Section 3.4.3 of the DP reads as follows:

> **3.4.3. Verbal Communication with Generators**
>
> Normal verbal communication of Dispatch Instructions between the ISO and Generators will be via the relevant SC. Each SC must immediately pass on to the Generator concerned any verbal communication for the Generator which it receives from the ISO. If the ISO considers that there has been a failure at a particular point in time or inadequate response over a period of time by the Generating Units to the Dispatch Instruction, the ISO will notify the relevant SC. In situations of deteriorating system conditions or emergency, the ISO reserves the right to communicate directly with the Generator(s) as required to ensure System Reliability.

It is in this context that one must interpret the next section of the DP, 3.4.4:

> **3.4.4 Consequences of a Failure to Respond or Inadequate Response**
>
> The ISO may apply penalties, fines, economic consequences or the sanctions referred to in DP 9.5.2 for any failure or inadequate response under DP 3.4.3 to the SC representing the Generator Responsible for such failure or inadequate response (which may be appropriately weighted to reflect its seriousness) subject to any necessary FERC approval.

Read in context, Section 3.4.4 of the DP clearly concerns actions by Scheduling Coordinators, and not merely by Generators. Scheduling Coordinators are liable for their failure to pass on communications from the ISO immediately. Moreover, it is only when the Scheduling Coordinator is unavailable, or when system conditions render it impossible to route communications through the Scheduling Coordinator, that the Generator would be contacted directly by the ISO. The intention of such direct ISO-Generator communication is to prevent Scheduling Coordinators from inappropriately making themselves unavailable for communications from the ISO and thereby avoiding liability when the ISO must deal directly with the Generator, and to ensure liability for responding to everyday instructions.

Regarding Dynegy's argument that the Scheduling Coordinator "may not have any relationship to the Generator beyond the Scheduling Coordinator Agreement" (Initial Brief of Dynegy at 3), Dynegy inappropriately limits the Scheduling Coordinator role. The Scheduling Coordinator is not bound by the SCA in defining its relationship with the Generator, and may have other agreements which include appropriate indemnification provisions governing the potential liability in situations where the ISO must communicate directly with the Generator. The claim that a Scheduling Coordinator may have no "relationship" with the Generator provides no excuse for the breakdown of such communication; in fact, it reveals a failure to perform Scheduling Coordinator responsibilities properly. This is precisely the sort of behavior for which penalties are appropriate.

As noted above, Dynegy also argues that Section 3.4.4 of the DP is "superfluous," because the PGA "already gives the ISO authority to sanction Generators if they do not comply with the ISO Tariff." *Id.* In fact, Article 5.1 of the *pro forma* PGA states:

> **5.1 Penalties.**
>
> If the Participating Generator fails to comply with any provisions of this Agreement, the ISO shall be entitled to impose penalties and sanctions on the Participating Generator. No penalties or sanctions may be imposed under this Agreement unless a Schedule providing for such penalties or sanctions has first been filed with and made effective with FERC. Nothing in the Agreement, with the exception of the provisions relating to ADR, shall be construed as waiving the rights of the Participating Generator to oppose or protest any penalty proposed by the ISO to the FERC or the specific imposition by the ISO of any FERC-approved penalty on the Participating Generator.

This provision clearly allows for the imposition of penalties against Generators for failure to comply with the PGA. It is silent, however, regarding similar penalties against Scheduling Coordinators. Therefore Section 3.4.4 of the DP is *not* superfluous.

Finally, it is noteworthy that even though both the DP provision and the PGA provision contain penalty language, in fact the ISO has yet to file for Commission approval in order to assess any such additional penalties beyond those contained in Section 2.5.26 of the ISO Tariff. Therefore, Dynegy's concerns are at best premature until any such additional penalties are actually applied to a Scheduling Coordinator, or until duplicative penalties are applied to a Scheduling Coordinator and Generator involved in the same failure. Only if such a thing were to occur would it be possible to evaluate whether any particular penalty is "irrational" or "superfluous."

B.7. <u>Should information regarding price be included in the data provided to ISO dispatchers, pursuant to sections DP 8.6.3(e) and SP 11.2? [Issue Nos. 615 and 629, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - Dynegy]</u>

Dynegy has asked the ISO to agree to remove market price information from the software used by ISO Dispatchers or to agree to release information and explanations to Market Participants whenever the ISO makes an out-of-sequence or out-of-market trade, or Dispatches an RMR unit when bids in the same local Load Zone remain outstanding. Initial Brief of Dynegy at 15-16. Dynegy argues that without this relief the ISO's Dispatch actions cannot be trusted. *Id.*

There is no reason for the Commission to take any action with respect to this issue. First, Section 2.5.23.1 of the ISO Tariff specifies that the "ISO will record the reasons for any variation from the Dispatch instructions issued by the BEEP Software."[99] Consistent with this provision, the ISO already notifies Market Participants, usually by electronic mail, whenever it makes an out-of-sequence or out-of-market Dispatch. Second, the ISO is planning to increase the amount of information it provides to Market Participants in terms of (1) the hours during which calls were made, (2) the total MWh called, and (3) the cost of the total MWh called. The ISO will undertake to provide the additional information cited above as soon as possible after it receives the Commission's determination regarding the ISO's Request for Clarification in connection with the ISO's proposed Amendment No. 23 to its Tariff, regarding out-of-market Dispatch.

[99] BEEP stands for Balancing Energy and Ex Post Price.

Finally, Amendment No. 26 to its Tariff will eliminate most of the concerns associated with Dispatch of RMR units.

The Commission recently approved Amendment No. 26 to the ISO Tariff. *California Independent System Operator Corporation*, 90 FERC ¶ 61,345 (2000). This amendment will significantly decrease the amount of Energy from RMR units that will be called in real time, thus significantly decreasing the number of times RMR units will be Dispatched when bids in the same local area remain outstanding.[100]

In its order on Amendment No. 26, the Commission approved three Tariff revisions that work in tandem to ensure that Reliability Must-Run Generation that is Dispatched by the ISO is scheduled against Demand in a forward market. The ISO will Dispatch Reliability Must-Run Generation prior to the close of the PX Day-Ahead Market, so that the Reliability Must-Run Generation can be scheduled in that market. At that point, the owner of the Reliability Must-Run Generation must elect payment either through the market or under its RMR Contract. If the owner of the Reliability Must-Run Generation wishes to take payment through the market and schedules a bilateral transaction or bids into the PX Markets, the Dispatched Energy is scheduled against Demand. If the owner of the Reliability Must-Run Generation elects to receive the payment specified in its RMR Contract, the Reliability Must-Run Generation will nonetheless be scheduled in a forward market. The Demand that must be met by Reliability Must-Run Generation must therefore be "netted out" of the PX Day-Ahead

[100] A copy of the filing letter for Amendment No. 26 is provided as Attachment 9.

Market in order to ensure a balance between scheduled Loads and Generation and to avoid unnecessary distortions in the PX and ISO real-time Energy markets. In short, this pre-Dispatch of Reliability Must-Run Generation will mitigate much of the concern about the Dispatch of Reliability Must-Run Generation in the Imbalance Energy market.

B.8. Has the ISO unreasonably delayed implementing the direction from the October 30, 1997 Order that the ISO compute for each Advisory and Final Schedule in the Day-Ahead and Hour-Ahead markets the dispatch and Usage Charges that would have resulted if the ISO had been allowed to resolve Congestion without the restriction that Scheduling Coordinators keep their schedules balanced? [Issue No. 397, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - TURN / UCAN]

In the October 1997 Order, the Commission stated as follows:

> In order to facilitate the Congestion Management process and to inform market participants about potential trading opportunities, we will direct the ISO to publish certain non-confidential information, by March 31, 1998, or when technically feasible. Specifically, we direct the ISO to compute, for each Advisory and Final Schedule in the Day-Ahead and Hour-Ahead markets, the dispatch and Usage Charges that would have resulted if the ISO had been allowed to resolve Congestion without the restriction that Scheduling Coordinators keep their schedules balanced. This dispatch is exactly the dispatch that the ISO would have found had all Adjustment Bids been submitted by a single Scheduling Coordinator instead of by various Scheduling Coordinators. Consequently the implementation of this extra computation would require only a relabeling of the input data (by attributing all Adjustment Bids to a single Scheduling Coordinator) and would not require any modification of the computational part of the Congestion Management software. The Commission will require only that the Usage Charges and not the actual dispatch be published simultaneously with the Advisory and Final Usage Charges. The Usage Charges should be published for every hour in the Day-Ahead and Hour-Ahead market.

October 1997 Order, 81 FERC at 61,482. The purpose of the information described is to inform Market Participants about potential trading opportunities. *Id.*

TURN/UCAN correctly notes that the ISO has not yet implemented this requirement. *See* Initial Brief on Issues B.2.d, B.8, and N.4, at 7. TURN/UCAN requests that the Commission require the ISO to perform the analysis described by the Commission – both for past periods and on a real-time, going-forward basis – to ensure that the data is available for consideration in the Congestion Management redesign stakeholder process. *Id.* at 7-8.

The ISO agrees with TURN/UCAN that such an analysis would be helpful and would inform the discussions on certain aspects of Congestion Management reform. As the Commission is aware, a significant outstanding issue in the Congestion Management reform process is whether the ISO should retain the Market Separation Constraint. Accordingly, as part of the Congestion Management redesign process, the ISO agrees to provide Market Participants with information regarding the impact on Usage Charges that would have resulted in the absence of the requirement that Scheduling Coordinators keep their Schedules balanced. This will be a time-intensive effort requiring the collection of a large amount of data. In order to provide Market Participants with the information as quickly as possible, the ISO intends to limit its collection of data to the historical hours in which Congestion occurred. The ISO believes that such information will provide Market Participants and the Commission with data sufficient to inform future deliberations on this matter. The ISO disagrees with TURN/UCAN that the ISO should also provide this data on a real-time, going-forward basis. While the ISO recognizes that the original Commission directive called for the ISO to analyze such data, the development and analysis of this data in real time would require a significant amount of staff resources to be devoted to the task but would add little to the historical analysis. Moreover, to the extent that the ISO ultimately decides to remove the Market Separation Constraint as part of its Congestion Management redesign initiative, the ISO will no longer need to perform such an analysis on a going-forward basis. Therefore, the ISO respectfully requests that the Commission defer ruling on this aspect of the Commission's directive until the ISO's Congestion Management reform process is complete.

B.9. Is the failure of the ISO to include Ancillary Services in its Congestion Management program unjust and unreasonable? [Issue No. 591, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - Dynegy]

Dynegy recognizes that in the June 1, 1998 Compliance filing the ISO deleted Section 7.2.5.2.6 of the ISO Tariff because the ISO's Congestion Management software did not account for Ancillary Services. *See* Initial Brief of Dynegy at 17. Dynegy notes that the ISO is undertaking a comprehensive redesign of its approach to Congestion Management in response to the Commission's order on Amendment No. 23. *Id.* at 18. Dynegy recommends that the Commission order the ISO to revise its Inter-Zonal Congestion software to take into account Ancillary Services and to restore the deleted language in Sections 7.2.1.1 and 7.2.5.2.6 of the ISO Tariff.

The ISO agrees with Dynegy that the integration of Ancillary Services and Congestion Management is an issue appropriately discussed as part of the ISO's recent commitment to reexamine its Congestion Management protocols.[101] As

[101] *See* Motion for Clarification or, In the Alternative, Request for Rehearing, and Request for Expedited Consideration of the California Independent System Operator Corporation, Docket No. ER00-555-001 (Feb. 7, 2000), at 13-14.

the ISO stated in a recent compliance filing:

> [T]he integration of Ancillary Services procurement and scheduling and Congestion Management (AS/CONG Integration) has long been an item targeted for implementation by the ISO. AS/CONG Integration has been actively considered for inclusion in every major market redesign initiative undertaken by the ISO. In each instance, however, the ISO and Market Participants have identified higher-priority items for inclusion in such initiatives.[102]

The ISO also stated as follows:

> In light of the ISO's commitment to reexamine and potentially redesign its Congestion Management mechanisms and file such revisions with the Commission by October 31 of this year, the ISO believes that it is appropriate to address the development and implementation of a bidding mechanism such as the one referred to by the Commission in the context of such a proceeding. While the ISO understands and appreciates the Commission's desire to see such bidding mechanisms implemented as quickly as possible, the ISO believes that it would not be an appropriate allocation of resources to develop and implement such a mechanism prior to the conclusion of the ISO's review of its approach to Congestion Management. Therefore, the ISO commits to closely examine and consider the Commission's recommendation in the context of its broader reexamination of its Congestion Management mechanisms.[103]

The ISO believes, however, that in the interim the Commission should accept the proposed deletions concerning Sections 7.2.1.1 and 7.2.5.2.6 of the ISO Tariff, and should defer any determination on this matter pending the conclusion of the ISO's Congestion Management redesign process. The October 1997 Order required the ISO to delete elements of its Tariff that were not ready for implementation. *See* October 1997 Order, 81 FERC at 61,478. To date, the

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[102] Transmittal Letter for *AES Redondo Beach, L.L.C.* compliance filing, Docket Nos. ER98-2843-010, *et al.* (Feb. 14, 2000), at 3-4 (footnote omitted). The compliance filing was made in response to the Commission's directives in *AES Redondo Beach, L.L.C., et al.*, 90 FERC ¶ 61,036 (2000).

[103] *Id.* at 4 (footnote omitted).

Commission has demonstrated patience regarding implementation of certain features of the original California market design. Through its previous orders, the Commission has long recognized the difficulties in implementing market design elements that are largely dependent on the development and testing of software. *See, e.g., AES Redondo Beach, L.L.C., et al.*, 85 FERC ¶ 61,123, 61,456-59 (1998). Moreover, the Commission has recognized that the markets in California and elsewhere must be continuously monitored and reexamined and that markets are evolving in nature. *See New England Power Pool*, 85 FERC ¶ 61,379, 62,479-80 (1998). Therefore, the Commission should defer any final determination on this matter until the ISO and the stakeholders have undertaken a review of the ISO's existing Congestion Management system. This will allow the ISO to implement the most effective solution for the California market.

B.10. <u>Has the ISO complied with the Commission's October 30, 1997 order requiring the filing of generation unit availability standards, or whether the ISO should be ordered "to file availability standards with the Commission as part of the mitigation proposal as soon as practicable," in order to prevent abuses of market power? [Issue Nos. 436 and 503, Docket Nos. EC96-19-029 and ER96-1663-030. Proponents - MWD and TANC]</u>

As to unit availability standards, the Commission stated the following in the October 1997 Order:

> To prevent the Companies [i.e., PG&E, SCE, and SDG&E] from withholding capacity and thereby causing prices to rise, we find unit availability standards to be an appropriate response. We direct the ISO . . . to file availability standards with the Commission as part of the mitigation proposal as soon as practicable.

October 1997 Order, 81 FERC at 61,546. Proponents note the Commission's statement in their initial brief (*see* Joint Initial Brief on Issues B-10 and C-3, at 2-3), but fail to consider sufficiently the context in which the Commission made it, or the measures that the ISO has taken since October 1997 to detect and deter actions based on gaming behavior. Nevertheless, the ISO recognizes that there may be a benefit to developing unit availability standards.

The Commission issued the October 1997 Order in the context of PG&E, SCE, and SDG&E being the owners of extensive Generating Units in California. Since late 1997, those companies have divested themselves of significant numbers of their Generating Units. At the time of the October 1997 Order, the Commission stated that "it is not clear when divestiture will be completed." October 1997 Order, 81 FERC at 61,546. This uncertainty no longer exists. The context in which PG&E, SCE, and SDG&E might withhold capacity has changed significantly. As Proponents themselves assert, the Commission's order "was the direct result of stakeholder concern regarding the potential for the exercise of market power by the three California investor-owned electric utilities ("Companies") *prior to the divestiture of their generating units*." Joint Initial Brief on Issues B-10 and C-3, at 3 (emphasis added) (footnote omitted). Therefore, the rationale behind the Commission's specific goal in the October 1997 Order no longer applies.[104]

[104] With regard to potential market power concerns arising from the divestiture of PG&E's hydroelectric facilities (*see* Joint Initial Brief on Issues B-10 and C-3, at 4), the ISO believes that any such divestiture would include appropriate market power mitigation measures.

However, the ISO recognizes that concerns still exist regarding the negative impact caused by the strategic withholding of capacity. The ISO has adopted and proposed measures to guard against entities engaging in gaming behavior. First, the MMIP requires the DMA to monitor the activities of Market Participants to detect "anomalous market behavior" including "withholding of Generation capacity under circumstances in which it would normally be offered in a competitive market" and "unexplained or unusual redeclarations of availability by Generators." *See* MMIP 2.1.1. Monitoring capacity withholding is the best means of guarding against the exercise of market power.

Second, in its recent order accepting Amendment No. 25, the Commission approved the ISO's proposal to publish individual bid data with a six-month delay measured from the Trading Day to which the data corresponds. *California Independent System Operator Corporation*, 90 FERC ¶ 61,316, slip op. at 5-7. The data released will be resource-specific; although the specific resource or the bidding Scheduling Coordinator will not be revealed, the data released will allow the bidding behavior of individual, unidentified sources and Scheduling Coordinators to be tracked over time. The publication of this bid data will assist in identifying gaming behavior that has caused bid prices to rise, and will thus serve to detect and prevent such behavior.

Nevertheless, the ISO agrees with Proponents that unit availability standards can be an effective tool for monitoring market power. The ISO believes there are three elements of a conceptual approach to monitoring whether generating capacity is being purposefully withheld from the market.

The first element involves developing resource-specific availability standards. Such standards would be developed from specific data provided to the ISO by each Generating Unit that participates in the ISO markets.[105] The second element involves utilizing generic availability standards, such as those developed by NERC or the Energy Information Agency. These generic standards are developed by Generating Unit size and fuel type, and can be used to fill in data gaps and serve as a check on the unit-specific data. The third element involves the use of the Day-Ahead Ancillary Services bid and Energy Schedule information to track capacity withholding compared to certified values of ramp rate and operating limits. The ISO would require Generating Unit owners to schedule all their generating capacity in markets, but would permit the unit owners to arbitrage among markets. The ISO would compile hourly measures of the extent to which unit owners scheduled their capacity in Day-Ahead Energy markets (either through the PX market or through bilateral Schedules) or bid the capacity into the Day-Ahead Ancillary Services and Supplemental Energy markets, even if part of it were bid at the level of the price cap. Even if a unit owners had to schedule the sum of their units' capacity, the unit owners' flexibility in participating in the Energy and Ancillary Services markets would not be limited, because they could reduce their bids below the cap in the markets where they intended to seriously compete. To the extent that a unit owner did not schedule all of its available capacity, it would be subject to a penalty based on the

[105] The development of unit-specific availability standards would require each Generating Unit in the market to provide sensitive market-related and operational information to the ISO. The ISO believes that Generating Unit owners might be reluctant to turn over to the ISO such

frequency and magnitude of such unavailability, and its market impact. On a case-by-case basis, the penalty would be waived if the unit owner could demonstrate that the lack of full participation was due to a unit outage or derate consistent with the availability standard. This approach would allow the ISO to use the unit owner's participation in the market plus its bilateral Schedule as a measure of the unit owner's available capacity on a Day-Ahead basis. This would provide a check on the availability data provided by the Generator and an incentive to participate in the forward markets, both of which would be highly desirable.

The ISO, however, has not yet had an opportunity to review this approach and its elements with Market Participants through an ISO stakeholder process. The ISO anticipates that such discussions will need to take place in the near future in the context of the expiration of the ISO's price-capping authority. The ISO respectfully requests that the Commission defer further consideration of this issue until that stakeholder process is well underway or complete.

B.11. <u>Should the term "ISO Operations Protocols" in section 2.3.1.2.2 of the ISO Tariff be a defined term. [Issue No. 516, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - CAC]</u>

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. 516, but that another party "desires to litigate the issue."[106] MWD stated that "based upon its understanding that the ISO remains willing to

information, and that ultimately a FERC directive might be required to compel them to turn over the information.

[106] *See* 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.

honor its settlement offer, [MWD] will not address such issues in its Initial Brief."[107]

EPUC/CAC, the party that desired to litigate the issue, has withdrawn its advocacy. Joint Initial Brief on Issue B.11, at 1. The ISO remains willing to settle the issue in accordance with the previously proposed terms. Unresolved Issue No. 516 was resolved in accordance with Unresolved Issue No. 283, based on the following revisions to the ISO Tariff:

- Deletion of Section 2.3.1.2.2 and revision of Section 2.3.1.2.1 to read as follows: Comply with Operating Orders Issued. With respect to this Section 2.3.1.2, all Market Participants within the ISO Control Area shall comply fully and promptly (with no more delay than specified in the response times set out in the ISO Protocols) with the ISO's operating orders, unless such operation would impair public health or safety. For this purpose, ISO operating orders to shed Load shall not be considered an impairment to public health or safety.

- Revision of the last sentence of Section 2.3.1.3 to read as follows: Within the ISO Control Area, ~~All~~ all Market Participants and the ISO shall comply with the ISO reliability criteria, standards, and procedures.

- Clarification of the applicability of Section 5.6.2 by revising the definition of "Participating Seller or Participating Generator" to read as follows: A Generator or other seller of Energy or Ancillary Services through a Scheduling Coordinator over the ISO Controlled Grid, ~~and~~ which has undertaken to be bound by the terms of the ISO Tariff, in the case of a Generator through a Participating Generator Agreement.

- Replacement of the word "facilities" in the first line of Section 5.1.1 with the words "Generating Units."

107 *Id.*

B.12. With respect to Tariff Amendment No. 7, should the Commission require the ISO to revise the "temporary rule" to impose a price cap for Imbalance Energy bids evaluated by the ISO's BEEP software? [Issue No. 371, Docket Nos. EC96-19-023, ER96-1663-024, and ER98-3760-000. Proponent - Houston Industries Power Generation ("HIPG")]

The ISO understands that no initial brief was filed with respect to this issue.

B.13. Is section 23.2.1 of the ISO Tariff reasonable?

a. Has the ISO failed to justify the change to section 2.5.22.4 of that Supplemental Energy Bids must be submitted to the ISO not later than 45 minutes prior to the operating hour rather than 30 minutes?

The ISO changed Section 2.5.22.4 of the ISO Tariff to provide that Supplemental Energy bids must be submitted to the ISO not later than 45 minutes prior to the operating hour in order to expand the Supplemental Energy market and to comply with WSCC requirements. Scheduling Coordinators can bid Supplemental Energy from Generating Units and Curtailable Demands within the ISO Control Area and from System Resources on interties. As a matter of standard practice, WSCC requires that interchange scheduling be completed 20 minutes before the operating hour, with interchange ramps commencing 10 minutes before the hour. Therefore, in order to be certain that the ISO will have access to this Supplemental Energy, the ISO increased the time frame in which bids must be submitted from 30 minutes to 45 minutes before the hour.

Dynegy objects to the ISO's 45-minute time frame. It argues that the Commission's discussion in Order No. 888-A regarding the *pro forma* tariff provision (which permits scheduling changes up to 20 minutes before the hour) somehow supports requiring the ISO to permit bid changes up to 30 minutes before the hour. Initial Brief of Dynegy at 20. In Order No. 888-A, the Commission explained that allowing scheduling changes to be made closer to the hour provides more certainty, because then forecast Load better coincides with actual load, which, in turn, reduces the cost to customers.[108] However, this reasoning does not apply in the same way to the time period for allowing Supplemental Energy bid changes. On the contrary, the reverse is true.

Requiring firm bids into the Supplemental Energy market 45 minutes before the hour, rather than 30 minutes, provides the ISO with an expanded market for Supplemental Energy, given the ability of Scheduling Coordinators to bid Supplemental Energy at the interties, as explained above. This, in turn, reduces the cost of Supplemental Energy. The change also results in more certainty that Supplemental Energy will be available if needed, and at a price certain, which additionally decreases risk to customers. Dynegy's conclusion – that it increases the risk to customers and is contrary to the rationale enunciated in Order No. 888-A – is incorrect. Thus, the ISO's time frame for submission and withdrawal of Supplemental Energy bids is reasonable and should be upheld.

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[108] Dynegy quotes from Order No. 888-A as follows:

> To help customers with the difficulty of forecasting loads far in advance of the hour, the Final Rule *pro forma* tariff permits schedule changes up to twenty minutes before the hour at no charge. By updating its schedule before the hour begins, a transmission customer should be able to reduce or avoid energy imbalance and associated charges.

Initial Brief of Dynegy at 20, *quoting* Order No. 888-A, FERC Stats. and Regs. III, Regs. Preambles ¶ 31,048, at 30,233.

b. <u>Should the ISO be required to modify certain language relating to resources that provide Imbalance Energy at section 2.5.23.1, as it allows the ISO to use Regulation for Imbalance Energy?</u>

The ISO does not intentionally use Regulation for Imbalance Energy. The ISO has, however, found itself forced to do so because of the failure of resources supplying Imbalance Energy to respond reliably to ISO Dispatch instructions. The ISO has two initiatives underway that will significantly reduce the unintended use of Regulation for Imbalance Energy: 10-Minute settlements and the Generator Communication Project ("GCP").

The ISO Dispatches Generating Units providing Regulation Service to meet NERC and WSCC ACE performance requirements. Once ACE has returned to zero, the ISO determines whether the Regulation Generating Units and System Units are operating at a point away from their Set Point. The ISO adjusts the output of units available (either providing Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, or offering Supplemental Energy) to return the Regulation Generating Units to their Set Points to restore their full regulating margin. *See* ISO Tariff, Sections 2.5.22.2(a) and 2.5.22.2(b). This is accomplished by calling on Imbalance Energy in price merit order. *See id.*, Section 2.5.22.6.

While the outputs of Generating Units providing Regulation Service may be moved up or down, the Energy output over the hour for Regulation is expected to be a net zero. Nevertheless, units providing Regulation service can produce measurable amounts of Energy in both upward and downward directions. To the extent this output differs significantly from scheduled output, deviations are settled at the Hourly Ex Post Price (as Uninstructed Imbalance Energy). The ISO has commenced a stakeholder process to evaluate ways in which units providing Regulation can be kept closer to their preferred operating points, and can be relied upon less in terms of providing Imbalance Energy at the Hourly Ex Post Price. The stakeholder process is aimed at minimizing the opportunities that non-regulating resources have to take advantage of Hourly Ex Post Prices (e.g., by disregarding ISO Dispatch instructions to take advantage of the expected Hourly Ex Post Price). Non-regulating units are free to change the output of their resources based on their expectations of Hourly Ex Post Prices. These deviations from final schedules, to follow the Hourly Ex Post Price, cause units providing Regulation to be driven off of their preferred operating points (in order to maintain the balance of Loads and resources in the ISO's Control Area). To minimize this manner of operation, the new approach to real-time Imbalance Energy pricing would have uninstructed deviations settled on 10-minute BEEP Interval Ex Post Prices, as opposed to Hourly Ex Post Prices. Scheduling Coordinators would continue to be free to change the output of their resources in the absence of Dispatch instructions from the ISO in light of real-time prices; the difference being that the prices they would be following would be 10-minute ex post prices as opposed to the hourly average ex post prices. The resulting manner of operation by all resources participating in this reformed real-time Imbalance Energy market will be to keep the units providing Regulation closer to their preferred operating points.

The GCP will also help. This program will give the ISO direct control of Regulation units through Remote Intelligent Gateways. Currently, changes in Dispatch of Regulation units are subject to delays at area control center interfaces as the ISO goes through an intermediary to communicate with the Generator.

For these reasons, the ISO Tariff provisions regarding the use of Regulation units are reasonable, and they require no further changes at this time.

c. <u>Does the statement at section 2.5.23.1 that the ISO will follow its BEEP software "to the extent practical" afford the ISO unreasonable latitude?</u>

The ISO puts the Energy Bids for Spinning, Non-Spinning, and Replacement Reserves in the BEEP stack for use as needed in the real-time Imbalance Energy market. Section 2.5.23.1 of the ISO Tariff[109] provides that the "ISO will respond to the Dispatch instructions issued by the BEEP Software to the extent practical in the time available and acting in accordance with Good Utility Practice." The section goes on to specify that the "ISO will record the reasons for any variation from the Dispatch instructions issued by the BEEP Software." The latitude afforded the ISO by this Tariff provision is thus circumscribed and subject to review. It is also necessary to its efficient operation.

Sometimes it is infeasible or inconsistent with Good Utility Practice to Dispatch the next resource in the BEEP stack. For example, if the resource next

[109] Section 2.5.23.1 was formerly one of the temporary sections included in Section 23.2.1 of the ISO Tariff. Section 2.5.23.1 was made a permanent section of the ISO Tariff by the Unresolved Issues settlement which the ISO filed on December 1, 1999 and which the

in price merit order is on the wrong side of a congested interface and will cause, or exacerbate, loading on a congested path, it will not be Dispatched. As a second example, consider the following situation. Suppose that there is a sudden loss of a large generator (e.g., a loss of 1000 MW). Suppose further that in the BEEP stack there is a series of bids with small amounts of capacity (e.g., 1 to 3 MW), but down the line there is a bid with a large, capacity-associated resource. The ISO may decide that it is not practical in the time available to maintain frequency or path loading, or both, or to otherwise avoid financial sanctions under the WSCC Reliability Management System, or to expend time calling all the small resources appearing in price merit order before calling the larger generator.

Allowing the ISO to make exceptions to the BEEP stack order "to the extent practical and consistent with Good Utility Practice" is a reasonable Tariff provision that has proven important to the reliable operation of the ISO's Control Area and ISO Controlled Grid. Requiring the ISO to keep record of the reasons for any variations from the merit order of bids makes the ISO accountable for any exercise of discretion. Dynegy's characterization of the Tariff provision as a "free ticket to ignore" Dispatch instructions, Initial Brief of Dynegy at 22, is thus incorrect.[110]

Commission approved by letter order dated February 24, 2000, *California Independent System Operator Corporation*, 90 FERC ¶ 61,178.

[110] Moreover, the ISO has taken steps to more fully automate the issuance and logging of Dispatch instructions, by designing, through a stakeholder process, the Automated Dispatching System ("ADS"). Testing of ADS has already commenced. ADS should be available to ISO operators and Scheduling Coordinators by the summer of 2000.

Dynegy asks that the Tariff provision be replaced with "objective standards" but does not propose any standards for the ISO's or the Commission's consideration. It is difficult to know what alternative standards Dynegy has in mind. The current standard – "to the extent practical and consistent with Good Utility Practice" – is a reasonable one. It provides the ISO with a reasonable amount of judgment to make appropriate changes necessary for the efficient operation of the ISO's Control Area and protection of the reliability of the ISO Controlled Grid.

d. Should the ISO be ordered at section 2.5.23.2 to implement the necessary changes to its software in order to make the prices associated with the 10 minute posted price for instructed deviations the final price?

[Issue Nos. 597, 598, 599, 600, and 601, Docket Nos. EC96-19-029 and ER96-1663-030. Proponent - Dynegy]

Bidders of Imbalance Energy know that if their Energy is used, they will at a minimum receive their bid price. Instructed Imbalance Energy is priced using the BEEP Interval Ex Post Prices (i.e., the 10-minute prices). These prices are based on the bid of the marginal Generating Unit, Load, or System Resource Dispatched in each 10-minute BEEP Interval. Because these Ex Post Prices are calculated and posted every ten minutes in real time, there are circumstances in which errors occur. For example, consider the situation in which a Dispatch instruction is issued, the 10-minute ex post price is calculated and posted to the ISO Home Page, and then the Scheduling Coordinator or resource operator calls the ISO and declines the instruction. Given the unpredictable occurrence of situations such as this one, the ISO cannot post ex post prices as final, or settlement quality. However, the ISO has committed to a process of correcting errors detected in real time within 96 hours of the hour in which the error occurred. The corrections are posted to the ISO Home Page and to the database for financial settlements on compatible time frames. In addition, ISO Market Operations sends to Scheduling Coordinators notices by electronic mail of any changes in posted prices. This new error correction process has already minimized the number of disputed prices incorporated into preliminary statements and invoices. Previously, errors were not routinely corrected until after they had been incorporated into preliminary statements and invoices.[111] The ISO's current process for correcting and updating errors is reasonable.

Dynegy's request that the ISO be ordered to make the posted price the final price is unreasonable and impractical. Dynegy argues that because the New York Stock Exchange's prices are final prices, the ISO's BEEP Interval Ex Post Prices should not be allowed to be corrected for errors in their calculation. Initial Brief of Dynegy at 22. Dynegy's analogy to the New York Stock Exchange fails in this case because the price paid for Imbalance Energy is an ex post price, and the price paid for a stock on the Exchange is not. Successful bidders into the Imbalance Energy market at a minimum receive their bid price. Whether a sale of Energy occurs is not determined by the subsequently calculated BEEP Interval Ex Post Price. Thus, bidders are not unduly harmed by a recalculated BEEP Interval Ex Post Price. Nevertheless, the ISO does not want to make

[111] Even now, some errors are not detected in real time and therefore cannot be corrected within 96 hours of the hour in which they occurred. These errors may have to be corrected in statements. When this happens, ISO Client Relations notifies Scheduling Coordinators, usually by electronic mail.

mistakes in the calculation of prices. It harms the ISO's relations with its customers and causes the ISO to incur costs to correct errors; and the longer the ISO takes to correct an error, the more it harms customer relations and the more it costs the ISO. The ISO has every incentive to keep errors to a minimum and to report them and correct them as soon as they are known. The fact that the ISO has recently initiated a new process to achieve this (without being ordered to by the Commission) is a testament to this fact.