UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))))	Docket No. ER00-555-000

ANSWER OF
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO MOTIONS TO INTERVENE, COMMENTS, PROTESTS, AND REQUEST FOR HEARING

I. INTRODUCTION AND SUMMARY

On November 10, 1999, the California Independent System Operator Corporation ("ISO") filed Amendment No. 23 to the ISO Tariff ("November 10 Filing").[1] Amendment No. 23 modifies the ISO Tariff to implement a decision by the ISO Board of Governors ("Governing Board") to address pricing and cost allocation issues related to the ISO's authority to Dispatch resources.[2] Amendment No. 23 includes proposed revisions that clarify the circumstances in which the ISO will use Dispatch orders to address locational problems, confirming that the ISO will use that authority both when effective economic redispatch bids are unavailable and when a competitive market for such bids is not present. Amendment No. 23 would also modify the Tariff to provide an alternative payment option for resources responding to such Dispatch orders. Resources would be given the choice to continue to receive the current pricing

[1] Capitalized terms not otherwise defined herein are used in the sense given in the Master Definitions Supplement, Appendix A to the ISO Tariff.
[2] Resources, as used herein, include Generating Units, imports, and Participating Loads.

for ISO Dispatch orders (the "Hourly Ex Post Price") or a new payment option that includes, if applicable, a payment for market capacity, market Energy, and verifiable start-up fuel costs and gas imbalance charges. The alternative payment option (as well as the current pricing provisions) would apply to resources that have not bid into the relevant ISO markets and to resources required to satisfy a local need where there is a non-competitive supply of bids. Amendment No. 23 also modifies provisions that govern the allocation of costs for all ISO Dispatch orders, whether a resource is paid for such Dispatch orders under the current pricing mechanism or the new payment option.

On November 19, 1999 the Commission issued a Notice of Filing in the above-captioned proceeding, and on November 24, 1999, the Commission granted an extension of time until December 3, 1999 for filing interventions in this proceeding. Numerous parties filed motions to intervene in this proceeding, many accompanied with comments and/or protests, and one accompanied with a conditional request for hearing.

Pursuant to Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213, the ISO submits its Answer to the Motions to Intervene, Comments, Protests, and Request for Hearing submitted in the above-captioned docket. The ISO does not oppose the intervention of any of the parties that have sought leave to intervene in this proceeding.

The ISO does not believe, however, that there is substance to any of the objections to the revisions proposed in Amendment No. 23. Amendment No. 23 does not represent a retreat from the ISO's commitment to primary reliance on markets to maintain the reliability of the ISO Controlled Grid. Rather, it recognizes that redispatch bids voluntarily submitted by Market Participants may not always be available from resources that would enable the ISO to preserve reliability by responding to real-time system problems. Where bids have been exhausted or where there are no effective bids (*i.e.*, bids from resources that can be adjusted to address a line overload or other real-time system problem), the ISO's exercise of its authority to issue supervisory instructions is entirely consistent with Commission policy and the current provisions of the ISO Tariff.

Similarly, Amendment No. 23 appropriately recognizes that the ISO's responsibility to remedy market rules that present opportunities for the exercise of market power applies to markets for the relief of Intra-Zonal Congestion. The ISO has observed numerous instances (examples of which are discussed below) of Market Participants' recognizing these opportunities and increasing their redispatch bids to levels in excess of their costs following the onset of Intra-Zonal Congestion. Currently, when a Reliability Must-Run ("RMR") Unit cannot be used to relieve the Congestion, the ISO must accept these bids, even though they are the product of a non-competitive market. The amendment makes it clear that the ISO no longer will accept redispatch bids for the relief of Intra-Zonal Congestion that are the product of a market that is not workably competitive. The ISO has established reasonable, objective criteria for determining when the markets for the Intra-Zonal Congestion relief are competitive, and has published both those criteria and the results of the ISO's application of those criteria. The determination of whether such a competitive market is present would be made *a* *priori*, based on stable features of the ISO Controlled Grid, such as Generator locations and rated line capacities, as well as actual data on the exercise of local market power. Such a determination would not be made on an *ad hoc* basis in response to bids submitted to the ISO.

The ISO has also committed to use RMR Generation for Intra-Zonal Congestion Management in non-competitive markets, where RMR Units are located so that they can be adjusted for that purpose. There is no basis, however, for claims that the ISO should be required to enter into RMR Contracts with additional Generating Units -- imposing on consumers the burden of subsidizing those units' costs -- to deal with the possibility that Intra-Zonal Congestion may arise in areas that do not meet the criteria established by the ISO Governing Board for the designation of RMR Units. Taken to the extreme, this logic would undermine ISO reliance on markets. If the ISO were required to sign an RMR Contract with Generating Units for every situation or grid configuration where they might conceivably be needed, every unit would have an RMR Contract. This would subsidize cost recovery of every Generator in what is supposed to be a competitive generation market.

Further, the alternative pricing mechanism for resources that respond to ISO Dispatch orders constitutes a reasonable mechanism for fairly compensating those resource owners that choose to elect the new option. It represents a compromise between resource owners, who generally wanted absolute assurance that they would receive compensation at least equal to the costs they incur, and concerns expressed by other stakeholders and the ISO that an alternative providing for excessive compensation could give resource owners an incentive to withhold output in order to receive the specified payments. The alternative payment option relies to the extent possible on market prices to determine the compensation resource owners will receive, while ensuring that those prices will not reflect the impact that a resource could have on market prices when the ISO's need for output (or a reduction in output) from the resource to address localized problems creates locational market power.

In addition, some intervenors have maintained that the ISO will substitute exercise of its Dispatch authority for reliance on RMR Contracts This is entirely incorrect. From the beginning of ISO Operations, the ISO has designated RMR Units under a set of technical criteria that takes into account system configuration and contingencies (including possible outages). Studies applying these criteria evaluate possible outages on the transmission system to determine which units (if any) must be on-line to mitigate the effects of those outages. The ISO Governing Board must approve any changes to these criteria for contingencies that are studied. The ISO's authority to dispatch resources is not taken into account as a reason or justification for any changes to these criteria.

Finally, objections to the allocation of the costs the ISO incurs for payments to resources that respond to Dispatch orders are unfounded. Where the ISO must issue Dispatch orders to resolve problems on the transmission grid, Amendment No. 23 appropriately allocates the costs to the Participating Transmission Owner that is in the best position to remedy the problem and to which the costs would be allocated if the ISO were able to call upon an RMR Unit for that purpose. The ISO firmly believes that these enhanced price signals will encourage Participating Transmission Owners to upgrade their systems as necessary to alleviate local reliability problems and to schedule their transmission maintenance work in a manner that is both cost-effective and minimizes the impact on the market.

The Commission should accordingly accept Amendment No. 23 without substantive modification. The Commission should also grant the requested waiver to permit Amendment No. 23 to take effect as of January 1, 2000.

II. BACKGROUND

A. Amendment No. 23

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 (*e.g.*, to satisfy locational requirements) from Energy that resources have bid into the ISO's Real Time Markets or from capacity that has been selected in the Ancillary Services Markets. Recourse to these 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 seasons or off-peak, 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 Dispatch orders to Participating Generators, Participating Loads and System Resources[3] that have not bid into the relevant ISO markets.[4] These circumstances include the following:

- a deficiency of Ancillary Service Energy bids and of Supplemental Energy bids in the Balancing Energy and Ex Post Pricing ("BEEP") stack;
- the absence of Adjustment Bids and Imbalance Energy bids in the BEEP stack that can be effective in resolving adverse system conditions (e.g., due to locational requirements); or
- an imminent or existing real-time system problem or System Emergency.

All Energy Bids associated with Ancillary Service capacity awards and Supplemental Energy are placed in economic order in the Imbalance Energy or "BEEP" stack. When the ISO responds to real-time requirements by dispatching a resource that has bid into the Imbalance Energy market (*i.e.*, submitted a Supplemental Energy bid or has been awarded capacity in the Ancillary Services Markets), the resource receives the BEEP Interval Ex Post Price. If the ISO, in order to meet a particular need, selects a resource that has bid into the Imbalance Energy market out of sequence, the resource is paid (or charged, in the case of decremental Dispatch) its bid price (unless it is capable of exercising locational market power, in which case its out-of-sequence bid may be subject to scrutiny, and disqualified).[5] If, however, for the reasons discussed above, the ISO issues a Dispatch order to a resource that has not submitted a market bid, the dispatched resource receives (or pays in the case of decremental Dispatch)

3 System Resources are a group of resources located outside the ISO Control Area capable of providing Energy and/or Ancillary Services to the ISO Controlled Grid.

4 *See, e.g.,* Sections 5.1.3, 5.6.1, and 7.2.6.2 of the ISO Tariff.

5 *See* Section 7.3.2 of the ISO Tariff; *see also* MMIP 2.1.1.4.

the Hourly Ex Post Price.[6] The Hourly Ex Post Price is the weighted average of the BEEP Interval Ex Post Prices during each hour.

Ever since the ISO Operations Date, Generating Unit owners have informed the ISO through stakeholder meetings and individual correspondence that payment for these Dispatch orders at the Hourly Ex Post Price does not always provide adequate compensation for out-of-pocket costs. A Generator may be off-line when it receives a Dispatch order, and an owner can be at risk of operating without sufficient compensation for start-up fuel costs and variable costs and any potential gas imbalance charges. As a result of these concerns, the ISO has explored alternative payment options for resources to which the ISO has issued such Dispatch orders.

A new payment option and clarification of ISO Dispatch authority is also appropriate in circumstances where the ISO must manage transmission outage contingencies and locational market power problems where Reliability Must-Run ("RMR") Generation is not available. The ISO has encountered situations where the forced or scheduled maintenance of a transmission facility required local generation to be on-line and provided opportunities for the exercise of locational market power due to a lack of adequate competition to resolve the attendant Intra-Zonal Congestion. These situations are generally described in the attached Opinion of the ISO's Department of Market Analysis ("DMA"); specific examples of this type of behavior based on actual experience are described below. In these situations, as soon as the condition is known to the market, sudden

6 *See* Sections 11.2.4.1 and 11.2.4.2 of the ISO Tariff. The currently effective version of Section 11.2.4.1 is found in the temporary provisions in Section 23 of the ISO Tariff.

changes in bid prices invariably occur. The ISO has observed what appears to be intentional capacity withholding or intentional overscheduling, which creates Intra-Zonal Congestion, along with a sudden change in the bid prices for the resources needed to resolve Intra-Zonal Congestion where no competitive market exists. Because of the limited numbers of Scheduling Coordinators (typically only one or two) representing resources that can be adjusted to relieve Intra-Zonal Congestion, and concomitant local market power concerns, the ability to use a market-based approach to resolve Intra-Zonal Congestion, as contemplated in the ISO Tariff, is limited at this time. To date, the ISO has managed these outages and locational market power problems using RMR Generation where available. However, the ISO does not always have RMR Contracts in place with Generating Units that could exercise locational market power in these circumstances.

In Amendment No. 23, the ISO proposes Tariff revisions that would clarify the ISO's authority to call upon resources through Dispatch instructions in these circumstances. Amendment No. 23 would also permit resources that may be subject to Dispatch orders to elect, on an annual basis, to receive either the Hourly Ex Post Price for ISO Dispatch orders (as currently provided) or a new, alternative payment option. Discussions of these issues with stakeholders led to the approval by the ISO Governing Board, at its August 1999 meeting, of a proposal to provide an alternative pricing option for resources that have not bid into the markets but are called upon by the ISO. The ISO circulated draft tariff language to Market Participants in early October and, after considering the comments that were received, the ISO Governing Board confirmed its approval of the proposal at its October 28, 1999, meeting. In addition, the Governing Board directed Management to convene a stakeholder meeting to discuss the implementation details of the proposal. On November 3, 1999, at its monthly Market Issues Forum ("MIF") meeting, the ISO Management discussed with stakeholders the circumstances in which it requires Energy from resources that have not bid into the markets or are dispatched to satisfy a locational requirement that cannot be meaningfully met through the market, and in which the proposed payment alternative would apply. At the MIF meeting, Management provided the details regarding the criteria and circumstances under which the ISO will call upon resources through Dispatch orders. Management also made a commitment to work with stakeholders to develop operating procedures that would reflect such details.[7]

Under Amendment No. 23, the payment to be made under the alternative option for incremental Dispatch orders would include a capacity component tied to market indicators, an Energy component tied to market indicators, a component that permits the recovery of fuel-related start-up costs, and a component that would permit recovery of verifiable daily gas imbalance charges incurred solely as a result of the ISO's Dispatch order. The capacity payment component is tied to the average Day-Ahead price for Spinning and Non-

[7] There is an existing Operating Procedure that addresses Out of Market and Non-Scheduling Coordinator purchases. *See* ISO Operating Procedure S-318, which is posted on the ISO Home Page at www.caiso.com/thegrid/operations/opsdoc/sched/. As noted below, the ISO is currently developing, through a stakeholder process, operating procedures that will provide additional detail to Market Participants on how the ISO dispatches resources out-of-market and on the alternative pricing mechanism proposed in Amendment No. 23.

Spinning Reserves for the preceding three similar days (*e.g.*, Business Days when the Dispatch order occurs on a Business Day) for the same Settlement Period, and the Energy payment component is tied to an average calculated using the PX Day-Ahead, PX Hour-Ahead and ISO Real Time Energy prices for the preceding three similar days for the same Settlement Period. For decremental Dispatch orders, there would be an Energy payment to the ISO equal to the Market Clearing Price for the relevant Settlement Period for the applicable Energy market less any verifiable daily gas imbalance charges. The ISO's proposal requires all resources subject to an ISO Dispatch order to use "best efforts" to mitigate or eliminate gas imbalance charges.

Amendment No. 23 also modifies provisions that govern the allocation of costs for all ISO Dispatch orders. As modified, the cost responsibility for these payments will be allocated according to the reason for the Dispatch order. If a resource is dispatched to address transmission outages or the ISO's locational reliability needs, the costs of such calls will be allocated to the Participating Transmission Owner ("PTO") in whose Service Area the transmission facility is located or the location-specific requirement arises. If the Dispatch order is the result of market shortages or any other system-wide requirement, the costs will be allocated to Load. If the ISO needs to procure such services Zonally, the ISO will allocate the costs related to such Dispatch orders to Load within the Zone. As is done today, when the ISO issues any such Dispatch order, the ISO will record the reason.

B. Interventions

A notice of intervention was filed by the CPUC and motions to intervene were filed by a number of parties.[8] Many of these parties accompanied their interventions with comments and/or protests.

A number of intervenors, including the CPUC and the Oversight Board, support Amendment No. 23. Others sought clarification of aspects of Amendment No. 23 or requested conditional approval of aspects of Amendment No. 23, while still others opposed aspects of Amendment No. 23. The ISO does not oppose the intervention of any of the parties that have sought leave to intervene. The ISO does not believe, however, that any of the challenges to Amendment No. 23 has merit.

[8] Timely motions to intervene were filed by the California Department of Water Resources ("DWR"); California Electricity Oversight Board ("Oversight Board"); California Power Exchange Corporation ("PX"); Calpine Corporation ("Calpine"); Dynegy Power Marketing, Inc. ("Dynegy"); Enron Power Marketing, Inc. ("Enron"); Independent Energy Producers Association ("IEP"); Metropolitan Water District of Southern California ("MWD"); Modesto Irrigation District ("Modesto"); Pacific Gas and Electric Company ("PG&E"); the City of Palo Alto ("Palo Alto"); the Cities of Redding and Santa Clara, *et al.* ("Redding"); Reliant Energy Power Generation, Inc. ("Reliant"); Sacramento Municipal Utility District ("SMUD"); Sempra Energy ("Sempra"); Southern California Edison Company ("SCE"); Southern Energy California, L.L.C., *et al.* ("Southern"); Transmission Agency of Northern California ("TANC"); Turlock Irrigation District; and Williams Energy Marketing & Trading Company (Williams"). Duke Energy North America, LLC and Duke Energy Trading and Marketing, LLC ("Duke") initially filed its motion to intervene concerning Amendment No. 23 in Docket No. ER99-4462. On December 7, 1999, Duke filed a Motion to File Corrected Copy of Intervention and Protest in the instant proceeding.

III. ANSWER TO COMMENTS AND PROTESTS[9]

A. Amendment No. 23 Reflects an Appropriate Balance Between Reliance on Market Mechanisms and the Need to Address Locational Market Power

1. Amendment No. 23 Appropriately Clarifies the Authority of the ISO To Dispatch Participating Generators and Loads when Market Bids Are Unavailable or Not the Product of a Workably Competitive Market.

A number of intervenors argue that Amendment No. 23 gives the ISO undue authority to issue Dispatch orders to Participating Generators and Participating Loads. They contend that any exercise of such authority would contravene the ISO's commitment to the "Markets First" principle or that such authority should be limited to the circumstances of System Emergencies, as defined in the ISO Tariff.[10] In particular, some intervenors argue that transmission Congestion does not constitute a System Emergency warranting the ISO's issuance of out-of-market Dispatch instructions to Generators.[11] Other intervenors challenge the ISO's authority to issue Dispatch orders to resources to relieve Intra-Zonal Congestion when market bids are available, but the ISO determines that the market is not workably competitive.[12]

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[9] Some of the intervenors commenting on Amendment No. 23 do so in portions of their pleadings that are variously styled, without differentiation. Intervenors also request affirmative relief in pleading styled as protests. There is no prohibition on the ISO's responding to the comments in these pleadings. The ISO is entitled to respond to these pleadings and requests notwithstanding the labels applied to them. *Florida Power & Light Co.*, 67 FERC ¶ 61,315 (1994). In the event that any portion of this answer is deemed an answer to protests, the ISO requests waiver of Rule 213 (18 C.F.R. § 385.213) to permit it to make this answer. Good cause for this waiver exists here given the nature and complexity of this proceeding and the usefulness of this answer in ensuring the development of a complete record. *See, e.g., Enron Corp.*, 78 FERC ¶ 61,179, at 61,733, 61,741 (1997); *El Paso Elec. Co.*, 68 FERC ¶ 61,181, at 61,899 & n.57 (1994).

[10] Williams at 5-8; Calpine at 3-5; Dynegy at 4-6; SMUD at 6.

[11] Calpine at 3-5; Dynegy at 6-7.

[12] *See, e.g.*, Duke at 6; Dynegy at 5-6.

These complaints are unfounded. As explained below, Amendment No. 23 is entirely consistent with the ISO's commitment to maintain the reliability of the transmission system for which it is responsible first through market mechanisms and then, if no market exists, through alternative means. The amendment is narrowly framed to specify that, consistent with existing Tariff provisions and the ISO's responsibility to safeguard short-term reliability, the ISO will rely on its authority to exercise supervisory control over resources participating in its markets only when a *real-time* system problem or emergency exists or could result in the absence of ISO action and market bids are exhausted or available bids would not be effective to resolve the problem, or when the ISO has determined *in advance* that the market for effective bids is not workably competitive due to locational requirements. The amendment also confirms that when the ISO must issue Dispatch instructions for one of these reasons, 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 instructions to non-RMR resources rarely, but must have that authority if it is to meet its responsibility to safeguard short-term reliability and to prevent the exercise of market power.

a. The ISO Tariff recognizes the authority of the ISO to issue Dispatch orders to obtain resources necessary to preserve reliability when Market Participants have failed to submit bids.

The ISO remains strongly committed to the "Markets First" principle cited by intervenors. This principle, however, does not require the ISO to ignore situations in which market bids that can be used to respond effectively to a system problem or emergency are unavailable. Rather, it 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. Where the bids available in the market are not sufficient or effective to address a system condition, the ISO will not simply throw up its hands in surrender: the principle is "Markets First," *not* "Markets Only." Where the bids voluntarily submitted to the 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 will accordingly issue Dispatch orders to Participating Generators, imports, and Participating Loads whose resources may serve to alleviate the condition that threatens reliability.

The ISO's authority to issue Dispatch orders in these circumstances is clear in the ISO Tariff, even without the revisions proposed in Amendment No. 23. Section 5.6.2 of the ISO Tariff directs the ISO to respond to an actual, imminent or threatened System Emergency, "where practicable, [by] utiliiz[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 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 ISO 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 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.

The recognition in the ISO's Tariff of the ISO's authority to redispatch resources is consistent with the Commission's ISO Principles, as adopted in Order No. 888.[13] There, the Commission stressed the importance of an ISO's retaining and exercising "the primary authority in ensuring short-term reliability of grid operations."[14] 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.[15] The tariff provisions described above are critical to the ISO's ability to fulfill this paramount of ISO functions.[16]

[13] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21540, FERC Stats. & Regs. ¶ 31,036 (1996), Order on Reh'g, Order No. 888-A, 62 Fed. Reg. 12274, FERC Stats. & Regs. ¶ 31,048 at 30,249 (1997), Order on Reh'g, Order No. 888-B, 62 Fed. Reg. 64688, Order on Reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

[14] Order No. 888, 61 Fed. Reg. at 21,596.

[15] *Id.*

[16] Contrary to the claims of SMUD (SMUD at 6), nothing in the current provisions of the ISO Tariff or the revisions proposed in Amendment No. 23 contravene the ISO's commitment to honor Existing Contracts, including interconnection agreements. In this respect, the amendment serves only to clarify the circumstances under which 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.

Some intervenors contend that the authority to issue Dispatch orders to avoid or relieve a System Emergency should not extend to the relief of Congestion. These claims are unfounded in several respects. First, they ignore the fact that the ISO's authority to redispatch resources is not limited to System Emergencies, as defined in the ISO Tariff (without the changes proposed in this Amendment).[17] As noted above, Section 5.1.3 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 the overloading of lines and other elements of the transmission grid. If Generation and Loads 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. In Order No. 888, the Commission recognized that real-time Congestion would constitute a circumstance requiring the ISO "to exercise some level of operational control over generation facilities."[18]

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

[17] A System Emergency is defined as "Conditions 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."

[18] Order No. 888, 61 Fed. Reg. at 21,596.

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.

b. The ISO should not be required to rely on bids to relieve Intra-Zonal Congestion when the market that can supply such bids is too small to be workably competitive.

Challenges to the ISO's authority to issue Dispatch orders to resources to relieve real-time Intra-Zonal Congestion when bids are available, but the market supplying those bids is not workably competitive, are unfounded, as well.

i. The ISO must have effective alternatives to excessive bids for the relief of Intra-Zonal Congestion that are the product of non-competitive markets.

When the number of Market Participants who can submit economic bids to adjust the real-time output of their resources to enable the ISO to relieve Intra-Zonal Congestion is limited, real opportunities are presented for those Market Participants to exercise market power. Absent workable competition for incremental and decremental bids to relieve a constraint on a particular Intra-Zonal Interface, a Market Participant can create artificial Congestion within a Zone by withholding capacity or scheduling transactions that exceed the capacity of an Intra-Zonal Interface and then submitting redispatch bids that bear no relationship to the Market Participant's costs.[19] In the absence of a competitive market, those bids can far exceed the true economic cost of Congestion.

Where a competitive market does not exist to discipline the bids submitted in these circumstances, the ISO must have tools available to mitigate the exercise of local market power. Where the ISO has an RMR Contract in place with the resource that can be adjusted to relieve the Congestion, it can rely on its authority under that contract.[20] As explained below, however, application of ISO Governing Board-approved criteria for the designation of RMR Units does not result in the availability of RMR Units to manage all Intra-Zonal Congestion. Nor should the ISO be required to enter into RMR Contracts that are not otherwise necessary for reliability to address potential Intra-Zonal Congestion. As the Commission has recognized, Intra-Zonal Congestion is expected to occur infrequently on any particular path. If the ISO is deprived of the authority to issue Dispatch instructions to non-RMR resources when the market for bids that can be used to relieve Intra-Zonal Congestion is not competitive, consumers will necessarily suffer, either because the ISO will have no choice but to accept bids that are not subject to effective competition or because the ISO will have to enter into otherwise unnecessary RMR Contracts.

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[19] The circumstances giving rise to a Market Participant's ability to exercise market power by creating artificial Intra-Zonal Congestion are described more fully in the attached Opinion of the ISO's Department of Market Analysis. This Opinion is provided as Attachment A.

[20] MWD asks for confirmation that the ISO will rely on Dispatch instructions to non-RMR resources to manage Intra-Zonal Congestion only when no RMR unit is available that can resolve the Congestion. MWD at 6-7. The ISO believes the proposed Tariff revisions are clear on this point. As revised, Section 11.2.4.2 would specify that a resource may be called upon to resolve Intra-Zonal Congestion "[i]n circumstances where an RMR unit would be used . . . and there are no RMR Units available."

The concern that Market Participants will exploit opportunities to profit from Intra-Zonal Congestion is not simply theoretical; the ISO has observed this behavior on a number of occasions:

- For example, on August 1, 1999, a Scheduling Coordinator was submitting incremental Supplemental Energy bids of $40 to 45/MWh (which can be considered a fair reflection of the unit's incremental cost) in one hour for a particular Generating Unit in the SP15 Zone. Then, a transmission line within the Zone went out of service, prompting the ISO to accept this unit's supplemental incremental bids to mitigate Intra-Zonal Congestion on a parallel line. The next hour, the incremental bids from this same unit jumped to $77 to 78/MWh, then increased again, by a factor of three, to $227/MWh the next hour. The Imbalance Energy prices in the Zone for those three hours were $44.45/MWh, $35.50/MWh and $18.00/MWh, suggesting that the bid price for this supplemental incremental Energy from this resource was not escalating due to a Zonal scarcity of Imbalance Energy, but rather due to the Scheduling Coordinator's recognition that this unit was needed to address an Intra-Zonal Congestion problem.

- Similar conditions prevailed on August 12, 1999 and produced similar results. The bid prices for Hour 16 for incremental Supplemental Energy from two Generating Units in the SP15 Zone were $41.98/MWh. The ISO called on these bids to mitigate Intra-Zonal Congestion, and in Hours 17 and 18 the bid price from these same units skyrocketed to $230/MWh. The Hourly Ex Post Prices for SP15 for those three hours were $30/MWh, $26/MWh and $25.17/MWh, respectively. Once again, the recognition of the Scheduling Coordinators that the ISO was relying on bids from these units to mitigate Intra-Zonal Congestion, rather than a scarcity of Imbalance Energy in the Zone, appears to be the reason for the sudden and dramatic change in bid price.

- The ISO has seen the same type of response from Generating Units whose output needed to be *reduced* to mitigate Intra-Zonal Congestion. On June 16 and 17, 1999, the ISO needed to reduce the output of generating units north of Path 26 (and South of Path 15) to mitigate south-to-north Congestion on that path. The only effective decremental market bids the ISO could exercise to mitigate this Intra-Zonal Congestion came with a price of -$250/MWh. This bid price means that the ISO would pay the Scheduling Coordinator representing the Generator $250 for each MWh by which the output of the unit was reduced – even though the owner of the Generating Unit would actually incur fuel cost *savings* by reducing the unit's output.[21]

- Finally, on October 28, 1999, following the loss of several 500 kV transmission lines in the NP15 Zone, creating Congestion on other transmission circuits within that Zone, the ISO received incremental Supplemental Energy bids from a number of Generating Units in the Zone at prices ranging from $290/MWh to $710/MWh. At the same time, the ISO also received supplemental decremental bids from a Generating Unit on the supply side of the congested path of -$650/MWh; only hours before the loss of the transmission lines, the bid prices for the same service from the same units had been an order of magnitude less.

In its Order on Amendment No. 19, the Commission stressed the importance of the ISO's ensuring that its protocols for the relief of Intra-Zonal Congestion did not produce inflated Congestion prices by relying on market mechanisms in the absence of a well-functioning market.[22] In the Amendment No. 19 Order, Commission described the "heart of the problem" with the proposal that the Commission rejected there as the prospect that the ISO might be "relying on a market-based bid for redispatch where there is not a competitive supply of redispatch bids."[23] As the ISO explained in its Request for Rehearing of that Order, the ISO agrees and accordingly does *not* use economic bids to set prices for Intra-Zonal Congestion when the market for such bids is not competitive. Intervenors opposing this aspect of Amendment No. 23, however, would require

[21] This situation occurred prior to the effectiveness of Amendment No. 18, which expanded the pool of resources that the ISO could draw upon to manage Intra-Zonal Congestion. *See California Independent System Operator Corp.,* 88 FERC ¶ 61,146 (1999). While this step was effective in increasing the competitiveness of the market for Congestion relief on Path 26, which was subsequently converted to an active Inter-Zonal Interface, effective February 1, 2000, the markets for Congestion relief on other Intra-Zonal Interfaces that have experienced Congestion remains limited to resources represented by only one or two Scheduling Coordinators.

[22] *California System Operator Corp.,* 88 FERC ¶ 61,221 (1999) ("Amendment No. 19 Order").

[23] *Id.* at 61,729 (footnote omitted).

the ISO to rely on redispatch bids from a market that is not providing "a competitive supply of redispatch bids." As the Commission recognized in the Amendment 19 Order, such a requirement would be inappropriate. The CPUC similarly supports the ISO's authority to issue Dispatch orders for Intra-Zonal Congestion relief when the market for redispatch bids is not competitive and no RMR Unit is available or effective to relieve the Congestion.[24]

The ISO's authority to require resources to respond to Dispatch instructions and the ISO's ability to pay such resources a reasonable price are critical to the ISO's ability to protect consumers against paying for Congestion costs that reflect the exercise of power without at the same time incurring excessive costs for unnecessary RMR Generation.

ii. The ISO has clear standards for determining when the market for Intra-Zonal Congestion relief is workably competitive.

Some opponents of Amendment No. 23 contend that the ISO has not established objective criteria for determining when a competitive market for redispatch bids is not present.[25] There is no merit to these claims.

In its Request for Rehearing of the Amendment No. 19 Order, the ISO explained that it has issued an operating procedure addressing this very issue. In Procedure M-401, which is posted on the ISO's Home Page, the ISO explained that it would consider a market for the relief of Intra-Zonal Congestion competitive if more than two Scheduling Coordinators represent resources on one side of the congested interface that could submit bids to relieve the

[24] CPUC at 3-4.
[25] Williams at 15-17; Reliant at 4, 8-10.

Congestion.[26] The ISO therefore has established and made publicly available the standard it applies to determine whether a competitive market for redispatch bids is present. Moreover, the ISO's standard is manifestly objective and reasonable: when only one or two Scheduling Coordinators can submit redispatch bids to relieve Intra-Zonal Congestion, the potential for the exercise of market power is clear.[27]

Procedure M-401 also describes the result of the ISO's application of this standard to those locations on the ISO Controlled Grid where Intra-Zonal Congestion has been experienced. The posted procedure explains that, with one exception, a competitive market for redispatch bids is lacking in those locations where Intra-Zonal Congestion has been experienced.[28] The ISO has thus provided advance notice to Scheduling Coordinators of the circumstances in which their redispatch bids will not be accepted for Intra-Zonal Congestion relief. The ISO therefore will not use its authority to issue Dispatch instructions to resources to constrain the exercise of market power in the redispatch market as

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[26] ISO Operating Procedure M-401 at 3, version 3.1 (June 18, 1999). Procedure M-401 was attached to the ISO's Request for Rehearing of the Amendment No. 19 Order and may be found on the ISO Home Page.

[27] Reliant notes that a different standard for determining whether a market was workably competitive was developed as part of the new generator interconnection policy proposed in Amendment No. 19. Reliant at 8-10. Reliant, however, confuses an operating procedure with a planning procedure. Moreover, the refinement of standards for assessing the competitiveness of markets only underscores the reason why the ISO believes, and the Commission agreed in its order on Amendment No. 22, that it is appropriate to implement such standards through operating or planning procedures so that the ISO can use the experience it gains through market monitoring to ensure that the standards remain appropriate. In any event, because the Commission rejected Amendment No. 19, there is no present conflict between the two standards cited by Reliant.

[28] ISO Operating Procedure M-401, Attachment A. The procedure explains that only in the case of Path 26, which was subsequently converted to an Inter-Zonal Interface, effective February 1, 2000, do more than two Scheduling Coordinators represent resources that can be adjusted to relieve Intra-Zonal Congestion. The ISO will periodically review the application of these criteria to determine whether there other locations might pass the competitive screen in the future.

a means of requiring Scheduling Coordinators, without prior notice, to accept prices for Intra-Zonal Congestion relief that are below the amounts of their bids.[29] Nor will it determine whether a competitive redispatch market exists on an *ad hoc* basis after observing the actual bids submitted for a given hour.

A number of intervenors argue that the ISO should be directed to notify Market Participants, by posting information on its Home Page, whenever out-of-market Dispatch orders are issued, so that the appropriateness of the orders can be verified.[30] The ISO agrees that information regarding the issuance of out-of-market Dispatch orders should be made available to the market and commits to post on the ISO Home Page information concerning the specific circumstances that gave rise to the issuance of such orders.

2. Reliability Must-Run Contracts Are Not a Substitute For the ISO's Authority To Dispatch Participating Generators and Loads when Market Bids Are Unavailable or Not the Product of a Workably Competitive Market.

A number of intervenors contend that the ISO is attempting to use out-of-market Dispatch as a substitute for RMR.[31] These assertions reflect a misperception of the distinct fundamental purposes of RMR Contracts and of Dispatch instructions for the relief of infrequently experienced real-time locational problems.

The need for RMR Units is based on the "CAISO Reliability-Must-Run Criteria," as approved by the ISO's Governing Board. These criteria, which are

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[29] *See ISO New England, Inc.*, 89 FERC ¶ 61,209 (1999) (where the Commission held that participants generally should be made aware of any applicable market restrictions prior to submission of bids).

[30] Reliant at 10; SCE at 4-5; Sempra at 8-10.

[31] Calpine, Dynegy, Duke, Reliant, Southern, and Williams.

available on the ISO Home Page, are developed using, as a starting point, the reliability criteria of NERC, WSCC, and the Participating TOs. Based on the above criteria, the ISO then determines whether it is prudent to enter into RMR Contracts to cover certain contingencies. Application of the criteria is intended to identify local areas within the ISO Control Area with structural reliability deficiencies that could require the ISO to call upon Generating Units on a relatively regular or frequent basis. The designation of a local area as one requiring RMR Units thus indicates that they would otherwise violate the applicable reliability criteria, *not* that they would frequently be expected to experience Intra-Zonal Congestion.[32] The ISO therefore contracts with RMR Units so that they will be available to allow the ISO to satisfy the RMR Criteria. When Intra-Zonal Congestion occurs in an area that requires RMR Generation, the ISO can sometimes exercise its rights under the RMR Contracts to redispatch the RMR Units to relieve the Congestion.

Intra-Zonal Congestion can, however, also occur in areas where there is no need for RMR Generation. Indeed, as explained in the attached Opinion of the ISO's Department of Market Analysis, redispatch bids for Intra-Zonal Congestion relief can be required from areas that have an abundance of

[32] Dynegy is correct that the ISO does not maintain records that distinguish between RMR Dispatches for Intra-Zonal Congestion and RMR Dispatches for reliability. *See* Dynegy at 8. Indeed, the ISO also informed Dynegy in the same set of data responses to which Dynegy refers that Intra-Zonal Congestion is a reliability problem. Because all such Dispatches have been relatively infrequent, however, the ISO does not need to distinguish Intra-Zonal Congestion from reliability purposes in order to know that Intra-Zonal Congestion is infrequent. The fact that the ISO has created a new Zone does not contradict this statement. It merely demonstrates that when Intra-Zonal Congestion does reach a certain threshold on a path, a new Zone is created to permit Inter-Zonal Congestion Management mechanisms to be used on that path, ensuring that Intra-Zonal Congestion Management remains infrequent.

Generating Units and therefore would be unlikely to contain RMR Units. Even where RMR Generation has been designated in an area from which redispatch bids are required, the RMR Unit or Units may be unavailable when the Congestion occurs. In addition, an unplanned transmission line outage can create Intra-Zonal Congestion. Such Intra-Zonal Congestion can occur almost anywhere. It is for these circumstances that the ISO must rely upon Dispatch instructions issued in real-time to non-RMR resources to prevent the Intra-Zonal Congestion from precipitating a "real-time system problem" or System Emergency.[33] As the ISO noted in its transmittal letter, in order to rely upon RMR Contracts to address such circumstances, the ISO would have to enter into contracts with virtually *every* Generating Unit in the state. If it did so, end-use customers -- who are ultimately responsible for RMR costs -- would have to subsidize the market operations of all of these Generators. While Generators would understandably prefer the ISO to enter into RMR Contracts so that they can receive these subsidies, the relief of infrequent Intra-Zonal Congestion presents an insufficient basis for saddling customers with these costs.

The fact that the ISO has so far relied upon a limited number of RMR Contracts and few non-RMR Dispatch instructions to address Intra-Zonal Congestion, as asserted by Williams[34] is merely the consequence of the infrequency of Intra-Zonal Congestion. It does not imply that the ISO could

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[33] Thus, the assertions that the ISO's out-of-market Dispatch mechanisms discriminate between RMR Owners and other Generators, Dynegy at 12, and deprive RMR Owners of cost recovery to which they are entitled, Duke at 5, are misplaced. There is a rational distinction between reliability problems that occur that do not violate RMR criteria (or that occur when RMR units are unavailable) and more predictable problems in areas that violate RMR criteria.

[34] *See* Williams at 18.

predict all sources of Intra-Zonal Congestion and avoid Dispatch instructions by arrangements with only those sources.

Thus, the ISO's need to rely occasionally on out-of-market Dispatch does not mean that the Local Area Reliability Service ("LARS") process, by which the ISO identifies local area reliability needs, is flawed, as Dynegy suggests.[35] Rather, it is the result of the fact, explained above, that the LARS process is not designed or intended to identify the locations on the grid from which Intra-Zonal Congestion relief may be needed. Neither does the recognition that a reduction in RMR generation may lead to a greater number of out-of-market Dispatches indicate that the ISO is using such Dispatch instructions to replace RMR Units.[36] Any temporary increase of out-of-market calls is merely the *consequence* of the determination, *based on the RMR criteria,* that less RMR Generation was necessary.[37] Any such temporary increase is expected to subside as the frequency of real-time Intra-Zonal Congestion, attributable to strategic behaviors that Amendment No. 23 is designed to address, is reduced. To have maintained unnecessary RMR Generation, with the Participating TOs and ultimately their customers saddled with the costs of ensuring that such Generation is available, just to prevent the possibility of a rare out-of-market Dispatch order to relieve

[35] Dynegy at 9-11.

[36] *See* Williams at 17-18, Southern at 9-12, Duke at 5.

[37] The ISO's request for a January 1, 1999, effective date simply reflects the need to have the modified out-of-market Dispatch mechanisms in place when RMR generation is reduced, in case additional out-of-market Dispatch becomes necessary. Contrary to the suggestions of some intervenors (*see, e.g.,* Reliant at 4, Williams at 17-19), it does not reflect any hidden agenda of the ISO.

Intra-Zonal Congestion, would have been fiscally irresponsible.[38]

Intervenors are correct that the ISO is endeavoring to reduce its reliance on RMR Generation when more cost-effective alternatives to RMR are available, be they Generation, transmission or Load-based.[39] The ISO has a well-established policy of examining all alternatives to existing RMR Generation where the use of such alternatives would lower costs to consumers. As described above, out-of-market Dispatch is a remedy for addressing unpredictable real-time reliability concerns; it is not intended to be a substitute for RMR Contracts.

3. Amendment No. 23 Properly Applies to Generating Units, Imports, and Participating Loads.

Several intervenors express concern about the ISO's use of the term "resource" in Amendment No. 23. One intervenor claims that the use of "resource" in revised Section 11.2.4.2 is ambiguous, and that the ISO should be required to identify those resources which it has the right to Dispatch.[40] There is no need for such clarification. As explained above, Section 7.2.6.2 as currently approved by the Commission makes it clear that the ISO has "authority to direct the redispatch of resources." The revisions to Section 11.2.4.2 simply brings the terminology used in Section 11.2.4.2 more closely in accord with the language used in Section 7.2.6.2. The Amendment No. 23 transmittal letter also explains that the term "resources" includes "Generating Units, imports, and Participating

[38] Duke incorrectly states that the ISO is shifting the cost of "RMR-type service" from TOs to Scheduling Coordinators. Under Amendment No. 23, if an out-of-market Dispatch is due to Intra-Zonal Congestion or a transmission outage, the costs will be borne by the Participating TO in whose Service Area the need arises.

[39] *See, e.g.,* Calpine at 6-8, Duke at 5, Southern at 9-12, Williams at 1-19.

[40] Dynegy at 9.

Loads."[41] Other intervenors suggest the addition of language to Section 11.2.4.2 to make it clear that the provision applies only to resources with respect to which the ISO has authority to issue a Dispatch order.[42] This addition is unnecessary and redundant on its face. Nothing in Amendment No. 23 suggests that the ISO Tariff would (or even could) apply to resources with respect to the ISO does not have the authority to issue a Dispatch order.

One intervenor argues that Participating Loads should be exempt from the ISO's Dispatch authority.[43] MWD incorrectly contends that the ISO's proposed revisions to Section 7.2.6.2 will make that provision applicable to Loads. This argument ignores the fact that Section 7.2.6.2 is already applicable to "resources" and that none of the revisions proposed in Amendment No. 23 have anything to do with that provision's applicability to Loads. Other provisions of the ISO Tariff, as currently approved by the Commission, leave no doubt that the ISO already has Dispatch authority for Loads as well as Generators. For example, as currently in effect, Section 11.2.4.2 applies to "Loads . . . which have not bid into Imbalance Energy markets but which have been dispatched by the ISO."[44]

MWD does not offer any justification for excluding Participating Loads from the ISO's Dispatch authority. As the ISO explained in its filings in Docket No. ER99-3289 concerning Amendment No. 17 to the ISO Tariff and the *pro*

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41 November 10 Filing at 2 n.2.

42 Palo Alto at 5-6; Redding at 7-8; TANC at 9.

43 MWD at 8-10.

44 Section 11.2.4.2.1, as proposed in Amendment No. 23, refers to "Participating Loads." As the Commission is aware, the term "Participating Loads" was only added to the Tariff with Amendment No. 17, filed with the Commission on June 17, 1999. *See California Independent System Operator Corp.*, 88 FERC ¶ 61,182. Tariff provisions which predate the filing of Amendment No. 17 therefore refer to "Loads" generically.

forma Participating Load Agreement ("PLA"), the PLA is designed to facilitate the participation of Loads in the ISO's markets on terms similar to those of Participating Generators. There is no reason why the ISO should not be able to call upon a Load that has entered into a PLA with the ISO if necessary to address an imminent real-time system problem or System Emergency or a non-competitive market for Intra-Zonal Congestion just as it would call upon a Participating Generator.

B. The ISO Governing Board Approved Reasonable Pricing and Cost Allocation Mechanisms

1. The Alternative Payment Option Approved by the Governing Board Represents a Reasonable Compromise Which Provides Generators With Fair Compensation for Dispatch Orders.

A few intervenors argue that the alternative payment option for ISO Dispatch orders introduced by Amendment No. 23 will put Generators at a risk of undercompensation when called upon to operate pursuant to the ISO's Dispatch authority. Others argue that payment under this option "will plainly be greater than the variable cost of [a] generating unit."[45] The reality is best expressed by the CPUC, which states that "the ISO has made a good-faith effort in this amendment to balance legitimate generator concerns with consumer protection" and which supports the alternative payment option as a fair balance of those interests.[46]

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[45] Sempra at 5-6.

[46] CPUC at 2-3.

Some intervenors contend that the alternative payment option should include a variety of additional cost categories and variable costs.[47] The ISO considered a purely cost-based approach for the alternative payment option and rejected it. As explained further below, there were substantial concerns that such an 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. It was necessary for this option to be based on market indicators that could not be manipulated by Generators to their advantage. In the Commission's order on Amendment No. 19, the Commission specifically stated that the ISO should avoid pricing mechanisms which perpetuate excessive prices "exacted by existing generators in noncompetitive markets."[48] The ISO determined that a payment option based on rolling three-day averages for Energy and capacity would minimize the risk of market manipulation while providing fair and adequate compensation for Generators dispatched by the ISO. This is the approach that was approved by the ISO's stakeholder Governing Board.

A purely cost-based approach would also have required the ISO to negotiate cost-based contracts with every Generator in the state. The Commission is well aware of the extensive negotiations that have been required to address cost-based compensation for the limited group of Generators designated as Reliability Must-Run pursuant to the RMR selection criteria.

[47] Duke; Dynegy; and Williams.
[48] Amendment No. 19 Order at 61,729.

Requiring the ISO to enter into similar negotiations with every Generator that may, in any possible circumstance, need to be dispatched through an out-of-market call would place a massive administrative burden on the ISO and ultimately the Commission itself.

Although the ISO has determined that a purely cost-based payment option would be unworkable, the ISO recognized that there are certain cost categories that place Generators at an exceptional risk of operating at a loss when dispatched by the ISO, especially when those Generators are not running when called upon by the ISO. The alternative payment option therefore 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 the Generator 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.[49]

The ISO considered and rejected one intervenor's proposal that the ISO annually solicit competitive bids for the provision out-of-market service.[50] As noted above, the circumstances under which the ISO may have to call on a given Generator out-of-market may be extremely limited. For example, due to a

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[49] One intervenor also suggests that "since the ISO is likely to use its authority to redispatch only in hours when prices are high, [the alternative payment option] will have the effect of denying generators a price based on the actual market." Duke at 7. First, it is far from clear that prices will be high in those situations where the ISO must call on a resource out-of-market. In addition, this comment ignores the fact that resources can elect to continue to be compensated at the Hourly Ex Post Price, a price which is based on the actual real-time market prices during the hour when the resource was dispatched by the ISO.

[50] Williams at 21.

transmission outage, the ISO may have to issue an out-of-market Dispatch order for a particular Generator once a year. During that outage, however, locational concerns may make that one Generator the only Generator that is capable of addressing a system condition. The ISO will therefore have no choice but to dispatch that Generator, whether or not it has bid into the relevant markets. Any solicitation process therefore, by definition, would not result in truly "competitive" bids from all Generators the ISO may need to call under its Dispatch authority, since in some circumstances there will only be one or two Generators which the ISO might need to dispatch to address system conditions.

Several intervenors note that the cost-based components of the alternative payment option were developed with gas-fired generation in mind and request confirmation that this payment option is also available to hydroelectric units.[51] The ISO clarifies that hydro resources will have the same opportunity to elect the payment options available under revised Section 11.2.4.2 as other resources. The cost components of the alternative option were simply designed to ensure recovery for specific costs that place some, primarily gas-fired, Generators at greater risk of cost under-recovery when dispatched out-of-market. Hydro units and other resources will still be able to take advantage of the Energy and capacity components of the alternative payment option. Where any resource -- regardless of its fuel source -- that has elected this option does not incur any of the specified costs when it responds to a Dispatch instruction, it will receive no payment for the specified components of the alternative payment formula.

[51] Redding at 9-10; Palo Alto at 7-8; PG&E at 8.

Two intervenors contend that the inclusion of both an Energy and capacity component in the alternative payment option creates a risk of "double-recovery" or overcompensation of Generators, arguing that Generators are not entitled to a capacity payment because they have not reserved Generation capacity for the ISO.[52] This argument is based on a misconception of the purpose of the alternative payment option. Unlike other capacity payments in the ISO markets, the capacity component of the alternative payment option is not designed to pay Generators for reserving capacity for ISO use; this should be evident from the fact that the capacity component is paid only when the Generator is dispatched, and not for capacity that is reserved independent of an ISO Dispatch order. The capacity component is included to ensure that Generators receive sufficient compensation when dispatched by the ISO, to reduce the possibility that they will be required to operate at a loss. Limiting the alternative payment option to just an Energy-based component would reduce the likelihood that this goal will be accomplished. Indeed, the ISO's proposal is offered as an alternative to the current payment provisions, which call for payment based on Energy prices alone, *i.e.*, the Hourly Ex Post Price.

2. The Alternative Payment Option Will Not Encourage Strategic Withholding of Bids.

One intervenor claims that the fact that the alternative payment option proposed in Amendment No. 23 includes a capacity component will encourage Generators to withhold bids from the ISO's Ancillary Services and Imbalance Energy markets, in the hope that the ISO will issue a Dispatch order and provide

52 PG&E at 7; Sempra at 5-6.

payment at higher than the market price.[53] This intervenor suggests that the ISO's proposal will create an incentive for withholding similar to that experienced under the RMR "A Contract" which led to price distortions in the California markets in the summer of 1998. As explained in the Amendment No. 23 transmittal letter and above, the ISO specifically designed the alternative payment option to minimize the possibility that Generators might be encouraged to engage in such strategic behavior to their advantage. Unlike the RMR "A Contract," in which the capacity component was set to reflect a Generating Unit's actual fixed costs, the use of a rolling three-day average for the Energy and capacity components of the alternative payment option proposed in Amendment No. 23 will link a unit's payment to actual competitive market outcomes and greatly reduce the chance that the payment option will reflect excessively high prices. Generators will also have no assurances that the alternative payment option for any given period will be higher than the market clearing price. Moreover, out-of-market Dispatch calls are expected to be infrequent. Any Generator engaged in withholding strategies will therefore have to predict with considerable accuracy that it will be called and will carry a substantial risk of not being called at all.

Although the ISO believes the risk of such withholding behavior is minimal, the ISO has committed to have its Department of Market Analysis closely monitor the frequency of Dispatch orders and any changes in bidding strategy that may be attributable to implementation of the new payment option. If such withholding behaviors are observed in practice, the ISO will take appropriate responsive

53 Sempra at 6-7.

measures pursuant to its existing authority under the Market Monitoring and Information Protocol.[54] This approach is consistent with the comments of a number of intervenors, who state that monitoring and the issuance of reports, as necessary, should be sufficient to address the risk of strategic withholding.[55]

3. Amendment No. 23 Allocates the Costs of Dispatch Orders to Entities That Can Take Steps to Avoid the Need for Such Orders.

Some intervenors object to aspects of Amendment No. 23 that allocate the costs of ISO Dispatch orders to Participating Transmission Owners if a resource is dispatched to address transmission outages or local reliability needs. These objections come mainly from the PTOs themselves, and it is apparent that their primary concern is that the cost allocation provisions of Amendment No. 23 not be placed in effect without the opportunity for the PTOs reasonably to pass through these costs. The PTOs accordingly request that Amendment No. 23 not be placed in effect until the Commission approves changes to Transmission Owner Tariffs or other mechanisms that will allow the PTOs to pass through such costs.[56] While the ISO has no objection to the PTOs' filing proposed changes to their TO Tariffs or other mechanisms to reflect the appropriate allocation to them of costs incurred by the ISO to pay resources dispatched to preserve reliability in the face of transmission-related system problems,[57] the ISO's proposal in the instant proceeding should not be held hostage to such filings. Many of the ISO's

54 November 10 Filing at 7.

55 SCE at 5-6; Redding at 10-11; Palo Alto at 8.

56 SCE at 3-4; PG&E at 4-5; Sempra at 8.

57 In fact, the ISO understands that some of the PTOs have already submitted such proposals to the Commission.

Tariff amendments have resulted in the allocation of new or modified costs to PTOs and other Market Participants. The Commission has never tied the effectiveness of any of those amendments to proposals by Market Participants to pass through such costs, and it should not do so now. The ISO notes that the PTOs are free to request, and the ISO would not oppose, that the Commission make any revisions to the TO Tariffs or other pass-through proposals effective as of the date Amendment No. 23 goes into effect.[58]

Claims that the payments to resources that respond to the ISO's Dispatch orders should not be passed through, in certain circumstances, to PTOs for other reasons are unconvincing. When Dispatch orders are issued in order to address a problem on a Participating TO's transmission facilities that cannot be remedied through competitive redispatch bids, allocating the costs to that Participating TO provides it with an incentive to take measures to address the problem, if the costs of doing so are less than the costs the ISO incurs to make payments to resources that respond to the Dispatch orders. This provides the appropriate price signal to the PTOs, which are the Market Participants best situated to take steps to prevent the need for such Dispatch orders. Sempra complains that fixed transmission rates may prevent cost signals resulting from such allocations from being transmitted to end-users.[59] This misses the point. It is not the end-users but the PTOs themselves that should obtain the price signals in this

[58] PG&E's conditional request for hearing in this proceeding is based upon its stated intention to seek a pass-through mechanism for costs allocated to it as a PTO under Amendment No. 23. PG&E at 4-5. Because PG&E has the opportunity to request that the Commission make any pass-through proposals effective as of the date Amendment No. 23 goes into effect, there is no justification for granting PG&E's conditional request. In addition, PG&E has not made the requisite showing that a hearing would be in any way useful or appropriate in this proceeding.

[59] Sempra at 7.

circumstance. Although exercise of the ISO's Dispatch authority differs from the use of RMR Contracts for reasons explained above, the cost allocation principles are very similar. As the Commission recognized most recently in its order approving Amendment No. 22, Participating TOs are properly allocated the costs of RMR Contracts because they are responsible for the status of the transmission facilities in their Service Area which create the need for RMR Contracts.[60] For the same reason, PTOs should bear the costs of ISO Dispatch orders which address a transmission outage or other locational reliability need.[61] Only when the Dispatch orders are issued due to market shortages or other system-wide conditions should the resulting costs should be borne by all Loads.

Two intervenors claim that allocation of ISO Dispatch costs to PTOs is in conflict with the rationale underlying the "TO Debit solution" proposed by the ISO and approved in Amendment No. 13 to the ISO Tariff.[62] These intervenors are incorrect when they suggest that the TO Debit solution was based on the proposition that PTOs should not be allocated costs related to line derations. The purpose of that aspect of Amendment No. 13 was instead to address a particular situation where Scheduling Coordinators were able to receive compensation for reduced transmission volumes that become unavailable due to a line deration at a much greater level than they had committed to pay in the

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60 *California Independent System Operator Corp.*, 89 FERC ¶ 61,229 (1999).

61 TANC suggests that PTOs should not be allocated the costs of Dispatch orders necessary due to planned Transmission Outages because the ISO is responsible for maintaining System Reliability and coordinating Outages. TANC at 8. As a revenue neutral entity, the ISO must allocate the costs of such Dispatch orders to some Market Participant. When even planned outages create locational needs for the ISO to exercise its Dispatch authority, the PTO is in the best position to add transmission upgrades which will avoid that need in the future.

62 PG&E at 6; TANC at 8.

Day-Ahead Market.[63] PTOs were being forced to pay the difference, which was based solely on the disparity between Day-Ahead and Hour-Ahead Usage Charges. The ISO's proposal in Amendment No. 13 limited the PTO's exposure to the level of the Day-Ahead Usage Charges. In the absence of this amendment, PTOs might have been forced to pay the Scheduling Coordinators *more than* the Dispatch cost (as expressed in the Scheduling Coordinators' Day-Ahead bids). Amendment No. 13 simply ensured that the PTOs would not be required to pay Scheduling Coordinators an unearned premium due to the disparity between Day-Ahead and Hour-Ahead prices. Under Amendment No. 23, however, the actual costs of real-time Dispatch are being allocated to PTOs. There is no possibility for the type of disparity and inequity that was addressed by the ISO's TO Debit solution.

Two intervenors raise "cost allocation" issues that go beyond the proper scope of this proceeding. MWD raises an issue related to the application of Section 11.2.4.2.1 in connection with a proposed Tariff amendment approved by the Governing Board but not yet filed with the Commission.[64] It would be premature to prejudge any issues related to that proposal in the instant proceeding. MWD will have an opportunity to raise its concerns once the ISO presents that proposal to the Commission. DWR objects to the application of Section 11.2.4.2.1 in any manner that allocates Intra-Zonal Congestion Management costs to Scheduling Coordinators that are Existing Contract

[63] *See California Independent System Operator Corp.*, 86 FERC ¶ 61,122 at 61,419-20 (1999).

[64] MWD at 11.

holders.[65] The ISO notes that it already has the authority, under Section 7.2.6.2, to issue Dispatch orders to manage Intra-Zonal Congestion and that such costs are currently allocated to Scheduling Coordinators in accordance with Sections 11.2.4.1 and 11.2.4.2 of the Tariff. Nothing in Amendment No. 23, however, will affect the right of a party to raise an issue validly preserved in the "Unresolved Issues" proceeding in Docket No. ER98-3760.

C. Other Objections to Amendment No. 23 Are Without Merit

1. Amendment No. 23 Is Consistent With the Rationale of the Commission's Order Extending the ISO's Purchase Price Cap Authority

Four intervenors argue that Amendment 23 violates the Commission's pricing policies.[66] They argue that the ISO is effectively setting a price under which a seller must provide energy. The intervenors also argue that Amendment No. 23 converts the "purchase price cap" approved by the Commission in its order on Amendment No. 21, 89 FERC ¶ 61,169 (1999) to a seller's price cap.[67] They cite the Commission's orders in *California Independent System Operator*, 83 FERC ¶ 61,209 (1998) (providing that the ISO must pay for Imbalance Energy at the bid price)[68] and in *Pacific Gas and Electric Co., et al.,* 81 FERC ¶ 61,320 (1997) (stating that the ISO, as purchaser, cannot file RMR rates schedules) as prohibiting such pricing.

The intervenors' citation of authority is inapt. The "purchaser's price cap" to which the Commission referred involved the ISO's ability to limit on a forward

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65 DWR at 1-2.
66 Duke, Dynegy, Reliant, and Southern.
67 Reliant at 12-14. *See also* Dynegy at 7-8.
68 Dynegy has apparently incorrectly cited this Commission ruling as 82 FERC ¶ 61,327.

basis the amount it is willing to pay in its markets for Ancillary Services. The Commission's order concerning Imbalance Energy addressed circumstances in a competitive market. The RMR Contracts involve the provision of services on a forward basis. None of these Commission orders concerns the price the ISO must pay when it must act in real-time to address Intra-Zonal Congestion in order to avert a real-time system problem or a System Emergency and it is faced with a lack of Energy bids or a non-competitive market.[69]

Although they may contest the specific pricing provisions, none of the intervenors appears to suggest that the ISO is precluded from establishing the price it will pay for Energy dispatched to mitigate Intra-Zonal Congestion when there are no bids.[70] The real question is whether out-of-market Dispatch by the ISO is appropriate when bids are available, but are demonstrably not the product of a competitive market. As explained above, there is no justification for requiring the ISO to accept bids in such circumstances. Indeed, the very authorization for market-based rates upon which intervenors rely in order to participate in the markets is predicated on the lack of market power. Sellers should not be permitted to profit from opportunities created to set monopolistic prices when the ISO is forced to take steps to avoid a real-time system problem or System Emergency. The ISO has narrowly tailored the circumstances in which it will

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[69] Reliant's suggestion that, because of the pricing terms, the Participating Generator Agreements should be amended to limit out-of-market Dispatch to System Emergencies is thus misplaced. The use of out-of-market Dispatch to avoid Intra-Zonal Congestion in real-time is a use to avert a System Emergency.

[70] Southern does state that Amendment No. 23 usurps a Generator's right to charge market-based rates. Southern at 14. The ISO cannot, of course, pay a seller's specific market price in the absence of a bid. The pricing options of Amendment No. 23, however, provide the optimal substitute. The amendment specifies the price paid by the market, or an alternative price, based largely on market indicators that also ensures recovery of certain fixed costs.

issue Dispatch orders to resources, in lieu of accepting market bids, to circumstances when the market has been determined, *a priori*, to be non-competitive and action is necessary in real-time operations to avert or recover from a system problem or emergency.

The Commission has previously recognized that emergency situations may justify price limitations. In *ISO New England, Inc.*, 89 FERC ¶ 61,209 (1999), the Commission approved an interim price cap on ISO New England's payment for Operating Reserves in periods of capacity deficiencies or emergencies. The Commission stated:

> During such periods, all operating reserve bids must be taken, giving some or all providers unconstrained market power (that is, allowing them to bid substantially above their costs). Under these conditions, prices paid to all suppliers in the operating reserves markets should be capped at the energy price to limit the suppliers' market power.

Id., slip op. at 14. The same reasoning applies to the need to address real-time Intra-Zonal Congestion in the face of a non-competitive market.

2. Comments on the ISO's Market Design Are Unfounded and Unrelated to Amendment No. 23

Two intervenors use their comments on Amendment No. 23 to raise broader issues about the ISO's current market design. One intervenor notes that the ISO's Intra-Zonal Congestion Management process is extremely complex and questions whether any proposals to improve that process should be implemented before consideration of options to simplify the process.[71] As the ISO has explained above, Amendment No. 23 is needed in the near-term to address

[71] PG&E at 3.

current issues related to Intra-Zonal Congestion Management and compensation of resources dispatched to manage Intra-Zonal Congestion, including locational market power issues. Deferring action on Amendment No. 23 would permit resources to continue to take advantage of the gaming opportunities described in the attached Opinion of the ISO's Department of Market Analysis that arise when the ISO is limited to a noncompetitive "market" for the relief of Intra-Zonal Congestion. In Stage 2 of the ISO's Market Redesign 2000 initiative, the ISO has committed to pursue other reforms related to Intra-Zonal Congestion Management, including forward management of Intra-Zonal Congestion. The ISO welcomes further input from all interested parties in that process. The reforms proposed in Amendment No. 23, however, should not be postponed in the meantime.

Another intervenor suggests that the ISO's current market design is insufficient because it suppresses locational differentiation in energy prices.[72] Sempra seems to suggest that there would be no need for the ISO to exercise Dispatch authority under an alternative market design, such as a nodal design. This is simply not the case. Locational price signals are most effective when there are competitive markets and ease of entry into markets. The ISO's current market design provides proper price signals under those circumstances. Absent workable competition in all situations, however, there are and would be opportunities for Generators to exercise market power under either a zonal or a nodal market design. In either case, an independent system operator must have

[72] Sempra at 4-5.

some alternative to accepting excessive bids which are the result of market power and must have the ability to address locational reliability issues. Sempra's comments also ignore the fact that the ISO's current Zonal market design has been approved by the Commission and upheld in prior proceedings.[73] Such broad and superficial comments should not have any impact on the Commission's consideration of the ISO's proposal in the instant proceeding, especially when the recommended action does nothing to address the matter at hand.

3. Amendment No. 23 Was Developed and Presented to Market Participants Through a Sufficient Stakeholder Process Which Culminated in Approval of the Proposed Tariff Revisions by the Governing Board.

A few parties have complained that the stakeholder process for the development of Amendment No. 23 was incomplete.[74] As the ISO noted in the transmittal letter, the ISO developed the initial proposal based on stakeholder input, and presented it to the ISO Governing Board at its August 1999 meeting. Subsequent to Board approval, the ISO Management further developed the proposal and provided it to Market Participants in early October for comment. As the ISO noted, ISO Management took those comments into account in deciding upon the ISO Tariff amendments that the ISO presented to the ISO Board in October.

The primary complaint raised by intervenors is that the ISO did not revise the proposal in accordance with their comments. The ISO, however, does not

[73] *See, e.g.*, *California Independent System Operator Corp.*, 89 FERC ¶ 61,229, slip. op. at 4 (approving creation of a new Zone under the ISO's current market design).
[74] *See, e.g.,* Dynegy at, 2-3, Enron at 4, PG&E at 7, Southern at 6-8, Williams at 10.

see the stakeholder process as requiring the ISO to adopt all comments. Indeed, because may comments conflict with others, that would be impossible. In this case, the ISO determined that many of the comments did not warrant any changes to the proposal. In some cases, the ISO concluded that the comments could be addressed through implementation procedures; in others, the ISO concluded that (like may of the arguments raised by intervenors in their protests) they were misplaced.

Following review of the comments, the ISO Management provided the ISO Governing Board with the revised language. Contrary to Dynegy's assertions,[75] the ISO Governing Board, after review of the proposal, *confirmed* its authorization to ISO Management to file Amendment No. 23. The only additional direction from the ISO Governing Board was an instruction to ISO Management that it work with stakeholders on the implementation of Amendment No. 23. The view expressed that the ISO will not heed stakeholder concerns in implementation[76] is thus belied by the Board's instruction. As noted in the transmittal letter, the ISO began that process with a Market Issues Forum held on November 3, 1999. Subsequent to the November MIF and the November Board meting, the ISO has diligently worked to develop operating procedures that will detail to Market Participants how the ISO dispatches resources out-of-market and how the new alternative pricing mechanism will work. As noted in the attached Market Participant notice issued December 20, 1999, the ISO will share

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[75] Dynegy at 2-3.

[76] *See* Enron at 4; PG&E at 7.

that operating procedure with Market Participants and hold a stakeholder meeting on January 4, 2000 to discuss the proposed procedure.[77]

IV. CONCLUSION

For the foregoing reasons, the Commission should accept Amendment No. 23 to the ISO Tariff without modification and permit it to go into effect on January 1, 2000.

Respectfully submitted,

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Roger E. Smith
Senior Regulatory Counsel
The California Independent
System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 608-7135
Fax: (916) 351-4436

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Edward Berlin
Kenneth G. Jaffe
Michael E. Ward
Sean A. Atkins
Swidler Berlin Shereff Friedman, LLP
3000 K Street, N.W., Suite 300
Washington, D.C. 20007
Tel: (202) 424-7500
Fax: (202) 424-7643

Dated: December 20, 1999

[77] This notice is provided as Attachment B.

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all parties on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, D.C. this 20th day of December, 1999.

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Sean A. Atkins