UNITED STATES OF AMERICA87 ferc ¶ 61,208
FEDERAL ENERGY REGULATORY COMMISSION

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

AES Redondo Beach, L.L.C.	)	Docket Nos. ER98-2843-005
	)	ER98-2843-006
	)	and ER98-2843-007
AES Huntington Beach, L.L.C.	)	Docket Nos. ER98-2844-005
	)	ER98-2844-006
	)	and ER98-2844-007
AES Alamitos, L.L.C.	)	Docket Nos. ER98-2883-005
	)	ER98-2883-006
	)	and ER98-2883-007
	)	(Not Consolidated)
El Segundo Power, LLC	)	Docket Nos. ER98-2971-006
	)	ER98-2971-007
	)	and ER98-2971-008
Long Beach Generation, LLC	)	Docket Nos. ER98-2972-006
	)	ER98-2972-007
	)	and ER98-2972-008
	)	(Not Consolidated)
Ocean Vista Power Generation, L.L.C.	)	
Mountain Vista Power Generation, L.L.C.	)	Docket Nos. ER98-2977-004
Alta Power Generation, L.L.C.	)	ER98-2977-005
Oeste Power Generation, L.L.C.	)	and ER98-2977-006
Ormond Beach Power Generation, L.L.C.	)	
Williams Energy Services Company	)	Docket Nos. ER98-3106-002
	)	ER98-3106-003
	)	and ER98-3106-004
Duke Energy Oakland, L.L.C.	)	Docket Nos. ER98-3416-004
	)	ER98-3416-005
	)	and ER98-3416-006
Duke Energy Morro Bay, L.L.C.	)	Docket Nos. ER98-3417-004
	)	ER98-3417-005
	)	and ER98-3417-006
Duke Energy Moss Landing, L.L.C.	)	Docket Nos. ER98-3418-004
	)	ER98-3418-005
	)	and ER98-3418-006
	)	(Not Consolidated)

Southern California Edison Company	)	Docket No. EL98-62-003
	)	EL98-62-004
	)	and EL98-62-005
Sempra Energy Trading Corporation	)	Docket No. ER98-4497-002
San Diego Gas & Electric Company	)	Docket No. ER98-4498-002
California Independent System Operator Corporation	)	Docket No. ER99-1971-000

ORDER ON REHEARING, GRANTING CLARIFICATION, AND ACCEPTING REPORTS AND TARIFF REVISIONS, AS MODIFIED

(Issued May 26, 1999)

In this order, we accept for filing market monitoring reports that we directed to be submitted in AES Redondo Beach, L.L.C., et al.; 1/ we accept, as modified, tariff revisions and other proposals filed by the California Independent System Operator Corporation (ISO) as part of the comprehensive redesign of its Ancillary Services markets, also directed to be filed in our October 28, 1998 Order; and we grant clarification in one respect and deny rehearing of the October 28, 1998 Order.

Background

Summer 1998 Proceedings

The events surrounding the establishment of and problems in Ancillary Services markets in California are detailed in our October 28, 1998 Order. Here we provide a brief overview of pertinent events and proceedings.

In June and July of 1998, the Commission approved for the first time market-based rates for certain Ancillary Services in California. 2/ Subsequent to those orders, the ISO experienced significant increases in the price for Replacement Reserve capacity. The ISO and Southern California Edison Company (SoCal Edison) filed emergency requests for a stay of market-based rate authority, contending that there was insufficient supply to permit market-based pricing for Ancillary Services, and requested rehearing of the orders. Pending Commission action on its motions, the ISO capped the prices that it would pay to bidders

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1/ 85 FERC ¶ 61,123 (1998) (October 28, 1998 Order).

2/ See AES Redondo Beach, L.L.C., et al., 83 FERC ¶ 61,358 (1998) (June 30 order); Long Beach Generation, L.L.C. et al., 84 FERC ¶ 61,011 (1998), Ocean Vista Power Generation, L.L.C., et al., 84 FERC ¶ 61,013 (1998) (July 10 orders).

with market-based rate authority at $500/MW, and so informed the Commission. Several other entities submitted filings in support of the ISO's filing, while others filed requests for rehearing of the underlying market-based rate orders.

On July 17, 1998, the Commission issued an order denying the motions for stay and authorizing the ISO to reject bids in excess of whatever price levels it believed were appropriate for Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve. 3/ In addition, the Commission directed the Market Surveillance Committee of the ISO (MSC) and the Market Monitoring Committee of the California Power Exchange (MMC) to conduct independent studies of the bidding behaviors and structural characteristics of the markets that they administer, and to identify the causes of the market concerns raised in the pleadings.

Numerous entities filed motions to intervene, comments, and/or protests in these proceedings, and several requested rehearing of the orders granting market-based rate authority for Ancillary Services and of our July 17, 1998 Order. Parties sought rehearing of our findings that Replacement Reserve service does not constitute an Ancillary Service and that applicants need not submit a separate market analysis for Replacement Reserves, and requested that we rescind the market-based rate authority granted in the proceedings. Several generators requested rehearing of our decision to allow the ISO to cap the prices at which it will purchase Ancillary Services and Replacement Reserves. They argued that the July 17, 1998 Order was contrary to law because the Commission has no authority to delegate ratemaking to the ISO; that the Commission cannot suspend rates that have been accepted; that the Commission should have allowed those affected to respond to or comment on the ISO motion before acting; and that the ISO has no right under Federal Power Act (FPA) section 205 4/ to unilaterally and without FERC approval change the price in another party's rate schedule.

These parties also contended that the capping authorization in the July 17, 1998 Order was inconsistent with all of the following: the ISO tariff, prior Commission orders rejecting ISO proposals to cap prices, the premise of the California Restructuring Legislation, our rejection of the California Commission's previous request to allow one year of experience to examine the net impact of pricing peaks and valleys, and the Commission's holding in a recent order directing certain owners

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3/ California Independent System Operator Corporation, 84 FERC ¶ 61,046 (1998) (July 17, 1998 Order).

4/ 16 U.S.C. § 204d (1994).

to recover their acquisition premium from the market. 5/ They argued that the capping authority contained in the July 17, 1998 Order does not let competition work and is unfair to generators.

Later in the summer of 1998, the Commission issued additional orders granting market-based rate authority for Ancillary Services, observing the existing policy pending resolution of the issues on rehearing. 6/ Additional requests for rehearing followed those orders as well.

Pursuant to the Commission's July 17, 1998 order, the MMC and MSC filed reports in August 1998. Both reports concluded that the markets for Ancillary Services and Replacement Reserves had not been functioning as competitively as possible and identified factors that had limited competition. A key finding was that restricting some suppliers of Ancillary Services to cost-based rates was limiting the amount of supply offered during periods of high demand because the suppliers could earn more by selling into the market-based energy market. Other problems included demand for Ancillary Services that was higher than anticipated, exclusion of suppliers from outside the ISO control area, ISO software deficiencies, ambiguous dispatch and settlement practices for the provision of imbalance energy, and "perverse incentives" in reliability must-run (RMR) agreements that encourage suppliers not to bid into the Ancillary Services market.

The two Committees reached very similar recommendations to address the observed market problems. Both proposed that the Commission authorize market-based rates for all suppliers, while continuing in effect the ISO's authority to reject bids that are too high, and both recommended changing the market design to permit more flexible buying practices. This latter proposal, referred to as the "rational buyer" concept, would permit the ISO to substitute one service for another on the basis of cost where either service would physically satisfy the needs of ISO operations. The MSC added that ISO buying protocols must be transparent to market participants so that they are able to accurately predict revenues from particular bidding strategies. Both committees also thought that revised RMR protocols and rates could eliminate incentives to withhold capacity from the market in order to be called under the RMR Agreement at higher prices. In addition, the MSC recommended that the ISO always purchase Ancillary Services through a state-wide auction, eliminating the

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5/ Duke Energy Moss Landing, LLC, et al., 83 FERC ¶ 61,318 (1998), reh'g denied, 86 FERC ¶ 61,227 (1999).

6/ Williams Energy Services Company, 84 FERC ¶ 61,072 (1998), Duke Energy Oakland, L.L.C., et al., 84 FERC ¶ 61,186 (1998).

potential for zone-specific, locational market power. Finally, the MSC suggested that the ISO revise its scheduling and/or imbalance energy protocols to help reduce the need for Regulation capacity.

Many parties filed comments on the Reports concurring with much of the analysis therein. In addition to the MSC and MMC proposals, several parties also recommended that structural reforms also facilitate self-supply options, and most believed that market-based rate authority should be maintained and expanded to include all suppliers, to ensure an adequate supply of Ancillary Services. Bonneville recommended that the ISO help to increase supplies by lifting the 25 percent quota on supplies from outside the control area and that the ISO be required to provide better information to all market participants. While most parties agreed with the reports that the ISO's authority to impose a purchase cap should be maintained in the interim, the ISO's purchase capping authority was opposed by some generators. Many did not support the MSC's recommendations regarding changing the use of RMR facilities or reforming the RMR Agreements in the near term.

Order of October 28, 1998

We determined that we needed to take immediate steps to improve the Ancillary Services and Replacement Reserves markets and also to direct a comprehensive restructuring of the markets over the longer-term. To encourage maximum supply to be bid into these markets, we required all suppliers to the California markets with market-based rates for energy and capacity to amend their rate schedules to add Ancillary Services as a market-based product. 7/ We also allowed the ISO to continue the purchase price cap we had previously authorized. Although we recognized significant market shares held by PG&E, we concluded that there were sufficient deterrents and safeguards in place to prevent PG&E from increasing the market clearing price.

Thus, we denied rehearing of the earlier orders granting market-based rate authority, and of our July 17, 1998 Order. Additionally, we denied rehearing of our decision that Replacement Reserve service would not be considered an Ancillary Service, and directed all jurisdictional suppliers with market-based rates for Ancillary Services to amend their rate schedules by adding Replacement Reserves as a separate product.

The other thrust of our order was to require the ISO to facilitate a comprehensive, stakeholder process designed to

7/ This authority does not extend to Scheduling, System Control and Dispatch Service, and Reactive Supply and Voltage Control from Generation Sources Service.

develop structural solutions to the identified market design flaws. We directed the ISO to develop a redesign proposal to be filed no later than March 1, 1999. For any short term actions that could be implemented sooner, we stated that it would be appropriate for the ISO to make one interim filing before March 1, 1999. In addition, we directed the MMC and MSC to prepare reports "to further clarify the causes of the market anomalies identified in their initial reports" 8/ in January 1999.

Our order stressed that a purchase price cap was not an ideal approach and that we did not expect it to remain in place for the long term. Thus, we directed the ISO to indicate in its March 1st filing whether it intended to continue its discretion to set a cap and if so, to include objective criteria that would be used to exercise its discretion as well as a proposed formula or specific level for any cap. Also, we clarified that the ISO "as a purchaser, has the discretion to reject bids that are excessive; it does not have the unilateral authority to set rates or to reduce bids," or to "accept bids that are above the cap, but to pay no more than the stated level of the purchase cap." 9/

Finally, we dismissed the complaint filed by SoCal Edison under Docket No. EL99-62-000 requesting a stay of market-based pricing authority for Ancillary Services and Replacement Reserves. 10/

Requests for Rehearing and/or Clarification

On November 27, 1998, the ISO filed a request for rehearing "insofar as the October 28 Order limits the ISO's ability to implement price caps as authorized by the Commission's July 17, 1998 Order," 11/ or in the alternative, a motion for clarification to the effect that the ISO acted properly in treating above-cap bids submitted during periods of bid insufficiency as bids at the applicable price cap level. Bonneville also filed a request for rehearing, and the California Commission filed a request for clarification or rehearing. Certain parties (as identified below) filed answers to these pleadings. The arguments raised in these pleadings are described and addressed below.

8/ October 28, 1998 Order at 61,462.

9/ Id. at 61,463.

10/ No party sought rehearing of the complaint's dismissal. Subsequent listing of Docket No. EL98-62-003 in the caption of parties' filings was not necessary. We need not address the complaint further.

11/ ISO Request at 2.

Amendment No. 14

On March 1, 1999, the ISO filed its proposed Tariff Amendment No. 14, which it describes as Phase I of its comprehensive redesign of the Ancillary Services markets. The ISO discusses several interim actions affecting the Ancillary Services markets, including the ISO Governing Board adjusting the Regulation Energy Payment Adjustment (REPA) calculation, effectively suspending REPA; the ISO's proposal to extend its authority to reject bids in the real-time imbalance energy market (the "BEEP Cap"); 12/ and its tariff Amendment No. 13, proposing modifications to implement nonpayment for uninstructed deviations and allocating Ancillary Service obligations to Scheduling Coordinators based on their respective metered demands, rather than their scheduled demands. 13/

The ISO states that Amendment No. 14 responds to a range of problems the ISO has experienced with the operation of the ancillary services market, which were identified in the August 1998 preliminary reports of the MSC and the MMC. Principally, the problems are: (1) markets are often quite thin requiring the ISO to make out-of-market purchases or to rely upon reliability must-run (RMR) units, (2) prices for various products are extremely high at times with lower quality products often having higher prices than higher quality products, (3) current compensation mechanisms invite various types of strategic behavior; (4) various software and communication limitations impede efficient transactions; and (5) the structure of RMR contracts continue to give some generators poor incentives to participate in the market. The ISO states that all of the necessary and desirable improvements cannot be implemented at once and that the ISO has developed a phased approach. The ISO states that Amendment No. 14 implements six components of the market redesign that have been determined to have the highest priority, as well as certain other proposals. These proposals and the comments filed in this proceeding are discussed in detail below.

12/ The "BEEP Cap" was accepted by order issued on May 28, 1998 at 83 FERC ¶ 61,209 (1998). In January 1999, the Commission rejected the ISO's proposal to broaden this price capping authority, although the Commission authorized the ISO to adopt a purchase price cap for Imbalance Energy on the condition that it explain and justify its long-term plans regarding the cap in its March 1, 1999 filing. See California Independent System Operator Corporation, 86 FERC ¶ 61,059 (1998) (January 27, 1999 Order).

13/ See California Independent System Operator Corporation, 86 FERC ¶ 61,122 (1999), reh'g pending.

PX MMC Report and Comments

On March 10, 1999, the MMC filed its Second Report on Market Issues in the California Power Exchange Energy Markets in compliance with our October 28, 1998 Order. The MMC examined the California energy markets to assess their progress towards competition. Much of the report is descriptive. It explains how the generation market was created when the three major IOUs divested a portion of their generation capacity to four new generation owners (NGOs). It shows, for example, that regulatory must-take generation accounts for as much as 90 percent of the average market-clearing quantity and that market-clearing prices have been extremely volatile. In describing interactions between the ISO-administered markets and the PX markets, the report concludes that a comparison of energy and reserve prices indicates arbitrage opportunities have not been fully exploited as would be expected if markets were functioning smoothly.

The report also analyzes the bidding behavior of the NGOs. Since the IOUs remain major purchasers as well as suppliers, NGOs are expected to have greater incentives to exercise seller market power, if it exists. Although the MMC recognizes several important limitations in the analysis, such as lack of data on bilateral sales and reliability must-run and Ancillary Service transactions, it tentatively concludes that bidding by some NGOs was consistent with an attempt to exercise market power. The MMC's observations that market-clearing prices sometimes were well above any firm's marginal generating cost, and that over time, the same quantity of energy was clearing the market at a higher price are the main support for this conclusion. The MMC concludes that, to date, the effects of high prices on end users have probably been moderate, although in the future, high average prices would be harmful.

To remedy the market problems, the MMC strongly supports improvements to demand-side responses, such as letting end-users bid into Ancillary Services markets. In particular, the MMC recommends giving large users greater latitude to respond to prices, and that problems with noncompliance, including generator noncompliance, should be met with penalties. The MMC also supports the rational buyer approach recommended in Amendment No. 14, but would go even further and consider simultaneous bidding across energy and Ancillary Services markets. The MMC agrees with the MSC that RMR contracts must be reformed to give owners the proper incentives to bid into the Ancillary Service market. Finally, the MMC sees a continuing need for price caps and disclosure of bid data, with a lag, to let others analyze the California markets and develop better long-term policies.

The NGOs object to the conclusions the MMC draws about their supposed attempts to exercise market power. The NGOs emphasize that the MMC has not properly defined the relevant market, that it is much broader than the California PX. Even the MMC estimates that about half of the NGOs' capacity was sold outside the PX. The NGOs also stress that opportunity cost, not simply marginal operating cost, is the relevant consideration in deciding whether a seller in the California PX is exercising market power. The NGOs strongly object to the disclosure of bid data under any circumstances.

SoCal Edison and the Sacramento Municipal Utility District (SMUD) generally support the conclusions of the MMC's report. SMUD agrees that there needs to be greater demand-side response, penalties for noncompliance with ISO instructions, and retention of price caps. SMUD particularly wants to be able to sell Ancillary Services from its system resources rather than from designated generators, which current ISO policies and software prohibit. Finally, SMUD agrees with the MMC that there are potentially important benefits to simultaneous bidding across energy and Ancillary Services markets.

The Oversight Board generally supports the majority of the MMC's recommendations. The Board notes that the MMC's findings regarding NGOs' behaving as if attempting to exercise market power appears to be fully supported, "indicat[ing] that the PX and ISO markets are not sufficiently competitive and that changes to the market rules and/or new mitigation measures are needed." 14/ The Board states that the ISO faces risks from either over-purchasing or under-purchasing reserves but, for reliability purposes, recommends that the ISO err on the side of over-purchasing. The Board believes that other measures may result in the ISO purchasing less reserves, mentioning in particular that the ISO should explore the possibility of purchasing energy in the PX's day-of market as a substitute for Ancillary Services.

The ISO agrees with the MMC's analysis of the indirect impact of its purchase price cap on the PX markets. The ISO emphasizes that, as IOUs' divestiture of generating assets and acquisition of these assets by NGOs continues, the market share of NGOs, and the effect of any market power on prices, will increase.

The California Commission also generally supports the comments and conclusions in the report and believes that the MMC's findings regarding NGOs' bidding behavior appear to be well supported. The California Commission notes the MMC's recommendation that FERC or itself organize a technical conference on approaches to demand-side bidding and is considering hosting such a conference. Finally, the California Commission supports the MMC's recommendation that the ISO and PX should release aggregate bid data with a one-month lag.

14/ Oversight Board at 5.

ISO MSC Report and Comments

The MSC submitted a redacted version of its report on March 25, 1999, withholding portions relating to RMR contracts, and on April 6, 1999, submitted a complete version. The report focuses on 5 major topics: (1) market performance from July 1 through December 31, 1998; (2) the status of the MSC's recommendations from its August 1998 preliminary report; (3) the ISO's redesign proposals contained in Amendment 14; (4) long term redesign issues; and (5) the impact of RMR contracts on the performance of the ancillary service and imbalance energy markets. The MSC's comments on the ISO's proposals in Amendment No. 14 are discussed in detail in the Discussion.

Market Performance

The MSC observes that ancillary service costs for the ISO have accounted for about 15% of the total energy cost, compared to the historical 3%-5% under the vertically integrated utility regime. Part of this cost increase can be explained by shifting from the old regime to the current market regime.

First, according to the MSC, utilities previously provided ancillary services at cost to themselves. Hence, the total cost was the sum of all the costs to the utility. However, under the market regime, each unit providing ancillary services is paid the highest marginal cost of the last unit needed to supply ancillary services. Therefore, the total cost is the number of units supplying the service multiplied by the marginal cost of the highest cost unit accepted. The MSC points out that, even if all participants bid in at marginal cost (assuming perfect competition), the total cost would be higher; if there is not perfect competition, the cost differential becomes even greater.

Second, the MSC states that, under the old regime, vertically integrated utilities could plan ahead and ramp units up and down as needed so that supply and demand were equal (i.e., load following), with the effect of maintaining regulation as a zero net energy service. Under the market regime, however, generating units can generate at any level regardless of their schedules, requiring the ISO to procure more regulation service than it would if generators had to follow their schedules. Having to procure more of any service drives up the ancillary services costs as a percentage of energy costs, and the MSC points out, regulation service accounted for over half of the total ancillary service cost from June to December.

During the July through December period, the MSC points out that every ancillary service market saw prices that hit the price cap of $250/MW. It notes that many of these high prices came during peak periods, and that as system load decreased, the frequency of high prices dropped. The MSC also observes that after all participants became eligible for market based prices at the beginning of November, prices reached the $250 cap only once during that month. 15/ December saw more high prices and more price volatility than the previous two months.

In examining ancillary service quantities, the MSC notes that these markets may not be workably competitive. The MSC notes that during months with higher prices (July, August, December) there was a problem with bid sufficiency, yet in the months with lower prices and lower volatility there was little, if any, problem with bid sufficiency. 16/

Finally, the MSC notes that bid prices and quantities do not follow expected patterns. The MSC contends that higher quality services should have higher prices and lower bid quantities than lower quality services. It notes that many times, lower quality services receive higher prices, and that quantities bid into the markets often show lower bid quantities for lower quality services. The MSC notes that PX prices and imbalance energy prices seem to follow expected patterns, that is, higher prices and volatility in peak demand periods and lower prices and volatility in off peak periods.

Status of August 1998 Recommendations and Amendment 14 Proposals

In its August 1998 report the MSC recommended seven changes to make the ancillary service markets workably competitive. Of these recommendations, only three have been implemented in part or in total: approval of market-based prices, statewide auction for ancillary services, 17/ and retention of a damage control price cap. A fourth recommendation, the rational buyer protocol, is a part of Amendment 14, while the reform of RMR contracts is a part of an ongoing settlement process soon to be decided by the Commission. Recommendations on reducing the demand for Regulation service and establishing clear dispatch protocols for

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15/ The MSC also notes that Ancillary Services were procured on a statewide basis during November.

16/ MSC Report at 10, n.3 (noting that high bid sufficiencies may be due to bids from outside the control area which could not be chosen due to the 25% import limit imposed by the ISO).

17/ The MSC notes that the statewide auction for ancillary services has only been partially implemented, as evidenced by the observation that both zonal and statewide procurement practices have been employed.

imbalance energy are still under consideration by the ISO and stakeholders.

Long Term Redesign Issues

The MSC describes 8 longer-term redesign projects identified by the ISO's stakeholder process to improve the Ancillary Services and real-time market structures. Of note, one of these is implementation of a load following/ramping function to reduce the ISO's excessive burden on Regulation reserve.

RMR Contracts

The MSC describes the three types of RMR contracts ("A," "B," and "C" contracts) and two effects that the RMR contracts have on energy markets: the insurance effect and the portfolio effect. The insurance effect describes the behavior of RMR units that bid into the energy markets. These units know that, at certain times, they can submit a high bid price into the energy markets, but if it is not accepted, it is likely that they will receive large payments from the RMR contract. The portfolio effect describes the impact of RMR units bidding into energy markets at high prices and having their bids accepted. This implies higher prices earned by all units in the energy markets. The MSC argues that the current practice of calling RMR units after the day-ahead market and not bidding them as must-take units will cause the price in the day-ahead energy market to be above the efficient price.

The MSC cites two studies, included as Attachments C and D to its report, finding that total payments in the energy market without RMR contracts would have been several hundred million dollars less than they actually were. 18/ The MSC supports several recommendations from one of the studies, believing that the changes "are essential to workable competitive energy and ancillary services markets in California." 19/ First, RMR contracts should be reformed into true call option contracts; that is, each RMR unit receives a fixed up-front payment independent of energy produced, and is paid its marginal cost of production when called upon to produce energy. Second, the ISO should change the bid/RMR call sequence so that RMR units are

18/ MSC Report at 32-33. The reports were by Wolak and Bushnell (Attachment C) and the ISO Market Surveillance Unit (Attachment D). The MSC cautions that the results may be sensitive to the assumptions made in the respective studies. In order for outside parties to do similar studies, the MSC urges the release of all aggregate data from the ISO and PX markets after a 3-month lag.

19/ Id. at 36.

called before the start of the day-ahead energy market. This change would also give the unit the option to take the RMR call, or to bid into the day-ahead market and receive the PX price for energy. Third, RMR units should be bid into the PX market as must-take units so that they are bid into the market at a price of zero to guarantee their operating.

Most of the comments on the MSC report pertain to particular proposals in Amendment No. 14 and are considered in the discussion below. Broader comments include the critique of Reliant Energy Power Generation, Inc. (Reliant) that "the MSC tries to demonstrate that any problems in the California electricity markets can be attributed to generators, and particularly to RMR Owners, while ignoring the motivations and documented conduct of the incumbent utilities." 20/ In a similar vein, El Segundo and Long Beach assert that the MSC reached "unnecessarily pessimistic conclusions about competition," 21/ leading to recommendations that will slow progress toward efficient markets. El Segundo and Long Beach particularly criticize the MSC's use of "workable competition" as an economic concept. Finally, SMUD argues that the MSC's overall assessment of the various markets' performance is flawed. SMUD implies that competition in California electric markets to date has not benefitted consumers and argues for close scrutiny of Ancillary Services markets. In addition, Duke Energy Moss Landing, LLC, Duke Energy Oakland LLC, and Duke Energy South Bay, LLC (collectively, Duke affiliates) filed comments on the MSC report and a request for a technical conference.

Additional Filings

On April 12, 1999, the ISO filed an answer responding to the various comments and motions filed by the parties in Docket No. ER99-1971-000 (Amendment No. 14). The ISO states that the protests and requests for substantive modifications of Amendment No. 14 are unsupported and provides additional explanation and clarification as to the reasonableness of each proposed redesign element. The ISO agrees to make some non-substantive modifications and commits to make certain changes in a compliance filing, as discussed in detail below.

Also on April 12, 1999, PG&E, SoCal Edison, and the California Commission (collectively, the Answering Parties) filed a limited answer addressing protests of the ISO's proposal regarding crediting of Ancillary Services payment under RMR contracts, contained in Attachment M to Amendment No. 14. The Answering Parties attempt to clarify how market revenues of RMR

20/ Reliant at 9.

21/ El Segundo and Long Beach at 2.

generators are to be treated under the proposal.

Notice and Interventions

Intervenors in Docket Nos. ER98-2843-000, et al., as listed in Appendix A of this order, continue to have party status regarding the rehearing requests described above, and the MMC and MSC reports.

Notice of the PX MMC's report in Docket Nos. ER98-2843-006, et al., was published in the Federal Register, 64 Fed. Reg. 14,900 (1999), with comments due on or before April 12, 1999. Notices of the ISO MSC's initial, redacted report and subsequent unredacted report in Docket Nos. ER98-2843-007, et al., were published in the Federal Register, 64 Fed. Reg. 15,958 and 18,416 (1999), with comments due on or before April 12 and April 19, 1999, respectively. The substance of intervenors' comments and protests are described below.

On April 2, 1999, U.S. Generating Company (USGen) filed a motion to intervene in Docket Nos. ER98-2943-006, et al. On April 12, 1999, Enron Power Marketing, Inc. (Enron) filed a motion to intervene in Docket Nos. ER98-2843-007, et al. On April 13, 1999, PSEG Resources, Inc. (PSEG) filed a motion for leave to intervene out-of-time in Docket Nos. ER98-2843-007, et al. On April 19, 1999, Automated Power Exchange, Inc. (APX) filed a motion to intervene in Docket Nos. ER98-2843-007, et el. Finally, on April 20, 1999, USGen filed a motion to intervene out-of-time in Docket Nos. ER98-2843-007, et al.

Notice of the ISO's filing in Docket No. ER99-1971-000 was published in the Federal Register, 64 Fed. Reg. 12,300 (1999), with comments, interventions, and protests due on or before March 26, 1999. Timely, unopposed motions to intervene were filed by the entities listed on Appendix B. On March 31, 1999, Enron filed a motion to intervene out-of-time in this proceeding.

Discussion

Procedural Matters

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1998), the timely, unopposed motion to intervene of USGen in Docket Nos. ER98-2843-006, et al., and the timely, unopposed motions to intervene of Enron, PSEG, and APX in Docket Nos. ER98-2843-007, et al. serve to make them parties to this proceeding. Also pursuant to Rule 214, the notice of intervention and the timely, unopposed motions to intervene of the entities listed in Appendix B serve to make them parties to ER99-1971-000. Given the early stage of the proceeding and the absence of undue delay and prejudice, we find good cause to accept Enron's motion to intervene out-of-time in

ER99-1971-000. 22/

Although answers to protests generally are prohibited under 18 C.F.R. § 385.213(a)(2), we nevertheless find good cause to allow the ISO's answer of April 12, 1999, because it provides additional information that assists in our understanding and resolution of the issues in this proceeding.

On April 2, 1999, in another proceeding, the parties to ongoing litigation involving the RMR contracts filed an Offer of Settlement. The Offer of Settlement resolves most of the contested issues in Docket Nos. ER98-441-001, et al. On April 27, 1999, the Chief Judge certified the settlement agreement as uncontested. On April 21, 1999, ECI filed a motion to consolidate the ISO's proposal related to the RMR contracts with the proceedings in Docket Nos. ER98-441-001, et al. For reasons discussed below, we will reject the motion to consolidate.

ER99-1971-000

1. Rational Buyer Protocol

ISO Proposal. Currently, the ISO determines separately the amount of capacity that is needed for each of four Ancillary Services, which are (ranked in descending order of quality) 23/ Regulation, Spinning Reserves, Non-Spinning Reserves, and

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22/ On April 20, 1999, USGen filed a motion to intervene out-of-time in Docket Nos. ER98-2843-007, et al. USGen already was a party to the proceeding by virtue of its timely, unopposed motion to intervene filed on April 2, 1999. Accordingly, we need not address the second motion to intervene.

23/ Quality is determined in terms of technical characteristics of the reserves, such as the speed of response to an ISO instruction. For example, Replacement Reserves is lower in quality than Non-Spinning Reserves because Replacement Reserves must respond to an ISO instruction to produce energy within 60 minutes while Non-Spinning Reserves must respond within 10 minutes. A principal implication of the quality ranking is that, with one exception, any generating unit satisfying the technical characteristics of a given quality of service would also satisfy the technical characteristics of, and be capable of providing, any lower quality service. The one exception is Regulation; generation capacity providing Regulation service must be able to fully ramp up or down to meet an instructed level of energy production within 30 minutes of instruction, while Spinning and Non-Spinning Reserves must meet the instructed level within 10 minutes.

Replacement Reserves. Loads must either self-provide their designated portion of each of these Ancillary Services or pay the ISO for the costs of procuring them. The ISO procures the capacity to meet the non-self-provided requirements for each Ancillary Service in separate, sequential auctions. Current rules do not let the ISO substitute higher quality Ancillary Services for lower quality ones even when substitutions would lower the overall cost of satisfying ancillary service requirements; the ISO proposes in Amendment No. 14 to allow such substitution, while holding the overall ancillary service capacity demanded constant. The ISO states that this method, referred to as the "rational buyer" protocol (or RBP), would eliminate the opportunity for sellers to game the sequential auction and may lead to bidding behavior more consistent with a competitive market.

In Attachment D to Amendment No. 14, the ISO includes an analysis by the MSC of four alternative ways of implementing RBP. The Price-Comparing Sequential Auction (Rational Buyer Type 0) provides for substitution of a higher quality service for a lower quality service when the higher quality service bid price is lower than the lower quality service market-clearing price before such substitution. This auction does not consider the effect of additional procurement of the higher quality service on the market-clearing price of that service. The Cost-Comparing Sequential Auction (Rational Buyer Type 1) allows the ISO to increase its demand for a higher quality service and reduce its demand for a lower quality service if and only if this substitution lowers total cost. The MSC concludes that this method tends to produce lower purchase costs to the ISO than the Price-Comparing auction. Both the Price-Comparing and Cost-Comparing Sequential Auctions could be implemented immediately with the ISO’s existing software.

The Cost-Comparing Simultaneous Auction (Rational Buyer Type 2) permits substitution of both supply and demand bids across the four products if such actions reduce total purchase costs. For example, the Regulation bid from a generating unit may not be used for Regulation even though it is cheaper than the Regulation market-clearing price if using that unit’s Spinning Reserves bid in the Spin market reduces total Ancillary Services costs. The MSC concludes that this method tends to produce lower purchase costs to the ISO than either of the two previous methods. However, unlike the two previous methods, the Cost-Comparing Simultaneous Auction requires more complex software that could not be available until after the summer. Finally, a Product Specific Simultaneous Auction uses each bid only to satisfy the demand in the market it was bid into, while minimizing either bid prices or procurement costs. The MSC concludes that this method is not as effective in reducing procurement costs, and may actually increase them. The MSC recommends adopting the Cost-Comparing Sequential Auction initially, and exploring whether to adopt the Cost-Comparing Simultaneous Auction for the future. The ISO proposes in Amendment No. 14 to adopt the Cost-Comparing Sequential Auction.

The ISO's proposed Rational Buyer Protocol would not affect the amount of each Ancillary Service that must be self-provided by Scheduling Coordinators which choose to self-provide. Thus, for example, if in a particular hour the ISO elected to procure 10 percent more Non-Spinning Reserve and to reduce the amount of Replacement Reserves procured by a corresponding amount, the amount of Non-Spinning Reserves required to be self-provided by self-providing Scheduling Coordinators would not be increased. (Of course, generators technically capable of providing Non-Spinning Reserves would also meet the technical requirements of Replacement Reserves. So a self-providing Scheduling Coordinator could redesignate some Non-Spinning capacity to fulfill its Replacement Reserves requirement, if it would be cost-effective to do so.)

The ISO states that the financial settlements under the proposed rational buyer approach can lead to an imbalance between the ancillary service charges to load and payments to suppliers. The imbalance will be assigned to scheduling coordinators on a pro rata basis.

Response of the MSC and ISO Reply. The MSC supports the RBP as a positive step toward better functioning ancillary service markets. However, the MSC has some concerns over the financial settlement for Ancillary Services. The MSC explains that while the ISO may change its demand for a particular service under the RBP, self-providers and load are only obligated to pay for the initial requirements. The MSC claims this settlement system subsidizes self-providers since the charges for Ancillary Services will in general exceed the payments to suppliers. The MSC claims this is inefficient and will not lead to higher quality Ancillary Services selling for higher prices. Also, Regulation will sell for lower prices than would occur if self-providers and load faced the same obligation as the ISO's purchases. As a remedy, the MSC proposes to make obligation of self-providers and load equal to the amount of the service purchased by the ISO. This would eliminate the imbalance between payments to suppliers and charges to load, and it would provide the right incentives for self-providers and suppliers of Ancillary Services to sell these products so that higher quality services sell for a higher price. The MSC does not believe it would be difficult to implement such a protocol.

The ISO replies that the MSC has misinterpreted the filing. The ISO claims that the amounts paid to suppliers in general will be greater than the amounts charged to loads. As a result, self-providers will be encouraged to participate in the ISO-facilitated markets. The ISO states that the MSC's proposal would create uncertainty for self-providers of Ancillary Services regarding how much to self-provide. Further, the ISO claims that the MSC proposal would require the ISO to inform Scheduling Coordinators of the change in the procurement mix (so that self-providers would be aware of their adjusted obligations), and that providing this information would be difficult.

Intervenor Comments and ISO Response. With one exception, all intervenors commenting on the Rational Buyer Protocol support it and recommend adopting it, although some commenters recommend modifications. The California Commission supports the proposed rational buyer protocol, 24/ but prefers the stronger form (the Cost-Comparing Simultaneous Auction) outlined by the MSC in Attachment D of the filing. The Metropolitan Water District of Southern California (Metropolitan) would like the ISO to change language and/or clarify certain technical and definitional terms in the ISO tariff revisions in Attachment E that it finds confusing. 25/

The three California IOUs support the idea of the rational buyer protocol, but are concerned that Regulation Service may not always be able to substitute for Spinning and Non-Spinning Reserves, because Regulation is currently a 30-minute product while Spinning and Non-Spinning Reserves are 10-minute products. SDG&E is concerned with the MSC analysis in Attachment D that indicates Regulation may be redefined as a 10-minute product. SDG&E believes that reducing Regulation from a 30-minute to a 10-minute product would create an even thinner market for Regulation and lead to substantial price and cost increases. Additionally, SDG&E recommends that the ISO ultimately adopt the Product Specific Simultaneous Auction method (as described by the MSC in Attachment D) for implementing the Rational Buyer Protocol. However, SDG&E acknowledges that the software limitations currently in place preclude implementing this method at present and supports the current proposal as an appropriate interim measure. PG&E believes the Commission should monitor this program to ensure that there are no cost increases. 26/ PG&E is also concerned with the imbalance between charges to users and payments to suppliers. SoCal Edison would like to see both demand and product substitution as explained in Attachment D.

24/ The rational buyer protocol is also supported by the Oversight Board.

25/ The changes refer to language in tariff section 2.5.28 and Appendix C of the Settlement and Billing Protocol, section C 2.2.4.

26/ See PG&E at 5 (providing an example which shows one way in which the protocol might increase prices).

The ISO responds that it will purchase additional Regulation capacity to substitute for Spinning and Non-Spinning Reserves after it has checked that the purchased Regulation capacity includes enough capacity that may be reached within 10 minutes to meet the total ISO requirements for those reserves. The ISO states that no change is contemplated in the definition of Regulation under the ISO Tariff and Protocols. The ISO states that RBP will be used only if it leads to cost reductions. The ISO reiterates that Scheduling Coordinator (SC) obligations for each ancillary service will be calculated based upon the requirement for each ancillary service as the ISO determines prior to the RBP adjustments. 27/

Electric Clearinghouse, Inc. (ECI) disagrees with the rationale behind the rational buyer protocol in many respects and recommends that it be delayed until market participants have gained some experience with inter-Scheduling Coordinator (inter-SC) trading (described below). ECI opines the RBP is a "cost based vestige of utility regulation - e.g., because a plant that is spinning burns fuel, Spinning Reserve should sell for more than Non-Spinning Reserves-and thus derives from control area responsibilities of a tradition regulated utility." 28/ ECI argues that differing conditions may lead the market to value a product like Replacement Reserves more highly than Spinning Reserves. Finally, in requesting a delay of RBP implementation, ECI contends that inter-SC trades of Ancillary Services along with import firmness preservation may help alleviate any concerns about perfectly price inelastic demand problems cited by the MSC. In response, the ISO states it is responding to market price signals in order to reduce its overall cost of procurement. For example, if a service with less stringent technical requirements (lower quality) is signaled to have higher value than services with stricter technical requirements (higher quality) according to the market, it is rational for the ISO to purchase more of the higher quality service to reduce costs.

If the Commission approves the RBP, ECI contends that SCs should also be allowed to substitute higher quality Ancillary Services for lower quality Ancillary Services. SCs should be able to exercise the same option in self-provision or inter-SC trades. However, if the ISO will not allow this sort of substitution possibility, ECI asserts that the ISO should be required to inform market participants what the ISO substitutions are so the SCs may adjust their procurement of self-provided or traded Ancillary Services accordingly. ECI further claims that

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27/ See ISO Answer at 12. The ISO acknowledges that this wording was unintentionally omitted from another section and will add it in a compliance filing.

28/ ECI at 5.

the current and revised ISO tariff does not explicitly define how much ancillary service capacity must be purchased, nor does it explicitly define the mix of services. The tariff only defines the minimum based on WSCC standards. ECI argues this information is crucial to a well functioning market. ECI is also concerned with the settlements for both suppliers and load under the RBP and claims the settlements are not transparent.

The ISO, in response, claims that SCs already have this same flexibility. The ISO states this proposal only changes the way the ISO is allowed to procure Ancillary Services. The ISO also responds to ECI's request for further explanation of cost allocation under the RBP by stating that it is a result of the stakeholder process and that no further explanation is necessary.

Commission Response

The Commission accepts the RBP with conditions and modifications as stated below. The RBP will allow the ISO to reduce the cost of meeting its Ancillary Services requirements. Our acceptance of RBP is consistent with our requirement that ISOs in New York and New England 29/ pursue similar procurement of Ancillary Services. We disagree with ECI that the cost-savings from RBP should be delayed until market participants have gained experience with inter-SC trading.

As noted by the MSC, there are alternative ways of implementing the RBP. The ISO proposes to implement the RBP via the Cost-Comparing Sequential Auction, as recommended by the MSC. We will accept for now this method of implementing RBP. The ISO’s software is capable of using this auction method immediately, and it is designed to result in lower procurement costs to the ISO than the other methods that could be implemented immediately. However, we have some questions about this method for the longer run, as discussed below. Therefore, we will direct the ISO to have the MSC evaluate the ISO's experience with this method during the coming summer, and to file a report on its evaluation on October 15, 1999.

First, we note that this method may not always result in ancillary service prices varying directly with service quality. That is, high quality ancillary service prices in a given hour may not always equal or exceed lower quality ancillary service prices. This result may occur because the Cost-Comparing Sequential Auction considers the effect of changing prices on the cost of "inframarginal" capacity in determining whether to change the procurement mix. This effect can be described by way of an

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29/ See New England Power Pool, 85 FERC ¶ 61,379 (1998); Central Hudson Gas & Electric Corporation, et al., 86 FERC ¶ 61,062 (1999).

example. Suppose that under one mix of Ancillary Services, the ISO observes that the price of a high quality ancillary service such as Spinning Reserves is lower than the price of a lower quality service such as Replacement Reserves. For example, suppose that price of Spinning Reserves is $10/MW and the price of Replacement Reserves is $25/MW. Suppose also that additional Spinning Reserves are available for $20 and could displace some Replacement Reserves whose bids are $25. By purchasing the additional Spinning Reserves, the price of Spinning Reserves would double -- from $10 to $20. The higher price would be paid not only for the additional MW of Spinning Reserves, but also for the original quantity of Spinning Reserves (i.e., the inframarginal quantity of Spinning Reserves). The higher cost to the ISO of procuring the inframarginal Spinning Reserves would tend to offset the cost savings from displacing expensive Replacement Reserves with cheaper additional Spinning Reserves. In certain circumstances, the increased cost of procuring the inframarginal Reserves may be the stronger effect, so that the more expensive Replacement Reserves would not be displaced. In these circumstances, the price of the higher quality Spinning Reserves would remain lower than that of the lower quality Replacement Reserves. Such an inverse price relationship would generally be inconsistent with efficient ancillary service markets, as the MSC and MMC have stated. Moreover, an inverse price relationship might continue to provide incentives for owners of generation capacity to submit higher bids for lower quality service than for higher quality service. The MSC's report should address this issue.

Second, while the ISO's proposal to use the Cost-Comparing Sequential auction may be appropriate as a way to correct existing market flaws and to counteract any seller market power that such flaws may create, we are still undecided whether it is consistent with efficient markets once those flaws are corrected. Therefore, the MSC should discuss in its report which approach is most appropriate in the long run. The MSC's report should evaluate at least two alternative approaches. One approach would be to continue to conduct Ancillary Service auctions using the objective proposed here -- that is, to minimize buyers' procurement costs and to ignore sellers benefits. An alternative approach would be to operate the Ancillary Services markets using the same objectives as those used in the California energy markets -- that is, to promote efficiency considering both the demand and supply sides of the market. 30/

We will accept for now the ISO's proposal that any RBP adjustments to the procurement mix of Ancillary Services will not affect Scheduling Coordinators' MW obligations for each Ancillary Service. Any changes that we might require now could delay implementation of the RBP and the associated benefits. However, we note that the MSC and ECI express concerns about this feature of the ISO's proposal. They recommend that an entity's MW obligation for a given Ancillary Service reflect the ISO's procurement of that service after any RBP adjustments. As we explain more fully in Appendix C to this order, we are concerned that over the long run this feature of the ISO's proposal may encourage inefficient self-provision of Ancillary Services. By self-providing an Ancillary Service, an entity avoids the ISO's charge for procuring the service. Under the ISO's proposal, this charge can differ from the market price paid to sellers for the same service. Thus, in order to avoid the ISO's charge, an entity may self-provide expensive capacity when the ISO could have procured cheaper capacity. We will direct the ISO to have the MSC monitor the market's experience under the ISO's proposal and evaluate whether it results in inefficient self-provision. The MSC should discuss its conclusions in the report we have directed to be filed on October 15, 1999.

We note that the ISO's RBP proposal, as well as the ISO's "Buy Back" proposal discussed later in this order, involve the possibility that the effective compensation for self-providing Ancillary Services may differ from the price for selling the same Ancillary Services in the market. We suggest that the ISO, the MSC, and the stakeholders explore the possibility of adopting policies that remove this difference in compensation. We also suggest that the parties consider whether the market process is or can be designed in such a way as to effect self-supply through the market process rather than through a separate self-supply

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30/ That is, the ISO and PX energy auctions are operated so as to maximize the difference between buyers' aggregate bid value and sellers' aggregate bid requirements (subject to certain constraints). By contrast, the ISO auction proposal here would maximize the difference between buyers' aggregate bid value and buyers' procurement costs. One major difference in these two approaches is that the proposed ancillary service auctions would consider the effect of price changes on the buyers' costs of procuring inframarginal capacity, while the energy auctions do not consider this effect. Changing the mix of Ancillary Services may change the buyers' procurement costs of inframarginal capacity but not the sellers' costs (and the social costs) of providing this capacity.

arrangement. If a simultaneous sale to and purchase from the ancillary service market would place a customer in the same financial position as supplying ancillary services on its own behalf, the ISO may be able to avoid having two separate processes that are difficult to reconcile operationally. While the Commission’s pro forma tariff includes a self-supply option, the parties should address whether the ability to sell into the ISO’s Ancillary Services markets may be another way of accommodating the ability to self-supply.

Nevertheless, we agree with Metropolitan that the Tariff is not completely clear regarding how settlements will be made under the RBP. For example, the ISO’s discussion of the Rational Buyer Implementation in Attachment C describes and illustrates the procedures to be used to determine settlements. The ISO’s stated objective in the discussion is to ensure that no classes of users would be made worse off as a result of the Rational Buyer procurement. However, the manner in which the ISO’s rates charged for Ancillary Services would reflect these procedures is not clearly specified in Section 2.5.28 of the Tariff or in the billing and settlement protocols submitted in Attachment E. 31/ We direct the ISO to add language to its tariff to clarify how the settlements are to be computed.

2. Proposal for Uninstructed Deviations and Use of Replacement Reserves

ISO Proposal. The ISO states that scheduled supply and demand in California have commonly been less than actual, real-time supply and demand. To create incentives for Scheduling Coordinators (SC) to submit schedules for supply and demand that more closely match actual, real-time transactions, the ISO proposes three related measures. First, the ISO will procure extra Replacement Reserves to account for the difference between scheduled load and the ISO’s forecast load, reduced by the additional supplies that the ISO expects to be available from other sources in real-time. Second, the cost of extra Replacement Reserves will be borne by SCs whose actual demands exceed scheduled demands or whose actual generation is less than scheduled generation. In effect, an SC's obligation for Replacement Reserves will have two parts: one part based upon reliability needs and the other part based upon deviations from

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31/ For example, it is not clear in calculating the user rate for Replacement Reserves in Section 2.5.28.4 whether "Total Replacement Reserve payments" refers to (1) the actual payments made to suppliers of Replacement Reserves, or (2) the payments attributed to Replacement Reserves under the Rational Buyer Protocol, as illustrated in Table 2 under the "Management Recommendation" column, in Attachment C of the filing.

schedules. Third, generators that fail to follow ISO instructions will have settlements determined at the "effective price," which is defined as the average price paid or charged for real-time, imbalance energy paid to those units that followed dispatch instructions.

These proposals are to work in concert with elements of Amendment No. 13 that eliminate compensation to a generator that produces energy -- without instruction from the ISO -- from capacity committed to ancillary service markets, and that allocate Ancillary Services costs based upon metered demands rather than scheduled demands.

Response of the MSC. The MSC states the effective price proposal will not discourage generators from deviating from their dispatch instructions. It believes one possible alternative is to settle deviations at the 10 minute BEEP price, but concedes this would increase the complexity of the settlement system. The MSC criticizes the ISO's proposal to recover the costs of the additional procurement of Replacement Reserves from those generators and loads that have under scheduled in the day-ahead and hour-ahead markets. The MSC argues that this implicitly taxes loads that wish to shift their demands from the day-ahead markets to the hour-ahead and real-time markets and may lead to higher prices in the PX and real-time energy markets. 32/ The MSC states that the PX Day-Ahead price may be artificially inflated due to certain market design flaws, such as the ISO's procedure of waiting to commit Reliability Must Run (RMR) units until after the close of the Day-Ahead Market. According to the MSC, this procedure causes the PX to schedule more (and higher cost) supply than is necessary to meet the Day-Ahead demand. To protect themselves against these inflated prices, some purchasers may shift some of their demands away from the Day-Ahead market and into later markets such as the real-time market. The MSC is concerned that the ISO's proposal would make it more difficult for purchasers to shift their demands away from the Day-Ahead Market to protect themselves from higher prices in that market.

Intervenor Comments and ISO Response. ECI claims the proposal to purchase Replacement Reserves to cover any difference between the ISO's load forecast and load scheduled by SCs runs counter to the ideas behind the RBP since the proposal makes demand for this service more rigid. ECI and SoCal Edison further argue that the cost of these extra Replacement Reserves would be "socialized" over the entire market or be borne by those who did not impose those costs.

32/ The MSC also recommends making real-time energy bids further in advance of the dispatch hour and penalizing those who withdraw their bids so there is a more reliable BEEP stack from which to dispatch real-time energy.

SoCal Edison claims the effective price proposal will be ineffective. SoCal Edison also claims the ISO's settlement system cannot distinguish between Regulation imbalance energy and undelivered instructed energy from the same source. Therefore a generator providing Regulation service would never be assessed penalties for undelivered energy. The ISO responds by stating that any generator providing Regulation during a particular hour must be on automatic control, and hence cannot deviate from its schedule uninstructed.

PG&E believes there are mistakes in the formulae implementing the effective price changes in Attachment G. It says these errors have been brought to the attention of the ISO. 33/ In its response, the ISO agrees with the technical revisions proposed by PG&E and states these revisions will be included in a compliance filing.

The Transmission Agency of Northern California (TANC) laments the lack of explicit procedures or clear explanations in the revised tariff to implement the Replacement Reserves proposal. It recommends that the Commission order the ISO to provide a clear explanation.

Commission Response

We will accept the ISO's proposal to procure extra Replacement Reserves to meet unscheduled demand and overscheduled generation and to recover the costs from underscheduled load and overscheduled generation. To the extent that the ISO must procure additional Replacement Reserves to meet unscheduled load and to replace scheduled generation that is not produced in real-time, it is reasonable to charge the costs of these reserves to the loads and generation that cause them. We disagree with the MSC and others that the proposal would impede the ability of purchasers to shift their demands away from the Day-Ahead Market to protect against Day-Ahead price increases caused by market design flaws. Purchasers will be able to shift their demands from the Day-Ahead to the Hour-Ahead Schedules without incurring the proposed additional charge. We disagree with TANC that the proposed Tariff language is unclear.

We will also accept the ISO's effective price proposal. No party objects to it, although some argue that it will be ineffective. We find that it would help to provide incentives for generators to follow ISO instructions by reducing the net compensation for failing to follow ISO instructions. We note that the effective price proposal is directed at generators that

33/ See PG&E Comments, Attachment A, listing the proposed corrections.

overschedule, i.e., that produce less energy in real-time than they have scheduled. The proposal would not apply to generators that overgenerate, i.e., that produce more energy in real-time than they have scheduled. The ISO states that overgeneration may create problems of its own. We encourage the ISO to develop, in consultation with stakeholders, proposals to address any problems created by overgeneration.

3. Separate Pricing of Regulation Up and Regulation Down

ISO Proposal. Previously, bidders into the Regulation market submitted only one capacity price bid and separate ranges for upward and downward Regulation. The equilibrium capacity price for both upward and downward Regulation was then jointly determined. Amendment No. 14 proposes to separate the two markets completely, since each type of Regulation is a different product, so that each will have a separate market clearing price. The ISO states that separate pricing will decrease its costs of procuring both Regulation products.

Response of the MSC. The MSC asserts that further segmenting the market will only "enhance the opportunities generators have to set high prices in these markets." 34/ It recommends that the ISO explore other options to improve the efficiency of the Regulation market. It cites the continuing periodic bid insufficiencies and price spikes in the Regulation markets as evidence that the market is thin and not workably competitive.

Intervenor Comments and ISO Response. TANC in general agrees with the ISO that separate pricing of upward and downward Regulation should reduce costs. 35/ However, TANC believes the actual tariff changes are potentially confusing. It claims that the ISO's single formula applying to both services and its explanation as such could lead to confusion and potential error in computing prices. The ISO agrees with TANC's suggestion and states that it will add the necessary formula in a compliance filing.

PG&E generally supports the ISO's proposal to have separate Regulation markets but believes that the "issue regarding the use of regulation to soften up the morning and evening peaks" must be addressed. 36/ PG&E recommends that the use of a new or modified commodity to address morning and evening ramps should be studied

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34/ MSC Report at 18.

35/ Modesto, Turlock, and MSR adopt TANC's comments and protests.

36/ PG&E at 8.

by the ISO and the MSC.

Commission Response

We will accept the ISO's proposal to separate the markets for upward Regulation and downward Regulation. We agree that, since each product is different, their individual prices should be determined independently of one another. Moreover, the ISO has agreed to include separate formulae for computing upward and downward regulation prices, as requested by TANC. We note that the ISO is developing a load following product, as PG&E has suggested.

4. Trades of Ancillary Services Between Scheduling Coordinators

ISO Proposal. Currently ISO software does not recognize bilateral trades of ancillary service obligations or capacity between Scheduling Coordinators (SCs). Trading between SCs could enhance their ability to self-provide Ancillary Services. The ISO has given high priority to developing this software capability, and Attachment I provides tariff changes necessary to implement inter-SC trading when the software is ready.

Intervenor Comments and ISO Response. No intervenor opposes trades of Ancillary Services between SCs. In fact, ECI identifies it as one of the most important changes the ISO is making to the Ancillary Services markets. However, ECI points to two problems. First, it opposes limiting inter-SC trades to resources located within the ISO's control area. Second, it objects to the requirement that any excess self-scheduled Ancillary Services must be sold in the ISO's market. ECI claims that SCs might find it more profitable to sell such excess in other markets.

The ISO responds that ECI has misunderstood and/or misread the proposal. First, the ISO states that it does not intend to prohibit trading with resources outside its control area and has offered to add Tariff language to clear up any confusion. Second, the ISO responds that without inter-SC trading, there is no alternative to making excess ancillary service capacity available to the ISO. With trading as proposed, excess capacity will be made available to the ISO only to the extent the SC has not made other arrangements. This should satisfy ECI's second concern that the ISO's markets and inter-SC trades are treated equally.

Commission Response

We agree that inter-SC trading is an important enhancement to Ancillary Services markets and accept this proposal. However, as the ISO has agreed, we direct it to revise its Tariff to clarify that trading with resources outside the control area is permitted.

5. Tariff and Protocol Modifications to Implement Billing Based on Metered Demand (Buy-back proposal)

ISO Proposal. Modifications approved as part of Amendment No. 13, approved in the Commission's February 9th Order, result in charging SCs for Ancillary Services based upon actual metered demands for energy as opposed to scheduled demands. The ISO states that, in developing the software to implement this change, it has discovered a possibility for SCs to engage in strategic behavior that lets them profit at the expense of others. An SC with self-schedule Ancillary Services in the day-ahead market, if it believes the hour-ahead price will be higher, could withdraw the self-supplied Ancillary Services and sell them into the hour-ahead market. Under current Tariff provisions, the SC would pay for non-self-provided Ancillary Service requirements at the ISO's "average cost" -- the average of the day-ahead and hour-ahead costs. But the SC would be paid the higher, hour-ahead price for the capacity it had withdrawn from self-provision and sold into the hour-ahead market. Thus, it would make a profit at the expense of other SCs that must now pay more for Ancillary Services.

In Amendment No. 14, the ISO proposes that any SCs that self-supplied Ancillary Service capacity in the day-ahead market would pay the ISO the applicable hour-ahead price for any of that capacity that is subsequently withdrawn from self-provision. That is, such self-provided capacity would be bought back at the hour-ahead price. Moreover, if the day-ahead scheduled quantities of Ancillary Services of an SC are reduced for any reason by the ISO, the SC would be required to buy back the capacity at the hour-ahead price, regardless of whether the Ancillary Services are self-provided or sold into the ISO facilitated market.

The ISO also proposes crediting SCs for any self-provided Ancillary Services in excess of their requirements at the ISO's average procurement cost. The ISO explains this might arise since the self-provision or trade of these products are in whole MW and the charges are based upon metered demand.37/

Intervenor Comments and ISO Response. Many commenters oppose the ISO's buy back proposal. Joint Intervenors 38/argue

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37/ Attachment J, Section 2.5.28.

38/ The Joint Intervenors consist of Arizona Public Service Co., Bonneville, Enron Power Marketing, Inc. (Enron), Los Angeles (continued...)

that it gives the ISO a right to force suppliers of Ancillary Services, whether self-provided or sold into the market, to buy back for any reason Ancillary Services that were committed day-ahead at the hour-ahead price. The parties claim this is not merely a clarification in the tariff, but a major change in the allocation of costs and risks between sellers and loads. The commenters state that forced buy back could occur, for example, due to derating of transmission paths after the close of the day-ahead market, or from congestion due to over scheduling new firm uses and existing contracts. 39/ They argue that higher risks to suppliers will lead to lower supplies, greater bid insufficiency problems, and hence high prices faced by the ISO. The intervening parties further claim that there is no way to hedge against such risks given the nature of circumstances that might surround a forced buy back such as line derating or congestion, and that there is no notification of the forced buy back until after it is completed. Finally, the joint intervenors claim the only time the ISO has brought up the potential gaming opportunity is in the transmittal letter. They claim that in meetings with the MSC and stakeholders, the ISO only intended this change as a clarification and never mentioned this gaming opportunity.

The Cities of Redding and Santa Clara and the M-S-R Public Power Agency (collectively, MSR) and TANC believe the proposal is inappropriate when day-ahead schedules are reduced due to factors over which the supplier of Ancillary Services has no control, such as changes in system generation schedules and transmission curtailment and that, in these cases, the supplier should not be required to buy back Ancillary Services at the hour-ahead price.

The Turlock Irrigation District (Turlock), SMUD, and Metropolitan argue that SCs that self-provide Ancillary Services should not be forced to buy back Ancillary Services if load decreases. Instead, the ancillary service requirement should decrease without any penalty. Metropolitan further asserts that self-providers of Ancillary Services would then, in effect, be subsidizing those SCs which do not self-provide their Ancillary Services. Metropolitan proposes that the provision be changed to force the buy back only if the self-provider does not have the

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(...continued)
Department of Water and Power (LADWP), PG&E Energy Services Corp. (PG&E Energy), Portland General Electric Co. (PGE), the Salt River Project Agricultural Improvement and Power District (Salt River), and Western Power Trading Forum (Western). LADWP has filed a separate intervention which supports the Joint Intervention. Many of the same arguments are echoed by NCPA, Modesto,

39/ Joint Intervenors at 5, n.4. They also claim this forced buy back is done without notifying suppliers in advance.

resources to meet its ancillary service obligation. SMUD proposes that active day information be provided to SCs until the close of the hour-ahead market; then the ISO can use the up to date information to update reserve requirements and reduce the demand for Ancillary Services.

Modesto Irrigation District (Modesto) believes the buy back provision violates the binding commitments made in the day-ahead market as stated in Section 2.5.21 of the ISO Tariff. It claims this is discriminatory since those SCs that purchase Ancillary Services from the ISO do not face any additional risk as a result of the revision. SDG&E echoes the sentiments above that this practice harms market efficiency and proposes that generators submit bids to buy back Ancillary Services if necessary. 40/ PG&E wants the Commission to send this back to a stakeholder process. It prefers that units not be price takers in such situations.

In response, the ISO argues that day-ahead self-provision should be a binding commitment to supply, just like accepted bids into the ISO facilitated market. Backing out of that commitment imposes costs upon the ISO and SCs, and self-suppliers that withdraw capacity should bear those costs regardless of whether the withdrawal was voluntary or was due to forced outages, line deratings, or congestion. The ISO further contends that intervenors have overstated the concerns about thinness of these markets due to this proposal and that failure to treat self-supply in the same manner as supply bid into the market would encourage suppliers to stay away from the ISO's market and increase the risk to those participating in the market.

In response to comments that it has already instituted this policy, the ISO states it does not plan to retroactively bill based upon this proposal, and that these comments are beyond the scope of this proceeding.

With respect to comments on decreased load, the ISO offers two potential solutions. One is for an SC to defer part of its self-provision until the hour-ahead market to see what its demand is likely to be, or it can self-supply day-ahead and keep that capacity committed and receive a credit for the excess.

Commission Response

We will accept the ISO's buy back proposal as it applies to self-provided capacity that is subsequently withdrawn voluntarily by the SC. We will reject the buy back proposal as it applies to

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40/ SDG&E also seems to indicate this practice has been going on subsequent to the filing of Amendment No. 14.

self-provided capacity that is subsequently withdrawn at the instruction of the ISO.

The ISO states that it has proposed the buy back provision to remove the incentive for an SC to withdraw previously self-provided capacity during the day-ahead schedule and then sell the same capacity into the hour-ahead market. We see no harm in the proposal as it applies to capacity withdrawn voluntarily by an SC. Moreover, while SCs would lose the flexibility and financial benefits from self-supplying day-ahead and then withdrawing in the hour-ahead schedule without penalty, an SC can achieve the same flexibility and financial benefits in other ways. For example, the SC can elect not to self-provide in the day-ahead schedule, and instead wait until the hour-ahead schedule to decide whether or not to self-provide or sell. Self-providing has the same financial effect (i.e., allowing the SC to avoid the ISO's average-cost-based charge for procuring Ancillary Services) whether the self-provided capacity is offered in the hour-ahead or day-ahead schedule.

We encourage the ISO to consider other measures to address gaming. The potential gaming opportunity cited by the ISO arises because the effective compensation for self-providing capacity is different from the compensation for selling capacity. That is, the effective compensation (or financial benefit) from self-providing is the ISO's charge for procuring the applicable ancillary service, since by self-providing, the SC avoids this charge. The charge is a weighted average of the day-ahead and hour-ahead prices for the service. Thus, for example, if the day-ahead price for Spinning Reserves is $10 and the hour-ahead price is $20, the ISO's charge would be between the two prices, say, $14. If an SC does not self-provide, it must pay the $14 charge. It avoids the $14 charge by self-providing, thereby paying nothing to the ISO for Ancillary Services. If the SC sells into the hour-ahead market rather than self-providing, it receives the $20 hour-ahead price while incurring the $14 charge -- resulting in net revenue of $6 from the ISO. We see no reason why capacity should receive different compensation based solely on whether it is self-provided or sold; the capacity would provide the same function and benefit whether self-provided or sold. The ISO's buy back proposal does not change this feature, and the differential compensation still leaves room for gaming. The issue of differential compensation for self-provision and sales of Ancillary Services also arises in the Rational Buyer protocol, discussed above. As we also noted in that earlier discussion, we encourage the ISO and the stakeholders to consider mechanisms that would remove the differential in compensation for self-provided and sold capacity. And we encourage the parties to consider, as an alternative, whether the market process is or can be designed in such a way as to effect self-supply through the market process rather than through a separate self-supply arrangement.

We will reject the buy back proposal as it applies to self-provided capacity that is withdrawn involuntarily by the SC on instruction from the ISO. Applying the proposal to involuntary withdrawals does not help to achieve the ISO's stated purpose for its buy back proposal, i.e., to remove the incentive for SCs to withdraw previously self-provided capacity. Moreover, applying the proposal to involuntary withdrawals is inconsistent with the ISO's argument that self-providing capacity should represent a binding commitment. 41/ We believe that the binding nature of the commitment should apply to both parties -- the SC and the ISO. If the ISO is unable to honor its commitment and must require the capacity to be withdrawn (for example, because a transmission line is derated), the withdrawal should not occur on terms that disadvantage the SC. The ISO's proposal in these instances would be unreasonable, because it would require the SC to buy back the capacity at an hour-ahead price potentially greater than the charge that the SC would have paid if it had never self-provided capacity.

For the longer term, we encourage the ISO to consider implementing a bidding mechanism to address situations in which it must reduce the amount of capacity self-provided or sold into the Ancillary Services markets. The ISO already uses a bidding mechanism in the imbalance energy market to address similar situations. In the imbalance energy market, if the ISO must back down generation (e.g., because a transmission line is derated and/or congestion develops), it does so based on the adjustment bids submitted by SCs. As a result, any generator that is backed down pays no more than it is willing to pay, as reflected in its bid. Allowing sellers and self-providers of Ancillary Services to submit adjustment bids would allow the ISO to reduce ancillary service capacity in various locations as needed more efficiently and in a way that is mutually beneficial to suppliers and the ISO.

6. Automation of Imbalance Energy Instructions

Currently, the ISO communicates dispatch instructions by phone. This is a time-consuming process, and the ISO states that at times it may pass over energy from several smaller units and take more expensive energy from a few larger units in order to reduce the number of phone calls. The ISO proposes software modifications that will automatically notify sellers of imbalance energy that their bids have been accepted and that they should generate, reducing the need to dispatch out-of-merit order. The ISO asserts that this change does not require a tariff modification and plans to notify market participants by

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41/ See ISO Answer at 26 (noting that "Day-Ahead Ancillary Services schedules are a commitment that must be honored by the supplier ...").

electronic mail when the system is ready to operate.

The parties agree with this proposal in principle, but ECI, Metropolitan, and the Northern California Power Agency (NCPA) raise several concerns with the implementation: (1) whether tariff revisions are required to codify the new procedures, (2) whether SCs may be forced to purchase additional copies of the software at an indefinite cost, and (3) whether the software should be redesigned to allow scheduling coordinators to save the instructions they receive. NCPA is concerned that it will not be able to track how much it generates and which generators should be compensated how much.

The ISO answers that a stakeholder group was involved in selecting the contractor for software development and continues to meet as progress proceeds.

Commission Response

We find that the ISO's proposal is reasonable and no revisions to the ISO's tariff are required. We will not require any software changes at this stage in the software design process.

7. Generator Communications Project for Resources Supplying Regulation

ISO Proposal. In order to improve control over generating units supplying Regulation service, reduce Regulation requirements, and comply with NERC policy and WSCC operating criteria, the ISO proposes that each generator supplying Regulation service be capable of being controlled and monitored by the ISO's remote control system, the Remote Intelligent Gateway System (RIGS), by the end of 1999. The proposal requires that each generating unit must be capable of responding to all ISO control commands during periods when the generator has offered Regulation service to the ISO, without manual operator intervention of any kind. In the alternative, a generator may install non-RIGS equipment if the ISO agrees that it provides an equivalent level of communication and control. In addition, the ISO will require that certain voice communications systems be in place at each generating site, a requirement which has the effect of excluding generators that are not staffed around the clock.

Intervenor Comments and ISO Response. Although all parties agree that the ISO needs control over generating units supplying Regulation, there is opposition to the specifics of this proposal as overly broad and not cost-effective. Some intervenors argue that, because some generators currently providing high quality Regulation service may have limitations on making these changes, 42/ this proposal could make Regulation markets even thinner. Some argue that, for generator sites in remote locations, it is impractical to have operators on-site continuously. Also, some complain that the proposal does not reflect the realities of operating hydroelectric facilities which must comply with requirements governing the use of water resources and hydroelectric licenses. 43/ While the ISO explains that it will make exceptions, it does not give any specific criteria for exemptions, and parties do not believe that the ISO should have this much discretion.

ECI, SoCal Edison, Metropolitan, and the Energy Producers and Users Coalition and the Cogeneration Association of California (collectively, EPUC/CAC) object to the performance standards that the ISO will use to govern whether a unit can bid into the Regulation market as vague and subject to change and argue that the standards should be made part of the ISO's tariff. SDG&E points out that it is normal for an operator to intervene occasionally to ensure stable operations, and proposes that the ISO limit its restrictions on manual operator interventions to those that actually cause delays. Turlock protests the exclusion of generating units with 10 MW or less capacity.

Several parties comment that the proposal lacks cost justification, arguing that it is not clear that the goals cannot be achieved in a more cost-effective manner. EPUC/CAC and PG&E warn that high installation and leasing costs 44/ may deter generators from participating in the market.

The ISO states that it will work with market participants to accommodate hydroelectric generator issues. It explains that it will only control the capacity that is bid into the Regulation market, and that generators can incorporate any limitation on their operations into their Regulation bids. The ISO asserts that RIGS provides digital technology for generator control, meter data, and voice communications, yielding significant cost

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42/ SoCal Edison cites as an example to its Hoover Dam contract with the Western Area Power Administration (WAPA), which does not allow it to install RIGS equipment on WAPA resources.

43/ The California Department of Water Resources (CDWR) explains that RIGS requirements should not place the ISO in the position of having to become a co-licensee.

44/ See EPUC/CAC at 8 (citing estimates of $30,000 for installation and $45,000 per year to lease the software) and PG&E at 10 (citing its 110 generating units at 68 powerhouses, many of which are remote with difficult access).

benefits by avoiding redundant systems, and that it has determined RIGS to be the lowest-cost solution to improve communications and control. The ISO maintains that its proposal sufficiently describes the technical requirements and leaves to the owners how they wish to meet the requirements. Regarding incorporating waiver criteria into its Tariff, the ISO argues that it cannot anticipate the circumstances under which a generator might seek waiver, and that making the criteria public and applying them in a non-discriminatory manner (which is what it intends to do) should be sufficient.

Commission Response

We recognize the ISO's need to govern the instantaneous electrical output of the generating units providing Regulation service. We are encouraged by the ISO's statements that it will accommodate exceptions to the extent practicable. It is in the ISO's interest not to preclude so many generators that it cannot maintain sufficient supplies of Regulation service. However, we caution the ISO that the degree of control implied in the RIGS proposal cannot conflict with requirements of FERC hydroelectric licenses. A licensee must have sufficient control of its project to allow the Commission, through the licensee, to regulate all licensed purposes of the projects. 45/ Although hydroelectric generators may limit their Regulation bids to be consistent with license requirements, it is not clear, based on the limited record before us, whether the ISO's proposal would allow licensees to intervene manually if or when needed to ensure compliance with their licenses and with Commission orders thereunder, most notably with respect to matters involving public safety.

We also recognize that responsibility for ensuring that supplies of Regulation service are reliable rests with the ISO and clarify that the ISO may find it necessary to disqualify some generators from bidding into this single market -- Regulation service -- if they cannot satisfy the ISO's reliability requirements.

Regarding intervenors' complaints about the proposal's costs, we do not view a supplier's unwillingness to incur the costs of installing equipment as a basis for granting exemptions; each supplier must determine for itself whether the costs outweigh the benefits of making Ancillary Services sales.

Conditions related to exemptions from RIGS are unique by nature and do not lend themselves to incorporation into a tariff. The ISO's proposal to post exemptions on its Web Home Page is a

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45/ See Eugene Water & Electric Board, 81 FERC ¶ 61,270 at 62,337 (1997) and the order cited thereat.

reasonable method to disseminate this information. We disagree with the intervenors that the performance standards for generators to qualify for Regulation service must be incorporated into the ISO's tariff. The performance standards simply set forth the supply characteristics that the ISO requires; there is no need to incorporate these requirements into the tariff.

8. Participation of Loads in the Ancillary Services Markets

The ISO's tariff permits customers to provide Ancillary Services by offering to reduce load (called dispatchable loads). The ISO states that it is developing a pro forma Participating Load Agreement.

SoCal Edison, Metropolitan, and the TANC believe that the ISO should file a pro forma agreement with the Commission before executing agreements.

The ISO states in its Answer that it is continuing the stakeholder process to develop the agreement, will circulate a draft agreement in the near future, and expects that the stakeholder process will encompass the merits of filing the resulting agreement on a pro forma basis before individual agreements are executed and filed. This satisfies the intervenors' concerns.

9. Status of Market Surveillance Committee

The ISO proposes to revise its tariff to state explicitly that the MSC is independent of the ISO. While no parties object to the description of MSC members as not being employees or agents of the ISO, several intervenors object to the restriction that "Members are not available to provide expert witness services to the ISO or any other party in a FERC proceeding relating to the ISO, except to the extent that the ISO MSC makes an advance determination that providing such service is not inconsistent with the independence of the ISO MSC." 46/

The ISO answers that the MSC's filing of a report with the Commission provides adequate opportunity for review. The ISO states that, as an independent party, the MSC is appropriately treated as a separate party for discovery purposes.

We agree that an element of the MSC's independence is the ability to determine when it will provide expert witness services to the ISO and other parties. We will accept the ISO's proposal.

46/ Amendment No. 14, Attachment N.

10. Proper Crediting of Ancillary Services Payments under RMR Contracts

Currently, the rates under some RMR contracts do not reflect revenue credits for sales made directly into the Ancillary Service markets. The ISO proposes to make billing adjustments to impute these revenue credits.

This revision was proposed before an Offer of Settlement was filed in Docket Nos. ER98-441-000, et al. (see above at p. 16). The Offer of Settlement proposes new RMR contract provisions that differ from those in existence when the ISO filed Amendment No. 14. We are accepting the Settlement in a separate order. The settlement resolves in part, and leaves for further hearing in part, payments and credits under the new RMR contract provisions. The issue of future credits under the former contracts is now moot, and the issue of credits under the new contracts is best addressed in Docket Nos. ER98-441-000, et al. Therefore we will dismiss this element of the proposal. As a result, we will reject ECI's motion to consolidate this proposal with the settlement proceedings as moot.

11. Purchase Price Cap

ISO Proposal. In the October 28, 1998 order, the Commission confirmed the ISO's authority to impose caps on Ancillary Service prices, but directed the ISO to set out the criteria through which it would exercise that authority in the future. Also, in our January 28, 1999 Order, we directed the ISO to explain and justify its long-term plans for its imbalance energy price cap. In response, the ISO states that it anticipates that the combination of several changes will make the Ancillary Service markets sufficiently competitive so that it may raise (and ultimately eliminate) existing price caps on Ancillary Services and imbalance energy. These changes include several of the proposals included in Amendment No. 14 -- namely, (1) the proposed RBP, (2) revised pricing for uninstructed deviations, (3) the use of Replacement Reserves to minimize out-of-market purchases, (4) automation of imbalance energy instructions, and (5) separate pricing of upward and downward Regulation, -- as well as implementation of Amendment No. 13, and elimination of perverse incentives in RMR contracts and the dispatch of RMR generation. Until these conditions are met, the ISO proposes that the current $250 price cap remain in place.

The ISO will periodically review progress in implementing these redesign elements to determine if markets are sufficiently competitive to lift the cap. Once the price caps are raised from their present levels, the ISO will implement a Market Design Safety Net policy that will subsequently guide its price cap authority. Under the Safety Net, the ISO will observe the performance of the Imbalance energy and Ancillary Service markets to identify price patterns indicative of market failure and supply conditions indicative of insufficiency. Where the ISO determines based on its observations that intervention is appropriate to prevent serious harm due to a major market failure, the ISO would announce the imposition of lower caps in one or more markets. In so doing, the ISO would report its observations, analysis and findings to the ISO's Governing Board.

Response of the MSC. The MSC recommends that price caps for imbalance energy and Ancillary Services be retained until the following measures have been fully implemented.

- The Rational Buyer Protocol. Although the present proposal is a step in the right direction, it does not fully implement the MSC's earlier recommendations, as it does not permit participants providing their own Ancillary Services to alter their quantities. As a result, subsidies are introduced into an already complex scheme.

- Ancillary Services Redesign proposed in the ISO's March 1, 1999 Filing. (In addition, the MSC strongly recommends that Ancillary Services be acquired through a statewide auction with RMR units making up any shortfall in specific zones. Although not a prerequisite to lifting price caps, the MSC believes that there should be a timetable for integrating the ISO's congestion management with its acquisition of Ancillary Services.)

- Full Reformation of the RMR Contracts. This would include (1) removal of reliability payment from "A" contracts and removal of credit-back from "B" contracts, (2) reversal of the bid/call sequence, and (3) requirement for RMR units to bid into the PX Day-Ahead market as must-run units.

Upon implementation of these measures, the MSC recommends lifting the cap in phases while making sure that no major market dysfunctions continue to exist. The MSC supports the ISO's safety net proposal.

Intervenor Comments. Although intervenors are divided over whether caps should or should not be lifted, many contend that the ISO has not complied with the Commission's directives. Specifically, intervenors do not believe that the ISO has proposed specific, objective criteria that give a sound basis for judging whether the cap can or should be lifted. Some note that even if Amendment No. 14 ultimately proves effective, lifting the cap now would be premature. They suggest that the ISO must first demonstrate that markets are workably competitive. Also, some intervenors favor having the MSC and MMC verify that proposed changes in Amendment No. 14 are sufficient and having the intended effect on market development. Other intervenors emphasize that the caps themselves are impediments to the development of a workably competitive market; these intervenors want the caps lifted immediately and they do not want a safety net that threatens the imposition of caps in the future without a very specific rationale for doing so.

Commission Response

We will allow the ISO to retain its authority to impose a purchase price cap for ancillary services and imbalance energy for now, but we will remove that authority as of November 15, 1999. After this summer's experience under its proposed market reforms, if the ISO believes that price caps continue to be necessary for an additional period of time, it may file at that time to continue them. In our October 1998 order in Redondo Beach, we directed the MSC and the MMC to file reports with us by October 15, 1999 evaluating the experience under implementation of the ISO's market reforms. The decision by the ISO whether to request additional authority to impose purchase price caps can be informed by the analyses in the MSC and MMC reports.

As we stated in our October 1998 order, the ISO's purchase price cap is not an ideal approach to operating a competitive market, and we do not expect it to remain in place on a long-term basis. Therefore, we directed the ISO in that order to file a comprehensive proposal to develop a structural solution to the market design flaws that have necessitated the purchase price cap. In response, the ISO has proposed market reforms in Amendment No. 13, which we accepted in February, 47/ and in Amendment No. 14, which we are accepting here. It is reasonable to obtain experience during the coming summer season under these reforms before removing the price caps. However, after the summer, we see no reason to leave the caps in place unless the ISO can demonstrate, based on the experience of the summer, that significant market design flaws remain.

We note that the ISO, as well as the MSC and the MMC, argue that purchase price caps should not be lifted until an additional reform, not included in Amendment Nos. 13 or 14, is also implemented. The additional reform would allow the ISO to require RMR units to bid into the PX day-ahead energy market as must-run units. RMR generation is currently dispatched only after the day-ahead schedule is finalized, even when the ISO concludes in advance that RMR generation will be needed. Since Scheduling Coordinators must submit balanced day-ahead schedules and these schedules do not reflect RMR generation that will ultimately be needed, the day-ahead schedule will at times include more generation than is needed to meet day-ahead demand. The MSC and MMC conclude that, as a result, the day-ahead energy

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47/ California Independent System Operator Corporation, 86 FERC ¶ 61,122, (1999).

price may at times be inefficiently inflated. Under the RMR settlement in Docket Nos. ER98-441 et al., which we are accepting in a separate order today, the ISO must continue this scheduling arrangement at least until October 1, 1999. However, on or after October 1, 1999 (and thus, before the expiration of the purchase price caps on November 15), the ISO may file with the Commission to allow it to require RMR units to bid into the PX day-ahead energy market as must-run units. Such a proposal could be implemented as early as December 1, 1999, if approved by the Commission.

Reliant argues that the day-ahead energy price has not been inflated under the existing scheduling arrangement, because purchasers have anticipated the excess day-ahead supply and shifted their demands to later markets such as the real-time market. As a result, Reliant concludes, removing the price caps need not be delayed until the ISO may schedule RMR generation as must-run in the day-ahead schedule. The MSC and MMC acknowledge that purchasers may tend to shift their demands away from the day-ahead market, but are skeptical that such shifts will necessarily eliminate the day-ahead price increases.

This is an issue that should be explored further. The MSC and MMC should include in their reports due on October 15, 1999 a further analysis of the effects of the RMR dispatch order on PX day-ahead energy prices, especially in light of experience under the reforms addressed in this order and in the recently-filed settlement of RMR issues. However, to minimize the possibility that the existing dispatch order may inflate PX day-ahead energy prices, we direct the ISO to announce in advance of each PX day-ahead auction the amount of RMR energy that it estimates will need to be committed after the day-ahead schedule is completed. Such an announcement will provide PX energy purchasers and other market participants with additional information to aid them in their decisions, including purchasers' decisions about whether to shift demand away from the day-ahead market.

12. Twenty-five Percent Import Quota

Amendment No. 14 does not discuss the ISO's practice of limiting imports of Spinning and Non-Spinning Reserves to 25 percent of total requirements, as described above in Bonneville's request for rehearing. Bonneville and a number of other parties (Joint Protesters) 48/ protest its omission, raising substantially the same arguments that are in the request for rehearing. In addition, the Joint Protesters point out that no

48/ The Joint Protesters include Bonneville, Enron, LADWP, PG&E Energy, PGE, Salt River, and Western. In addition, Modesto, SDG&E, and Sempra protest the ISO's import quota on similar grounds.

other proposals in Amendment No. 14 would add additional Ancillary Services supply, but lifting the cap on imports would.

If the Commission is not willing to direct the ISO to eliminate the cap, Joint Protesters propose an alternative interim procedure for the ISO to adopt. The interim procedure "would place limits on imports over particular ties for a particular trading hour taking into account for that hour the energy import over that intertie and the ISO's total operating reserve requirements." 49/ Specifically, the quantity of operating reserve imports for any hour over an intertie must be less than or equal to the control area reserve requirement minus imports over the same intertie. 50/ The Joint Protesters believe this could be implemented manually and assert that the procedures ensure the ISO would be able to meet NERC reliability criteria.

In response, the ISO argues that the import quota issue is beyond the scope of this proceeding and that the protests are substantively unfounded. It states that it is required to take the geographic dispersion of ancillary service capacity into account when procuring Ancillary Services, including the amount procured from outside its control area. 51/ The ISO contends that removing the import limits could require it to procure greater amounts of Ancillary Services to meet the requisite level of reliability.

Commission Response

We will not require the ISO at this time to alter its limit on the amount of Ancillary Services that it will acquire from external sources. The ISO states that the 25 percent limit on imports is needed, in its view, to meet its reliability requirements in a cost-effective manner. The ISO states that it is currently performing studies and evaluating alternatives for increasing imports of Operating Reserves from sources outside its control area. We encourage such assessments, since procuring additional supplies from outside the control area could expand supply options and reduce prices. As part of its assessment, we direct the ISO to consult with the WSCC regarding steps that could be taken to increase imports while maintaining reliability. And we direct the ISO to file a copy of its reports when they are completed.

49/ Joint Protest at 16.

50/ See id., Attachment A, pp. 1-2. Available Transmission Capacity limits over an intertie may be more restrictive.

51/ See also ISO Answer, Appendix B at 2 (describing six ways that increasing the import cap could have a negative impact on system reliability).

We will not require the ISO to file with us at this time the 25 percent limitation. We see no need to restrict the ISO's ability to adjust the level of imports as its reliability concerns are met.

Issues on Rehearing

The ISO argues that the Commission erred in the October 28, 1998 Order in finding that the ISO may not adjust bids down to the applicable cap level. The ISO asserts, first, that discussion in the July 17, 1998 Order support authority beyond automatic disqualification of above-cap bids. Specifically, the ISO cites language directing "'the ISO to provide advance notice to all market participants . . . of any adjustments in the price at which it will accept bids for these services'" and permitting the ISO to make "'necessary adjustments in the appropriate level that the ISO will accept, based on the recommendations of the market surveillance committee.'" 52/ Further, the ISO points to discussion in the June 30 and July 10 Orders in which "the Commission expressed concerns that automatic rejection of all bids above a specific price cap might limit the availability of Ancillary Services." 53/ Thus, the ISO asserts it acted reasonably in interpreting its price capping authority as broader than merely disqualifying above-cap bids.

The ISO also relies on its timely, unambiguous notification to market participants that above-cap bids would be reduced, contending that participants that knowingly submitted such bids "were improperly attempting to profit during this period of bid insufficiency, subverting the Commission's authorization to the ISO to limit the prices it paid for Ancillary Services." 54/ The ISO argues that if a market participant was not ready to accept the capped price, then it could have refrained from submitting any bid.

The ISO argues additionally that if it were unable to adjust above-cap bids downward, the purpose of our granting the price capping authority would be "substantially vitiated." 55/ It asserts that it was faced with two unacceptable alternatives: first, having insufficient resources to obtain the services needed to ensure reliability, and second, paying the suppliers in accordance with their bids, consequently failing to curtail their opportunity to exercise market power. The ISO believes that this

52/ Id. at 7, quoting the July 17, 1998 Order at 61,199.

53/ Id. at 8.

54/ Id. at 9.

55/ Id. at 14.

latter result would be contrary to our July 17, 1998 Order.

Arguing for the reasonableness of its actions, the ISO points out that the price cap was never any lower than the highest cost-based rate accepted by the Commission; thus, all suppliers were able to recover their legitimate costs. The ISO also contends that its practice was consistent with its tariff in that all successful bidders authorized to sell Ancillary Services at market-based rates received the market clearing price; by setting the market clearing price equal to the applicable price cap, the ISO ensured that every successful bidder received the applicable market clearing price.

The ISO surmises that market participants submitted above-cap bids in "misplaced reliance" on the Commission's order addressing the ISO's price capping authority for imbalance energy bids, proposed as part of Amendment No. 7. 56/ The ISO explains that its authority there is limited to rejecting or disqualifying automatically any bids submitted above the imbalance energy price cap, and that we later clarified that cap "should not 'prevent a unit that is actually called upon from receiving a price at least equal to its bid price . . . for any deliveries it actually makes.'" 57/ The ISO attempts to distinguish the two caps by pointing out that the July 17, 1998 Order contains no similar restrictions or caveats in the Ancillary Services price cap, and that the imbalance energy price cap was designed to address a shortcoming in the ISO's software, while the Ancillary Services cap is necessary to address a shortage of bids. Moreover, the ISO contends that adjusting bids to the price cap level did not comprise "unilateral authority to set rates or to reduce bids," 58/ because sellers had prior knowledge that bids exceeding the cap would be adjusted, and because it did not reduce the prices for the bids, but treated them as if they were bids at the applicable cap level.

The ISO supports its alternative motion for clarification that it treated above-cap bids properly by pointing out that it did not adjust every bid submitted above the cap level; it only "accepted above-cap bids (at the adjusted price level) when there were insufficient bids available at or below the cap level." 59/ The ISO again describes the dilemma it perceives existed: if it

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56/ See California Independent System Operator Corporation, 83 FERC ¶ 61,209 (1998).

57/ Id. at 61,923.

58/ ISO Request at 16, quoting the October 28, 1998 Order at 61,463.

59/ Id. at 18.

rejected all the above-cap bids, it may not have been able to maintain grid integrity, while if it paid the prices bid, energy consumers would not have been protected from the costs "in excess of the Commission-authorized and ISO established price cap." 60/

Finally, the ISO argues that it cannot re-run the procurement process for last summer. If all above-cap bids had been rejected, the ISO states it would likely have called on RMR resources to maintain system reliability, and "the many variables that would have affected this procurement process cannot accurately be recreated." 61/ Thus, the ISO asks that we find that last summer's procurement of Ancillary Services should not now be revisited. The ISO listed all of the above-cap bids that it accepted during July and August 1998 in Appendix A to its filing, listing for each transaction the date, bid price, price cap, number of MW, and the difference between the total payment as bid versus the actual payment under the price cap. Had these sellers received their full bids, they would have jointly earned nearly $26,800,000 more during July and August 1998. 62/

Houston Industries Power Generation, Inc. (HIPG) and El Segundo Power, LLC (El Segundo) and Long Beach Generation, LLC (Long Beach) filed answers to the ISO's request. El Segundo and Long Beach explain that market participants challenged the ISO's plan to "reform" market-based bids and notified the ISO of such disagreement; thus, when they submitted bids in excess of the established cap, they were not conceding to the ISO's interpretation of its authority. Thus, El Segundo and Long Beach argue that the ISO should pay the bid prices that were submitted. El Segundo and Long Beach also criticize the ISO for releasing bid information with its request for rehearing, stating that such information is confidential and that the release was a direct violation of the ISO's tariff.

HIPG argues that the ISO's scarcity argument is unconvincing because there was a third alternative: during periods of bid insufficiency, the ISO could establish the market clearing price at the cap level but still call on bids above the cap and pay the prices bid by those sellers. Thus, generators called on would receive the price authorized under their rate schedules. HIPG secondly asserts that by paying sellers less than they bid, the ISO effectively dictates a price to a seller unwilling to sell at the price announced by the ISO, thus unilaterally changing prices

60/ Id. at 20.

61/ Id. at 21.

62/ See Rehearing, Appendix A. The figure represents the sum of [MW Accepted * (Bid Price - Price Cap)] for each adjusted bid.

and practicing unlawful ratemaking. HIPG argues that "[p]roviding notice that one intends to violate the FPA does not cure or obviate a violation of the FPA." 63/

Also on November 27, 1998, the California Commission filed a request for clarification, or in the alternative, a request for rehearing on two discrete aspects of the October 28, 1998 order. First, the California Commission argues that we inappropriately relied on the retail rate freeze in permitting the IOUs to sell Ancillary Services at market-based rates. It explains that, although FERC recognized that PG&E has market power in Ancillary Services markets, we held there were sufficient "deterrents and safeguards in place to prevent" the exercise of that power. The California Commission cites five such deterrents and safeguards relied upon by FERC, one of which is the retail rate freeze. According to the California Commission, however, the retail rate freeze does not preclude a utility from recovering high Ancillary Services costs from its customers because these costs simply displace stranded cost recovery that would have been reflected in the rate and extend the stranded cost recovery period. The California Commission states that the IOUs may have an incentive to raise market prices in order to extend the rate freeze and delay entry of other competitors.

Second, the California Commission asks whether dicta in the order stating that generators have no obligation to participate in one market over any other affected "the IOUs' obligation to adhere to the buy-sell requirement previously approved by FERC." 64/ The California Commission submits that the buy-sell requirement generally requires the IOUs to purchase the requirements of their retail customers from the PX alone, although "[t]o the extent that there is residual capacity not accepted in the PX auction, or unanticipated load not bid into the PX, the IOUs may participate in other markets, such as the Ancillary Services markets and/or the imbalance energy market." 65/ Thus, the California Commission asks us to clarify that nothing in the October 28, 1998 Order obviates that requirement.

Lastly, the California Commission discusses appropriate monitoring and mitigation measures. The California Commission states that we have granted market-based rates for Ancillary Services to entities which have not applied for them and which we acknowledge have market power. While not seeking any particular action from this Commission, the California Commission asserts that "it is imperative that the mitigation and monitoring

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63/ HIPG at 8.

64/ California Commission Request at 4.

65/ Id. at 11.

measures upon which FERC relied in granting the Order be effective." 66/ It states that continued effective market monitoring and reporting by the ISO and PX monitoring committees is necessary and that it supports the reporting requirements contained in the October 28, 1998 Order. In closing, the California Commission requests that we "commit to ensure that monitoring and mitigation are effective to ensure that market-based rates in the Ancillary Services markets are just and reasonable." 67/

The three IOUs jointly answered the California Commission's filing. They counter that it would be "nonsensical to find that the IOUs are precluded from purchasing and selling ancillary services and imbalance energy simply because those pool markets were ultimately placed in the ISO rather than the PX," 68/ and assert that the buy/sell requirement is only intended to disallow bilateral transactions outside a central auction-based pool. They characterize the California Commission's interpretation as a "new proposal, never before suggested, to sequence the IOUs' use of the PX and ISO markets," 69/ and contend that such a requirement would distort the markets' proper functioning and would remove additional capacity from the Ancillary Service markets.

The IOUs also address the California Commission's assertion regarding the retail rate freeze, arguing that they have a strong incentive to keep market prices from rising artificially. They claim first, that it is very uncertain whether the rate freeze will end early, and second, that stranded cost recovery and a longer transition period would not create a barrier to entry in the retail direct access market, as the California Commission asserts. In addition, the IOUs request that this Commission clarify that the buy-sell requirement will end after 4 years, or full recovery of the Competition Transition Charge, whichever comes first, rather than after 5 years as the California Commission states in its request.

Bonneville also filed a request for rehearing on November 27, 1998, arguing that the Commission erred in not ordering the ISO to remove its cap on imports of Spinning and Non-spinning Reserves from outside California. Bonneville reasons that each time the cap is reached the market is deprived of competitors, and price formation in the auction is affected.

66/ Id. at 13.

67/ Id. at 15.

68/ Joint Response at 3.

69/ Id. at 4.

Bonneville asserts that the ISO does not explain why such a limitation is needed for reliability purposes nor do any published reliability criteria mandate one; further, the disparity in treatment between generation inside and outside the control area is unduly discriminatory. Bonneville concludes that we should order the ISO to eliminate the cap or, in the alternative, order the ISO to file any restriction on imports with us. SDG&E filed an answer in support of Bonneville's request.

We shall grant the ISO's request for clarification of our October 28, 1998 Order. The ISO does not contend that it can compel any supplier to provide it with Ancillary Services through the Ancillary Service markets, and this is consistent with our July 17, 1998 Order which simply authorized the ISO to reject any bid into those markets that exceeded the ISO's specified price. The confusion arises with respect to procedures used to implement the order. Under those procedures, the ISO announces its intention to reject any bids above its specified price and, if suppliers continue to bid at prices above the cap, the ISO treats those offers as made at the specified cap instead. For example, after the ISO announced that it would reject bids in excess of \$250/MWh, if a supplier bid \$1000/MWh, the ISO would adopt \$250/MWh as the actual bid price. If that supplier were chosen, the ISO would set the market clearing price at \$250/MWh and pay all suppliers this price. Under these procedures, a supplier would not offer its services unless it was willing to sell power at the maximum price specified by the ISO.

HIPG, El Segundo, and Long Beach argue that the ISO should have adopted a different procedure whereby suppliers were allowed to place bids inconsistent with the announced ceiling in the expectation that the ISO would not adhere to its ceiling and pay them a higher price if needed. They contend that this is consistent with the approach used when suppliers in the imbalance energy market are selected out of merit order. El Segundo and Long Beach state that the ISO should pay them the difference in their bid price and the ceiling price for those occasions when the ISO accepted their offers to supply but based their price on the specified maximum; 70/ they suggest that the ISO's position

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70/ They do not address the fact that, under the imbalance energy market approach, the prices paid to out of merit generators do not set the market clearing prices paid to all sellers, *i.e.*, given the earlier example, these parties would expect the supplier to be paid \$1000/MWh, but they do not suggest that the market clearing price paid to other sellers be reduced to reflect the highest bidder selected among those that bid at or below \$250/MWh.

is an attempt to avoid arbitration of the disputed amounts (about $26.8 million in total). 71/

We find that the ISO's procedures implement our order in an appropriate manner, i.e., suppliers are notified of the pricing rules in advance, including the maximum price that the ISO will pay for supply bid into the market, and may elect to place bids on that basis or place no bids at all. The fact that a different procedure was used when the ISO selected imbalance energy suppliers out of merit order (displacing a lower cost supplier that was available) is not dispositive. To the extent that suppliers were confused initially about the implementation procedures and placed bids above the ceiling in the expectation that the ISO would pay them more than the ceiling is no reason for suppliers to continue placing bids above the ceiling over an extended period. Apparently, a number of suppliers who were willing to sell at the specified maximum price nonetheless continued to place bids above the ceiling, well aware of the ISO's implementation rules, so as to protect their claim to higher payments should the Commission find the ISO's implementation procedures were not appropriate. Nonetheless, we are granting the ISO's request for clarification.

We will deny the California Commission's request for clarification and alternative request for rehearing. The California Commission does not seek to reverse our decision to give the IOUs market-based rates, but requests that we limit our reliance on the retail rate freeze as a factor constraining the exercise of market power. We remain convinced that the rate freeze is one (of several) factors that will help to mitigate the exercise of market power by PG&E and other IOUs. Because of the retail rate freeze, retail rates will not increase during the transition period. Since the IOUs are net buyers of ancillary services, attempting to raise ancillary service prices would increase their costs without increasing their revenues. However, while our October 28, 1998 Order relied on the retail rate freeze in part to justify releasing PG&E and the other IOUs from cost-based rates for Ancillary Services, it was not the sole basis for doing so. As the California Commission explained in its request, 72/ we also relied on the presence of six other suppliers, the existence of the purchase price cap, PG&E's need to buy substantial amounts of Ancillary Services and thus desiring a low cost as a customer, and the ISO's efforts to redesign the

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71/ The figure represents the sum of [MW Accepted * (Bid Price - Price Cap)] for each adjusted bid. See ISO's Rehearing, Appendix A.

72/ California Commission at 6-7.

Ancillary Services markets. 73/ Moreover, the California Commission itself noted another factor that should have a mitigating effect on market power, namely, divestiture by PG&E and SDG&E of their fossil-fuel generation, and the California Commission recognized that continued divestiture will also result in PG&E's being a net buyer of Ancillary Services in more circumstances.

We will also deny the California Commission's request concerning the IOUs' obligations under the buy-sell requirement. We agree with the IOUs' position that the requirement was intended to prohibit bilateral transactions. We see no benefit from excluding the IOUs from the ISO's auctions, and doing so would impede the addition of needed supply into the Ancillary Services markets. A key reason for the buy/sell requirement was to ensure adequate supply in the PX auction for its viability. Although participation by the IOUs in the ISO's Ancillary Services and imbalance energy markets would divert some supply from the PX, the relative quantity of power required in the ISO's markets generally is much smaller than that traded in the PX, small enough not to impact on the PX's viability. Thus, we agree with the IOUs that the purposes for which the requirement was approved are being met, i.e., ensuring a viable PX and the existence of transparent auction markets, and we conclude that the buy/sell requirement should not prevent the IOUs from participating in the Ancillary Services and imbalance energy markets.

This outcome promotes maximum competition in the largest number of markets. Any other result would undermine our October 28, 1998 Order. Permitting the IOUs to participate in the ISO's markets only to the extent envisioned by the California Commission may not contribute enough additional supply to alleviate the thin Ancillary Services markets.

Finally, we need not address Bonneville's request for rehearing regarding the ISO's 25 percent import quota, as that matter has been resolved above.

73/ In addition, we note that our order conditionally authorizing operation of the ISO and PX directed the IOUs to file a market power analysis 60 days prior to the end of the transition period assessing the need for continued mitigation. Pacific Gas and Electric Company, et al., 81 FERC ¶ 61,122 at 61,591 (1997). These analyses will need to discuss the Ancillary Services markets as well as the energy markets.

The Commission orders:

(A) The ISO is hereby directed to submit a compliance filing as discussed in the body of this order within 30 days of the date of this order.

(B) The ISO's proposed tariff changes, as modified pursuant to Ordering Paragraph (A), are hereby accepted for filing, without suspension or hearing.

(C) The ISO's proposal regarding proper crediting of Ancillary Services payments under RMR contracts is hereby rejected, as discussed in the body of this order.

(D) The late motion to intervene by Enron in Docket No. ER99-1971-000 is hereby granted.

(E) ECI's motion to consolidate is hereby rejected, as discussed in the body of this order.

(F) The ISO's request for clarification is hereby granted and all other requests for rehearing and/or clarification of the Commission's October 28, 1998 Order are hereby denied, as discussed in the body of this order.

(G) The ISO is hereby directed to file its report and the report of the MSC with the Commission, as discussed in the body of this order.

(H) The ISO is hereby informed that the rate schedule designations will be supplied in a future order.

(I) The March 1999 reports of the MMC and MSC are hereby accepted for filing.

By the Commission. Commissioner Massey concurred with a separate statement attached.

(S E A L)

David P. Boergers,
Secretary.

Appendix A

Intervening Parties in ER98-2843, et al.

  ** AES Alamitos, L.L.C.
  ** AES Huntington Beach, L.L.C.
  ** AES Redondo Beach, L.L.C.
* ** Bonneville Power Administration
* ** California Department of Water Resources
     California Electricity Oversight Board
     California Independent System Operator Corporation
* ** Cogeneration Association of California
*   Duke Energy Morro Bay LLC
*   Duke Energy Moss Landing LLC
*   Duke Energy Oakland LLC
* ** El Segundo Power, LLC
* ** Enron Power Marketing, Inc.
     Energy Producers and Users Coalition
  ** Houston Industries Power Generation, Inc.
* ** Imperial Irrigation District
* ** Long Beach Generation, LLC
     Metropolitan Water District of Southern California
* ** Northern California Power Agency
*   Pacific Gas and Electric Company
     Public Utilities Commission of the State of California
*   Public Service Resources Corporation
* ** Redondo Beach, City of 74/
* ** San Diego Gas & Electric
     Southern California Edison
*   Sacramento Municipal Utility District
* ** Turlock Irrigation District
  ** Williams Energy Services Company

*   Party did not intervene in ER98-3106-000

  ** Party did not intervene in ER98-3416-000, et al.

74/ Redondo Beach intervened only in Docket No. ER98-2843-000.

Appendix B

Intervening Parties in ER99-1971-000

Bonneville Power Administration
California Department of Water Resources
California Electricity Oversight Board
California Power Exchange Corporation
Cogeneration Association of California
Duke Energy Morro Bay LLC
Duke Energy Moss Landing LLC
Duke Energy Oakland LLC
Duke Energy South Bay LLC
Electric Clearinghouse, Inc.
Energy Producers and Users Coalition
Enron Power Marketing, Inc. *
Los Angeles Department of Water and Power
Member Systems of the New York Power Pool
Metropolitan Water District of Southern California
Modesto Irrigation District
M-S-R Public Power Agency
Northern California Power Agency
Pacific Gas and Electric Company
Portland General Electric Company
PSEG Resources, Inc.
Public Utilities Commission of the State of California
Redding, City of
Reliant Energy Power Generation, Inc.
Sacramento Municipal Utility District
Salt River Project Agricultural Improvement and Power District
San Diego Gas & Electric Company
Santa Clara, City of
Sempra Energy Trading Corp.
Southern California Edison Company
Southern Energy California, L.L.C.
Southern Energy Delta, L.L.C.
Southern Energy Potrero, L.L.C.
The Utility Reform Network
Transmission Agency of Northern California
Turlock Irrigation District
U.S. Generating Company
Utility Consumer Action Network
Western Area Power Administration
Williams Energy Marketing & Trading Company

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Appendix C

The Rational Buyer Protocol and Self-Provision of Ancillary Services

Under the ISO's Rational Buyer Protocol proposal, the MW obligation for each ancillary service would not be affected by any adjustments in the ancillary service procurement mix. The MSC and ECI recommend that an entity's obligation for each ancillary service, as a percentage of its load, should be the same as the ISO's procurement percentage after its adjustments under the Rational Buyer Protocol. For example, suppose that the ISO's initial requirement for regulation in an hour is 3 percent of the ISO's load, but the ISO's Rational Buyer Protocol results in purchasing regulation amounting to 5 percent of the ISO's load. In this example, the ISO would propose to establish a regulation obligation for each entity equal to 3 percent of load, while the MSC and ECI recommend that each entity's obligation should be 5 percent of its load.

Under the ISO's proposal, the price charged by the ISO to loads for a given ancillary service would be different from the market price paid to sellers. This result can be seen from the example provided by the ISO illustrating its proposal in Attachment C of its filing, 1/ which is reproduced in part in the table below. In that example, the price paid to sellers for each ancillary service (after adjusting its procurement based on the Rational Buyer Protocol) would be $20/MWh. However, the price charged to load per MW of the load's obligation would differ from $20 for each ancillary service. For example, the price charged to load for Replacement Reserves would be $42.85, which is more than double the market price for Replacement Reserves. (The price charged to load for Replacement Reserves would exceed the price paid to sellers because the costs of procuring additional Regulation under the RBP would be allocated to, and recovered from, Replacement Reserve purchasers.) Entities could avoid the $42.85/MW charge by self-providing Replacement Reserves, and would have an incentive to do so if it could locate Replacement Reserve capacity at any cost lower than $42.85/MW. However, it would be inefficient for an entity to self-provide Replacement Reserves costing up to $42.85 when the ISO can procure Replacement Reserves for the lower cost of $20.

Under the MSC and ECI recommendation, the price charged to load would be the same as the price paid to sellers of ancillary services. That is because the full amounts paid to procure a given service would be allocated to that service.

1/ ISO filing of Amendment No. 14, vol 1, Attachment C, Tables 1 and 2.