UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Turlock Irrigation District and Modesto Irrigation District	)	
	)	
v.	)	Docket No. EL99-93-000
	)	
California Independent System Operator Corporation	)	

ANSWER OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO THE COMPLAINT AND REQUEST FOR INVESTIGATION OF THE TARIFF OF TURLOCK IRRIGATION DISTRICT AND MODESTO IRRIGATION DISTRICT

Pursuant to Rules 206(f) and 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.206(f) and 385.213 (1999), and the Notice of Filing issued on September 20, 1999, the California Independent System Operator Corporation ("ISO") submits this Answer in response to the "Complaint and Request for Investigation of Discriminatory Application of Tariff" ("Complaint") filed by the Turlock Irrigation District ("Turlock") and the Modesto Irrigation District ("Modesto") (or collectively "the Districts") on September 17, 1999.

I. INTRODUCTION AND SUMMARY

The Districts' Complaint concerns the terms and conditions under which the ISO, in accordance with its Tariff as approved by the Commission, permits entities to participate in the ISO's new Ancillary Services and Imbalance Energy markets.[1] It is comprised of three or four main allegations that are restated several times. The essence of the District's Complaint can be summarized as follows:

(1) While the ISO has established reasonable "technical standards" for participation in its Ancillary Services and Imbalance Energy markets, it has also established unreasonable and discriminatory "preconditions" for selling Ancillary Services and Imbalance Energy. Complaint at 9-17.

(2) The central discriminatory precondition is the requirement that generators sign a Participating Generator Agreement ("PGA") in order to participate in the ISO's markets. According to the Districts, the requirement to sign a PGA results in an unreasonable amount of control over their generating units such that" [e]ffectively, a PGA transfers ultimate control of the entire unit from the utility to the ISO." Complaint at 12.

(3) The consequences that flow from signing a PGA require a publicly-owned municipal utility to "set aside its lawful authority to operate

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[1] Capitalized terms used herein and not otherwise defined conform to those terms in the amended ISO Tariff, Appendix A Master Definitions Supplement.

as a full service utility in order to participate in the ISO's [Ancillary Services] and [Supplemental Energy] markets." Complaint at 12.

(4) The ISO unduly discriminates against the owners of generating units inside its Control Area because it requires them to sign a PGA while the owners of generating units outside the the ISO's Control Area do not have to sign a PGA to participate in the Ancillary Services and Imbalance Energy markets. Complaint at 13-16.

As explained in this Answer, the Complaint is without foundation and the Districts' request for investigation should be denied. As the Districts concede, the technical standards for participation in the ISO's markets are reasonable. Contrary to the Districts' assertions, there are no barriers to participation by publicly owned utilities or other entities in the ISO's Control Area that would require them to cease operation as an integrated utility system. Indeed, other municipalities have executed the requisite agreements and are participating in the ISO's markets, without compromising their ability to operate integrated utility systems within the ISO's Control Area.

Further, the Districts' challenge the terms applicable uniformly to <u>all</u> Generators within the ISO's Control Area that desire to participate in the ISO's markets. Under those terms, the Generators themselves are primarily responsible for determining the operation of their resources. The ISO reserves only the right to direct changes to their operation as necessary to preserve the reliability of the ISO Controlled Grid and of the ISO's Control Area. The Districts, however, claim an entitlement to an exemption from these generally applicable requirements, on the ground that they do not apply to resources located outside of the ISO's Control Area. Fundamentally, the Districts' claims of discrimination fail because Generating Units located within the ISO's Control Area are not similarly situated to external resources participating in the ISO's markets. The ISO's responsibility as a Control Area operator to maintain the safe and reliable operation of the system make it necessary and appropriate to distinguish between resources within the Control Area and resources outside the Control Area.

The Districts add to their unfounded claims about discriminatory treatment unrelated complaints about the manner in which costs would be allocated to them should they choose to participate in the ISO's markets. The Districts, however, have miscalculated the costs of participation in the ISO markets. They ignore the fact that they could sell their excess capacity and Energy in the ISO's markets, as other municipal utilities in California have done, without incurring any of the charges about which they complain. The costs at issue are allocated to entities participating in the ISO's markets to serve their Demands, not on the basis of Ancillary Services or Imbalance Energy sold in those markets from Participating Generators. The Districts' complaints about the manner in which those costs are allocated thus have nothing to do with their claims of unwarranted discrimination against internal Generators.

Indeed, the Complaint represents an improper end run around the other Commission proceedings and stakeholder processes where the identical issues are pending. The Districts improperly seek to use the complaint process to influence the difficult cost allocation issues currently under consideration in these fora and thereby secure all the benefits of participation in the ISO's new market structure without paying their appropriate share of supporting costs and competing on a equal basis with other participants. There is no basis for the Commission to establish duplicative proceedings to further the Districts' tactical objectives.

II. COMMUNICATIONS

Communication regarding this matter on behalf of the ISO should be directed to the following individuals, whose names should be entered on the official service list maintained by the Secretary for this docket:

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III. DISCUSSION

A. <u>The Preconditions for Participation in the ISO's Ancillary Service and Imbalance Energy Markets Are Reasonable</u>

The Districts do 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. Complaint at 9-11. They argue that the preconditions to qualify as a supplier of Ancillary Services and Imbalance Energy are not reasonably related to the technical standards. <u>Id</u>. at 11-12. In particular, the Districts object to the requirement that the ISO will only procure Ancillary Services and Imbalance Energy from generating resources within the Control Area that have executed a PGA. <u>Id</u>. at 11. They maintain that when a utility executes a PGA, the ISO has authority to order that Generating Unit to increase or decease Generation to alleviate Congestion, provide balancing Energy, satisfy reserve requirements, and manage over-generation. <u>Id</u>. at 12. According to the Districts, although this level of control is appropriate for a "voluntary market participant such as a stand-alone 'merchant' generating unit, [but] it is completely incompatible with the operation of a full service, publicly owned utility operating its own system." <u>Id</u>.

The Districts thus acknowledge that the requirements they challenge apply to <u>all</u> Generating Units located within the ISO Control Area. Although couched in terms of discrimination, the Districts in fact seek an exemption from the requirements that apply generally to all Generating Units in the Control Area. They base this claim on the fact that generating units located in other Control Areas are not required to execute a PGA, but can participate in the ISO's markets as "System Resources." Their Complaint thus reduces to the argument that Generating Units located within the ISO's Control Area, and owned by publicly owned utilities, must be treated like external resources, rather than like other Generating Units in the Control Area.

Contrary to the Districts' assertion, the ISO's requirements are appropriate for <u>all</u> 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, the Districts' 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. <u>A Generator Does Not Give Up Effective Control of its Generating Unit by Executing a PGA.</u>

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.[2] 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.

The Districts' unsupported allegations that execution of a PGA equates with a loss of control jeopardizing their ability to operate as vertically integrated, or full-service, utilities is unfounded. 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.[3] The Scheduling

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[2] A copy of the pro forma PGA contained in the pending Offer of Settlement in Docket No. ER98-992-000, et al. is provided as Attachment C.

[3] Affidavit of Trent A. Carlson ("Carlson Affidavit") provided as Attachment A at ¶ 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. The ISO's Dispatch Protocol and the ISO's dispatch instructions refer to the ISO's control over Energy and bid in the ISO's markets. Obviously, the ISO must have full dispatch authority over those bid quantities.

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, the Districts would be exposed to a substantial loss or other risk from curtailing (or having to increase) power production, they should submit bids that place a very high cost to the market from changing their output in that range. 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.

Second, it is important to remember that neither the ISO Tariff nor the execution of a PGA would require a municipal utility to relinquish the benefits of its Existing Contracts.[4] The Districts could sign a PGA and participate in the ISO's markets, without "joining" the ISO by: (1) executing a Transmission Control Agreement and transferring Operational Control of their facilities to the ISO or (2) "converting" their Existing Contracts to new firm uses for the benefit of

[4] See Attachment A, Carlson Affidavit at ¶ 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.

all ISO participants.[5] Moreover, the execution of a PGA for sales of excess capacity and Energy does not require the Districts to serve their 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 over-generation," it may do so only as a Control Area operator to take action to avoid or resolve an operating emergency. Attachment A, Carlson Affidavit at ¶ 12. This "market 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 at Section 5.1.3. Similarly, with respect to real-time Intra-Zonal Congestion Management, the ISO is required under its Tariff to use "available Adjustment Bids and Imbalance Energy bids, based on their effectiveness and in merit order, to minimize the cost of alleviating Congestion." ISO Tariff at Section

5 ISO Tariff at Section 2.4.4.2.

7.2.6.2. Only "[i]n the event no Adjustment Bids or Imbalance Energy bids are available, the ISO will exercise its authority to direct the redispatch of resources."[6]

The ISO, as a Control Area, is required to secure the required amounts of Ancillary Services to satisfy Western Systems Coordinating Council ("WSCC") criteria and North American Electric Reliability Council ("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. Attachment A, Carlson Affidavit at ¶ 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.

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[6] Id. This section was revised by Amendment No. 18 to the ISO Tariff. The ISO noted that "[t]he proposed revisions reflect the ISO's commitment to increasing efficiency and reducing costs through market mechanisms." Amendment No. 18 Transmittal Letter, Docket No. ER99-3301-000 at 5. The ISO also reiterated that "[u]nder the existing Tariff provisions, the ISO may exercise its authority to direct the redispatch or resources within the Zone that have not submitted Adjustment Bids or Imbalance Energy bids only if there are no available Adjustment or Imbalance Energy bids." Id.

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

The Districts' contention that execution of a PGA is "completely incompatible with the operation of a full service, publicly owned utility operating its own system" (Complaint at 12) 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.[7] The California Department of Water Resources has also executed a PGA and is an active participant in the ISO's markets.[8]

Additional municipally-owned resources are 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 the California Department of Water Resources have entered into

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[7] 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.

[8] 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.

Scheduling Coordinator Agreements with the ISO,[9] as has Modesto.[10] As Scheduling Coordinators, these utilities can submit Energy Schedules to the ISO and participate in the ISO's markets as buyers and sellers.

It is not the ISO's requirements that have prevented the Districts from making sales from their Generating Units in the ISO's markets, but rather the Districts' own insistence on linking such participation to the resolution of other issues in a specific manner – through the adoption of a Metered Subsystem ("MSS") concept that limits their responsibility for the payment of ISO-related costs. As noted below, these cost allocation issues are currently being addressed in other proceedings. The Districts could have been participating in the ISO's markets during the pendency of those proceedings, without sacrificing their ability to function as "full service" utilities, just as other municipal utilities have done.

B. 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.

The Districts recognize 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

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

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

participate as a "System Resource." Complaint at 13. They also note that Participating Generators located inside the Control Area must comply with the Scheduling Application Scheduling Infrastructure ("SA/SI") which "requires a utility to disaggregate its load and generation data and to schedule them separately with the ISO instead of supplying aggregated data, netted at points of utility system interconnection." Id. at 15. In contrast, when utilities outside the ISO Control Area comply with the SA/SI format requirements, they only provide data on net transfers to the ISO Controlled Area. Id. at 15-16. According to the Districts, "[f]or reliability purposes, the Districts are at least no different from outside utilities which supply and S[upplemental] E[nergy]." Id. at 23, citing Scheuerman Affidavit at ¶ 27. The Districts fault the ISO for not implementing a parallel concept of "System Units" for suppliers within its Control Area. Complaint at 14.

The Districts' assertion that Generating Units within the ISO's Control Area are indistinguishable for reliability purposes from suppliers outside the Control Area is completely unfounded. The Districts' assertion disregards the function of Control Areas, which are the basic units 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 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, the Districts' claim of preferential treatment with respect to generators located outside the Control Area fails to recognize corresponding limitations that have been placed on these participants. Finally, the Complaint ignores the fact that the Districts have another option available to them should they desire to participate in the ISO's markets in a manner equivalent to System Resources: they could establish their own Control Area or Control Areas, fulfilling all of the associated responsibilities and certify the delivery of their own System Resources.

1. <u>It Is Consistent With the ISO's Responsibilities as the Control Area Operator for Maintaining Grid Reliability To Impose Different Conditions on Generators Within the Control Area From Those Required of Generators Outside the Control Area.</u>

The Districts do not operate their own Control Areas. It is the ISO, not the Districts, that performs this function. The Control Area requirements derive from the standards and criteria established by the 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 Operational Transfer Capability ("OTC") violations (and reporting OTC violations to the WSCC);
- Maintaining an adequate supply of Operating Reserves (and reporting Operating Reserve violations to the WSCC);
- Minimizing Area Control Error (and reporting results to the WSCC);[11]
- Managing loop-flow;
- Managing inadvertent interchange (and reporting status to the WSCC); and
- Meeting WSCC criteria and NERC standards (including the responsibilities associated with WSCC Reliability Management System reporting and NERC Standard Compliance reporting).

Attachment A, Carlson Affidavit at ¶ 15.

The Districts complain of a double standard -- 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 must supply the ISO data on their "gross" Loads. Complaint at 15-16. This complaint fails on three grounds.

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[11] Area Control Error is the instantaneous difference between the actual and scheduled interchange of a Control Area and includes a component for frequency bias.

First, it has nothing to do with the ability of the Districts to participate in the ISO's markets as sellers. As explained above, the Districts 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, as the Districts concede, 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 the Districts or other municipal utilities. The Complaint does not even allege that the Districts have been disadvantaged relative to other utilities serving loads in the ISO's Control Area.

Third, contrary to the Districts' 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 under WSCC guidelines on its Load responsibility. Attachment A, Carlson Affidavit at ¶ 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, in the Control Area, Load and interchange with other Control Areas. Without this information, the ISO's ability to fulfill its Control Area responsibilities, and therefore, the reliability of the Control Area and interconnection, are compromised.[12]

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 external Demands even when the supplier schedules transactions on the ISO Controlled Grid. The ISO only requires accurate data regarding interchange schedules. The distinction between the Load reporting requirements applicable to internal and external loads are therefore reasonable and appropriate.

The Districts complain that the ISO has not instituted a parallel concept of System Units for facilities within its Control Area to System Resources located outside the Control Area. Complaint at 14. As described in the affidavits of Mr. Carlson and Mr. Dozier, the ISO is continuing to work with stakeholders on the development of the System Unit concept together with implementation of a

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[12] 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). Carlson Affidavit at ¶ 15(c). He explains that the extent to which generator output is <u>not</u> 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. <u>Id</u>.

Metered Subsystem methodology.[13] The pendency of those efforts, however, offers no basis for disregarding the ISO's responsibilities as a Control Area operator.

Whatever arrangements are developed to define a MSS, System Units within the ISO Control Area cannot be treated in an identical manner to System Resources located in other Control Areas, because they are not located in another Control Area. The fact is that there are significant distinctions between System Units and System Resources. For example, real time deviations by System Units would contribute to Area Control Error while similar deviations by resources outside the Control Area do not.[14] Also, because they are located in

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[13] Attachment A, Carlson Affidavit at ¶ 14(e); Attachment B, Dozier Affidavit at ¶ 18. See also, Attachment D, Summary of Preliminary ISO Priorities for Market Redesign 2000.

[14] In his affidavit, Mr. Carlson cites the following example: assume a that one of the Districts generating facilities which had been producing 120 MW trips and is disconnected from the system. The ISO's ACE then changes in this amount (plus the changes in system losses that will have occured 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 the District had its generation monitored by the ISO's EMS, the ISO would have also detected the cause of the ACE excursion. If the District did not have its generation being monitored by the ISO 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 the District's operators get the information to the ISO Control Area operators). Carlson Affidavit at ¶ 15(d).

other Control Areas, transactions involving System Resources can be scheduled as Control Area interchange. Such Schedules are inappropriate for Generating Units within the ISO's Control Area, whether or not they are System Units. Attachment A, Carlson Affidavit at ¶ 14(g).

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

> 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 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.[15]

With respect to the Districts' contention that previously Pacific Gas & Electric Company ("PG&E") was able to operate the Control Area using net transfer data supplemented by real time operating data from the Districts' EMS system (Complaint at 16), the ISO notes the fundamental changes in the California market structure since that time. PG&E was a vertically integrated utility with direct control of significant generating resources. Moreover, PG&E did not operate a bid-based market structure for provision of Ancillary Services, Congestion Management and Imbalance Energy. In contrast, the ISO does not have direct ownership of any Generating Units or Loads. It is dependent on Market Participants to supply the required capacity and Energy to maintain the Control Area and serve customers reliably.[16]

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[15] Id. and the Exhibit to the Affidavit. With respect to transactions that involving wheeling through or out of the Control Area, the Commission's landmark Order No. 888 recognizes that there are differences between entities serving load within the Control Area from entities wheeling through the Control Area. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21,540 at 21587 (1996) (Order No. 888), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12274 (1997), order on reh'g, Order No. 888-B, 62 Fed. Reg. 64,688 (1997), order on reh'g, Order No. 888-C 82 FERC ¶ 61,046 (1998), appeal pending. Internal loads are subject to real-time deviations. In contrast inter-Control Area transactions are scheduled with the Control Area being responsible for delivering the scheduled amount. See Order No. 888-A, 62 Fed. Reg. at 12306.

[16] Mr. Carlson notes that the ISO has recently added a safeguarding market mechanism that will allocate the cost of deviation Replacement Reserves

2. Commission Precedent Recognizes that Treating Differently Situated Entities Differently Does Not Constitute Undue Discrimination.

The Districts contend that the ISO has violated the Commission precedent stating that the alleged restrictive practice causing disparate treatment of similarly situated parties is not reasonably related to the objectives intended to be achieved. Complaint at 18, citing Mid-Continent Area Pool Agreement, 58 FPC 2622 (1977). The Commission, however, 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.[17] There is a long line of court and administrative decisions evaluating what distinguishing factors prevent entities from being considered

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to those that choose not to schedule a portion of their resources in either the Day-Ahead or Hour-Ahead processes. Carlson Affidavit at ¶ 15(c). The extent to which resources are not metered is the extent to which the allocation of Replacement Reserve costs will be shifted to other market participants. Id. This result is of particular significance now that the ISO bills market participants for Ancillary Services based on metered demand. Id.

[17] See e.g., Southern California Edison Company, 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."

"similarly situated", a threshold question in finding undue discrimination.[18] 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.

As described in the prior section, the ISO's responsibilities as a Control Area operator and WSCC requirements impose different requirements on entities operating within the Control Area. The Districts are not similarly situated to resources outside the Control Area. Different requirements for Market Participants serving internal load and external load do not demonstrate undue discrimination.[19]

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18 "[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 Company, 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).

19 For example, in Pacific Gas & Electric Company, 88 FERC ¶ 63,007 (September 1, 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 grid." Slip op. at 71.

3. The Districts Fail To Recognize the Additional Restrictions Placed on System Resources' Participation in the ISO Markets.

Missing from the Districts' 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: (1) the ability to supply Regulation, and (2) a limitation on the total amount of the ISO's requirements for Spinning and Non-Spinning Reserves that can be supplied from generators outside the ISO's Control Area.

Section 4.4.1 of the Ancillary Services Requirements Protocol ("ASRP") of the ISO Tariff and Appendix A.1 of the ASRP currently restrict the ability of generators located outside the ISO's Control Area to supply Regulation.[20] The ISO Tariff also specifically authorizes and requires the ISO to take the geographic dispersion of its sources of Ancillary Service capacity into account in procuring its Ancillary Service requirements.[21] It is plainly appropriate for the

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[20] The ISO is evaluating the necessary software and telecommunications requirements to permit Scheduling Coordinators to bid or self-provide Regulation from System Resources.

[21] 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

ISO to retain the discretion to ensure that the geographic mix of Ancillary Service resources is appropriate to maintain reliability. Absent that flexibility, the ISO could find itself required to buy greater quantities of Ancillary Service capacity to provide the requisite level of reliability.[22]

Based on these considerations, the ISO initially decided that a 25 percent limit on acquisition of 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 Ancillary Service markets. The Commission accepted this limitation. AES Redondo

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transmission and Generation availability.

[22] In November 1998, the ISO's Chief Operating Officer explained 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) 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 is provided as Attachment E.

Beach, L.L.C., et al., 87 FERC ¶ 61,208, 61,819 (1999). After further study and operating experience, the limitation has been raised to 50 percent.[23]

The Districts' allegations of undue discrimination fails 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.

4. If the Districts Were Willing To Accept the Responsibilities Associated with Being a Separate Control Area, They Could Participate as System Resources

A central theme in the Districts' Complaint is their desire for their Generating Units to be treated in a manner equivalent to that of a System Resource. Yet, there is nothing in the ISO Tariff that limits the Districts' abilities, either together or separately, to create a new Control Area. The Districts can, if they are willing to assume Control Area obligations, have their generation treated as System Resources and scheduled as interchange with the ISO 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

23 See Attachment F, notice to ISO Market Participants.

new ones. The ISO notes that its creation involved the combination of three formerly separate Control Areas and that 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 A, Carlson Affidavit at ¶ 16. Nevertheless, the availability of this option underscores the nature of the relief sought by the Districts: to enjoy the privileges of participating in the ISO's markets as a separate Control Area without taking on the associated responsibilities or incurring the associated costs.

C. The Districts' Calculations of the Expense of Compliance and Their Lost Earnings Potential Are Unsupported and Clearly Erroneous

The Districts contend that they would have incurred $7.04 million in charges to participate in the ISO's markets, while they would only have been able to earn $6.5 million. Complaint at 17. The Districts complain that the requirement to schedule gross Load would subject them to four ISO-related charges: (1) Grid Management Charges ("GMC"), (2) Unaccounted for Energy charges ("UFE"), (3) neutrality charges, and (4) Imbalance Energy charges.[24] The Districts provide no workpapers to show the specific basis of their calculations.[25]

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[24] Id. at 28. The ISO assumes that the Districts are referring to Uninstructed Imbalance Energy as opposed to Instructed Imbalance Energy.

[25] For example, the only support for the Districts' claim that they could have earned combined revenues of $6.5 million is an unsubstantiated statement

Without access to the data and supporting assumptions used in the Districts' calculations, it is impossible for the ISO to respond fully to the Districts' claims.[26] It is nevertheless clear that the Districts' calculations are fundamentally flawed in several respects.

First and foremost, none of the charges about which the Districts complain are assigned to Market Participants on the basis of the Energy and Ancillary Service capacity that they schedule or sell in the ISO's markets. The

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in Mr. Scheuerman's affidavit that he used "actual ISO prices" and "the surplus capacity each District had available," and used "conservative estimates as to the amount of capacity each might be successful in bidding." Scheuerman Affidavit at ¶ 39. These generalities cannot serve as a basis for a complaint. The Districts have failed to identify explicit amounts of capacity, the particular dates and markets into which this capacity could and would have been bid, and the potential effect that the additional capacity would have had on market prices.

[26] For example, Mr. Scheuerman states that compliance with the ISO metering requirements would cost $440,000 for Turlock and $160,000 for Modesto for "needless equipment". Scheuerman Affidavit at ¶ 16. The ISO's experience is that the one-time replacement meters cost approximately $2,500. See the Direct Testimony of Mark Morosky on Behalf of the ISO in Docket No. ER98-1499-000 at 7. Installation costs will vary by facility. Typically, entities that rely on internal resources for electrical work and design documents will spend less than those utilizing outside resources. Moreover, the ISO's metering requirements were developed as part of an extensive stakeholder process. Id. at 6. As the ISO performs extensive settlement and billing activities in support of its hourly market structure (ISO meters are polled directly daily, with five minute metering interval data aggregated for each hour), it is reasonable to insist that Market Participants provide data in a consistent manner that is compatible with the ISO's data processing systems. In testimony before the Commission, Southern California Edison Company stated that, in order to participate in the markets, it had "spent approximately $12 million to comply with the ISO metering requirements even though metering equipment already existed at its facilities." Prepared Cross-Answering Testimony of Mark Minick dated May 14, 1999 in Docket No. ER98-1499-000, et al. at page 6.

GMC, UFE, and neutrality charges are allocated to Scheduling Coordinators on the basis of the Demands they serve. Imbalance Energy charges are assigned to Scheduling Coordinators who purchase Energy in the ISO's real time market by failing to schedule sufficient Generation to cover their Demand. The Districts thus could execute PGAs and participate as sellers in the ISO's markets without incurring <u>any</u> of these costs. The Districts' claims that it would have cost them too much to participate in the ISO's markets as <u>buyers</u> simply have no relationship to their claims that the ISO Tariff imposed undue restrictions on internal Generating Units' participating in those markets as <u>sellers</u>.

Second, the Districts' calculations of costs and benefits are incomplete on their face. As noted, the Districts include all costs that they would bear if they were to participate as buyers <u>and</u> sellers in the ISO markets (and, as explained below, they overstate those costs), but include only the revenues they claim they would have earned as sellers. They omit entirely any mention of the benefits they would have derived through purchase of Ancillary Services and Imbalance Energy in the ISO's markets. Their calculus is therefore facially incomplete.

Third, even if the Districts' cost calculations were accurate and relevant to their claims of discrimination, the possibility that some Market Participants might find the costs of participating in the ISO's markets to exceed the potential revenues in a particular year does not render the ISO Tariff unduly discriminatory or preferential. There is no requirement in the Federal Power Act or Commission precedent guaranteeing every participant in competitive markets a profit at all times.

Finally, as explained below, while the absence of any workpapers or other support makes a complete analysis impossible, the Districts have significantly overstated the costs of ISO participation in a number of respects. Among other plain errors, their calculations presume the outcome of pending Commission dockets, apparently in an attempt to have the Commission short-circuit those proceedings and resolve the pending issues in a new docket.

1. The Districts' Assumptions Regarding the GMC Are Misplaced

The Districts state, and presumably performed their cost calculations based on the assumption that,

> scheduling of the total load into the ISO's scheduling system would result in the application of the full Grid Management Charge ("GMC") to that portion of the Districts' load served from their respective System Units as well as one-half of the GMC to the load served from their Existing Contracts.

Complaint at 28, citing Scheuerman Affidavit at ¶ 14.

This assumption is incorrect. As provided for by a currently effective GMC settlement, the GMC is charged to all Scheduling Coordinators in proportion to their metered Demand and exports with three exceptions:

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

(2) volumes in the ISO Control Area, but not on the ISO Controlled Grid are excluded; and

(3) volumes located within the Service Areas of municipal and governmental utilities in the ISO Control Area, served by Generation located within that same utility's Service Area are excluded.

Under these exemptions, the Demand served by a municipal utility's internal Generation is not subject to the GMC, even where the utility reports gross Load data to the ISO using the SA/SI templates The GMC settlement remains in effect, subject to refund.[27]

The Districts' assumption that their participation as buyers in the ISO's Ancillary Services and Imbalance Energy markets will render their entire Load subject to the ISO's GMC is therefore inconsistent with the ISO Tariff, as currently applied. The ISO does not assess any GMC on municipal Loads which are met by scheduled Generation from the municipal's own resources. The Districts' cost calculations are therefore inflated because the assume costs that the Districts should not have incurred.

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

The basis upon which the GMC is assessed may change, of course, depending on the outcome of the filing that the ISO is required to make before January 1, 2001.[28] That possibility, however, can hardly serve as the basis for a complaint that the ISO is subjecting the Districts to undue discrimination. The Districts and other municipal utilities would be subject to higher allocations of GMC charges if and only if the Commission concluded that such allocation is just and reasonable and not unduly discriminatory. In this regard, the ISO notes that the GMC is the charge that supports the ISO's operations, permitting it reliably to operate the grid over which the Districts receive significant amounts of power and to operate the markets into which the Districts would like to sell their power.[29] Because the charge is allocated on the basis of Load, exemption for some categories of Load shifts costs to other Loads. As described in Part E below, allocation of GMC costs is being considered in several ongoing stakeholder processes and proceedings before the Commission, including rehearing of the Commission order approving the extension of the current methodology.

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[28] California Independent System Operator Corporation, 87 FERC ¶ 61,304 (1999)

[29] The GMC supports the ISO's Control Area operations, as well as scheduling, market operations, settlements, billing, and metering activities. It enables the ISO to perform operational studies, system security analyses, and system planning; to integrate operations with neighboring Control Areas; and to coordinate outages. The GMC also supports the ISO's activities to provide market data and to conduct market monitoring as well as to perform the complex settlement and billing activities.

2. The Districts' Calculations May Overstate UFE and Neutrality Costs. Moreover, the Allocation of These Costs Is Being Considered in Other Proceedings.

UFE is the difference, for each Utility Distribution Company ("UDC") Service Area and Settlement Period, between the net Energy delivered into the UDC Service Area (adjusted for UDC Service Area Transmission Losses) and the total metered Demand within the UDC Service Area (adjusted for distribution losses). It is assigned to Scheduling Coordinators on the basis of the Load they serve in each UDC Service Area.

The purpose of the neutrality adjustment charge is to ensure the ability of the ISO to balance the ISO Clearing Account each Trading Day, when the charges calculated as due from ISO Debtors are different than the payments calculated as due to ISO Creditors. Contributing factors to neutrality charges include: (1) inadvertent Energy interchanges at Control Area tie points; (2) differences between payments and charges, including charges for UFE, in Zones between which Inter-Zonal Congestion is experienced; (3) differences in the calculation of Transmission Losses on imports in the calculation of Imbalance Energy deviations and in the calculation of UFE; (4) lack of balance in the sum of scheduled Generation, imports, Loads, exports, and Inter-Scheduling Coordinator Trades (within the tolerance band for Balanced Schedules); (5) differences in settlements for Instructed Imbalance Energy and Uninstructed Imbalance Energy due to differences in meter reads from resources and the Energy instructed from those resources; (6) calculations to exclude Schedules relying on Existing Contracts from liability for UFE charges; and (7) adjustments necessary to implement the Regulation Energy Payment Adjustment (“REPA”) for Scheduling Coordinators providing Regulation service. The neutrality Charge, too, is allocated to Scheduling Coordinators on the basis of Loads served.

There are several issues with respect to the Districts’ analysis of UFE and neutrality charges. First, the ISO’s GMC settlement provides that UFE, like the GMC, does not apply to municipal Loads served by internal Generation. In addition, the ISO has applied the same treatment to the neutrality adjustment charge. The Complaint’s assumption that these charges would have applied to the Districts is therefore incorrect.

Second, the Districts fail to note that UFE and neutrality charges have decreased significantly in recent months. The ISO, in partnership with the Utility Distribution Companies and Scheduling Coordinators, performed an investigation into the unexpectedly high levels of UFE encountered during the April through November 1998 period.[30] It was determined that the primary causes were errors in Scheduling Coordinator meter data reports and in the complex calculations by the Utility Distribution Companies related to Existing Contracts. UFE has been reduced from the 4% to 6% range during this period to less than +/-1% for the months September through March 1999 (UFE can be a

[30] Attachment G, ISO Investigation into Unaccounted For Energy.

negative number).[31] Moreover, the ISO has initiated a program of adjustments to refund excess collections of UFE to those Scheduling Coordinators that the ISO's study determined to have been overcharged in 1998.

One of the more significant factors in the neutrality charge was the REPA that was added by Amendment No. 8 to the ISO Tariff. California Independent System Operator Corporation, 83 FERC ¶ 61,309 (1998). This payment was designed to stimulate additional bids into the thin market for Regulation. Based on subsequent improvements in the Ancillary Services markets, the ISO Governing Board phased out the REPA payment at its November 1998 meeting.

Third, the issue of the proper allocation of UFE and neutrality costs is currently pending in the "Unresolved Issues" proceeding, Docket No. ER98-3760-000, and in ongoing settlement discussions regarding the ISO's transmission Access Charge.[32]

The Districts' flawed cost analysis cannot serve as support for their Complaint. The presumptions in the cost analysis regarding allocation of UFE and neutrality are misplaced and subject to further review in ongoing matters.

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31 Attachment H, UFE Loss Calculation and Allocation at 2.

32 See the discussion in Part E, below.

3. Payment of Uninstructed Imbalance Charges Promotes Good Scheduling Practices, Discourages "Gaming" and Treats the Districts in a Consistent Manner with all Other Market Participants

The Districts also complain about being subject to ISO payments or charges for Uninstructed Imbalance Energy when they adjust their own Generation from the scheduled quantities to match real time demands of their Load. Complaint at 28. The thrust of this complaint is unclear. Although the Districts seek to portray Imbalance Energy charges as a penalty, that is inaccurate. They are payments made by Scheduling Coordinators who purchase Energy in the ISO's real-time market because they have not scheduled sufficient resources to cover their Loads. The availability of Imbalance Energy to cover forecast error or scheduling adjustments is a benefit to Market Participants. If the Districts' argument is that they should be entitled to receive this service for free, while other Market Participants pay for it, they have advanced no justification for this position. If the Districts choose to become Scheduling Coordinators, they should receive the same treatment as other Scheduling Coordinators regarding deviations from their Schedules.[33]

One purpose for limiting payments or imposing costs for mismatches between scheduled and actual Demand is to promote good scheduling practices on the part of Scheduling Coordinators. The ISO must rely on the accuracy of

[33] See ISO Tariff Scheduling Protocol at Sections 7.5, 7.5.1, and 7.5.2.

these Schedules as an important part of ensuring the reliability of the Control Area.

As noted in the summary of ongoing market redesign priorities (Attachment D), the ISO is actively considering implementation of a Load following service or refinements to the Imbalance Energy market. However, any such product or other market refinements must be available and applicable to all Market Participants on a non-discriminatory basis. It would not be appropriate only to enable the Districts an opportunity after the close of the markets to deviate in "real time" without consequences. Such a benefit would constitute an undue preference and could create gaming opportunities.

D. The ISO Has Worked Diligently to Improve Its Ancillary Services Markets

The Districts allege that the ISO's exclusion of the Districts from the Ancillary Services markets has harmed the public interest. Complaint at 24. As the ISO has noted, the Districts have not been excluded from the Ancillary Services and Congestion Management markets; they could participate in those markets today on the same basis that other municipal utilities in California are doing. The Districts appear to equate the public interest with their ability to sell Ancillary Services and Imbalance Energy in accordance with their own terms. Id. at 26. The ISO and the Commission, however, must take a broader perspective.[34]

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[34] City of Lafayette, LA v. Louisiana Power & Light, 435 U.S. 389 at 403-04, 98 S.Ct. 1123 at 1131-32 (1978). In the opinion Justice Brennan noted,

The ISO has, with the Commission's oversight, worked diligently to improve its Ancillary Services markets. On March 1, 1999, the ISO filed Amendment No. 14 to the ISO Tariff implementing a number of significant improvements to the Ancillary Services markets. This filing, Docket No. ER99-1971-000, was conditionally approved by the Commission on May 26, 1999. California Independent System Operator Corporation, 87 FERC ¶ 61,208 (1999); reh'g denied in part 88 FERC ¶ 61,096 (1999). The ISO has continued to work with stakeholders to prioritize and implement enhanced market design features. See Attachment D regarding market redesign priorities.

The Districts are improperly trying to utilize the Commission's complaint process as a means of redirecting the ISO's priorities from those established by the ISO Governing Board, after consultation with all stakeholders. The Commission should deny the Complaint and require the Districts to continue to work with the ISO and the other stakeholders.

> [T]he economic choices made by public corporations in the conduct of their business affairs, designed as they are to assure maximum benefits for the community constituency, are not inherently more likely to comport with the broader interests of national economic well being than are those interests of private corporations....
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> * * *
>
> Th elimination of customers in an established service area would likely reduce revenues, and possibly require abandonment or loss of existing equipment the effect of which would be to reduce its rate base and possibly affect its capital structure. The surviving customers and the investor-owners would then bear the brunt of these consequences.

E. <u>The Districts' Contention That the Issues Raised in the Complaint Are Not Currently Pending Before the Commission Does Not Withstand Scrutiny</u>

The Commission's recently revised Rules of Procedures require parties filing complaints to,

> state whether the issues presented are pending in any existing Commission proceeding or a proceeding in any other forum in which the complainant is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum.

18 C.F.R. § 385.206(b)(6). This provision is designed to discourage forum shopping by parties and to preserve the resources of the Commission and respondents from having to address similar issues in multiple proceedings. The Commission has stated that it intends to "strictly enforce the filing requirements of Rule 206." Notice of Proposed Rulemaking - Complaint Procedures, 63 Fed. Reg. 41982, 41984 (Aug. 6, 1998). This requirement is of particular importance as applied to organizations such as the ISO, which rely extensively on stakeholder processes to address complex and controversial issues pertaining to the revised electric marketplace. The Commission should not countenance the attempt by an entity or limited group of participants to try to utilize the complaint process to achieve a desired outcome in other pending proceedings and ongoing stakeholder processes.

The Districts attempt to skirt the clear intention of the Commission's requirements by claiming that the issues raised in the Complaint are not pending elsewhere. Complaint at 30. Their efforts to distinguish the subject matter of the Complaint from the issues being addressed in Docket No. ER98-3760-000, the "Unresolved Issues" proceeding and in Turlock's rehearing request of the

Commission's October 16, 1998 Order regarding Amendment No. 10 to the ISO Tariff in Docket Nos. EC96-19-035, EC96-19-041, ER96-1663-036, and ER96-1663-042, California Independent System Operator Corporation, 85 FERC ¶ 61,061 (1999), cannot withstand scrutiny. The fact is that the Districts are seeking to "end run" not only these matters, but also the future proceedings involving the ISO's GMC and the current stakeholder negotiations in preparation for filing with the Commission a successor transmission Access Charge.

The ISO is well aware of the Districts' desire to obtain the full benefits of participation in the ISO's markets through implementation of a MSS concept. The question being addressed in these other fora is whether or not the Districts are improperly seeking to avoid the appropriate level of responsibility either: (1) by failing to commit to provide the same level of assistance with respect to the reliable operation of the ISO Controlled Grid as that being provided by other Generators; or (2) by failing to pay a full share of the GMC and other ISO charges. The ISO believes that these issues are best addressed with all stakeholders in these other proceedings. The Districts should not be permitted to use the complaint process to prejudice the outcome of these ongoing matters.

1. The Complaint Is an "End Run" Around the "Unresolved Issues" Process Established by the Commission

On October 30, 1997, the Commission issued an order conditionally authorizing limited operation of the ISO. Pacific Gas & Electric Company et al., 81 FERC ¶ 61,122 (1997). In an order issued on December 17, 1997, the

Commission conditionally accepted certain of the ISO's proposed tariff changes and pro forma agreements. Pacific Gas & Electric Company et al., 81 FERC ¶ 61,320 (1997). The Commission also noted that the ISO would be making a compliance filing sixty days from the commencement of operations and stated that interested parties would be permitted to pursue at that time certain issues not previously resolved by the Commission.[35]Id. at 62,476. The Commission also required the ISO to file its protocols under Section 205 of the Federal Power Act in that same compliance filing, specifying that "[a]t that time, we will afford the parties an opportunity to file comments." Id. at 62,471. See also, California Independent System Operator Corporation, 82 FERC ¶ 61,327 at 61,294 (1998).

In its July 15, 1998 filing in Docket No. ER98-3760-000, the ISO submitted a procedural proposal for addressing issues previously raised in Docket Nos. EC96-19 and ER96-1663, but not resolved in prior Commission orders in those proceedings (the "WEPEX" proceedings).[36] In an order issued September 11,

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[35] The Commission stated:

> At that time, the Commission will afford the parties an adequate opportunity to address the filings in view of actual ISO and PX operational experience. All issues raised by these filings, including, but not limited to ISO and PX issues regarding Tariff amendments not addressed in this order, will be the subject of a future order.

Id. At 62,476. The Commission also required the ISO to file its protocols under Section 205 of the Federal Power Act in that same compliance filing, specifying that "[a]t that time, we will afford the parties an opportunity to file comments." Id. At 62,471. See also, California Independent System Operator Corporation, 82 FERC ¶ 61,327 at 61,294 (1998).

[36] Under the ISO's proposal, these outstanding issues would be addressed in a comprehensive process through which all stakeholders would endeavor through negotiations to resolve as many of these issues as possible. The parties would identify the issues that could not be resolved through negotiation and propose procedures for the resolution of those remaining issues by the Commission.

1998, California Independent System Operator Corporation, 84 FERC ¶ 61,217 (1998) (the "September 11 Order"), the Commission, with certain modifications, adopted many of the procedures described in the ISO's proposal. The Commission directed the ISO and the other participants in the WEPEX proceedings to develop a comprehensive list of the issues that remained active and in dispute, including issues pending on rehearing, using the issues matrix attached to the Clarification Filing as a starting point. California Independent System Operator Corporation, 84 FERC at 62,048. The Commission further directed its Trial Staff to participate in and facilitate negotiations involving the ISO and participants to resolve as many of these outstanding issues as possible through settlement. Id. Lastly, the Commission directed the ISO and participants to submit a report on the results of these negotiations within 120 days of the September 11 Order and indicated that this report should include a list of the outstanding issues that had been resolved through settlement and a list of those issues that remained for Commission resolution. Id.

Of the approximately 677 Unresolved Issues that are currently under consideration, approximately 32 relate to implementation of the MSS concept. [37] Approximately 15 other issues concern the scope of the ISO's dispatch authority over Generators, and 17 pertain to the ISO's UFE or neutrality charges.[38]

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[37] Attachment I contains a list of these Unresolved Issues.

[38] See Attachment I.

The Districts' claim that their Complaint is not about MSS (Complaint at 32) is belied by the fact that the Districts state throughout the Complaint that their concerns would be addressed if their version of an MSS was implemented by the ISO. Complaint at 14, 23 n.14, 32, and 35. Moreover, as explained above, the bulk of the Districts' complaints concern the allocation of costs to municipal utilities in California, which is one of the principle subjects of the MSS discussions.

On the theory that the best defense is an aggressive offense, the Districts preemptively accuse the ISO of "deflect[ing] the Districts' Complaint about the ISO's unduly discriminatory conduct by deferring any investigation of its actions to some future Commission proceeding and essentially try to run out the clock on the Districts' IAs." Id. at 32. The Districts' charges are both unsupported and unfounded. The Districts conveniently forget that Docket No. ER98-3760 was pending first. They are the ones seeking to divert certain issues from that proceeding. Moreover, the Districts' own actions in that proceeding have contributed to the delay in the Commission's consideration of the MSS issue.

Following the submission of the ISO's March 11, 1999 Report on the proposed disposition of the 677 Unresolved Issues, the Commission issued its Order Accepting for Filing Report on Outstanding Issues and Establishing Further Procedures. California Independent System Operator Corporation, et al., 87 FERC ¶ 61,102. In this order, the Commission accepted for filing the March 11, 1999 Report, established procedures to incorporate the issues that had been resolved by the parties into a settlement, and established further procedures to address the remaining issues.[39]

If the Districts were truly concerned about the Commission "deferring investigation" of the MSS issues, it would be incumbent upon them to review and respond to the ISO draft settlement documents in an expeditious manner and to encourage the other participants to do the same. The ISO notes, however, that it last circulated draft settlement documents consisting of a proposed transmittal letter, Explanatory Statement, Offer of Settlement and approximately 250 pages of revised tariff sheets on August 4 and 5, 1999. For the parties' convenience, the ISO also provided a table indicating the changes it had made from the prior draft and a separate table that matched the tariff changes to specific Unresolved Issues. The ISO requested comments by August 20, 1999. After having received comments or approvals from only a limited number of parties, the ISO again requested either approval of the settlement documents or comments on September 2, 1999 and September 11, 1999. To date, neither Turlock nor Modesto has provided a response to the ISO's latest settlement proposal.

As the Commission has recognized, there are over 120 Unresolved Issues that remain to be decided by the Commission after briefing. California

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[39] The Commission required the ISO to file an updated Unresolved Issues report and a Joint Statement of Issues identifying the issues to be briefed to the Commission two weeks after the initial comments on this Offer of Settlement are filed. Initial briefs are due 24 days following the filing of the Joint Statement of Issues; reply briefs are due 42 days later, and final answering briefs by the proponent are due 21 days after the submission of the reply brief.

Independent System Operator Corporation, 87 FERC at 61,425. The Commission should not countenance this transparent attempt to circumvent the established procedures that have been established in the Unresolved Issues case. Granting the Districts' request would encourage other participants similarly to attempt to use the complaint process to seek special consideration by the Commission of their particular concerns. The Commission should deny the Complaint and encourage the Districts to adhere to the established procedures.

2. The Districts Previously Raised the "Undue Discrimination" Argument in Turlock's Rehearing Request on Amendment No. 10 to the ISO Tariff.

The Districts maintain that the Complaint is not a collateral attack on the Commission's October 16, 1998 Order accepting the ISO's compliance filing regarding Amendment No. 10 to the ISO Tariff and certain clarifying changes. California Independent System Operator Corporation, 85 FERC ¶ 61,061 (1998). Turlock's request for rehearing of this order is pending. The Districts contend that while they "pointed out" the "disparate treatment in procuring Ancillary Services between utilities within and outside the ISO control area" in their pleadings, they did not allege "undue discrimination." Complaint at 30-32. This is sheer sophistry. As illustrated by Table 1, there is no substantive difference between the issues raised in the Districts' Complaint and Turlock's pending rehearing request on Amendment No. 10:

Table 1

Statement from Turlock's Rehearing Request on Amendment No. 10[40]	Statement from the Complaint
"the barriers to electric systems inside the ISO wishing to supply such services are higher than to systems outside the ISO." [p. 2 (emphasis in original)]	The ISO maintains "unreasonable preconditions for utilities inside its control area at the same time it applies less restrictive preconditions to the same activities of utilities outside its control area." [p.2]
"One key distinction is that a non-ISO member system inside the ISO control area must sign a Participating Generator Agreement (PGA), but one outside the control area need not." [p. 2]	"The ISO requires that utilities inside its control area, such as the Districts, sign a PGA for their generators." [p. 20]
"A System Resource is controlled by an entity providing Ancillary Services and is scheduled into the ISO in a manner similar to the way energy is scheduled... The ISO does not have any control over where the energy is supplied from within the provider's system. It only knows (or expects) that the net inflow to the ISO Control Area at its interconnection point will increase by the amount it has instructed... The same should be true for a 'System Unit' which is a source for Ancillary Services located within the ISO Control Area." [p. 3-4]	"As of August 1998, the ISO allowed utilities outside the control area to bid AS through a 'System Resource' without signing a PGA...[t]he comparable 'System Unit' device existed for use by the Districts but the ISO never implemented it." [p. 20-21]
"To Turlock's knowledge, the ISO has not shown why units belonging to these systems should be treated any differently than those of an external provider." [p. 4]	"That the imposed preconditions are unrelated to the technical standards established is amply demonstrated by the ISO's unjustified preferential treatment of similarly situated utilities outside its control area for purposes of bidding AS. [p.20]
"the ISO is acting in an unduly discriminatory manner in allowing out-of-area entities to bid Ancillary Services through System Resources without surrendering unnecessary control and information, while shutting out in-area utilities such as Turlock and other municipals" [p. 8]	The ISO has "aggravated the unduly discriminatory nature of its conduct by continuing to impose preconditions for utilities bidding AS from inside the ISO control area, such as the Districts, while not requiring them for similarly situated utilities outside the ISO control area. [p. 17]

40 A copy of the rehearing request is provided as Attachment J.

The issues raised in the Complaint are virtually identical to those presented in Turlock's rehearing request. Contrary to the Districts' assertion, the claim of "undue discrimination" was expressly raised in the Amendment No. 10 docket.

It is important to update one potentially significant issue relating to the Commission's October 16, 1998 order. At the time of the Order, the ISO's Responsible Participating Transmission Owner ("RPTO") Agreement prohibited Existing Rights holders such as the Districts from bidding Ancillary Services through the RPTO.[41] On July 16, 1999, the Commission approved the Offer of Settlement filed by the ISO in Docket Nos. ER98-1057-000, et al. This settlement included a commitment by the RPTOs to modify Section 4.4 of their RPTO Agreements to remove the prohibition on their bidding Ancillary Services on behalf of Existing Rights holders. The Commission recently approved the compliance filing incorporating these changes by a letter order dated September 23, 1999. Thus, the Districts have another potential avenue for participation in the ISO's markets.

[41] As noted in the order, the Existing Rights holder was free to utilize the services of another Scheduling Coordinator to bid Ancillary Services. California Independent System Operator Corporation, 85 FERC at 61,199.

3. The Complaint Is an Attempt by the Districts to Circumvent the Future Proceedings Regarding the ISO's Grid Management Charge

As noted above, the current settlement involving the ISO's GMC provides significant benefits to the Districts. It exempts 50% of the volumes flowing over the ISO Controlled Grid pursuant to Existing Contracts and 100% of the volumes located within the service areas of municipal and governmental utilities served by Generation located within that same utility's Service Area. Preservation of these significant benefits is at the core of the Districts' Complaint.

The Commission, however, has deemed it prudent to defer consideration of GMC allocation issues until the ISO completes further unbundling studies in support of the filing to become effective on June 1, 2001:

> In view of the fact that the ISO still has neither the computer capability nor the data to make its unbundling proposal at this time, we continue to believe that it would not make sense to establish a hearing until the ISO has produced an unbundling study.

California Independent System Operator Corporation, 87 FERC at 62,230. In its Order on Amendment No. 16, the Commission instituted an investigation under Section 206 to establish refund protection. In essence, the Districts' Complaint proposes to institute dueling Section 206 cases – the proceeding already in place in Docket Nos. ER99-2730-000 and EL99-67-000 to determine if entities such as the Districts should bear a greater proportion of GMC and the Districts' Complaint seeking to perpetuate their current settlement benefits. As explained in the following section, the ISO believes that a preferred course is to attempt to address the GMC issue as part of a broader settlement of the transmission Access Charge proposal.

4. The Complaint Is Also an Attempt by the Districts to Circumvent the Future Proceedings Regarding the ISO's Transmission Access Charge

Section 9600 of the California Public Utilities Code (as added by California Assembly Bill 1890) established a process whereby two years after the start of ISO operations, the ISO is to recommend for adoption by the Commission a rate methodology for the transmission Access Charge. This requirement was incorporated into Section 7.1.6 of the ISO Tariff and approved by the Commission in its October 30, 1997 Order. Pacific Gas & Electric Company, et al., 81 FERC at 61,500-501. The ISO has been engaged in an extensive stakeholder process over the past ten months in an effort to reach a consensus prior to the required filing date.

The Districts use a draft confidential document to allege that the ISO's goal is to get the Districts to turn control of their transmission systems over to the ISO. Complaint at 23, citing Scheuerman Affidavit at ¶ ¶ 37, 38. Setting aside the question of the propriety of the Districts' reliance on a draft confidential document,[42] the ISO readily acknowledges that it has been exploring incentives

[42] The Districts' claim that this document was "received during the regular course of business" (Scheuerman Affidavit at ¶ 37) is a gross mischaracterization of the facts. The document was mistakenly attached to an unrelated electronic mail message to all Market Participants. When the error was discovered, the ISO sent a second message (less than two hours later) stating that by accident a confidential document had been sent out and

to expand participation in the ISO as part of a comprehensive approach to the issues associated with the revised transmission Access Charge. All Market Participants could potentially benefit from having greater access through the Municipal Customers' facilities to resources located outside the state. The ISO itself would also benefit from the reduced administrative burden by not having to administer contracts and entitlements with scheduling provisions different than those provided for under the ISO Tariff. Absent Municipal Customers' membership in the ISO, the ISO would not be able to schedule transactions over their facilities and would have to continue to administer contracts with terms and conditions different than those under the ISO Tariff.

Currently, the ISO assesses Access Charges on a utility-specific basis. Historically, however, the municipal utilities in California have advocated transmission pricing based on a regional/local methodology. See for example, Pacific Gas & Electric Company, et al., 77 FERC ¶ 61,204, 61,285 (1996). As described in the California utility restructuring legislation, this methodology would roll-in to a single ISO-wide charge all "regional" facilities such as those rated at 230 kV and above. California Public Utilities Code § 9600(a)(2)(C). The Access Charge for lower voltage facilities would continue to be applied on a utility-specific basis. Id.

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requesting, where the message could not be recalled electronically, that the recipients either return or destroy the document. See Attachment K. Obviously, the Districts elected not to comply with this request.

A concern with the regional/local approach is that combining the relatively newer municipally-owned transmission facilities with the more extensively depreciated (lower cost) facilities of the current Participating Transmission Owners would result in significant cost shifts.

In an effort to resolve differences of opinion with regard to the transmission Access Charge, the ISO has encouraged the stakeholders to consider the potential benefits of wider participation in the ISO. Certain of these benefits are noted by the Commission in its Notice of Proposed Rulemaking on Regional Transmission Organizations.[43]

Other potential benefits to the current Participating Transmission Owners and their customers of wider participation include the possible spreading of the grid management costs over a larger number of participants and the reduction of "phantom congestion."[44]

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[43] Notice of Proposed Rulemaking, Regional Transmission Organizations, IV FERC Stats. & Regs ¶ 32,541 (1999). These benefits included: (1) improved efficiencies in transmission grid management; (2) improved grid reliability; (3) removal of remaining opportunities for discriminatory transmission practices; (4) improved market performance, and (5) facilitation of lighter handed regulation. Id., Slip op. at 7-8.

[44] Phantom congestion arises from the fact that the ISO is required under its Tariff to honor the scheduling timelines in grandfathered transmission contracts. The ISO operates Day-Ahead and Hour-Ahead Markets. Certain of these Existing Contracts, however, allow for schedules to be submitted within an hour. Accordingly, the ISO is required to reserve capacity under these contracts that might be called. If the Existing Rights holder does not schedule all of the withheld capacity, it is too late to offer it to the market. This unused physical capacity over the transmission interface results in unnecessary Congestion costs being passed on in the ISO settlements process.

In an effort to create a "win-win" scenario, the ISO has, as part of the settlement processes, sought to balance the benefits of broader ISO participation with minimization of potential cost shifts. As the ISO commenced operations at the end of March 1998, it will be filing the revised transmission Access Charge proposal in the near future.

F. The Districts Have Mischaracterized the ISO's Efforts to Resolve the MSS Issue

The Districts' state that they have attempted informally to resolve these issues with the ISO. Complaint at 32. The ISO certainly agrees that it has worked diligently and in good faith with the Districts and other stakeholders to develop MSS and System Unit concepts that can be implemented consistent with other requirements of the ISO Tariff. The ISO takes exception to the Districts' characterization of these negotiations, in particular, the Districts' assertion that there was an "acceptable agreement" with ISO staff on MSS. Scheuerman Affidavit at ¶ 31. These issues are addressed in the Affidavit of Michael Dozier provided as Attachment B.

IV. CONCLUSION

Wherefore, for the reasons discussed above, the Districts' Complaint should be denied.

Respectfully submitted,

____
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Dated: October 7, 1999

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the service list compiled by the Secretary in this proceeding.

Dated at Washington, DC, this 7th day of October, 1999.

____

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October 7, 1999

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Turlock Irrigation District and Modesto Irrigation District v. California Independent System Operator Corporation; Docket No. EL99-93-000

Dear Secretary Boergers:

Enclosed for filing are an original and fourteen copies of the Answer of the California Independent System Operator Corporation to the Complaint and Request for Investigation of Turlock Irrigation District and Modesto Irrigation District. Also enclosed is an extra copy of the filing to be time/date stamped and returned to us by the messenger. Thank you for your assistance.

Respectfully submitted,

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Enclosures

cc: Service List